ORIGINAL

IN THE SUPREME COURT OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Administration of the Significantly Excessive Earnings Test under Section 4928.143(F), Revised Code, and Rule 4901:1-35-10, Ohio Administrative Code	:	**Case No. 2011-0751** **Appeal from the Public Utilities Commission of Ohio Case No. 10-1261-EL-UNC**

MERIT BRIEF OF APPELLEE/CROSS-APPELLANT COLUMBUS SOUTHERN POWER COMPANY

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STATEMENT OF THE CASE

For the three-year period commencing January 1, 2009, Columbus Southern Power ("CSP") is meeting its statutory obligation, under R.C. 4928.141, to provide a standard service offer for all competitive retail electric service, including a firm supply of generation service, to all consumers in its certified territory through an electric security plan ("ESP"), authorized by R.C. 4928.143. As an electric distribution utility ("EDU") providing service under an ESP with a term of three years or less, CSP became subject to the significantly excess earnings test ("SEET") set forth in R.C. 4928.143(F). The purpose of the proceeding below was to apply the SEET to CSP for calendar year 2009.

R.C. 4928.143(F) provides:

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

The meaning of the SEET has confounded the Commission, the EDUs and the customer advocates since its enactment. CSP first attempted to get guidance as to how the SEET would be administered as part of its initial ESP case. *In re Columbus Southern Power and Ohio Power Company*, PUCO Case No. 08-917-EL-SSO (the "ESP Case"). Not surprisingly, the intervening parties in that case had widely divergent views as to what the SEET meant and how it should be administered. As a result, the Commission determined that it would defer the issue and conduct a stakeholders' workshop to develop "a common methodology for the excessive earnings test that should be adopted for all of the electric utilities." *Id.* Opinion and Order (March 18, 2009) at 68. (IEU Appx. at 157.)[1]

The SEET workshop was held on October 5, 2009. After the workshop, the Commission's Staff issued a set of eleven recommendations concerning the meaning of the SEET and how it should be administered. Interested parties were given an opportunity to file written comments and to address the Commission in a question-and-answer session held on April 1, 2010. *In the Matter of the Investigation into the Development of the Significantly Excessive Earnings Test Pursuant to Amended Substitute S.B. 221 for Electric Utilities*, PUCO Case No. 09-786-EL-UNC, Finding and Order (June 30, 2010) ("*SEET Investigation Order*") (Appx. at 001-5.) The EDUs and the customer parties again had very divergent and conflicting views on what the SEET meant and how it should be administered. Notably, Appellant Industrial Energy Users-Ohio ("IEU") did not participate in the SEET investigation proceeding and, as a result, did not share any of its ideas regarding how the statute should be interpreted or how the SEET should be administered. *Id.* at 3. (Appx. at 003.) Because of the complexity of the issues and the

[1] As directed by S.Ct. Prac. R. 6.3(B) and & 7.1(C), CSP has not duplicated in its appendix documents already included in the appendices or supplements filed by other parties to this appeal. CSP cites the appendix and supplement of Industrial Energy Users-Ohio as "IEU Appx." or "IEU Supp."

many different interpretations of the statute and how it should be applied, the Commission determined that most of the eleven issues vetted in the workshop could not be answered on a common basis for all of the State's EDUs and, therefore, would be deferred for determination on a case-by-case basis only after the EDUs made their first annual SEET filings, as required by Ohio Admin. Code § 4901:1-35-03(C)(10).

The CSP SEET proceeding commenced on September 1, 2010. (Dkt. 1: Application.) Notwithstanding the prior discussions of the SEET in CSP's 2008 ESP case and in the generic investigation case, there still was no common understanding of what the SEET meant or how it would be administered. As evident from the briefs and applications for rehearing filed in the proceeding below, virtually all aspects of the SEET analysis were up for grabs. IEU took the position that the Commission, CSP, and the other intervenors *all* misunderstood the fundamentals of the SEET. It argued that because the Commission did not require CSP to isolate the revenue, expenses and earnings related to the adjustments authorized in CSP's ESP, and determine an earned return on common equity limited to only CSP's ESP adjustments standing alone, the proceeding was a nullity and the Commission should start all over. (Dkt. 35: IEU Brief (11/19/2010) at 28.) The Office of the Consumers' Counsel ("OCC") and the Ohio Energy Group ("OEG") disputed CSP's position and the Staff's position on so many issues they ultimately concluded that CSP should refund $155.9 million – the entire increase in rates for 2009 authorized by the Commission's approval of CSP's 2008 ESP application. (Dkt. 33: OCC/ OEG Brief (11/19/2011) at 59.)

IEU maintains its position in this appeal. It continues to argue that the Commission so fundamentally misread R.C. 4928.143(F) that the Court should order a complete do-over of the entire case. On appeal, OCC and OEG temper their prior position and argue, as their sole

proposition of law, that the Commission erred in excluding the revenue CSP derived from its off-system sales from the calculation of its earned return on equity. In accordance with S.Ct. Prac. R. 6.5(C)(1)(b), CSP responds to both these arguments in its Propositions of Law 1 – 3. CSP also cross-appeals, asserting in Proposition of Law 4, as it did below, that R.C. 4928.143(F) is unconstitutionally vague, as evident from the Commission's various unsuccessful attempts to divine its meaning.

LAW AND ARGUMENT

COLUMBUS SOUTHERN POWER'S RESPONSES TO APPELLANTS' PROPOSITIONS OF LAW

Proposition of Law No. 1

IN ADMINISTERING THE SEET, THE COMMISSION MUST EXCLUDE MARGINS ON OFF-SYSTEM SALES FROM THE DETERMINATION OF AN ELECTRIC DISTRIBUTION UTILITY'S RETURN ON COMMON EQUITY BECAUSE OFF-SYSTEM SALES ARE NOT INCLUDED IN THE ELECTRIC SECURITY PLAN AUTHORIZED BY R.C. 4928.143 AND ARE WHOLESALE SALES NOT SUBJECT TO THE COMMISSION'S JURISDICTION.

The Commission's decision that revenue derived from off-system sales should be excluded from the determination of an EDU's return on common equity for the purpose of the SEET fully comports with R.C. 4928.143(F) because the statute specifically provides that only earnings resulting from adjustments included in the EDU's ESP are subject to refund under the SEET. The exclusion of off-system sales margins from the SEET calculation also is required to maintain the well-established distinction between wholesale sales, which are subject to the exclusive jurisdiction of the Federal Energy Regulatory Commission ("FERC"), and retail sales which may be regulated by the States.

A. R.C. 4928.143(F) requires a determination of whether adjustments made in an EDU's ESP have resulted in significantly excess earnings.

Appellants' argument that the statute "requires the PUCO to compare *all* of a utility's earnings to *all* of the earnings of companies with comparable risk" (OEG/OCC Merit Br. at 8) is based on a misreading of the statute. The inquiry under R.C. 4928.143(F) is "with regard to the provisions that are included in an electric security plan" and asks whether "adjustments" made in the ESP resulted in significantly excessive earnings. As OEG and OCC concede, "[o]ff system sales are wholesale sales by a utility to third parties that are not Ohio retail customers." (OEG/OCC Merit Br. at 5.) Because they are wholesale sales, they are not – indeed they cannot be – provided for in an ESP or be the result of rate adjustments included within an ESP. An ESP is one of two methods by which an EDU can satisfy its obligation under R.C. 4928.141 to "provide consumers . . . within its certified territory, a standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service." As this Court held *In re Application of Columbus S. Power Co.,* 128 Ohio St.3d 512, 520, 2011-Ohio-1788, 947 N.E.2d 655, at ¶ 32, R.C. 4928.143(B) enumerates – and limits – the provisions that may be included in an ESP. Off-system sales to third party wholesale customers are not included in the enumeration of provisions properly included in an ESP. And indeed, there is no provision or adjustment in CSP's 2008 ESP for off-system sales. *In re Columbus S. Power Co. and Ohio Power Co.*, PUCO Case No. 08-917-EL-SSO, Opinion and Order (March 18, 2009) ("*ESP Order*") at 17 ("[W]e do not believe that OSS should be a component of the Companies' ESP, or factored into our decision in this proceeding.") (IEU Appx. at 106.)

For the same reason, OEG and OCC err in arguing that the SEET is similar to the traditional "comparable earnings" standard (Merit Br. at 7.) The SEET is a *sui generis* construct

enacted by the General Assembly in S.B. 221. The world of electric generation service is very different now than it was in 1923 when the United States Supreme Court decided *Bluefield Water Works v. Pub. Serv. Comm. of West Virginia* (1923), 262 U.S. 679, 43 S.Ct. 675, 67 L.Ed. 1176. Concepts like "competitive retail electric service", "EDUs", "ESPs", and "SEET" were unknown then and have existed in Ohio for only a short time. In administering the SEET, the Commission was governed by R.C. 4928.143(F), and not the past. If the General Assembly intended to claw back from the EDUs allegedly "excess" earnings from *all* sources, including earnings from wholesale off-system sales, then it would not have limited the SEET provision to earnings arising from "adjustments" within an ESP.

OEG/OCC argue that off-system sales should be included in CSP's earnings because such sales are possible only because the cost of the generation assets used to make such sales are recovered from Ohio ratepayers. (Merit Br. at 10.) This is a frequent "go-to" argument for intervenors, but it is always wrong. Customers pay rates for retail service, not for the assets that produce those services, let alone assets that produce wholesale services. Consequently, they have no entitlement to share in margins produced by off-system sales. *In re Ohio Power Co.*, PUCO Case No. 93-101-EL-EFC, Opinion and Order (May 25, 1994) at 17. (Appx. at 034.)

B. The SEET statute cannot be interpreted or applied to encompass the claw back of off-system sales margins, as doing so would violate the Federal Power Act and the Supremacy Clause.

Off-system sales margins result from wholesale – not retail – transactions, the rates for which are regulated exclusively by the FERC. Ordering earnings that result from FERC jurisdictional wholesale sales to be returned to retail customers clearly would be unlawful. It also would be unlawful to include earnings resulting from wholesale sales in the SEET to justify refunds to retail customers. Under well-settled federal constitutional law, the State is preempted

from interfering with an electric utility's ability to realize revenue rightfully received from wholesale power sales pursuant to contracts or rates approved by the FERC. *Pacific Gas & Electric v. Energy Resources Comm.* (1983), 461 U.S. 190, 103 S.Ct. 1713, 75 L.Ed.2d 752; *Nantahala Power & Light Co. v. Thornburg* (1986), 476 U.S. 953, 106 S.Ct. 2349, 90 L.Ed.2d 943; *Mississippi Power & Light Co. v. Mississippi* (1988), 487 U.S. 354, 108 S.Ct. 2428, 101 L.Ed. 322.

While the typical federal preemption case under the Federal Power Act, 16 U.S.C. §§ 791-828c, and the Supremacy Clause arises in the context of the filed rate doctrine and states' attempts to disallow the recovery of the costs of FERC-approved wholesale power sales in retail rates, the preemptive effect of FERC's exclusive jurisdiction over wholesale power sales is broader than just that one application. Because FERC as a matter of federal law completely occupies the field of wholesale power sales, "the test of pre-emption is whether 'the matter on which the State asserts the right to act is in any way regulated by the Federal Act.'" *PG&E v. Energy Resources Comm.*, 461 U.S. at 213. Cf. *Northern Natural Gas Co. v. State Corp. Comm.* (1963), 372 U.S. 84, 90-91, 83 S.Ct. 646, 9 L.Ed.2d 601 (rejecting state's argument that its orders were not preempted because they did not actually invade the regulatory jurisdiction of the Federal Power Commission because the orders did not involve the price of gas).

Just as the State may not trap FERC-approved wholesale power costs, it may not in effect capture or siphon the revenue the utilities receive from FERC-approved wholesale sales for the purpose of reducing the retail rates paid by Ohio customers. A state determination that wholesale sales result in excessive earnings is no different than a state determination that wholesale rates are unreasonable. And, diverting wholesale power revenue to retail customers after-the-fact has the same practical effect as disallowing wholesale power costs in the first

instance. Both actions would interfere equally with FERC's exclusive right to regulate the wholesale power market – earnings as well as rates.

Moreover, even if the Commission stops short of actually seizing wholesale earnings and putting them in the pool of earnings to be refunded to customers, it's assertion of jurisdiction over earnings from wholesale sales still is unlawful. Including earnings from wholesale power sales at any stage of the SEET calculation invades the exclusive authority of the FERC, albeit it may be a lesser included offense. FERC has "exclusive authority to regulate the transmission and sale at wholesale of electric energy in interstate commerce." *New England Power Co. v. New Hampshire* (1982), 455 U.S. 331, 340, 102 S.Ct. 1096, 71 L.Ed.2d 188. There is a "bright line" between wholesale regulation and retail regulation. *Mississippi Power & Light Co.*, 487 U.S. at 374, which means that the State may not reach across that line and use wholesale earnings to justify retail refunds. To do so, in effect, penalizes or disadvantages a utility for achieving earnings that were lawfully achieved as a matter of federal law.

The theory that the Commission must include wholesale earnings in calculating the rate of return in order to have an "apples-to-apples" comparison with the publicly traded companies used as the benchmark in the SEET analysis (OEG/OCC Br. at 10) is no defense to its conduct. The theory ignores the fact that the Commission has jurisdiction only over retail sales. For purposes of the SEET, the only relevant earnings – and the only earnings that may properly be at issue – are those derived from sales within the Commission's jurisdiction. Considering only the jurisdictional earnings in comparing the EDU's earned return to the comparable group is appropriate given that the *raison d'etre* of the SEET statute is to determine whether the rate adjustments of the ESP have resulted in significantly excessive earnings. Moreover, any "apples-to-apples" comparison is achieved through the establishment of the appropriate

comparable group and measuring the mean return of that group to establish the rate-of-return threshold against which the EDU's return on equity, as properly determined consistent with the applicable law limiting the Commission's jurisdiction to retail sales, will be measured.

Thus, OEG/OCC's argument that the Commission should have included off-system sales in CSP's earnings directly conflicts with the Federal Power Act and Congress' power under the Supremacy Clause. Moreover, because the State's obvious purpose in enacting the SEET is to protect state consumers from retail rate increases, an overly-broad order would be the type of economic protectionism legislation that would violate the federal Commerce Clause. *New England Power Co. v. New Hampshire* (1982), 455 U.S. 331; *Middle South Energy v. Arkansas Pub. Serv. Comm.* (C.A.8, 1985), 772 F.2d 404, 416 ("[W]here simple economic protectionism is effected by state legislation, a virtual per se rule of invalidity has been erected."). The Commission was correct in refusing to interpret the SEET as encompassing earnings related to FERC-jurisdictional transactions. Indeed, it was a conclusion the law compelled it to reach.

Proposition of Law No. 2

> **R.C. 4928.143(F) REQUIRES THE COMMISSION TO DETERMINE IF ADJUSTMENTS IN AN ELECTRIC DISTRIBUTION UTILITY'S ELECTRIC SECURITY PLAN RESULTED IN EXCESSIVE EARNINGS AS MEASURED BY A COMPARISON BETWEEN THE ELECTRIC DISTRIBUTION UTILITY'S EARNED RETURN ON COMMON EQUITY AND THAT EARNED BY PUBLICLY TRADED COMPANIES FACING COMPARABLE RISKS. THE STATUTE DOES NOT REQUIRE THE COMMISSION TO ISOLATE A RETURN ON COMMON EQUITY FOR ONLY THAT PORTION OF THE UTILITY'S EARNINGS THAT ARE DERIVED SOLELY FROM ADJUSTMENTS IN THE UTILITY'S ELECTRIC SECURITY PLAN.**

The Commission properly rejected IEU's argument that CSP was required to develop and present an earned return on equity for only that portion of CSP's business covered by its ESP. As the Commission noted, "[n]owhere in Section 4928.143(F), Revised Code, is a

comprehensive jurisdictional allocation study required in order to determine an earned ROE appropriate for use in the SEET." (Dkt. 56: Opinion and Order at 13.) (IEU Appx. at 46.)

In its initial SEET application, CSP complied with the Commission's rule, Ohio Admin. Code § 4901:1-35-03(C)(10)(a), which required it to provide "testimony and analysis demonstrating the return on equity that was earned during the year," "[t]he federal energy regulatory commission form 1 (FERC form 1) in its entirety for the annual period under review," and "the latest securities and exchange commission form 10-K in its entirety." As required by R.C. 4928.143(F) and the administrative rule, the information provided was for CSP (and separately for Ohio Power Company); the information permitted the Commission to conduct the SEET analysis for CSP without considering "the revenue, expenses or earnings of any affiliate or parent company." (Dkt. 1: CSP Application.) CSP also complied with the Commission's *SEET Investigation Order* by including in its submission the effect of including and excluding off-system sales in the SEET calculation. *SEET Investigation Order* at 9. (Appx. at 009.) (Dkt. 2: Hamrock Direct Testimony at 6-7.) (IEU Supp. at 21-22.) CSP's submission fully complied with the statute, the rule, and the Commission's order issued at the conclusion of the stakeholders' workshop.

It is very telling for purposes of the credibility of its position in the proceedings below and on appeal that IEU never raised its interpretation of the statute until the first day of hearing in the proceedings below. IEU did not actively participate in the Commission's and other stakeholders' efforts to decipher the SEET during CSP's 2008 ESP case. *ESP Order* at 65-69. (IEU Appx. at 154-158.) Instead it argued that the parties were wasting their time in that proceeding debating the competing methodologies for administering the SEET. (Dkt. 38: CPS Reply Br. at 5.) Not wishing to put its cards on the table in the ESP Case, IEU urged the

Commission to defer addressing the SEET by convening the proposed workshop. (Id.) When the time for the workshop rolled around, however, IEU sat silently on the sidelines, not filing any comments or participating in the discussion. *SEET Investigation Order* at 3. (Appx. at 003.) IEU likewise elected not to file any testimony in the proceeding below. Instead it unveiled its unique interpretation of what R.C. 4928.143(F) requires for the first time by oral motion on the first day of hearing. (Tr. v. I at 18-27.)

IEU's criticism of using CSP's earned return on equity in the SEET analysis, rather than modeling an ESP-specific return on equity, is unfounded. R.C. 4928.143(F) states that the SEET is to determine whether the adjustments in the ESP resulted in excessive earnings "as measured by whether the earned return on common equity *of the electric distribution utility* is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies." (Emphasis added.) The statute does not state or imply that the SEET calculation should include a determination of the earned return on equity for some other entity created to reflect only that portion of the EDU's business governed by the ESP. The statute cannot be re-written to conform to IEU's desired interpretation and outcome. *Lorain County Auditor v. Ohio Unemployment Comp.*, 113 Ohio St.3d 124, 129, 2007-Ohio-1247, 863 N.E.2d 133 at ¶ 24.

IEU relies on the fact that "electric distribution utility" is a statutorily-defined term to argue that R.C. 4928.143(F) must be read to require a completely remodeled entity, relying on some type of jurisdictional cost and revenue allocation study that somehow calculates a return on equity for only that portion of the EDU's business governed by the ESP – an "ESP-specific" return on equity. (Merit Br. at 7.) The definition of "electric distribution utility," however, clearly recognizes that an EDU may have multiple lines of business. R.C. 4928.01(A)(6) & (11).

R.C. 4928.143 also recognizes that an EDU may have multiple lines of business, including retail electric service, distribution service, and transmission service. See e.g. R.C. 4928.143(B)(1), B(2)(g) & (h). The General Assembly knew that an EDU could incur costs and derive revenue and earnings from activities and services outside of those tied to the rate adjustments in the ESP. Accordingly, had the General Assembly intended to limit the SEET analysis to a return on equity for some truncated or completely remodeled version of an EDU, it surely would have used apt wording to express that intent. *Id.* It did not.

While OEG/OCC argue the Commission erred in making an adjustment to exclude off-system sales margins from CSP's earnings, IEU argues that the Commission erred in not making more adjustments, *i.e.* all the adjustments that would have been necessary to remodel CSP from a fully functioning EDU into a ESP-only parody of itself. Neither position has merit. As discussed above, the exclusion of off-system sales was necessary to comply with both R.C. 4928.143(F) (which only permits the claw back of earnings resulting from ESP adjustments) and with federal law (which prevents the states from regulating wholesale sales of power). It was legally necessary and appropriate for the Commission to exclude earnings from off-systems sales, because the record was clear that the inclusion of off-system sales would overstate CSP's return on common equity and result in impermissibly clawing back wholesale earnings for refunds to retail customers. There was no similar showing with respect to any other earnings outside the scope of the ESP adjustments. IEU never identified the effect of including or excluding in the SEET calculation any of the non-ESP earnings about which it complains. CSP acknowledged that there were other non-jurisdictional activities that it could have excluded from the SEET calculation, but explained that, unlike the margins for off-system sales, these other non-jurisdictional activities were cost-based and/or had little or no profit impact in 2009. While

IEU argues that the Commission's administration of the SEET without requiring CSP to reform itself into an ESP-only entity "helped [Ohio Power] and CSP hide the actual profitability of their Ohio retail business via the ESPs" (Merit Br. at 30), there is no record support for that conclusion. Quite to the contrary, the record shows that it is more likely that the failure to make all the non-jurisdictional adjustments CSP could have made *overstated* – not understated – its earned return on equity. (Dkt. 32: CSP Initial Hearing Br. at 53 (citing record).) (Dkt. 56: Opinion and Order at 22 (noting CSP waived its "right" to "further jurisdictionalize its 2009 earnings".) (IEU Appx. at 55.)

Proposition of Law No. 3

R.C. 4928.143(F) DOES NOT PERMIT THE COMMISSION TO CLAW BACK A UTILITY'S EARNINGS MERELY BECAUSE THE UTILITY'S EARNED RETURN ON COMMON EQUITY IS HIGHER THAN THAT OF OTHER UTILITIES.

Appellants include in their briefs various references to CSP's 2009 return on equity compared to that of other investor-owned, regulated electric utilities. (OEG/OCC Merit Br. at 5 & 9; IEU Merit Br. at 16-18.) Such comparisons are legally irrelevant. R.C. 4928.143(F) does not purport to limit Ohio EDUs' earned return on equity relative to other investor-owned utilities. Rather, it requires the Commission to evaluate whether an Ohio EDU's earned return on equity is significantly excessive in comparison to that earned by "other publicly traded companies, including utilities, that face comparable business and financial risk."

The Commission expressly rejected OEG/OCC's use of "an electric only proxy group" as the comparable group for purposes of administering the SEET, finding that it "predetermines, to some extent, the characteristics of the comparable group without any direct relationship to the electric utility." (Dkt. 56: Opinion and Order at 21.) (IEU Appx. at 54.) OEG/OCC did not ask for reconsideration on this issue and it is not properly raised on appeal. R.C. 4903.10; R.C.

4903.11; *Communications Workers v. Pub. Util. Comm.* (1979), 57 Ohio St.2d 76, 387 N.E.2d 230. The Commission concluded that it concurred with CSP Witness Hamrock's testimony regarding the various and unique business and financial risks CSP faced – risks not necessarily faced, or faced to the same degree, by other regulated utilities in Ohio or other states. (Dkt. 56: Opinion and Order at 25.) (IEU Appx. at 58.) Mr. Hamrock testified:

> Ohio electric utilities such as CSP and OPCo that own generation assets bear additional risks as compared to utilities that do not own generation assets. The generation-owning utilities in Ohio are no longer guaranteed recovery of their substantial capital-intensive assets. Rather, under SB 221, the competitive nature of generation 12 service created a shopping and customer migration risk. Given the "hybrid" nature of SB 221, this risk goes beyond the risk presented in other retail choice states.

(Dkt. 2: Hamrock Testimony at 19.) The Commission found:

> In addition to initial capital outlays that CSP must make in order to fund its obligations under the ESP and its provision of service in general, there are other risks, not clearly associated with a rider, of which the Commission must remain mindful. For example, the Commission concurs with CSP that electric utilities are not assured recovery of their generation assets due to the change in the regulatory environment; the prospect of future industry restructuring and carbon regulation is unknown; and market prices for generation-related services are volatile. Lastly, the Commission gives consideration to the challenge of fulfilling the various mandates of SB 221, within the context of a rapidly changing electric market.

(Dkt. 56: Opinion and Order at 26.) (IEU Appx. at 59.)

The fact that CSP's 2009 return on equity was numerically higher than that of other utilities is irrelevant to any issue before the Court. It is not a consideration for purposes of applying R.C. 4928.143(F). The sole reason Appellants highlight this fact is to goad the Court into second-guessing the Commission and further penalizing CSP, even though there is ample, uncontroverted evidence that the current regulatory structure in Ohio exposes CSP to risks not borne in like measure by other regulated utilities.

COLUMBUS SOUTHERN POWER'S CROSS-APPEAL

Proposition of Law No. 4

R. C. 4928.143(F) IS VOID AND UNENFORCEABLE BECAUSE IT IS IMPERMISSIBLY VAGUE AND FAILS TO PROVIDE ELECTRIC DISTRIBUTION UTILITIES WITH FAIR NOTICE, OR THE COMMISSION WITH MEANINGFUL STANDARDS, AS TO WHAT IS MEANT BY "SIGNIFICANTLY EXCESSIVE EARNINGS."

In the prior propositions of law, CSP explains why the Commission did not err in excluding off-system sales margins from its calculation of the SEET or in using CSP's earned return on equity in conducting its analysis. The fact the Commission's order is appropriate in these two narrow respects, however, does not change the fact that the statute taken as whole is unconstitutionally vague. The Commission got it right in excluding off-system sales because there is an established body of law that holds that a state commission cannot regulate the wholesale sale of power; that body of law guided, if not compelled, the Commission to the correct conclusion. Likewise, the fact that there is clarity as to what was meant when the General Assembly referred to measuring the earned return on common equity of the "electric distribution utility," rather than some subset of the EDU's business, does not establish clarity as to any other terms in the statute or the statute taken as whole. In this proposition of law, CSP explains why the statute taken as whole violates due process by failing to give the EDU fair notice of what the law requires or to give the Commission sufficient guidance as to how it is to be enforced.

A. The void-for-vagueness doctrine.

The Due Process Clauses of the Fifth and Fourteenth Amendment give rise to the void-for-vagueness doctrine. The doctrine has two primary goals. The first goal is to ensure "fair notice" to the subject of the law as to what the law requires; the second is to provide standards to

guide the discretion of those charged with enforcing the law. *Columbia Natural Resources, Inc. v. Tatum* (C.A.6, 1995), 58 F.3d 1101, 1104. The Supreme Court has defined the first goal with greater specificity by holding that "[a] statute which either forbids or requires the doing of an act in terms so vague that men of common intelligence must necessarily guess as to its meaning and differ as to its application, violates the first essential of due process of law." *Id.* at 1105 (citing *Connally v. General Constr. Co.* (1926), 269 U.S. 385, 391, 46 S.Ct. 126, 70 L.Ed. 322). The second goal "relates to notice to those who must enforce the law . . . . [t]he standards of enforcement must be precise enough to avoid 'involving so many factors of varying effect that neither the person to decide in advance nor the jury after the fact can safely and certainly judge the result.'" *Id.* (citing *Cline v. Frink Dairy Co.* (1927), 274 U.S. 445, 465, 47 S.Ct. 681, 71 L.Ed. 1146).

Although the vagueness doctrine arises most often in the context of criminal laws that implicate First Amendment values, "vague laws in any area suffer a constitutional infirmity." *Ashton v. Kentucky* (1966), 384 U.S. 195, 200, 86 S.Ct. 1407, 16 L.Ed.2d 469 (collecting cases at n. 1). See also, *Cline*, 274 U.S. at 463 ("The principle of due process of law requiring reasonable certainty of description in fixing a standard for exacting obedience from a person in advance has application as well in civil as in criminal legislation."). Laws that impose criminal penalties or sanctions or reach a substantial amount of constitutionally protected conduct, however, must satisfy a "higher level of definiteness." *Belle Maer Harbor v. Charter Twp. of Harrison* (C.A.6, 1999), 170 F.3d 553, 557.

Belle Maer Harbor, for example, involved a township ordinance that regulated the use of mechanical agitators ("bubblers") to clear the surrounding waterway of ice. A marina operator challenged the ordinance on vagueness grounds because it empowered enforcement officials to

determine whether the area of open water created by the agitator was within a "reasonable radius" around the protected object. The lower court upheld the ordinance. The Sixth Circuit disagreed, finding it unconstitutional. The appellate court applied a heightened scrutiny standard – requiring a "high level of definiteness" – because violation of the ordinance carried criminal penalties:

> This court does not disagree with the Township that many ordinances, statutes and other enactments have "gray areas" requiring the use of an officer's discretionary judgment in their enforcement. However, due process requires at least sufficient exactness to prevent arbitrary enforcement and give notice of what an individual must do to comply with the enactment. . . . Under the present scheme, neither the enforcement officer nor the bubbler operator can ascertain by examining the language of the Ordinance alone whether criminal sanctions will result from one foot or ten feet of open water created by a bubbler around a protected object. This level of imprecision cannot withstand a due process challenge on vagueness grounds.

Id. at 559. See also *Connally*, *supra*, 269 U.S. at 393-95 (holding state statute requiring state contractors to pay the "current rate of per diem wages in the locality" void for vagueness); *Cline*, *supra*, 274 U.S. at 465 (state anti-trust statute held void for vagueness).

This Court re-affirmed and clarified the void-for-vagueness doctrine in *Norwood v. Horney*, 110 Ohio St.3d 353, 2006-Ohio-3799, 853 N.E.2d 1115. The Court struck down a municipal ordinance that allowed private property in a "deteriorating area" to be taken by eminent domain, even though the municipal code set forth "a fairly comprehensive array of conditions that purport to describe a 'deteriorating area.'" *Id.* at ¶ 93. The Court applied the heightened scrutiny standard even though the statute carried no penalties or sanctions because the eminent domain power "necessarily entails the state's intrusion onto the individual's right to garner, possess and preserve property." *Id.* at ¶ 88. The Court held:

> In the cases before us, we cannot say that the appellants had fair notice of what conditions constitute a deteriorating area, even in light of the

> evidence adduced against them at trial. The evidence is a morass of conflicting opinions on the condition of the neighborhood. Though the Norwood Code's definition of 'deteriorating area' provides a litany of conditions, it offers so little guidance in application that it is almost barren of any practical meaning.
>
> In essence, deteriorating area is a standardless standard. Rather than affording fair notice to the property owner, the Norwood Code merely recites a host of subjective factors that invite ad hoc and selective enforcement – a danger made more real by the malleable nature of the public-benefit requirement.

Id. at ¶¶ 97-98.

B. Application of the void-for-vagueness doctrine to R.C. 4928.143(F).

Like the eminent domain statute in *Norwood*, R.C. 4928.143(F) results in the taking of private property rights. The statute requires an EDU to disgorge or forfeit earnings it lawfully gained through the efficient use of its own property so that those earnings can be re-distributed to its customers, even though the customers indisputably paid a just and reasonable price for the service they received. Notably, pursuant to R.C. 4928.143(C)(1), the Commission may approve an ESP only "if it finds that the [ESP] so approved, including its pricing and all other terms and conditions . . . is more favorable in the aggregate as compared to the expected results that would otherwise apply under [a market-rate offer]." As such, as in *Norwood*, the statute must satisfy the "heightened standard of review employed for a statute or regulation that implicates a First Amendment or other fundamental constitutional right." *Norwood* at ¶88. See also *Duquesne Light Co. v. Barasch* (1989), 488 U.S. 299, 307-08, 109 S.Ct. 609, 102 L.Ed.2d 646. As well illustrated by the record in this case, R.C. 4928.143(F) cannot withstand this scrutiny, either on its face or as applied herein.

The statute on its face gives no notice or guidance as to what is meant by "significantly excessive earnings" and how that determination is to be made. The Commission recognized this

deficiency early on, stating "there are many different views concerning what is intended by the statute and what methodology should be utilized." *ESP Order* at 68. (IEU Appx. 157.) In an effort to get a handle on what the statute meant, the Commission opened a special investigation and invited the stakeholders to participate in a workshop that to help it divine the meaning the SEET and how it should be administered. Eleven different issues were debated during the SEET Investigation proceeding:

1: Should off-system sales be included in the SEET calculation?

2: Should the Commission determine SEET on a single entity basis or company-wide basis?

3: What adjustments should be included in the SEET calculation?

4: What is the precise accounting definition of "earned return on common equity" that should be used?

5: What is the definition of "significantly in excess of the return on common equity"?

6: How should companies "that face comparable business and financial risk" be determined?

7: How are "significantly excessive earnings" to be determined, as that phrase is used in the third sentence of Section 4928.143(F), Revised Code?

8: What does "in the aggregate" mean in relation to the adjustments resulting in significantly excessive earnings?

9: How should the earnings of a comparable company be adjusted to compensate for the financial risk difference associated with the difference in capital structures?

10: What mechanism should be employed to return to customers the amount of excess earnings?

11: How should write-offs and deferrals be reflected in the return on equity calculation for SEET?

SEET Investigation Order at 2. (Appx. at 002.)

Even after receiving the input of the those stakeholders who chose to participate, and affording an opportunity for a free-flowing question-and-answer session, the Commission could not come to grips with most of these issues. The Commission concluded that whether off-systems sales or write-offs and deferrals should be included or excluded in the SEET calculation (Issues 1 and 11) would have to be deferred for further debate on a case-by-case basis in the context of each EDU's individual SEET proceeding. *Id.* at 9, 16. (Appx. at 009, 016.) With respect the meaning of "significantly excess earnings" (Issues 5 and 7), the only conclusion the Commission could reach was "that 'significantly excessive earnings' should be determined based on the reasonable judgment of the Commission on a case-by-case basis." *Id.* at 23 & 29. (Appx. at 023, 029.) With respect to Issues 6 and 9, the Commission concluded that it would not be prudent to establish a comparable group process in advance, and that, therefore, it would decide "the comparable group on a case-by-case basis" each year. *Id.* at 27. (Appx. at 027.) With respect to the mechanism for returning excess earnings to customers, the Commission concluded "such a determination has the potential to raise several issues, which are better addressed on a case-by-case basis." *Id.* at 32. (Appx. at 032.)

The fact that the Commission needed to conduct this extraordinary investigation to divine what the legislature intended, and the inconclusive results of that investigation, is compelling evidence of the vagueness of the statute. The Commission conceded the statute was too vague to be administered without further clarification, yet it was unsuccessful in finding, even with stakeholder input, any clear meaning for what was intended or any common understanding of how the statute should be administered.

The statutory SEET is far more deficient than the ordinance at issue in *Norwood*, which provided a "fairly comprehensive array of conditions that purport to describe a 'deteriorating

area,' including . . . incompatible land uses, nonconforming uses, lack of adequate parking facilities, faulty street arrangement, obsolete platting, and diversity of ownership." *Id.* at ¶ 93. If "deteriorating area" is a "standardless standard," *Norwood* at ¶ 98, notwithstanding the comprehensive listing of descriptive conditions in the ordinance, the SEET, which makes no attempt to define its terms or explain the intended methodology, is an all the more egregious violation of the void-for-vagueness doctrine.

R.C. 4928.143(F) also is far more deficient than the administrative provisions interpreting the Real Estate Settlement Practices Act struck down in *Carter v. Welles-Bowen Realty Inc.* (N.D. Ohio 2010), 719 F. Supp.2d 846. In *Carter*, the court invalidated a policy statement issued by the Department of Housing and Urban Development that described a ten-factor test for distinguishing between "sham" and "bona fide" providers of settlement services. The court found the test unconstitutionally vague because "half of the factors use vague terms reminiscent of the 'reasonableness' language struck down in *Belle Maer*, which invite a "highly subjective evaluation." *Id.* at 853. The court noted, among other things, that the HUD test gave no guidance "as to what level of capital would be deemed 'sufficient,' how many services must be performed to be deemed 'substantial,' what 'reasonable' rates are, or what an entity must do to 'actively compete.'" *Id.* The court concluded that because of the lack of meaningful definitions or standards in the ten-factor test, "any entity wishing to operate as an [affiliated business arrangement] (an arrangement RESPA specifically condones with certain limitations) is thus confronted with a massive gray area." *Id.*

If the HUD ten-factor test left settlement service providers in a "massive gray area," the SEET, in comparison, throws EDUs into a black hole. The terms used in the statute are hopelessly broad and general. No definitions, standards or guidance is provided to give the

EDUs fair notice of their risk of forfeiture or to give the Commission adequate standards to appropriately judge the result. As is evident by the parties' starkly conflicting positions on virtually every issue in the proceeding below (and particularly IEU's position that the Commission and parties so fundamentally misunderstood the statute that a do-over is required), the statute left the parties to speculate as to what constitutes significantly excessive earnings and failed to properly inform the exercise of the Commission's discretion. The parties had no common understanding of what level of earnings should be deemed "significantly excessive." They even diverged on the meaning of the factors to be used in this analysis, such as the scope of the "adjustments" to be measured in determining excess earnings, whether off-system sales should be included in the net earnings used to calculate the return on equity, how write-offs and deferrals should be treated, how to identify companies that face "comparable business and financial risk," or what is meant by the reference to "adjustments, in the aggregate."

R.C. 4928.143(F) is unconstitutionally vague because it does not put the EDU notice as to the action or conduct that can be undertaken to avoid the forfeiture penalty imposed. The vagueness of R.C. 4928.143(F) is further compounded by the fact that the statute applies in a retrospective manner, requiring an EDU to forfeit earnings from a prior year; by the fact that it imposes on the EDU the burden of proving its earnings in the prior year were not significantly excessive; and by the fact that it penalizes an EDU for excess earnings in the prior year but does not insulate the EDU from prior year earnings that may fall significantly below what was earned in the same period by companies with comparable business and financial risk. Given the harsh, asymmetrical consequences leveled by a finding of significantly excessive earnings, and the burden on the EDU to prove that their earnings were not excessive, the General Assembly had a heightened obligation to assure that an EDU had fair notice *in advance* of how its earnings would

be measured and judged and to assure that the Commission had clear direction on how the test was to be administered. The General Assembly failed to meet its constitutional duty in this instance, and the Commission's application of the SEET similarly has failed to cure the unconstitutionally vague enactment.

CONCLUSION

The Court should declare that R.C. 4928.143(F) is unconstitutionally vague and unenforceable. Alternatively, it should reject Appellants' arguments that the Commission erred in adjusting CSP's 2009 earned return on equity to exclude earnings due to off-system sales, or that it erred in not requiring CSP to transform itself into a truncated, ESP-specific entity for purpose of somehow estimating an return on equity for only that portion of its business governed by adjustments made in the ESP.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned certifies that a true and accurate copy of this Second Merit Brief and Appendix was served upon the following counsel of record by regular U.S. Mail, postage pre-paid, the 26th day of September, 2011.

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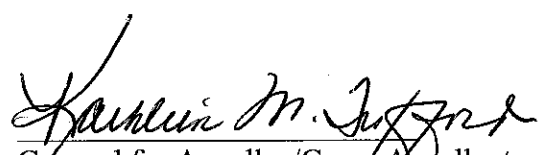

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COLUMBUS/1601122v.3

IN THE SUPREME COURT OF OHIO

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Administration of the Significantly Excessive Earnings Test under Section 4928.143(F), Revised Code, and Rule 4901:1-35-10, Ohio Administrative Code	:	**Case No. 2011-0751** **Appeal from the Public Utilities Commission of Ohio Case No. 10-1261-EL-UNC**

APPENDIX TO MERIT BRIEF
OF APPELLEE/CROSS-APPELLANT
COLUMBUS SOUTHERN POWER COMPANY

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Investigation into the Development of the Significantly Excessive Earnings Test Pursuant to Amended Substitute Senate Bill 221 for Electric Utilities.	))))	Case No. 09-786-EL-UNC

FINDING AND ORDER

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The Commission finds:

BACKGROUND:

On May 1, 2008, the governor signed into law Amended Substitute Senate Bill No. 221 (SB 221), amending various statutes in Title 49 of the Ohio Revised Code. Among the statutory amendments were changes to Section 4928.14, Revised Code, to establish a standard service offer (SSO). Pursuant to the amended language of Section 4928.14, Revised Code, electric utilities are required to provide consumers with an SSO, consisting of either a market-rate offer (MRO) or an electric security plan (ESP). Sections 4928.142(D)(4), 4928.143(E) and 4928.143(F), Revised Code, direct the Commission to evaluate the earnings of each electric utility's approved ESP or MRO to determine whether the plan or offer produces significantly excessive earnings for the electric utility.

After considering the arguments raised in the ESP and/or MRO proceedings of the electric utilities, the Commission concluded that the methodology for determining whether an electric utility has significantly excessive earnings as a result of an approved ESP or MRO should be examined within the framework of a workshop.[1] To carry out the Commission's directives, the Commission directed Staff to conduct a workshop to allow interested stakeholders to present concerns and to discuss and clarify issues raised by Staff. The workshop was held on October 5, 2009. Further, the Commission directed Staff to develop and file recommendations for the significantly excessive earnings test (SEET) subsequent to the workshop. Staff filed its recommendations on November 18, 2009.

By entry issued November 19, 2009, interested persons that wished to file comments were directed to do so by December 14, 2009, and to file reply comments by January 4, 2010. On December 23, 2009, a motion was filed for a five-day extension of the time to file reply comments with a request for an expedited ruling. The request for an extension of time to file reply comments was granted until January 11, 2010.

Initial comments were filed by the following interested persons: Ohio Consumers Counsel (OCC), Ohio Manufacturers' Association, Ohio Hospital Association and Ohio Energy Group (OEG) (jointly, Customer Parties); Duke Energy Ohio, Inc. (Duke); Ohio Edison Company, The Cleveland Electric Illuminating Company, and Toledo Edison Company (jointly, FirstEnergy); Columbus Southern Power Company (CSP) and Ohio Power Company (OP) (jointly, AEP-Ohio); Citizen Power, Inc. (Citizen); and Dayton Power & Light Company (DP&L). On January 11, 2010, Citizen filed a request to withdraw its initial comments in this matter and to recognize its support for the initial

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1 *In re Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company*, Case No. 08-935-EL-SSO, Opinion and Order at 64 (December 19, 2008) (FirstEnergy ESP case); and *In re Columbus Southern Power Company and Ohio Power Company*, Case No. 08-917-EL-SSO, et al., Opinion and Order at 68 (March 18, 2009) (AEP-Ohio ESP cases).

comments filed by Customer Parties. The Commission finds Citizen's request to withdraw its initial comments reasonable and the request is hereby granted. Reply comments were filed by Customer Parties (including, Citizen), Duke, FirstEnergy, AEP-Ohio, DP&L, and Ohio Partners for Affordable Energy (OPAE).

On April 1, 2010, a question and answer session was held before the Commission for interested stakeholders who filed comments or reply comments in this case. Prior to the session, 11 questions were posted to the Commission's web site for the commenters' consideration.

1. What is the legal basis for employing an earnings cap on total earnings that does not consider adjustments?

2. How should the Commission define and quantify "adjustments" that could be subject to return if the Commission found significantly excessive earnings?

3. Are adjustments which "will cause" earnings significantly in excess pursuant to Section 4928.142(D)(4), Revised Code, the same as those which "will result" in earnings significantly in excess pursuant to Sections 4928.143(E) and (F), Revised Code?

4. Does a return become "excess" as a result of "adjustments" (e.g., fuel) or as a result of the establishment of a standard service offer?

5. How should the Commission define what is significant? Is there a difference in its meaning in the various statutory sections in which it appears (Sections 4928.142(D)(4), 4928.143(E), 4928.143(F), Revised Code)?

6. What is the best way to establish the threshold for significantly excessive earnings?

7. Taking into account factors such as differences in capital requirements and business risks, should significantly excessive earnings thresholds be established on a state-wide or company-specific basis?

8. How should the Commission identify and consider "the capital requirements of future committed investments in this state"?

9. What is the mechanism that an electric utility might employ to select its proposed peer group?

10. How should the Commission treat deferrals to ensure that expenses and revenues are appropriately matched in each year and to facilitate comparisons with the reported earnings of other firms?

11. Are there any ways to apply the SEET or other steps the Commission can or should take to recognize efficient operations or discourage electric utilities from incurring inefficient or wasteful expenses to "manage" their reported earnings based on the expected results of their earnings test?

All of the commenters, and the Staff, participated in the question and answer session before the Commission.[2]

LAW:

Section 4928.142(D)(4), Revised Code, provides, in relevant part:

> The commission shall also determine how such adjustments will affect the electric distribution utility's return on common equity that may be achieved by those adjustments. The commission shall not apply its consideration of the return on common equity to reduce any adjustments authorized under this division unless the adjustments will cause the electric distribution utility to earn a return on common equity that is significantly in excess of the return on common equity that is earned by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. The burden of proof for demonstrating that significantly excessive earnings will not occur shall be on the electric distribution utility.
>
> Additionally, the commission may adjust the electric distribution utility's most recent standard service offer price by such just and reasonable amount that the commission determines necessary to address any emergency that threatens the utility's financial integrity or to ensure that the resulting revenue available to the utility for providing the standard service offer is not so inadequate as to result, directly or indirectly, in a taking of property without compensation

[2] In addition to participating in the question and answer session, Customer Parties filed its responses to the questions on April 1, 2010.

pursuant to Section 19 of Article I, Ohio Constitution. The electric distribution utility has the burden of demonstrating that any adjustment to its most recent standard service offer price is proper in accordance with this division.

Section 4928.143(E) and (F), Revised Code, provide, in relevant part:

(E) If an electric security plan ... exceeds three years from the effective date of the plan ... The commission shall also determine the prospective effect of the electric security plan to determine if that effect is substantially likely to provide the electric distribution utility with a return on common equity that is significantly in excess of the return on common equity that is likely to be earned by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. The burden of proof for demonstrating that significantly excessive earnings will not occur shall be on the electric distribution utility. If the test results are in the negative or the commission finds that continuation of the electric security plan will result in a return on equity that is significantly in excess of the return on common equity that is likely to be earned by publicly traded companies, including utilities, that will face comparable business and financial risk, with such adjustments for capital structure as may be appropriate, during the balance of the plan, the commission may terminate the electric security plan, but not until it shall have provided interested parties with notice and an opportunity to be heard. The commission may impose such conditions on the plan's termination as it considers reasonable and necessary to accommodate the transition from an approved plan to the more advantageous alternative. In the event of an electric security plan's termination pursuant to this division, the commission shall permit the continued deferral and phase-in of any amounts that occurred prior to that termination and the recovery of those amounts as contemplated under that electric security plan.

(F) With regard to the provisions that are included in an electric security plan under this section, the commission shall consider, following the end of each annual period of the plan, if any such adjustments resulted in excessive earnings as measured by whether the earned return on common equity of the electric distribution utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk,

with such adjustments for capital structure as may be appropriate. Consideration also shall be given to the capital requirements of future committed investments in this state. The burden of proof for demonstrating that significantly excessive earnings did not occur shall be on the electric distribution utility. If the commission finds that such adjustments, in the aggregate, did result in significantly excessive earnings, it shall require the electric distribution utility to return to consumers the amount of the excess by prospective adjustments; provided that, upon making such prospective adjustments, the electric distribution utility shall have the right to terminate the plan and immediately file an application pursuant to section 4928.142 of the Revised Code. Upon termination of a plan under this division, rates shall be set on the same basis as specified in division (C)(2)(b) of this section, and phase-in of any amounts that occurred prior to that termination and the recovery of those amounts as contemplated under that electric security plan. In making its determination of significantly excessive earnings under this division, the commission shall not consider, directly or indirectly, the revenue, expenses, or earnings of any affiliate or parent company.

DISCUSSION:

Staff Recommendation 1: Should off-system sales be included in the SEET calculation?

Staff proposes that off-system sales (OSS) should be included in the net earnings used to calculate return on equity for the SEET. Staff reasons that OSS are routine operating items and not one-time write-offs or non-recurring items and inclusion of ongoing revenue and expense items for OSS would have a representative effect on the financials. Therefore, Staff concludes that stated financial results, without adjustment for OSS, are appropriate for calculation of the return on equity.

Customer Parties and OPAE concur with Staff's position and add that the return on common equity earned by each of the electric utilities that owns generation could include profits from OSS pursuant to Section 4928.143(F), Revised Code. To eliminate OSS from the SEET calculation, Customer Parties and OPAE argue, would distort the comparison between the electric utility and the comparable group of companies. Further, Customer Parties and OPAE contend that excluding OSS ignores the fact that the cost of the power plant used to make OSS is included in the electric utility's capitalization. Customer Parties offer that including OSS in the SEET calculation results in an unbiased comparison of earnings and promotes fairness by sharing the profits from OSS between customers and the electric utility. Customer Parties assert that the Commission has previously ordered

that proceeds from OSS be shared between customers and the electric utility.[3] (Customer Parties Initial at 19; Customer Parties Reply at 4-6; OPAE Reply at 2.) Lastly, Customer Parties support offsetting the electric utility's ESP costs by profits from OSS. Customer Parties argue that sharing OSS profits between customers and the electric utility recognizes that the generation facility was constructed for the benefit of, and ultimately paid for by, jurisdictional customers. (Customer Parties Initial at 19; Customer Parties Reply at 4-6.)

In response, AEP-Ohio argues, among other things, that customers pay rates for retail service and not for the assets that produce those services. AEP-Ohio states that the proposal to share OSS margins is irrelevant and meritless in this proceeding. AEP-Ohio reasons that there is no statutory basis for incorporating a sharing of OSS margins into the SEET application based on Sections 4928.142(D)(4), 4928.143(E) or 4928.143(F), Revised Code, and that the Commission already rejected such arguments in AEP-Ohio's ESP cases. The only authorized adjustments to the SEET are from the company's ESP; to do otherwise, AEP-Ohio argues, would have the effect of disallowing cost recovery already authorized by the Commission. (AEP-Ohio Reply at 3-4.)

DP&L and AEP-Ohio argue that the focus of SB 221 is retail sales and OSS has not previously been included in retail rates under the Commission's jurisdiction. DP&L and AEP-Ohio also note that the purpose of conducting the SEET is to determine if the electric utility's ESP has resulted in excessive earnings for the electric utility and, therefore, it is inappropriate to include non-jurisdictional revenues. The costs and revenues associated with OSS, according to DP&L and AEP-Ohio, should be excluded from earnings in the SEET calculation. DP&L notes that acceptance of Staff's proposal would discourage electric utilities from making OSS, thus placing the interests of ratepayers and shareholders at odds. AEP-Ohio adds that excluding OSS from the SEET calculation also respects the Federal Energy Regulatory Commission's (FERC) jurisdiction and complies with well-settled federal constitutional law. Further, AEP-Ohio argues that under federal constitutional law, the State is preempted from interfering with the Companies' ability to realize revenue rightfully received from wholesale power sales pursuant to contracts or rates approved by FERC. *Pacific Gas & Electric v. Energy Resources Comm.*, 461 U.S. 190 (1983) (*Energy Resources Comm.*); *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953 (1986) (*Nantahala*); *Mississippi Power & Light v. Mississippi*, 487 U.S. 354 (1988) (*MP&L*); *Pacific Gas & Electric Co. v. Lynch*, 216 F. Supp. 2d 1016 (N.D. Cal. 2002) (*Lynch*). AEP-Ohio extends that reasoning to conclude that, just as the State may not trap FERC-approved wholesale power costs, it may not in effect capture or siphon the revenue the Companies receive from FERC-approved wholesale sales for the purpose of reducing the retail rates paid by Ohio customers. Any such order by the Commission, according to AEP-Ohio, would conflict with the Federal Power Act and Congress' power under the Supremacy

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3 See, for example, *In the Matter of the Application of the Cleveland Electric Illuminating Company for an Increase in Rates*, Case No. 84-188-EL-AIR, Opinion and Order at 61-65 (March 7, 1985).

Clause and this type of economic protectionism would also violate the federal Commerce Clause. *New England Power Co. v. New Hampshire*, 455 U.S. 331 (1982) (*NEPC*). (DP&L Initial at 2-3; DP&L Reply at 3; AEP-Ohio Initial 2-3.)

In response to the arguments of AEP-Ohio and DP&L, Customer Parties assert that the commenting electric utilities' position is inconsistent with the energy efficiency mandates of SB 221 and explain that customers pay the costs of energy efficiency programs and the power conserved as a result of these programs becomes available for sale in the OSS market. Customer Parties argue that if OSS margins are included in the SEET, OSS can serve as a form of off-set to the energy efficiency costs. However, according to Customer Parties, under AEP-Ohio's position, consumers would pay the full energy efficiency costs while AEP-Ohio would benefit from higher OSS profits made possible by energy efficiency programs. (Customer Parties Reply at 7.)

As to AEP-Ohio's legal argument, that including the OSS profits in the SEET violates the federal law, Customer Parties proclaim that none of the cases cited by AEP-Ohio support that claim. Customer Parties state that the cases cited stand for the proposition that when an electric utility prudently incurs FERC-approved costs, the state may not deny collection of such costs in retail rates. None of the cases deal with the retail ratemaking treatment of OSS margins derived from power plants included in retail rates. (Customer Parties Reply at 7.)

Upon further consideration of the issues raised by the electric industry and Customer Parties regarding OSS, the Commission concludes that this issue is more appropriately addressed in the context of each individual electric utility's SEET proceedings. In order to fully understand the impact of the treatment of OSS on an electric utility's earnings, the Commission directs the electric utility to include in its filing the identification of any OSS and the effect of excluding OSS from and including OSS in the SEET calculation.

Staff Recommendation 2: Should the Commission determine SEET on a single entity basis or company-wide basis?

Staff believes the General Assembly's intent is clearly expressed in the language of Section 4928.143(F), Revised Code, and division (C)(2)(b) of this section, to indicate that the SEET should be calculated for the electric utility as a single entity.

Duke offers that Staff's recommendation fails to take into account the difference in accounting issues where the electric utility wholly owns a subsidiary utility, like Duke owns Duke Energy Kentucky, Inc. (Duke-KY), as opposed to the situation where two electric utilities are owned by a parent holding company. Accordingly, Duke's financial books and records reflect its investment and costs associated with Duke-KY. In addition,

Duke indicates that the situation is further complicated since it is a combination utility, offering both electric and gas distribution services. While Duke acknowledges that there may be justification for omitting affiliates and the parent holding company from the SEET calculation for some electric utilities, Duke advocates that a different treatment should apply to electric utilities with wholly owned subsidiaries and combination utilities. Duke contends that separating Duke from Duke-KY and segregating its gas and electric businesses are difficult and the process to do so could easily lead to protracted disputes. Furthermore, Duke argues that if the Staff recommendation is adopted and is interpreted to include the wholly owned subsidiaries of a utility and combination utility operations, an additional process may be required to resolve accounting issues that would arise with regard to the allocation of capitalization between a utility and its wholly owned subsidiaries. (Duke Initial at 2-5.)

Customer Parties respond that Duke has previously been required to file with the Commission electric-only financial information to support its ESP application and electric rate cases. Customer Parties state that in each instance Duke has separated, calculated, and filed all the financial and regulatory information allocated to Duke's electric distribution system to comply with the filing requirements. Accordingly, Customer Parties contend that there is no undue burden imposed on Duke associated with preparing the information on rate base, operating expenses, operating income, return on equity, and rate of return solely for Duke's electric services and there is no reason that the same or similar type of information cannot be made available for the application of SEET. (Customer Parties Reply at 10-11.)

Duke contends that, while it may be relatively straightforward to determine net income on a single entity basis, it is more difficult than Customer Parties represent to extract the equity that supports the subsidiary from the equity of the electric utility. For this reason, Duke reiterates that to follow Staff's narrow interpretation of the statute and exclude all earnings from affiliates, as well as subsidiaries, the Commission should determine the common equity balance attributable to the single entity, the electric utility, on a case-by-case basis in order to review the underlying equity structure of the subsidiaries, and interest and dividend income of the electric utility. (Duke Reply at 2-3.)

AEP-Ohio argues that there are compelling reasons for performing the SEET on CSP and OP on a combined basis, as CSP and OP are vertically integrated electric utilities (generation, transmission, and distribution) and are operated as a single entity, with a single management structure. AEP-Ohio reasons that combining CSP and OP for purposes of performing the SEET helps to promote efficient investment and operating practices, encourages the companies to seek and achieve economies of scale, and is consistent with the Commission's analysis of AEP-Ohio's SSO in their respective ESP. Conversely, AEP-Ohio states that performing the SEET analysis on CSP and OP as separate entities assumes that investment and operations and maintenance (O&M)

spending are determined on a stand-alone basis and could result in the punishment of one of the affiliated electric utilities for management's focus on maximizing efficient investment and O&M spending on a combined-company basis. (AEP-Ohio Initial at 3-4.)

AEP-Ohio maintains that, while CSP and OP maintain different rate structures, those differences do not preclude performing the SEET's earned return on equity calculation on a combined-company basis, as any differences could be taken into account, in the event significantly excessive earnings are determined to have occurred on a combined-company basis, as part of the remedy the Commission adopts for returning such earnings to customers. (AEP-Ohio Initial at 4-5.)

Furthermore, AEP-Ohio reasons that the restriction in Section 4928.143(F), Revised Code, against considering the revenues, expenses, or earnings of "any affiliate or parent company" in the significantly excessive earnings determination, need not preclude the Commission from applying the SEET on a combined-company basis. According to AEP-Ohio, the reference to "affiliates" in Section 4928.143(F), Revised Code, only relates to entities that are not electric utilities, such as competitive retail electric service providers or generation-only and transmission-only companies. If one electric utility's return on equity is considered to be significantly excessive, the statute does not preclude the Commission from considering the combined return on equity of the affiliated electric utility. If that combined return is not significantly excessive that fact can and should be a factor for the Commission to consider and should reduce or eliminate the refund that might otherwise be imposed by the Commission. Lastly, AEP-Ohio argues that if the Commission determines that the statute precludes calculating return on equity on a company-wide basis, the Commission still should consider the policy concerns stated as part of any SEET refund. (AEP-Ohio Initial at 4-5.)

Customer Parties oppose calculating the SEET on a combined basis and assert that the arguments of AEP-Ohio are unsubstantiated and irrelevant to the application of the SEET. The approved rate of return, capital structure, cost of debt, and tariffs of CSP and OP are established separately by the Commission. Further, Customer Parties offer that the application of the SEET on a single-entity basis neither prevents nor precludes CSP and OP from improving operational efficiency or investments or benefiting from various economies of scale. (Customer Parties Reply at 9-10.)

The Commission finds the language in Section 4928.143(F), Revised Code, to be dispositive of whether the SEET is to be calculated for a single-entity or on a company-wide basis. The last sentence of Section 4928.143(F), Revised Code, clearly states that: "In making its determination of significantly excessive earnings under this division, the commission shall not consider, directly or indirectly, the revenue, expenses, or earnings of any affiliate or parent company." We believe that the intent of the language quoted above is to avoid penalizing or rewarding the electric utility for the business operations of its

affiliate or parent company. Accepting the arguments of AEP-Ohio to perform the SEET calculation on CSP and OP jointly is not only contrary to the plain language of the statute but would neutralize the earnings of one affiliate, and its customers, over the other. While AEP-Ohio may find it cost-effective for investment and operation and maintenance purposes to make decisions for CSP and OP on a combined-company basis, AEP-Ohio's management decisions do not override the requirements of the statute. As for Duke, with its wholly-owned subsidiaries, we find that the intent of the legislation is to extract, to the extent reasonably feasible and prudently justified, the expenses, earnings, and equity of any affiliate from the SEET calculation. Similarly, where Duke can separate and justify the revenue and expenses associated with its gas distribution service operations from its electric services, we find it appropriate to do so for calculation of the SEET. While making such adjustments may complicate the Duke SEET evaluation, it maintains what the Commission believes to be the intent of the legislation and protects the interest of Duke's electric customers.

Staff Recommendations 3 and 11: What adjustments should be included in the SEET calculation? How should write-offs and deferrals be reflected in the return on equity calculation for SEET?

Staff recommends that stated financial results, without adjustment, should be used for calculation of the SEET and extraordinary items should be excluded. Staff reasons that such definition provides a reasonable, representative, and consistent measure of return on equity. Extraordinary items could overwhelm normal levels of earnings and would not be pertinent to the SEET unless directly tied to an ESP or MRO. Where applicable, adjustments should also be made to remove items associated with non-Ohio service areas. Staff believes that the adjustments created by the implementation of an ESP or MRO are what should be determined on a company-specific basis, only if financial results, as stated, are deemed to be excessive. If excessive earnings, after exclusion of the total adjustments from the earned return, are brought below the threshold deemed to be excessive, then the amount of the excess shall be refunded to the electric utility's customers. If the return with the adjustments excluded is still excessive, then the adjustments cannot be at fault for excessive earnings, and no amount need be returned to the consumers.

Further, Staff recommends that if extraordinary items are created as an adjustment in the ESP or MRO, they should be included for purposes of the SEET in earnings and as adjustments. Extraordinary items that are not created as an adjustment in the ESP or MRO should not be included for purposes of the SEET, either in earnings or as an adjustment. Staff also advocates that OSS should be included as an adjustment in the SEET calculation only when OSS is also included as an adjustment to an electric utility's MRO or ESP. If OSS are not included as an adjustment to the MRO or ESP, then they should not be included as an adjustment in the SEET calculation. OSS are to be included in the earnings, in any case.

Customer Parties concur with the Staff Recommendation concerning the treatment of extraordinary items and OSS, but add that any SEET refund should be excluded from the SEET calculation in the year the refunds are reported on the income statement. (Customer Parties Initial at 15.) No commenters responded to this concern.

Customer Parties recognize that Staff proposes a two-pronged test for determining whether an electric utility's earnings are significantly excessive and subject to refund. Customer Parties assert, however, that the second prong of Staff's test is based on a fundamental misinterpretation of the law. Customer Parties agree that if the ESP rate increases are removed from earnings, and the return on equity is below the SEET threshold, the excess earnings should be subject to refund to the electric utility's customers and no further analysis is necessary. However, Customer Parties assert that the second prong of the analysis, as proposed by Staff, would not result in any refund to customers where the ESP rate increases are excluded from the earnings and the return on equity remains above the established SEET threshold. Customer Parties reason that even if the excess earnings are not a result of the ESP, the ESP contributed to the electric utility's excessive earnings and, therefore, the entirety of the ESP adjustments or rate increase should be returned to customers. Staff's interpretation of the statute, according to Customer Parties, nullifies the very reason for the statute. (Customer Parties Initial at 16-17; Tr. at 7-11.)

As to the adjustments to be included in the SEET calculation, FirstEnergy requests that for the purpose of calculating SEET, net income applicable to common shareholders be adjusted to exclude extraordinary or nonrecurring items which are otherwise non-representative of an electric utility's operations, and any specific adjustments defined in an electric utility's ESP then in effect. The denominator shall be the average monthly common equity balance during the measurement period, adjusted to exclude the related effects of any items excluded from net income. The resulting adjusted return on common equity becomes the reference point, as described in more detail in the company's comments regarding the definition of "significantly in excess of the return on common equity" at Recommendation 5. (FirstEnergy Initial at 2-3.) Customer Parties argue that excluding extraordinary items "which are otherwise non-representative of a utility's operations," as FirstEnergy proposes, would result in mini rate case proceedings and is unworkable. (Customer Parties Reply at 13.)

Duke notes that the Commission approved the stipulation filed in its ESP, which specifically provides that the return on common equity is to be computed using FERC Form 1 financial statements from the prior year, including OSS, subject to certain listed adjustments.[4] Duke mentions that its ESP Stipulation does not indicate that adjustments

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4 *In the Matter of the Application of Duke Energy Ohio Inc. for Approval of an Electric Security Plan*, Case No. 08-920-EL-SSO, Opinion and Order (December 17, 2008) (Duke ESP case).

would be made to remove items associated with non-Ohio service areas. Accordingly, Duke objects to the notion that any such change would be made pursuant to this proceeding. (Duke Initial at 5; Duke Reply at 4.) Similarly, FirstEnergy argues that its approved ESP Stipulation includes an express provision excluding deferrals related to deferred carrying charges in the SEET application.[5] Accordingly, FirstEnergy argues that this provision of the approved Stipulation should not be abrogated by this proceeding. (FirstEnergy Reply at 3.) While Duke argues that FirstEnergy's proposal to exclude extraordinary items, nonrecurring items and items that are not representative of an electric utility's operations only from the income statement is inappropriate, Duke supports the proposal as long as the impacts of such adjustments are accounted for in the SEET calculation. (FirstEnergy Initial at 2-3; Duke Reply at 4.)

DP&L avers that, in addition to excluding OSS, other adjustments to the SEET should include significant non-recurring adjustments that are related to regulated operations, such as out-of-period tax adjustments, adjustments for economic conditions, or potential significant loss of load. (DP&L Initial at 3.)

AEP-Ohio states that it agrees with Staff's recommendations regarding the treatment of extraordinary items, but holds that, when correctly interpreted, Staff's proposed treatment of extraordinary items necessitates an adjustment in the calculation of earnings for OSS since OSS are FERC-jurisdictional and associated with non-Ohio service areas. Furthermore, AEP-Ohio clarified its position that if the electric utility is found to have exceeded the significantly excessive earnings threshold, that only those components of the ESP that produce earnings for the electric utility are subject to refund (Tr. 24-25; AEP-Ohio Initial at 5-6.)

Customer Parties urge the Commission to strictly compare an electric utility's earnings to the determined SEET threshold, a one-step process, and if the electric utility's earnings exceed the threshold, adjust the electric utility's earnings accordingly. Customer Parties' proposal essentially establishes a cap on the electric utility's return on equity rather than ensures that the ESP adjustments do not result in significantly excessive earnings as Section 4928.143(E), Revised Code, requires.

Based on the clear, unambiguous language of the statute, the Commission is directed to analyze whether the ESP is the cause of the electric utility's significantly excessive earnings. The Commission finds the "one-step process" to be more appropriate than the two-pronged analysis advocated by Staff. In the context of the SEET analysis, it is unreasonable to presume that even if the electric utility was very profitable prior to the ESP, the adjustments in the ESP would not be adding to excess earnings. We also believe that the two-step analysis could encourage gaming by the electric utilities. The clear,

5 *FirstEnergy ESP cases*, Stipulation (February 19, 2009), paragraph B.6 at 17.

unambiguous language of the statute limits the amount of any refund to customers to the adjustments in the current ESP. More specifically, an adjustment for purposes of Section 4928.143(F), Revised Code, includes any change in rates when compared to the rates in the electric utility's preceding rate plan. Therefore, in any given year, the earnings, which if significantly excessive, subject to being returned is the difference between those earned under the rate in place in that year and what would have been earned if the utility's preceding rate plan had been in place in that year. For example, in the year 2010, the comparison for most electric utilities would be to the rates from the preceding rate plan for 2008. Thus, the Commission reasons that in 2010, we would not be permitted to "claw back" into 2009 profits if the 2009 profits were not significantly excessive. We find FirstEnergy's arguments to be persuasive. FirstEnergy reasoned that in the first sentence of Section 4928.143(F), Revised Code, the phrase "any such adjustments" should be read as referring to the first part of the sentence and the phrase, "the provisions that are included in an electric security plan under this section" (Tr. 20-22). We note that Customer Parties seem to agree with FirstEnergy's interpretation (Tr. 16-17, 18-19). Finally, we also agree, as Customer Parties emphasize, that any adjustment to the earnings of an electric utility, as a result of a refund, should be excluded from the SEET calculation in the year the adjustment is made to avoid distorting the electric utility's income. In order to facilitate the valuation of the ESP adjustments, the electric utilities are directed to include in their SEET filings the difference in earnings between the ESP and what would have occurred had the preceding rate plan been in place.

As to Staff Recommendation 11, regarding how write-offs and deferrals should be reflected in the return on equity calculation for SEET, Customer Parties advocate that any deferral of fuel costs or other items should be reflected in the return on equity calculation for SEET in the year when the retail sales occur, not in later years when the deferred revenues are received. Customer Parties argue that such would be consistent with Staff's recommendation that stated financial results should be used for calculation of the SEET. Customer Parties suggest that in any year where there is a deferral and a SEET finding of excess profits, that the excess profits could first be used to pay down the deferrals before any refund is awarded to customers. (Customer Parties Initial at 15-16; Tr. 34-35.)

AEP-Ohio disagrees, maintaining that a SEET obligation to return significantly excessive earnings due to ESP adjustments should not be premised on deferrals since the electric utility has not yet received the cash that would have to be returned. Further, AEP-Ohio argued that Section 4928.143(F), Revised Code, should not be applied in a manner that underminds the probability of the electric utility's future recovery of deferrals that were previously authorized by the Commission and jeopardizes the utility's ability to create the deferral to phase-in rate increases and moderate customer rate impacts and contends that Section 4928.144, Revised Code, supports its interpretation. (AEP-Ohio Reply at 4-5; Tr. 26-33, 36-37.)

OPAE argues that the focus of the SEET is to protect consumers and it is not necessary to put deferrals, booked pursuant to generally accepted accounting principles, at issue to achieve the goal of the SEET. OPAE believes the electric utility's revenues, in total, should be considered in the SEET analysis. (Tr. at 33-34.)

Duke explained that there are two types of deferrals. One type is deferred revenue with an underlying expense, like the FAC expense in AEP-Ohio's case. Duke argues that it would be unfair to require the electric utility to recognize the revenue or incur expense until it is received. The second type of deferral, according to Duke, is a deferred rate increase which may not have an underlying expense and is different in concept than the first type of deferral. (Tr. 35-36.)

The Commission recognizes that the issues surrounding the treatment of deferrals are extremely complex. The Commission notes that granting a company the ability to defer expenses does not equate to the unequivocal right to collect the deferral. However, deferrals are a regulatory tool used by the Commission to avoid rate shock to customers and as such can be a public benefit. The Commission is also mindful that from a financial reporting perspective that the recovery of deferrals by an electric utility needs to be fairly known so that it may be treated appropriately for accounting purposes. The Commission understands that to cast an unacceptable level of doubt on the recovery of a deferral, particularly a large deferral, will severely dampen the electric utility's willingness to agree to deferrals. Because many factors need to be considered in order to weigh the appropriateness of the treatment of any given deferral, the Commission finds that the treatment of deferrals, for purposes of the SEET, should be determined on a case-by-case basis. To facilitate the Commission's consideration of an electric utility's deferrals, in their SEET filings, the electric utility should identify any deferrals and the effects of excluding and including the deferrals in the SEET calculation. Furthermore, similar information should also be provided for extraordinary items.

In regards to Staff's recommendation 11, the Commission further finds that where an electric utility's ESP or MRO has been resolved by stipulation, which includes a method for the treatment of write-offs and deferrals in calculating the SEET, the Commission is not modifying the stipulation with this proceeding, to the extent that the issue is adequately addressed in the stipulation and the order approving the stipulation. Accordingly, the approved standard service offer stipulations of Duke and FirstEnergy shall stand as approved by the Commission to the extent the treatment of deferrals and write-offs in the SEET calculation were addressed.

As discussed further, in regard to Recommendation 10, the Commission will determine how any significantly excessive earnings are returned to customers based on the circumstances of the company-specific case.

Staff Recommendation 4: What is the precise accounting definition of "earned return on common equity" that should be used?

Staff proposes, and Customer Parties concur, that earned return should be the net income for the year divided by the average common equity over all months of the year with extraordinary items excluded. (Customer Parties Initial at 21.) Staff reasons that this definition is consistent with the use of stated financials with minimal adjustments. DP&L agrees that "earned return on common equity" should mean net income divided by average common equity. However, DP&L recommends that preferred dividends be excluded from net income and that average common equity be calculated using 13 monthly balances rather than the average of 12 calendar month balances. DP&L reasons that including December of the previous year reflects the capital structure that was in place for the full calendar year. (DP&L Initial at 4.)

For clarity, AEP-Ohio requests that, in the equation proposed by Staff, the numerator, net income, be defined as profit after deduction of all expenses, including taxes, minority interest, and preferred dividends, paid or accumulated, and excluding any non-recurring, special, and extraordinary items, and the denominator is average book equity as determined by averaging beginning of the year equity and end of the year equity. Further, AEP-Ohio argues that the earned return on common equity should not include deferred fuel adjustment clause (FAC) expenses. More specifically, AEP-Ohio explains that an electric utility should not be made to refund deferred amounts it has not yet collected. Instead, during the deferral period of AEP-Ohio's 10-year phase-in (2009-2011) all deferrals of FAC expenses would be excluded from the SEET and, during the recovery period of the phase-in (2012-2018), FAC expenses associated with the amounts previously deferred would be excluded from the SEET. (AEP-Ohio Initial at 7-8.)

Like DP&L and AEP-Ohio, FirstEnergy concurs that the methodology selected should capture an average of common equity over all months of the year as opposed to use of an unrepresentative, single point measure of equity. FirstEnergy also recommends that the exclusion of extraordinary or nonrecurring items, or those which are otherwise non-representative of the electric utility's operations, in order to maintain comparability with the sample of companies against which the electric utility's earnings are being considered. (FirstEnergy Initial at 3.)

Customers Parties object to AEP-Ohio's recommendation, specifically, that earned return on common equity exclude FAC revenues and, generally, that FAC revenues and expenses be excluded from the SEET calculation during the ESP period of 2009-2011 and also the recovery period of 2012-2018. Customers Parties argue such treatment would forever deny consumers a proper accounting. Customer Parties recommend that any deferral of fuel costs or other items should be reflected in the return on equity calculation for SEET in the year when the retail sales occur, not in later years when the deferred

revenues are received. Deferrals, according to Customer Parties, could be included in earnings and any excess profits should first be used to pay back the deferral before there are any cash refunds. However, Customer Parties express concern about pre-determining that deferrals should be collected from customers. (Customer Parties Reply at 14-15.)

Duke asserts that, while there appears to be some agreement between Staff and commenters that earned return on common equity is equal to net income available for common equity divided by some average of common equity balance, it may be necessary to carve out additional equity, in addition to adjusting the equity balance for any net income adjustments. (Duke Reply at 4-5.)

We find that Staff's proposal, with some commenter clarifications, is appropriate for the purpose of determining whether an electric utility has had significantly excessive earnings. Accordingly, for the SEET calculation, the earned return will equal the electric utility's profits after deduction of all expenses, including taxes, minority interest, and preferred dividends, paid or accumulated, and excluding any non-recurring, special, and extraordinary items. The average book equity used to calculate the SEET will be the book equity for the 12-month period. The Commission is not convinced that using the 13 monthly common equity book balances, as proposed by DP&L, is likely to lead to a significantly different result than the 12-month average. Furthermore, as the Commission declines, at this time, to make a generic finding with respect to the treatment of deferrals, the Commission directs the electric utilities to file their earnings with the inclusion of deferrals and also without the inclusion of deferrals.

Staff Recommendation 5: What is the definition of "significantly in excess of the return on common equity"?

Staff recommends that a return on common equity of the greater of 200 basis points above the mean or in excess of 1.28 (expressed as basis points) times the standard deviation above the mean of a comparable group of companies should be defined as significantly in excess. Assuming a normal distribution, this would establish a level of return below which 90 percent of the sample of comparables would fall. This methodology was used by Michael J. Vilbert in direct testimony filed in FirstEnergy's SSO cases and Staff believes the resultant level of return defined as significantly in excess to have been reasonable.[6] Two hundred basis points above the mean would act as a backstop when earnings are low.

Customer Parties' primary concern is the definition of "significantly in excess of the return on common equity" as Customer Parties believe it is the foundation of the consumer protection aspect of SB 221. Customer Parties contend that through the SEET,

6 *FirstEnergy ESP case*, Application, Ex. 8 at Appendix B-3 (July 31, 2008).

the legislature determined that Ohio electric consumers cannot be required to fund significantly excessive utility profits.

Customer Parties note that Staff's recommendation on this issue is a complete departure from Staff's position in the AEP-Ohio and FirstEnergy ESP cases, as demonstrated by the direct testimony of Staff witness Cahaan in the AEP-Ohio ESP case.[7] Customer Parties argue that the use of a statistical standard deviation approach requires an assumption that the return on equity for the comparable companies are normally distributed, and no evidence presented in the AEP-Ohio or FirstEnergy ESP proceedings supports such an assumption. AEP-Ohio retorts that this assumption exists with any statistics-based methodology and there is no basis for concluding that the returns on equity of a yet to be determined comparable group will not be normally distributed. Thus, AEP-Ohio argues that Customer Parties' criticism is without merit. (AEP-Ohio Reply at 8-9.)

Next, using AEP-Ohio witness Makhija's comparable group for 2007 as an example, Customer Parties argue that the proposed method may result in unreasonable SEET return on equity thresholds, in this case 55.5 percent.[8] Customer Parties maintain that this is not some inherent flaw in the SEET, as the test is very similar to the "comparable earnings" standard used by public utilities across the United States for years; the U. S. Supreme Court upheld the constitutionality of this standard in *Bluefield Water Works v. West Virginia*, 262 U.S. 679, 692 (1923) (*Bluefield*); and *F.P.C. v. Hope Natural Gas*, 320 U.S. 591, 603 (1944) (*Hope*). Further, Customer Parties note that, in comparison to the potential result of Dr. Makhija's methodology, for the first nine months of 2009 in 22 cases the average electric utility's return on equity authorized by state commissions was 10.43 percent, with the highest return on equity being 11.39 percent in 22 cases for the year 1996.[9] Customer Parties prefer the use of the threshold of 200-400 basis points above the mean return of the sample group instead of the recommendation now advocated by Staff. This approach was supported by OEG witness King in AEP-Ohio's ESP proceedings.[10] Mr. King proffered that the SEET threshold be set at a simple 200 basis points above the mean return of the comparable companies group. Customer Parties state that a 200 basis point premium is equal to the return on equity adder used by FERC to incentivize utilities to make especially risky transmission investments and provides an ample return on equity premium. Finally, Customer Parties reason that as long as the Commission retains ultimate authority regarding the return on equity premium to be added to the comparable

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7 *AEP-Ohio ESP cases*, Direct Testimony of Staff witness Cahaan (November 7, 2008).

8 The greater of: a) 13.91 percent plus 200 basis points which equals 15.91 percent; or b) 13.91 percent plus (32.51 multiplied by 1.28) which equals 55.5 percent. See *AEP-Ohio ESP cases*, Direct Testimony of AEP-Ohio witness Makhija (July 31, 2008).

9 Regulatory Research Associates, Regulatory Focus, October 2, 2009.

10 *AEP-Ohio ESP cases*, Direct Testimony of OEG witness King (November 3, 2008).

group return on equity, then a reasonable balancing of customer and shareholder interests can be maintained under any economic conditions. (Customer Parties Initial at 3-11.)

AEP-Ohio states that the use of a statistical approach for determining the SEET threshold is appropriate. Further, AEP-Ohio argues that Customer Parties have mischaracterized Dr. Makhija's testimony filed in AEP-Ohio's ESP proceeding. AEP-Ohio explains that, with a 95 percent confidence level, using 2007 data, results in a comparable group with a mean return on equity of 13.9 percent, an adder of 13 percent, and a significantly excessive earnings threshold of 26.9 percent. AEP-Ohio further states that using Dr. Makhija's method with a 90 percent confidence level or a 1.28 standard deviation variance reduces the adder to 8.3 percent, and when added to the mean return on equity of 13.9 percent yields a return on equity threshold of 22.1 percent for 2007, not an increase of 28 percent to 55.5 percent, as Customer Parties claims. (AEP-Ohio Reply at 8.)

In response to the criticism of Customer Parties, FirstEnergy notes that, while Customer Parties lament the use of a statistical criterion, Dr. Woolridge's approach, which Customer Parties supported in the FirstEnergy ESP proceeding, proposed the use of a statistical based criterion as the mechanism by which to define "significantly excessive earnings."[11] FirstEnergy, AEP-Ohio, and Duke further challenge Customer Parties' recitation of *Bluefield* and *Hope* as irrelevant to the issue of whether an electric utility has significantly excessive earnings during a given period in comparison to other businesses with similar business and financial risk. Duke argues that the Bluefield and Hope cases apply to FERC's setting of rates. Further, Duke also asserts that the Commission is not governed by federal law or case precedent and that those principles are inapplicable to Commission practice. FirstEnergy notes three specific differences in the analysis at hand as opposed to the rate of return on equity at issue in *Bluefield* or *Hope*. First, FirstEnergy argues, and AEP-Ohio agrees, that the determination of what rate of return should be allowed in a rate case is a forward-looking exercise which attempts to capture the return that will be required by an investor to make a future investment. In contrast, the SEET determination is a retrospective look at the financial results achieved in a prior fiscal period. Second, the commenting electric utilities agree that ascertaining an appropriate allowed rate of return focuses on market-based measures while the SEET relies on a comparison of accounting or book-based measures. Third, FirstEnergy opines that in setting an allowed rate of return, there is an inherent expectation that an electric utility may at times earn slightly more or less than the precise return on equity allowed; however, over time and on average, the electric utility will earn its allowed return. FirstEnergy and AEP-Ohio argue that the SEET mechanism presents the prospect that the electric utility may be required to return to customers that portion of earnings which is deemed to be "significantly excessive" and that requirement is not balanced out by any offsetting mechanism applicable in a period of particularly low earnings. Thus, FirstEnergy

11 FirstEnergy ESP case, Tr. V at 30 (October 22, 2008); FirstEnergy Reply Brief at 90.

concludes that determining the proper rate of return and the SEET application are fundamentally different. (FirstEnergy Reply at 4-5; AEP-Ohio Reply at 6-11; Duke Reply at 7.)

AEP-Ohio responds that Customer Parties' proposal to use a 200 basis points premium to the return on equity is a misguided comparison to the adder used by FERC to incent utilities to invest in new transmission line projects. AEP-Ohio reasons that the adder used by FERC is not, by definition, set at a significantly excessive level, but is based on a traditional just and reasonable standard. Further, AEP-Ohio surmises that the use of the FERC adder overlooks the SEET statutory requirement to establish the threshold for excessive earnings based on matching the business and financial risks of an electric utility to a group of comparable companies or change with economic conditions and the performance of comparable firms. (AEP-Ohio Reply at 10.)

Duke disagrees with the Staff proposal. In Duke's ESP case, Duke witness Rose recommended using a 95 percent confidence level or 1.64 standard deviations above the mean.[12] Mr. Rose advocated using a comparable group that is weighted by traditionally regulated utilities and fully non-regulated industries. Duke believes this is the threshold that defines the level of earnings that is "significantly excessive." Duke surmises the legislature included the adjective "significantly" in order to avoid capturing situations in which earnings are just somewhat higher than average. Without a threshold at the 95 percent confidence level, it is difficult to conclude that earnings are significantly excessive. In response to Customer Parties' support of 200 basis points above the mean approach, DP&L presents that two standard deviations is a more appropriate threshold for SEET and would result in only those companies that truly have "significantly excessive earnings." (Duke Initial at 6; DP&L Initial at 4; DP&L Reply at 2.)

Also, Duke argues that Staff's recommendation, which it attributes to FirstEnergy's witness Vilbert, disregards a significant qualification made by Dr. Vilbert that his recommended confidence level would increase from 1.28 standard deviations if a comparable group of companies is limited to regulated electric utilities for purposes of calculating the SEET.[13] For this reason, Duke contends that the Commission should recognize the impact of the composition of the comparable group in the determination of the confidence level. Duke interprets Section 4928.142(D)(4), Revised Code, to require electric utilities and other publicly traded companies to be part of the comparison group, with a commensurate standard deviation above the mean. (Duke Initial at 6; Duke Reply at 6-7.)

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12 Duke ESP case, Direct Testimony of Duke witness Rose (July 31, 2008).

13 FirstEnergy ESP case, Direct Testimony of Vilbert (July 31, 2008).

DP&L's comments focus on the word "significantly" and suggest that the Commission find significantly excessive earnings if an electric utility earns more than 2.00 standard deviations beyond the average of the comparable companies. DP&L notes that Vilbert's testimony represents that two standard deviations would result in 2.3 percent of the companies in the sample having earnings beyond the range of reasonableness and, therefore, deemed "significantly excessive earnings." In light of Dr. Vilbert's representation, Staff's recommendation of 1.28 standard deviations would result in 10 percent of the comparable companies' earnings beyond the range of reasonableness and their earnings excessive. DP&L argues that the test is for "significantly excessive earnings" and, thus, should not apply to 10 percent of the comparable companies each year. (DP&L Initial at 4.) Instead, DP&L also supports that two standard deviations is the more appropriate threshold for SEET and would result in a finding of only those companies that truly have "significantly excessive earnings." (DP&L Reply at 2.)

AEP-Ohio primarily agrees with the Staff recommendation but suggests that the multiplier for the standard deviation-based adder should be 2.00, rather than 1.28 as the Staff proposes. The 2.00 standard deviation level, which corresponds to a 95 percent confidence level, is a more commonly used measure of what is significantly above (or below) the mean than is a 1.28 standard deviation level (corresponding to a 90 percent confidence level).[14] (AEP-Ohio Initial at 8-9.) As discussed in detail in its initial comments, Customer Parties admonish AEP-Ohio's proposal for a 2.00 standard deviation adder, which by Customer Parties' calculations would yield a 78.9 percent return on equity, as unreasonable on its face and another example of why the statistical method is unreasonable and should be rejected. (Customer Parties Reply at 18.)

FirstEnergy explains that the Staff recommended methodology reflects the most conservative acceptable statistical confidence level of 90 percent. Further, FirstEnergy notes that this method and confidence level, assuming the sample group would include companies from industries other than the electric utility industry, reduces the prospect of a "false positive" result where the SEET would incorrectly identify the electric utility's earnings as significantly excessive, and mitigates the likelihood of imposing an asymmetric risk upon the electric utilities with regard to the electric utility's ability to actually earn the return allowed by the Commission.[15] However, FirstEnergy points out that if the sample of comparable companies is more restrictive it would be appropriate to use a higher confidence level of 95 percent or 97.5 percent. The higher confidence level is appropriate, as FirstEnergy reasons, since there is less variance in distribution of returns within more restricted samples and, therefore, the danger of the test resulting in false positives is increased and may yield an incorrect implication of significantly excessive

14 AEP-Ohio ESP cases, Direct and Rebuttal Testimony of AEP-Ohio witness Makhija (July 31, 2008 and December 8, 2008).

15 FirstEnergy ESP case, Companies' Exhibit 8, Direct Testimony of FirstEnergy witness Vilbert at 14-20 (July 31, 2008).

earnings.[16] Moreover, FirstEnergy emphasizes that beyond the mechanical application of a mathematical test, Section 4928.143(F), Revised Code, requires the Commission to consider the capital requirements of future committed investments in Ohio. (FirstEnergy Initial at 4-5.)

With respect to the appropriate "backstop" level, FirstEnergy and AEP-Ohio concur in Staff's recommendation to adopt, and the rationale for implementing, 200 basis points as a minimum increment above the mean return for the comparable companies as a "backstop." (FirstEnergy Initial at 5; AEP-Ohio Initial at 9.)

Duke believes that Staff's proposal to use 200 basis points rather than the 1.28 standard deviation is appropriate in difficult economic times (Duke Initial at 6). DP&L recommends that the electric utility's regulated return on equity established in its most recent rate proceeding plus 30 percent, be used as the appropriate backstop for determining significantly excessive earnings (DP&L Initial at 4-5).

Customer Parties state that DP&L's recommendation is not based on the company's testimony in its ESP or any other case and is, thus, without foundation. Further, Customer Parties request clarification of whether the 30 percent is an adjustment made as a percentage of the established return on equity as opposed to an adjustment of 30 percentage points over the established return on equity, and notes that the established rate of return on common equity for most of Ohio's electric utilities was established in rate proceedings ten to 15 years ago and have little relevance to the current cost of capital and economic conditions. Accordingly, Customer Parties oppose DP&L's backstop recommendation. (Customer Parties Reply at 17.)

Because the comments received in response to Recommendation 5 intertwine with the comments received in response to Recommendation 7, the Commission's finding with respect to Recommendation 5 will be provided in the discussion of its findings in response to Recommendation 7 so that interested stakeholders have a cohesive synopsis of the methodology establishing the SEET threshold.

> Staff Recommendations 6 and 9: How should companies "that face comparable business and financial risk" be determined? How should the earnings of a comparable company be adjusted to compensate for the financial risk difference associated with the difference in capital structures?

In regard to the method for comparable group sample selection, Staff suggests that since different companies are structured differently and economic conditions will vary over time, the comparable group samples should vary case-to-case. While leverage can be

[16] Id. at 16.

used as a factor in the group selection, Staff believes that not doing so and adjusting the resulting returns for the comparable group companies is preferable, as this enables a larger sample to be used. A larger sample enables greater validity for the results. Staff would leave this choice to the discretion of the Applicant companies as doing so would be consistent with the case-by-case group selection policy and because the leverage consideration is of secondary significance.

DP&L agrees with Staff that the comparable companies should vary on a case-by-case basis to reflect different company structures, business profiles, and economic conditions and that the earnings of the comparable companies may be adjusted on a case-by-case basis to account for different capital structures consistent with paragraphs (E) and (F) of Section 4928.143, Revised Code. (DP&L Initial at 5-6.)

AEP-Ohio generally concurs with Staff's recommendation and observations and, in particular, the recommendation that the choice for selecting the comparable group would be at the discretion of the electric utility (AEP-Ohio Initial at 10).

FirstEnergy suggests that the method for selecting comparable companies be uniformly applied to all Ohio electric utilities pursuant to the process set out in the FirstEnergy ESP cases. A uniform selection method, according to FirstEnergy, reduces potential uncertainty in the application of the SEET from year to year and from electric utility to electric utility but allows, if the specific circumstances presented justify, a departure from application of the uniform methodology on a limited basis. (FirstEnergy Initial 5-6.) FirstEnergy advocates the comparable companies selection process presented by FirstEnergy witness Vilbert in the FirstEnergy ESP case.[17]

FirstEnergy also supports, as advocated by FirstEnergy in its ESP proceeding and most recent distribution rate case, the Staff recommendation regarding the financial risk of comparable companies and notes such approach facilitates a larger sample of comparable companies to be used, which improves the validity of the results. (FirstEnergy Initial 6.)

Customer Parties and OPAE note that Staff originally advocated that a single methodology for selection of comparable companies be used for all electric utilities.[18] Customer Parties and OPAE contend that selection of the comparable group is critical for

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17 FirstEnergy ESP case, Direct Testimony of Vilbert at 10-14 (July 31, 2008). Dr. Vilbert's methodology may be summarized as follows: (1) determine that the companies have business risk similar to that of the electric utility selecting : (a) companies that operate in industries that rely on a network of assets to provide services to a customer mix that includes residential, commercial and industrial customers; and (b) the companies have high capital intensity; (2) adjust for differences in capital structure by adjusting the measure of return on capital; and (3) eliminate companies that: (a) have a credit rating below investment grade; (b) foreign companies; and (c) the necessary information to compute the asset turnover measure is not available.

18 AEP-Ohio ESP cases, Direct Testimony of Staff witness Cahaan (November 7, 2008).

two reasons. First, selection of the comparable group determines the mean (average) rate of return on equity and, second because the comparable group also determines the variability of earnings from which the statistical standard deviation is derived. Customer Parties argue that the recommended method will result in unreasonable return on equity thresholds. (Customer Parties Initial at 4, 12; OPAE Reply at 4-5; Tr. 40-41.)

Customer Parties insist that a common methodology for the selection of a comparable group of companies is essential to the SEET. If, as proposed by Staff, this issue is decided on a case-by-case basis, Customer Parties argue that this aspect of the SEET calculation will essentially be a mini rate case. Customer Parties propose the methodology offered by OCC witness Woolridge in the electric utility ESP cases be implemented for all electric utility SEET proceedings. (Customer Parties Initial at 13; Tr. 41.)[19]

AEP-Ohio asserts that Customer Parties' comparable group selection process is flawed to the extent that the process limits comparable firms to only those with the characteristics of other electric utilities, contrary to the language of Section 4928.143(F), Revised Code, and fails to consider the business and risk characteristics of the electric utility. Thus, AEP-Ohio points out that Customer Parties' proposed selection process results in the same list of comparable firms for each Ohio electric utility and, therefore, assumes that the risk of FirstEnergy's electric utilities, which are insulated from generation and transmission risks, is equivalent to the risk faced by AEP-Ohio, even though AEP-Ohio is not insulated from generation and transmission risks. Accordingly, AEP-Ohio continues to support a case-by-case approach to applying the SEET methodology to each electric utility, including the determination of the comparable group. (AEP-Ohio Reply 12-13.)

In regards to how the earnings of comparable companies should be adjusted for the financial risk difference associated with the difference in capital structure, Customer Parties assert there is consensus among three of the experts who offered testimony in the

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19 AEP-Ohio ESP cases, Direct Testimony of OCC witness Woolridge (October 31, 2008). Woolridge's methodology may be summarized as follows: (1) Identify a proxy group of electric utilities that must have: (a) an investment grade bond rating; (b) total revenue less than $ 10 billion; (c) percent of regulated electric revenue of at least 75%; and (d) a three-year history of paying cash dividends. (2) Identify a list of business and financial risk measures to insure that the comparable private sector companies are similar to the proxy group of electric utilities. These business and financial risk measures are: (a) stock price beta (a measure of stock price volatility); (b) asset turnover ratio (measures capital intensity); (c) common equity ratio (shareholder equity as percent of total capitalization); and (d) no foreign companies. (3) Determine the business and financial risk measures identified above (beta, asset turnover ratio, and common equity ratio) for the proxy group of electric utilities. (4) Use the beta, asset turnover ratio, and common equity ratios for the proxy group of electric utilities to screen the thousands of companies in the Value Line database. The result was 64 comparable companies, 44 of which were electric utilities. (5) Calculate the mean (average) ROE for the 64 company comparable group. (6) Finally, adjust the mean (average) ROE for the 64 company comparable group for the actual capital structure of the Ohio electric utility being examined.

ESP cases—Dr. Woolridge, Dr. Vilbert and Mr. King. The process involves computing the pre-tax return on capital for the comparable companies, and then making adjustments to reflect the difference in the benchmark return on equity based on the capital structure of the Ohio electric utility relative to the average of the comparable public companies. Dr. Woolridge's three-step process to make this adjustment includes:

(1) Compute the average pre-tax return on total capital for the comparable group of public companies, using the average return on equity, debt/equity percentages, income tax rates, and long-term debt cost rates;

(2) Compute the pre-tax return on equity for the Ohio electric utility using: (a) the average pre-tax return on total capital for the comparable companies; and (b) the individual debt/equity percentages, income tax rates, and long-term debt cost rates of the Ohio electric utility; and

(3) Compute the after-tax benchmark return on equity for the Ohio electric utility using its income tax rates.

Customer Parties assert that, using 2007 data, Dr. Woolridge's methodology results in a comparable group with a mean return on equity of 11.37 percent and a relatively stable standard deviation of 4.2. By contrast, Dr. Makhija's 2007 comparable group had a mean return on equity of 13.91 percent and a standard deviation of 32.51. The OCC and FirstEnergy witnesses both determined a similar mean return on equity (11.37 percent versus 13.91 percent). Customer Parties recognize that the standard deviation of the OCC's and AEP-Ohio's comparable group was widely different, 4.52 versus 32.51, which demonstrates why statistical standard deviation approach to SEET cannot be relied upon for protecting customers under the statutory standard. (Customer Parties Initial at 13-14.)

Customer Parties acknowledge that SB 221 explicitly states that the capital structure of the electric utility should be considered and accounted for in assessing the SEET. However, Customer Parties are concerned that the Staff recommendation makes consideration of the capital structure a secondary consideration and also that it should not be determined on a case-by-case basis. Further, as stated previously, Customer Parties object to each electric utility selecting the comparable group of companies pursuant to Dr. Vilbert's method since the statute requires that leverage (i.e., ratio of common equity) consideration be given primary and explicit consideration in the group selection process. Customer Parties assert that FirstEnergy's proposal ignores the leverage consideration in the sample group selection and instead adjusts the resulting return. (Customer Parties Reply at 19-20.)

Lastly, while Customer Parties and FirstEnergy both support a uniform statewide method for determining comparable companies, Customer Parties argue that the method proposed by FirstEnergy is flawed, unreasonable, and arbitrary and includes no risk measures. Customer Parties claim that if the Commission believes that the distribution-only FirstEnergy utilities are less risky than generation-owning utilities, then that factor can be accounted for with a lower basis point premium above the benchmark return. (Customer Parties Reply at 19-20.)

FirstEnergy challenges Customer Parties' representation that Dr. Woolridge, Dr. Vilbert and Mr. King "provide much the same methodology" for making the adjustment to account for financial risk. FirstEnergy states that there is considerable difference between the mechanism proposed by Dr. Vilbert and that offered by Dr. Woolridge and Mr. King, as Staff witness Cahaan recognized.[20] The uniform methodology for selection of the comparable companies as advocated by Dr. Woolridge is amiss with shortcomings and deficiencies, as FirstEnergy allegedly demonstrated in its briefs in its ESP case. DP&L asserts that a common methodology fails to recognize that each of the Ohio electric utilities have different financial and business risks. Further, FirstEnergy, AEP-Ohio, Duke, and DP&L note that Customer Parties' criticism overlooks the fact that under Section 4928.143(F), Revised Code, the electric utility bears the burden of proof on the SEET determination and that it is the Commission that will determine if the burden has been sustained. FirstEnergy reasons it is procedurally customary for the party with the burden of proof to present its case and prove its methodology with the active participation of interested persons. Further, AEP-Ohio points out that the electric utility cannot dictate the comparable group of companies as the statute sets forth the basis for evaluating the group of comparable companies. (FirstEnergy Reply at 8-10; AEP-Ohio Reply at 6-7; Duke Reply at 7-8; DP&L Reply at 2-3.)

At this time, the Commission declines to predetermine which companies shall be included in the "comparable group" in determining the SEET. Because each electric utility is unique, and conditions are constantly changing, the Commission does not believe it to be prudent to establish a comparable group process now which may be subject to change. All parties acknowledge that, at a minimum, there may need to be "tweaks" to a comparable group, among the companies and over time, if the group were predetermined now. The Commission also notes that it is the electric utility that will bear the burden of proof of demonstrating that its preferred comparable group is appropriate. As with other cases wherein earnings are considered, it is the Commission that will make the final decision as to the appropriate mix of companies comprising the "comparable group." Therefore, the Commission will decide the comparable group on a case-by-case basis each year. Doing so, fosters the goal of ensuring that the comparable group reflects current general market conditions and that of the individual electric utility.

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20 FirstEnergy ESP case, Tr. Vol. IX at 119 (October 28, 2008).

Staff Recommendation 7: How are "significantly excessive earnings" to be determined, as that phrase is used in the third sentence of Section 4928.143(F), Revised Code?[21]

Staff recommends that significantly excessive earnings be measured by whether the earned return on common equity of the electric utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. Staff endorses the concept that a return on common equity in excess of 1.28 times the standard deviation above the mean of a comparable group of companies should be defined as earnings significantly in excess, except in a low earnings environment when 200 basis points could be substituted.

AEP-Ohio agrees with the Staff's recommended approach; however, as discussed above in Recommendations 5, 6, and 9, regarding the definition of "significantly in excess of the return on common equity," and comparable companies, AEP-Ohio proposes that 2.00 standard deviations, rather than 1.28 standard deviations, should be used as the adder to determine the threshold for significantly excessive earnings. DP&L agrees with AEP-Ohio's claims and recommendation on this issue. (AEP-Ohio Initial at 10; DP&L Reply at 3.)

Customer Parties disagree with Staff's recommendation on this matter, arguing instead that a 200 basis point premium above the mean return of the comparable group is appropriate and should also recognize upcoming major capital expenditures of the electric utility, subject to certain conditions precedent. (Customer Parties Initial at 2, 8-9, 22; Tr. 37-39.) AEP-Ohio asserts that Customer Parties' proposal is misguided, as the company states in its comments in regard to Recommendations 3 and 9, above. (AEP-Ohio Reply 14.)

FirstEnergy reiterates its comments made with regard to Recommendation 5, the definition of "significantly in excess of the return on common equity." (FirstEnergy Initial at 4-6.) At the question and answer session, FirstEnergy interpreted Section 4928.143(F), Revised Code, to provide the Commission with some discretion to be used on a case-by-case basis to adjust the earnings of the electric utility in comparison to the comparable group (Tr. 39-40).

Having fully considered all the comments regarding establishing the threshold and in consideration of the discretion afforded the Commission in SB 221, the Commission

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21 The third sentence of Section 4928.143(F), Revised Code, states:
"The burden of proof for demonstrating that significantly excessive earnings did not occur shall be on the electric distribution utility."

concludes that "significantly excessive earnings" should be determined based on the reasonable judgment of the Commission on a case-by-case basis.

The Commission notes that within Ohio's electric utilities, there is significant variation, including, for example, whether the electric utility provides transmission, generation, and distribution service or only distribution service. For this reason, the Commission will give due consideration to certain factors, including, but not limited to, the electric utility's most recently authorized return on equity, the electric utility's risk, including the following: whether the electric utility owns generation; whether the ESP includes a fuel and purchased power adjustment or other similar adjustments; the rate design and the extent to which the electric utility remains subject to weather and economic risk; capital commitments and future capital requirements; indicators of management performance and benchmarks to other utilities; and innovation and industry leadership with respect to meeting industry challenges to maintain and improve the competitiveness of Ohio's economy, including research and development expenditures, investments in advanced technology, and innovative practices; and the extent to which the electric utility has advanced state policy. We therefore, direct the electric utilities to include this information in their SEET filings.

While a number of commenters request a bright line statistical analysis test for the evaluation of earnings, and the Commission agrees that statistical analysis can be one of many useful tools, utilizing only a statistical method for establishing the SEET threshold is insufficient by itself to meet the electric utility's burden of proof pursuant to Section 4928.143(F), Revised Code. Section 4928.143(F), Revised Code, places on the utility "the burden of proof for demonstrating that significantly excessive earnings did not occur." Passing a statistical test does not, in and of itself, demonstrate that excessive earnings did not occur. The statute requires more from the utilities to meet the burden of proof that excess earnings did not occur. The Commission may use a standard deviation test as one tool by which to determine whether an electric utility had significantly excessive earnings.

However, the Commission is willing to recognize a "safe harbor" of 200 basis points above the mean of the comparable group. To that end, any electric utility earning less than 200 basis points above the mean of the comparable group will be found not to have significantly excessive earnings.

Staff Recommendation 8: What does "in the aggregate" mean in relation to the adjustments resulting in significantly excessive earnings?

Staff interprets "in the aggregate" in relation to the adjustments resulting in significantly excess earnings to mean that the total of all the adjustments created by the implementation of an ESP is to be assessed for its impact in determining whether the

electric utility achieved a return on common equity significantly in excess of the earnings of comparable companies.

Customer Parties cite the language in Section 4928.143(F), Revised Code, in support of their arguments that: (1) an electric utility's SEET refund exposure is limited to the aggregate amount of the ESP rate adjustment the electric utility receives, and excludes any excess earnings which resulted from something other than the ESP; and (2) the cumulative level of the ESP rate adjustment is subject to refund (Customer Parties Initial at 18). FirstEnergy, AEP-Ohio, and Duke argue that the Customer Parties' concept that "in the aggregate" is also "cumulative" is unsupported and inconsistent with the statutory directive of applying the SEET annually based on the language in Section 4928.143(F), Revised Code, and modifies the General Assembly's design for SEET (FirstEnergy Reply at 10; AEP-Ohio Reply at 1-2; Duke Reply at 8). Further, AEP-Ohio argues that the inherent flaw in Customer Parties' argument is that the earnings from the first year of an ESP would be subject to refund in every year of the term of the ESP, but adjustments made in the first year are not considered in subsequent years. The initial adjustment, AEP-Ohio rationalizes, becomes a part of the base rate level for the next year. Therefore, AEP-Ohio emphasizes that the proposal could result in returning to consumers 2009 earnings in 2011, or later, depending on the term of the ESP. (AEP-Ohio Reply at 14.)

AEP-Ohio concurs with the Staff recommendation (AEP-Ohio Initial at 11). Duke asserts that the Staff's proposal is unclear and requests clarification (Duke Initial at 6-7). DP&L contends that pursuant to Section 4928.143(E) and (F), Revised Code, and the intent of SB 221, the SEET only applies to the adjustments made by the ESP. DP&L believes that the components of an electric utility's standard service offer, approved by the Commission prior to the ESP, are not subject to the SEET, as supported by the company's interpretation of the legislation's Final Analysis. DP&L points out that the legislature's Final Analysis of SB 221 specifically states: "the PUCO must determine if any price adjustments granted under the plan resulted in excessive earnings for the utility" and only if "the adjustments, in the aggregate, did result in significantly excessive earnings, it must require the utility to return to consumers the amount of the excess by prospective adjustments," subject to the electric utility's right to terminate the ESP and file an MRO immediately. DP&L asserts that the legislative analysis clearly provides that the SEET applies only to ESP-created adjustments to the standard service offer and, therefore, reasons that the phrase "in the aggregate" means that the adjustments to the standard offer should be looked at together, and not by each individual component. (DP&L Initial at 5-6.)

The Commission finds that "in the aggregate" refers to the total of any adjustments resulting from the ESP as advocated by Staff. In addition, we do not equate the phrase "in the aggregate" to mean "cumulative" as Customer Parties argue. The Commission reasons that to make the adjustments resulting in significantly excessive earnings cumulative would, as AEP-Ohio argues, make the electric utility's earnings from the first

year of an ESP subject to refund in every year of the term of the ESP without consideration of the adjustments made in the first year being considered in subsequent years. Furthermore, as previously explained in response to Recommendations 3 and 11, the Commission finds that the amount of adjustments eligible for refund will be the value of the adjustments in the current year under review compared to the revenues which would have been collected had the rates from the electric utility's previous rate plan still been in place. For these reasons, we adopt the recommendation of the Staff as to the meaning of "in the aggregate."

Staff Recommendation 10: What mechanism should be employed to return to customers the amount of excess earnings?

Staff recommends that the Commission determine in each electric utility's annual SEET proceeding the mechanism by which any excess earnings may be returned to customers. This would allow the Commission the discretion, based on any unique situation or time sensitive circumstance, to return the money to customers as the Commission believes appropriate. The Commission would also have the latitude to return the money in varying time periods and/or as reductions to other electric utility-imposed charges as the Commission deems appropriate.

Customer Parties generally concur with the Staff recommendation, but only to the extent that "other EDU imposed charges" means charges affecting customer rates and, thus, a reduction of such charges results in a reduction in customer rates. Customer Parties contend that after a finding of significantly excessive earnings, the parties should endeavor to stipulate to the mechanism to return the excess earnings to customers and, if a stipulation cannot be achieved, the parties should be provided an opportunity to present their respective position to the Commission. Customer Parties contend that SEET refunds may raise a number of issues better addressed as a part of the circumstances of any given case.[22] Finally, Customer Parties express some concern with the recommendation regarding the Commission's discretion to refund over varying time periods. Customer Parties argue that customers should get any excess earnings refund as promptly as possible without delay. (Customer Parties Initial at 23.)

AEP-Ohio, DP&L, and FirstEnergy agree with Staff's recommendation that the prospective adjustments should be determined on a case-by-case basis. DP&L, however, emphasizes that Section 4928.143(E) and (F), Revised Code, does not characterize the

22 Customer Parties state, for example, that a SEET proceeding may raise the following issues: (1) Should a SEET refund be bypassable or non-bypassable credit; (2) Over what period of time should the refund be made; (3) Should there be interest on the unamortized SEET refund balance and, if so, at what level; (4) Should a customer on discounted economic development contract (reasonable arrangement or unique arrangement) receive an additional discount through a SEET refund; and (5) Should any SEET refund first be used to pay off monies owed by customers to the electric utility in the form of deferrals.

adjustments as "refunds" and, therefore, proffers that any prospective adjustments from the SEET represent prospective changes in charges associated with providing future electric services. AEP-Ohio contends that the case-by-case determination should be addressed by the parties after a Commission determination of significantly excessive earnings. This two-step process would enable parties to a proceeding to consider the appropriate mechanism in the context of the amount of the significantly excessive earnings. (DP&L Initial at 6; AEP-Ohio Initial at 11; AEP-Ohio Reply at 14-15; FirstEnergy Initial at 7.)

As each of the commenters recognizes, if an electric utility is found to have significantly excessive earnings, such a determination has the potential to raise several issues, which are better addressed on a case-by-case basis. For that reason, the Commission may offer the parties to a SEET proceeding a reasonable, limited period of time to propose how any excess earnings should be returned to customers, including any buy-down of deferrals.

ORDER:

It is, therefore,

ORDERED, That pursuant to the decisions of the Commission as set forth herein, each electric utility's earnings be evaluated in accordance with this Order. It is further,

ORDERED, That Citizen's request to withdraw its initial comments and adopt the position of Customer Parties in its initial and reply comments be granted. It is, further,

ORDERED, That each electric utility file its proposed SEET application, in accordance with the Commission's directives, by July 15, 2010. It is, further,

ORDERED, That a copy of this entry be served upon all commenters, electric distribution companies and electric service companies operating in Ohio, and all other interested persons of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Paul A. Centolella

Valerie A. Lemmie

Steven D. Lesser

Cheryl L. Roberto

GNS/ vrm

Entered in the Journal
JUN 30 2010

Reneé J. Jenkins
Secretary

PUR Slip Copy

Re Ohio Power Company
Case No. 93-101-EL-EFC

Ohio Public Utilities Commission
May 25, 1994

APPEARANCES: Messrs. Richard Cohen, Ohio Power Company, 215 North Front Street, Columbus, Ohio 43215, Marvin I. Resnik, and Kevin F. Duffy, American Electric Power Service Corporation, One Riverside Plaza, Columbus, Ohio 43215, on behalf of Ohio Power Company. Mr. Lee Fisher, Attorney General for the State of Ohio, James B. Gainer, Section Chief, by Messrs. Thomas W. McNamee and William L. Wright, Assistant Attorneys General, 180 East Broad Street, Columbus, Ohio 43215-3793, on behalf of the staff of the Public Utilities Commission of Ohio. Mr. Robert S. Tongren, Consumers' Counsel, by Ms. Colleen L. Mooney, Associate Consumers' Counsel, 77 South High Street, 15th Floor, Columbus, Ohio 43266-0550, on behalf of the residential customers of Ohio Power Company. Emens, Kegler, Brown, Hill & Ritter, by Mr. Samuel C. Randazzo, Mr. Richard P. Rosenberry, Ms. Denise C. Clayton, and Mr. Mark R. Kempic, 65 East State Street, Suite 1800, Columbus, Ohio 43215, on behalf of Anheuser-Busch Companies, Inc., B.P. Oil Company, LTV Steel Company, Owens-Corning Fiberglass Corporation, Republic Engineered Steels, Inc., The Timken Company, and Stone Container Corporation (Industrial Energy Consumers). Cassidy, Myers, Cogan & Boegelin, LC, by Mr. Thomas M. Myers, 148 West Main Street, St. Clairsville, Ohio 43950 and by Mr. Eugene M. Trisko, P.O. Box 596, Berkley Springs, West Virginia 25411, on behalf of Larry Ward, President of District Six of the United Mine Workers of America and a Concerned Citizen, and Local Union Numbers 1604 and 6362, United Mine Workers of America (hereinafter jointly referred to as United Mine Workers of America).

Before Glazer, chairman, and Biddison, Fanelly (dissenting), Butler, and Johnson, commissioners.

BY THE COMMISSION:

*1 The new electric fuel component (EFC) rate for the Ohio Power Company's retail customers will be 1.541080[/kWh for the six-month period beginning June 1, 1994 through November 30, 1994. The new EFC rate is a decrease from Ohio Power Company's last approved EFC rate for the six-month period ending May 31, 1994, which was 1.583368[/kWh.

In addition to establishing a new EFC rate, the Commission reviews the results of the financial and management/performance auditors. The financial auditor found that Ohio Power Company (Ohio Power) had accurately computed the EFC rate and correctly applied it to its customer bills. The management/performance auditor found, *interalia*, that the company should develop a plan to address it problems with the Muskingum and Windsor affiliate mines and should continue to minimize capital expenditures and leased commitments for the Muskingum and Windsor mines. The management/performance auditor also examined several issues related to the sale of the Martinka Mine, the execution of the Peabody contract, the execution of the Sands Hill contract, the termination of the Donaldson contract and its replacement contract, and compliance with the Clean Air Act.

In this Opinion and Order, the Commission determines that the purchase of coal under the Peabody contract during the audit period was reasonable under the circumstances presented in the record and that such purchases will continue to be reviewed on an ongoing basis in future proceedings. Moreover, the Commission determines that the issue of fuel switching Cardinal Unit 1 will be reviewed further in the company's upcoming environmental compliance plan review proceeding and future EFC proceedings. The Commission also determines that the loss from the buy-out of a dragline lease should have been expensed during the period of the last stipulated price cap and that the proposed lease buy-out of a

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second dragline in 1994 should be reviewed by the next management/performance auditor. The Commission orders the financial and management/performance auditors for the next EFC proceeding to address several other issues, as set forth in the opinion and order. The Commission also directs Ohio Power to report upon several matters in the next EFC proceeding.

This summary was prepared to provide a brief statement of the Commission's action. It is not a part of the Commission's decision and does not supersede the full text of the Commission's order.

OPINION AND ORDER

The Commission, having reviewed the testimony and exhibits presented at the public hearing, relevant portions of the Revised Code and Ohio Administrative Code, and being fully advised, issues its opinion and order.

OPINION:

I. *Introduction*

Ohio Power Company (Ohio Power) is an electric light company under Section 4905.03(A)(4), Revised Code, and is, therefore, a public utility subject to the ongoing jurisdiction and supervision of this Commission pursuant to Sections 4905.02, 4905.04, 4905.05, and 4905.06, Revised Code. Ohio Power is also an electric utility within the meaning of Rule 4901:1-11-01(L), Ohio Administrative Code (O.A.C.).Section 4905.301, Revised Code, requires the Commission to review each electric utility's electric fuel component (EFC) at a hearing once annually, or at a lesser interval of time as ordered by the Commission. By Finding and Order issued June 24, 1993, the Commission initiated the mid-year adjustment and annual audit adjustment proceedings to review Ohio Power's EFC and related matters.

*2 On November 10, 1993, the Commission issued another finding and order in this proceeding. The Commission determined that Ohio Power timely filed the requisite data submissions, in accordance with the Commission's November 5, 1992 Finding and Order. Additionally, the Commission approved an EFC rate of 1.583368 cents per kilowatt hour ([/kWh) to become effective with the December 1993 cycle 1 billing on November 29, 1993. Moreover, the Commission noted that the establishment of the mid-year EFC adjustment would be subject to full review in Ohio Power's annual EFC hearing.

In addition to the hearing requirements set forth in Section 4905.301, Revised Code, the Commission is required by Section 4905.66(B)(2), Revised Code, to conduct or cause to be conducted, at least annually, an audit of the fuel-related policies and practices of each electric utility. Rule 4901:1-11-10, O.A.C., provides that each electric utility shall be subject to a management/performance (m/p) audit and a financial audit of its fuel-related policies and practices. Rule 4901:1-11-10(B)(1), O.A.C., requires the Commission to conduct the m/p audit or cause this audit to be conducted by a qualified independent auditing firm selected by the Commission, and Rule 4901:1-11-10(B)(2), O.A.C., requires the Commission to conduct the financial audit or cause this audit to be conducted by a qualified independent auditing firm selected by the electric utility. Rules 4901:1-11-10(B)(1) and 4901:1-11-10(B)(2), O.A.C., require the electric utility to bear the cost of the audits.

By Finding and Order dated June 24, 1993, the Commission determined that both the financial and m/p audits of Ohio Power would be conducted in conjunction with the annual audit adjustment proceeding. Ernst & Young conducted the company's financial audit and Energy Ventures Analysis, Inc. (EVA) conducted the m/p audit. On February 14, 1994, the m/p and financial audit reports were filed with the Commission. The scope of the respective audits was defined by Rule 4901:1-11-10(C), O.A.C., and the Commission's opinion and orders in *In the Matter of the Regulation of the Electric Fuel Component Contained Within the Rate Schedule of Ohio Power Company and Related Matters*, Case No. 92-01-EL-EFC (November 25, 1992), Case No. 92-101-EL-EFC (November 25, 1992), and Case No. 93-01-EL-EFC (May 26, 1993).

Section 4909.191(A), Revised Code, requires each elec-

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tric utility to file proof at the time of its EFC hearing that notice of the proceedings was published in accordance with that statute. Additionally, Rule 4901:1-11-11, O.A.C., requires that the same hearing notice be published once between 15 and 30 days prior to the hearing date. Ohio Power caused the required publications to be made (Ohio Power Exs. 1 and 13).

Section 4909.191(C), Revised Code, requires the Commission at each EFC hearing to consider, to the extent applicable, the efficiency of the electric utility's fuel procurement policies and practices, the results of the financial and the m/p audits, and the company's compliance with previous performance recommendations. Rule 4901:1-11-11(B)(5), O.A.C., additionally requires the Commission to determine the EFC rate to be charged by the company during the next current period. Section 4909.191(C), Revised Code, and Rule 4901:1-11-11(B), O.A.C., require each electric utility to demonstrate at its EFC hearing that its acquisition and delivery costs were fair, just, and reasonable. Ohio Power filed data pertinent to its fuel procurement policies and practices in accordance with Section 4909.191(B), Revised Code, and Rule 4901:1-11-11(D)(1), O.A.C. The direct testimony of the company's witnesses was filed in accordance with the Commission's June 24, 1993 Finding and Order.

*3 The Office of Consumers' Counsel (OCC), the Industrial Energy Consumers (IEC), and the United Mine Workers of America (UMWA) were granted intervention in this proceeding. A hearing in this matter commenced on March 15, 1994 and continued on March 16, 17, 21, 22, and 23, 1994. At the hearing, Messrs. Paul W. Daley, Henry W. Fayne, Gregory Campbell, Charles A. Oberlin, Robert M. Quinlan, and Charles A. Ebetino, Jr. testified on behalf of the company. Mr. Tom Meike testified as a representative of the financial auditor and Mr. Seth Schwartz and Ms. Emily S. Medine testified as representatives of the m/p auditor. IEC sponsored the testimony of Mr. Forrest E. Hill. The record in the previous EFC proceeding, *In the Matter of the Regulation of the Electric Fuel Component Contained Within the Rate Schedule of Ohio Power Company and Related Matters*, Case No. 93-01-EL-EFC (May 26, 1993), was incorporated into the record in this matter (Tr. II, 53) (hereinafter, references to the record in the previous EFC proceeding will be prefaced with '93-01'). The parties, except the UMWA, filed their briefs on April 11, 1994 and reply briefs on April 22, 1994.

II. *The EFC Financial Audit*

On February 14, 1993, Ernst & Young filed with the Commission its EFC Financial Performance Audit (Comm. Ord. Ex. 1). The financial auditor reviewed Ohio Power's calculation of the EFC rate in the review period (December 1, 1992 to November 30, 1993). The scope of the review included, *interalia*, the processing of fuel receipt and consumption transactions, processing of energy purchase and sale transactions, calculation of the EFC rate, procedures for processing fuel data, review of quality and quantity specifications, and the reporting of payments made for fuel acquisition and delivery. The auditor concluded the following in its review:

1) purchase order procedures are adequate and the process serves to ensure that the fuel ordered monthly reflects system fuel requirements; 2) the invoice and voucher procedures in effect should adequately ensure that the fuel paid for is in agreement with the fuel received and the governing contracts; 3) the freight voucher procedure is being followed; 4) the fuel analysis testing (weighted average British thermal units per pound and quality adjustments) were correct; 5) no other pending or approved escalation requests or accruals were identified as outstanding at the end of the audit period, other than the normal ongoing escalation requests and accruals; 6) no audit exceptions were found; 7) a new billing adjustment charge was properly applied during the first billing cycle for the months June and December; 8) the company performed its inventory adjustments during the audit period in accordance with its procedure; 9) the company's physical inventory adjustments were properly reflected in the calculation of the EFC rates; and 10) the company computed and reported the EFC in accordance with the fuel clause requirements.

*4 (*Id.* at II-1 to II-5).

In the 1992 EFC proceedings, the Commission ap-

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proved a stipulation in which the signatory parties agreed that, for all coal burned at the Gavin, Muskingum, Mitchell, and Cardinal (Units 1 and 2) plants from December 1, 1991 to November 30, 1994, Ohio Power shall use the predetermined price of 164[per million British thermal units ([/mBtu) to accelerate recovery of the Ohio Proportionate Jurisdictional Share of the Meigs affiliate mining operation. *Ohio Power Co.*, Case No. 92-101-EL-EFC,*supra*, at 15.PEC appealed the Commission's approval of the stipulation to the Ohio Supreme Court, which affirmed the Commission's adoption of the settlement on March 30, 1994. *Indus. Energy Consumers of Ohio Power Co. v. Pub. Util. Comm.* (1994), 68 Ohio St. 3d 559.Ohio Power included an additional $10,390,024 to the reconciliation adjustment, which reflects the effect of the stipulation on the price of coal burned at the four plants from December 1, 1992 to November 30, 1993. Ernst & Young reviewed this addition to the reconciliation adjustment and found Ohio Power's methodology and calculation to be reasonable (*Id.* at II-6).

Ernst and Young made no recommendations (*Id.*).

III. *The EFC Management/Performance Audit*

EVA conducted the m/p audit of the fuel procurement policies and practices of Ohio Power (Comm. Ord. Ex. 2). [FN1] This review covered the audit period of December 1, 1992 to November 30, 1993. In addition to the general objectives set forth in the Commission's Request for Proposal, the m/p auditor reviewed:

1) the management and operation of Ohio Power's affiliate coal mines; 2) issues related to fuel procurement, including: the buy-out of the Donaldson contract, the replacement contract, the Sands Hill contract, and the deviation between physical and book inventory in the pile inventory procedure; 3) Ohio Power's efforts to implement the recommendations from last year's m/p audit proceeding which were ordered by the Commission; 4) a list of issues regarding the sale of the Martinka Mine and the simultaneous execution of a coal contract with Peabody Development Company (Peabody); and 5) a list of issues related to Ohio Power's Clean Air Act compliance plan.

A. *Affiliate Operations*

As part of its audit, EVA reviewed Ohio Power's operations at its affiliate mines. During the audit period, Ohio Power owned three coal mining operations. They are: the Southern Ohio Coal Company (SOCCO), the Central Ohio Coal Company (COCCO), and the Windsor Coal Company (Windsor). SOCCO operates the Meigs mines, which send coal to Ohio Power's Gavin plant, and operated, prior to its sale, the Martinka mine, which sent its coal to Ohio Power's Mitchell plant. COCCO operates the Muskingum mines and sends its coal to the Muskingum River plant. Windsor operates the Windsor mine and sends its coal to the Cardinal plant.

Ohio Power is required to demonstrate that its acquisition and delivery costs for fuel to generate electricity are fair, just, and reasonable. In defining 'acquisition cost', Section 4905.01(F), Revised Code, states in part that affiliate coal included in the EFC rate shall not exceed a price that is reasonable when compared to the average cost per mBtu of similar quality coal purchased from all independent like mining operations under similar term contracts during the period. In addition, pursuant to Section 4905.67(B), Revised Code, the Commission is required annually to determine whether the acquisition cost of the fuel which is supplied to the electric utility by an affiliate company represents a sales price that produces a return on the affiliate company's actual investment base that is fair and reasonable.

*5 During the current audit period, Ohio Power purchased 16.2 million tons of coal, 51.9 percent of which was from its affiliate mines (Comm. Ord. Ex. 2, at 1-4). The average price of coal purchased during the audit period was 153.4 [/mBtu, a one percent decline from the prior audit period (*Id.*). The cost differential between affiliate and contract coal prices increased from 21.25 [/mBtu in the last audit year to 30.77[/ mBtu in the current audit period (Co. Ex. 8, at 26; Tr. III, 152-4). The growth in the differential between affiliate and non-affiliate coal prices was due primarily to a $5.88/ton free-on-board (FOB) production cost for a write-off of a COCCO dragline and the temporary closure of Meigs Mine No. 31 (*Id.* at 26-7). A prolonged, selective strike by the UMWA also occurred during the

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audit period and affected Ohio Power's performance (Comm. Ord. Ex. 2, at 3-3). EVA also noted that the Muskingum Mine scaled back to one dragline operation to mine a single pit in reserves closer to the preparation plant (*Id.* at 1-9). EVA agreed with this direction in general and, furthermore, stated that this plan should help minimize operating costs and future final reclamation costs if the mine stays open through 1999 (*Id.*). EVA further stated that the productivity of the continuous miner units at the Meigs mines had improved during the audit period, as recommended by the previous m/p auditor, and that the management should continue this improvement, particularly at Meigs Mine No. 31 (*Id.* at 2-26).

The average delivered price of affiliate coal increased from 164.66[/mBtu in the last audit year to 171.92[/ mBtu for this audit year (Co. Ex. 8 at Ex. 9 and 10). However, prior to the flooding of the Meigs Mine No. 31, the price of affiliate coal was significantly below the prior audit period (Comm. Ord. Ex. 2, at 3-4). EVA noted that, except for the Windsor affiliate, most of the productivity improvements resulted from manpower reductions, rather than production increases (*Id.* at 4-17). Also, EVA pointed out that the average selling price for the coal from the affiliate coal during the audit period, FOB mine, was $41.26/ton for Meigs coal, $41.32/ton for Muskingum coal, and $33.57/ton for Windsor coal (*Id.* at 4-23).

EVA made several recommendations with regard to Ohio Power's affiliate operations. First, EVA recommended that management evaluate the impact of alternative work schedules resulting from a new labor contract settlement between the UMWA and Bituminous Coal Operators Association (BCOA) (Comm. Ord. Ex. 2, at 4-41). EVA believes that the impact of the schedules on production and mining costs should be reviewed to determine if the alternative work schedules could reduce costs and by what amount (*Id.*).

Second, EVA noted that, on July 11, 1993, the Meigs Mine No. 31 flooded. On November 16, 1992, Ohio Power filed a motion to limit issues with the Commission. Ohio Power requested that issues concerning the inundation of water at the Meigs Mine No. 31 not be considered in this proceeding for several reasons, including the fact that the cause and costs of the flooding were still unknown. By entry dated December 13, 1993, the attorney examiner granted the motion to limit issues. EVA suggested that the next m/p auditor review the cause of the flood of Meigs Mine No. 31, the appropriate handling of the costs of the flood repair, and the decision to rehabilitate the mine (*Id.* at 4-3 and 4-41).

***6** Third, EVA recommended that the cost of litigation and damages which result from the lawsuit of BCOA against the affiliate mines (regarding the legality of the interim labor contract settlement referenced above) be included under the current price cap (*Id.* at 4-43). EVA believes this is appropriate because the affiliates received the benefit of the agreement during the time in which the price cap was in place and, thus, the costs should be included under the cap as well (*Id.*). Fourth, EVA noted that the level of capital and lease expenditures by the affiliates has been very high, as the mines were recapitalized (Comm. Ord. Ex. 2, at 4-43). EVA recommends that AEP continue to minimize capital expenditures and new lease commitments at the Muskingum and Windsor mines (*Id.* at 4-44). EVA stated that all 'attempts should be made to get by with existing equipment' and, when an existing lease expires, the affiliate mine should attempt to obtain short-term leases on existing equipment (*Id.*). EVA believes that this would limit the future liability to the ratepayer should the mines need to be closed (*Id.*).

Next, EVA noted that management modified its plans to mine the 'C' Block at Meigs Mine No. 31 as a result of the previous m/p auditor's recommendation (Comm. Ord. Ex. 2, at 4-44.). Management decided to mine two to three longwall panels from north-to-south (down dip) and, then, to switch to a south-to-north sequence when the southern part of the area is developed (*Id.* at 2-25 and 4-44). EVA sees two potential problems with the current plan: (1) the panels in the north will be mining down dip and (2) the last long-wall panel will be mined out on both sides, potentially creating a roof support problem and possibly rendering it unmineable (*Id.*). Although the company has been able to mine in this type of situation in the past, EVA prefers an alternate plan

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and recommended that the company evaluate the feasibility and associated costs of operating a supersection (two continuous miner units in one section) to accelerate the development of the southern part of the 'C' Block (*Id.*). Next, EVA recommended that all of the affiliate mines control excessive overtime (*Id.*). EVA stated that, typically, industry overtime levels are eight to 12 percent, while Meigs had 26 percent, COCCO had 15 percent, and Windsor had 23 percent overtime levels during the audit period (*Id.* at 4-45). EVA believes that overtime should not be scheduled just to meet tonnage goals (*Id.* at 1-12).

Lastly, EVA recommended that Ohio Power address its problems with disposing of the Windsor and Muskingum affiliate mines and develop a plan forthwith (Comm. Ord. Ex. 2, at 1-8). EVA believes that AEP made no progress in disposing of these affiliate investments in 1993 because it was waiting for a decision by the Commission on the Martinka transaction (*Id.* at 1-8). EVA stated that the mines are unlikely to be attractive assets without a coal supply agreement to Ohio Power (*Id.*). Yet, the delay in addressing the disposition of the mines has reduced Ohio Power's ability to recover the full book value of the assets through a transaction similar to the Martinka transaction because there are now smaller tonnage requirements at the stations which the mines currently supply (*Id.*). Additionally, EVA recommended that AEPSC commence negotiations with the relevant parties regarding future regulatory treatment for the Windsor and Muskingum mines (*Id.* at 1-11).

*7 Ohio Power addressed in its briefs only the EVA recommendation regarding overtime (Ohio Power Brief at 22-24). Ohio Power stated that the affiliate mines are not operated at 'normal industry' overtime levels (*Id.* at 23). Although Ohio Power did not object to EVA's formal recommendation that overtime should not be scheduled just to meet tonnage goals, Ohio Power suggested that the Commission not impose an 'industry standard' on the mines without at least some showing that such a standard is appropriate for each of the mines and that the application will actually reduce overall coal costs (*Id.*). Also, Ohio Power stated that overtime should not simply be compared to industry averages and that, if the Commission believes that overtime is a potential problem, then the next m/p auditor should be directed to investigate the reasons for overtime and the economic justification of any optional overtime employed (*Id.*).

IEC also only addressed the overtime recommendation. IEC did not support the recommendations because, if the company reduces overtime, there will be a parallel increase in the cost per ton of affiliate coal (IEC Reply Brief at 27). IEC believes that the increase will be the result of fewer tons over which to spread the fixed cost of affiliate coal production (*Id.*).

OCC argued that EVA's recommendation regarding the BCOA litigation costs should not be adopted at this time because the outcome of the litigation is unknown (OCC Reply Brief at 17). OCC believes that it is too early to determine the specific treatment for the costs associated with the litigation and recommended that the next m/p auditor address the issue (*Id.* at 18).

The staff noted that it agrees with all seven recommendations made by EVA as noted above (Staff Brief at 21-23). Moreover, the staff stated that the Commission should expressly direct Ohio Power to minimize capital/lease expenditures at the affiliate mines and to perform and submit an analysis of all options relative to both the COCCO and Windsor mines as part of its next audit proceeding (Staff Brief at 4 and 22).

The Commission has in the past consistently looked at coal costs between Ohio Power's affiliate and non-affiliate supplies when determining the reasonableness of affiliate coal. Such a comparison recognizes the unique position occupied by Ohio Power, relative to other Ohio regulated electric utilities, as a large purchaser of coal from affiliate mines. We find this approach reasonable and in accordance with the Rule 4901:1-11-10, Appendix D and E, O.A.C. We believe that, in determining what is a reasonable cost of affiliate coal, the Commission must not be myopic in its approach. The fact that Ohio Power's affiliate coal costs have been higher than non-affiliate supplies does not mean they are *perse* unreasonable. The Ohio Supreme Court in *Consumers' Counsel v. Pub. Util. Comm.*

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(1983), 6 Ohio St. 3d 469, upheld the Commission's position that factors other than simple dollar comparisons between affiliate and non-affiliate coal supplies play a part in determining the reasonableness of coal supplies.

*8 Sections 4905.69 and 4905.301, Revised Code, are intended to foster efficient fuel procurement and utilization practices through the EFC mechanism. Pursuant to these statutes, the Commission has been granted considerable authority to encourage efficient fuel procurement practices and fuel cost minimization. See, *Consumers' Counsel v. Pub. Util. Comm.* (1979), 56 Ohio St. 2d 78 and *Consumers' Counsel v. Pub. Util. Comm.* (1992), 63 Ohio St. 3d 531.The Commission notes that productivity continued to reach record highs at the Windsor and COCCO mines and only dropped seven percent at the Meigs mine, despite Meigs Mine No. 31 being out of production for the second half of 1993 (Ohio Power Ex. 8, at 5). Moreover, the weighted average delivered cost of coal from Ohio Power affiliates was only four percent higher than last audit year, given the flooding of the Meigs Mine No. 31 (*Id.*). The overall weighted average delivered cost of fuel during the audit period was 153.4 [/mBtu, well below the stipulated price (Comm. Ord. Ex. 2, at 1-4).

However, the Commission finds that most of EVA's recommendations are reasonable and should be adopted. Therefore, Ohio Power should: (1) evaluate the impact of alternative work schedules resulting from the new labor contract settlement; (2) continue to minimize capital expenditures and new lease commitments at the Muskingum and Windsor mines, including attempting to get by with existing equipment and attempting to obtain short-term leases on existing equipment when an existing lease expires; (3) evaluate the feasibility and associated costs of operating a supersection to accelerate the development of the southern part of the 'C' Block of Meigs Mine No. 31; and (4) address the disposition of the Windsor and Muskingum affiliate mines, including the development of a plan and the commencement of negotiations with the relevant parties. During next year's audit, the m/p auditor should review: (1) the amounts of overtime, reasons therefor, and the economic justification of any optional overtime employed; and (2) the cost of litigation and damages resulting from the BCOA lawsuit. Although the Commission is interested in general information concerning the flood of the Meigs mine, we remind the parties that the point of the stipulation in *Ohio Power Co.*, Case No. 92-101-EL-EFC,*supra*, was to eliminate constant Commission review of every aspect of the operation of the Meigs mines. The price cap, along with the termination date of mine amortization in the stipulation and our expressed desire to see the continued burning of Ohio coal at the Gavin plant, all work to drive efficiency and to protect the ratepayer without requiring Commission involvement in every aspect of the company's decisions concerning the future operation of the Meigs mine. Under the stipulation, the disposition of the mine is within the company's control.

B. *Fuel Procurement*

First, EVA noted that the AEPSC Coal Procurement Manual and Coal Procurement Procedures Manual need to be updated to reflect several changes in the fuel supply organization (Comm. Ord. Ex. 2, at 3-10). Next, EVA reviewed the performance of inventory reduction plan which was developed in last year's audit period (*Id.* at 3-12 to 3-15). EVA noted that the UMWA strike and the flooding of Meigs Mine No. 31 assisted in the implementation of the inventory reduction plan and that, at the end of November 1993, AEPSC was at or below the targets for all stations, except the Muskingum River Station (*Id.* at 3-15). EVA stated that, in recognizing the problem, AEPSC further reduced production levels at the Muskingum mine in December 1993 (*Id.*). EVA is not sure that the reduction is sufficient to achieve the desired inventory levels by the end of 1995 (*Id.* at 1-5 and 3-15).

*9 Also, EVA noted that AEPSC's 'general purchase objective' is to obtain approximately 15 to 20 percent of each operating company's total coal requirements under spot coal purchase agreements (Comm. Ord. Ex. 2, at 3-10). However, EVA's evaluation of the fuel procurements made during the current and prior audit periods leads it to conclude that AEPSC did not appear to be committed to achieving its stated spot target (*Id.* at 1-5 and 3-12). Last year's m/p auditor (Arthur D. Little,

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Inc.) also noted that purchasing policy was not adhered to and noted that, with the execution of the Sands Hill contract (which occurred during this audit period and, therefore, was not reviewed by Little), the FSD management should be questioned as to why it determined to exceed its contract commitment policy (*Ohio Power Co* ., Case No. 93-01-EL-EFC,*supra*, at 7). EVA stated that Ohio Power's overall performance continues to be adversely affected by the relatively high level of contract purchases (Comm. Ord. Ex. 2, at 3-7).

EVA also reviewed the activity relating to Ohio Power's long-term coal purchase contracts during the audit period. EVA noted that AEP appropriately handled several exceedences and quality problems during the audit year (Comm. Ord. Ex. 2, at 3-18, 3-26, 3-32). EVA found the execution of an amendment to the Marietta contract, which provided for additional shipments of coal and price reductions, and a concurrent agreement, which terminated the provision of spot coal by Rayle Coal, to be a neutral transaction (*Id.* at 3-30). EVA commended AEP's efforts in terminating a 1982 contract with CONSOL, Inc. and renegotiating another contract with CONSOL, Inc. for the supply of 2.5 lb/mBtu coal, in accordance with the decision to switch to low sulfur coal at the Kammer station in July 1995 (*Id.* at 3-30). EVA believes that AEPSC's options regarding the right to switch coal qualities and the right to terminate the contract at the end of Phase I are particularly attractive terms in the new contract (*Id.*). EVA also commended AEPSC for maintaining an appropriate spot versus contract mix at the Kammer station (*Id.*).

EVA also reviewed the purchase of the Donaldson contract and the execution of a replacement contract. Ohio Power and Buckeye Power Company (Buckeye) had entered into a 25-year coal supply contract with Donaldson Mine Company (Donaldson) in August 1975 (Comm. Ord. Ex. 2, at 2-26). [FN2] Donaldson is a subsidiary of Valley Camp Coal Company, which is a subsidiary of Quaker State Oil Company (Quaker State) (*Id.*). AEPSC entered into discussions with Buckeye and Donaldson to modify the contract (*Id.* at 2-27). Quaker State entered into an agreement with Arch Mineral (Arch), whereby Arch paid Quaker State to terminate the Donaldson contract and to purchase certain properties (*Id.* at 2-27 to 2-28). Cardinal Operating Company (Cardinal) entered into a replacement coal contract with Arch Coal Sales (*Id.* at 2-28). Buckeye secured the performance of Cardinal by establishing an escrow account (*Id.*). EVA concluded that AEPSC, on behalf of Ohio Power and Buckeye, acted prudently in terminating the Donaldson contract and entering into the replacement contract (*Id.* at 2-33). EVA noted that the replacement coal is lower cost and higher quality, all under a better contract (*Id.*). Moreover, EVA found that the avoidance of large, long-term, post-mining liabilities was significant (*Id.*).

***10** EVA reviewed the Sands Hill contract in accordance with the Commission directive in last year's audit proceeding. Ohio Power entered into a 12-year coal purchase contract with Sands Hill Coal Company, Inc. (Sands Hill) in December 1992 (Comm. Ord. Ex. 2, at 2-35). AEPSC indicated three justifications for the contract: (1) Ohio Power needed additional contract commitments at the Gavin station given the down-sizing of the Meigs operations, (2) Ohio Power needed to preserve the basic underlying economics of the Gavin price cap, and (3) the coal received under the Marietta contract could be considered spot coal (*Id.* at 2-37). EVA did not agree with any of the justifications (*Id.* at 2-37 to 2-40). Moreover, EVA questioned the appropriateness of the execution of the Sands Hill agreement for six reasons: (1) there was no clear need for the additional tonnage at the Gavin station; (2) Sands Hill's production in 1991 and 1992 were well below the annual 1.2 million tons per year required by the contract and it is not clear that the necessary reserves are available; (3) AEPSC did no independent investigation of the reserves situation and did no investigation of Sands Hill's financial capabilities (no guarantees or letters of credit were required); (4) committing to a large volume with a small, independent, spot producer, which has not been producing at contracted levels, does not seem appropriate; (5) the other two lowest bids were very close, such that AEP could have entered into two or three contracts to provide the 1.2 million tons per year without affecting the economics; and (6) the contract reduces the tonnage which Ohio Power has to offer producers who are

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willing to purchase its remaining affiliate mine assets (*Id.* at 2-40 to 2-41). EVA recommended that next year's m/p auditor review and monitor the contract to determine if the contract commitment results in excess costs (*Id.* at 1-11 and 2-42).

EVA further reviewed AEPSC's coal pile inventory procedure, since the Commission ordered the review in light of the last year's m/p auditor's finding of several 'fairly significant recurring deviations between physical and book inventory' (Comm. Ord. Ex. 2, at 2-42; *Ohio Power Co.*, 93-01, *supra*, Opinion and Order at 9). EVA found that the deviations were not as significant during this year's audit period because AEPSC guidelines consider deviations outside a five percent (plus or minus) band-width as significant, not the three percent used in the audit report (*Id.*). The September 1992 survey results were more in line with expectations and AEPSC could not identify any individual reason why the April 1992 results were skewed (*Id.*). EVA noted that AEPSC is trying to improve the physical inventory process and is currently reviewing the quality assurance program of its aerial survey vendors (*Id.*).

Ohio Power only addressed EVA's recommendation regarding the Sands Hill contract. Ohio Power stated that the Commission should reject the recommendation of the m/p auditor (Ohio Power Brief at 39). Ohio Power stated that EVA erroneously concluded that Ohio Power over-committed itself because EVA assumed that 4.7 million tons of coal from the Meigs mines would be going to the Gavin plant (*Id.* at 38). However, that determination is flawed because the company has the right to vary its Meigs mine production levels and, therefore, it is incorrect to reflect 4.7 million tons of coal as a contractual commitment (*Id.* at 38-39). Additionally, Ohio Power claimed that EVA's prior testimony estimated Sands Hill's maximum production capacity at two million tons of coal per year and its reserves at 25 million tons as of December 31, 1990 (*Id.* at 39). Thus, Sands Hill's capability should not be in doubt (*Id.*). Ohio Power next alleged that there is no support for staff's speculation that the existence of the Sands Hill contract will materially change Ohio Power's ability to negotiate another integrated transaction, assuming it were inclined to do so (Ohio Power Reply Brief at 22). Lastly, Ohio Power pointed out that, despite EVA's concerns over Sands Hill's ability to fulfill the contract, the company expects the contract to be fulfilled (*Id.*).

*11 IEC did not address any of the fuel procurement recommendations of EVA. OCC believes that further review of the Sands Hill contract is warranted (OCC Reply Brief at 17). OCC stated that, even if the Meigs tonnage can be varied, the Sands Hill contract does restrict Ohio Power's ability to purchase coal on the spot market (*Id.*). Also, OCC argued that, with respect to the Donaldson/Arch transaction, the issue of the market price for Arch coal should be revisited by the next m/p auditor (*Id.* at 20). OCC believes that it is not clear that the price of coal under Arch contract represents a market price (*Id.* at 19). Moreover, OCC stated that the avoidance of long-term, post-mining liabilities did not occur because they are included in the cost of Arch coal (*Id.*). OCC claimed that the transaction is very similar to the Martinka integrated transaction, except that Ohio Power and Buckeye were not owners of the Donaldson Mine and the Donaldson contract was not an affiliate contract (*Id.*).

Staff believes that there are a number of issues in need of further examination with regard to the Sands Hill contract (Staff Brief at 17). Staff agreed with EVA that further review of the impacts of the contract is needed and recommended that the Commission refrain from making any findings on the prudence of the execution of the contract until such review has been performed (*Id* .). Staff also noted that it concurs with EVA's analysis of the Donaldson/Arch transaction, in which EVA found that the termination of the Donaldson contract and the execution of a replacement contract with Arch to be prudent (*Id.* at 18).

The Commission finds that AEPSC should update its Coal Procurement Manual and its Coal Procurement Procedures Manual prior to the next audit proceeding. The next m/p auditor should review the performance of all plants under the inventory reduction plan and, specifically, indicate the effect of the reduction in production levels at the Muskingum mines in December 1993. Also, the next m/p auditor should verify that AEPSC's

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coal pile inventory procedure continues to produce acceptable results, report on AEPSC's attempts to improve the physical inventory process, and report on AEPSC's review of its quality assurance program as it concerns its aerial survey vendors.

With regard to the Donaldson/Arch transaction, the Commission agrees with EVA that the Arch contract appears to be, overall, a better contractual situation than that which existed under the Donaldson contract. However, the Commission does not approve contracts in EFC proceedings. Rather, the Commission determines whether a utility's acquisition and delivery costs are fair, just, and reasonable during the audit period. We do not find it necessary to adopt OCC's recommendation and order a special review of this transaction. Instead, the Commission will monitor the administration of this contract to ensure that the coal prices are reasonable, taking into account all facts and circumstances present at the time.

*12 As for the Sands Hill contract, the parties overstate the role of the Commission in its review in EFC proceedings. The issue at hand is the reasonableness of fuel costs *during the audit period.* The Commission neither manages the companies nor approves specific contracts for their term. Rather, the company's fuel procurement practices are reviewed during the audit period. Ohio Power's administering of this contract, along with its administering of all fuel procurement contracts, is to be looked at during EFC review proceedings. Because we are not approving the contract for future periods and because there is no evidence that the price during the audit period was unreasonable, we see no reason to reach out and speculate on how Ohio Power may administer this contract in the future. Thus, we do not find that special review of this contract, over and above the review for reasonableness which occurs in every EFC proceeding, is necessary relative to the Sands Hill contract. The company will be expected to continue to procure coal under this agreement at a reasonable price during its term and Ohio Power's actions in this regard will be reviewed in future EFC proceedings.

The Commission finds that AEPSC is not adhering to its 'general purchase objective' to obtain 15 to 20 percent of each operating company's total coal requirements under spot coal purchase agreements. A review of Ohio Power's spot versus contract purchases during the audit period reflects spot purchases of 10.9 percent (Comm. Ord. Ex. 2, at 3-4 to 3-5). While this percentage nearly doubled when compared to the last several audit periods, it is still clearly below AEPSC's objective. (*Id.* at 3-4). In the last four audit periods, the percentage of Ohio Power's spot purchases have been as follows:

12/1/89 - 11/30/90 (Case No. 91-01-EL-EFC)	5.7 percent
12/1/90 - 11/30/91 (Case No. 92-01-EL-EFC)	5.8 percent
12/1/91 - 11/30/92 (Case No. 93-01-EL-EFC)	5.6 percent
12/1/92 - 11/30/93 (Case No. 93-101-EL-EFC)	10.9 percent

Id., 93-01, Comm. Ord. Ex. 2, at 28; 92-01, Comm. Ord. Ex. 1, at 2-1. The Commission wishes to emphasize that diversity of coal suppliers and coal supplies is very advantageous to Ohio Power, as well as to the ratepayers. Ohio Power should be complying with the stated purchase policy and should justify its departure. Next year's m/p auditor should question AEPSC FSD and review the company's actions in this area.

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C. *Sale of the Martinka Mine and Execution of the Peabody Contract*

1. Summary of the Evidence and Arguments of the Parties

From late 1991 to early 1992, Ohio Power and SOCCO (through AEPSC's FSD) invited several vendors to submit combined bids for the purchase of the Martinka Mine and a coal supply contract. FSD did inform the bidders of the maximum price which it would consider for an accompanying coal supply agreement (93-01, Tr. III, 38-9). Ultimately, four companies submitted bids, three of which FSD considered competitive enough to seriously consider (93-01, IEC Ex. 5). FSD conducted several studies, which analyzed the purchase bids and the contract bids, and conducted detailed negotiations with the three bidders (93-01, *Id.*;Tr. III, 26-7, 108-9). In late spring 1992, Ohio Power and SOCCO decided to accept the Peabody bid.

*13 On July 1, 1992, SOCCO sold the Martinka mine to Martinka Coal Company, a subsidiary of Peabody (93-01, Comm. Ord. Ex. 2, at 26). [FN3] In Ohio Power's final accounting, as filed with the Securities and Exchange Commission, the sale of the mine yielded an after-tax loss of approximately $111,000 (93-01, Comm. Ord. Ex. 2, at 27). At the same time SOCCO sold the Martinka Mine, Ohio Power entered into a new, long-term coal supply agreement with Peabody (*Id.*). This contract provides for the delivery of coal, which complies with both the Phase I and Phase II requirements of the 1990 amendments to the Clean Air Act, to the Mitchell Generating Station (*Id.*). The coal deliveries commenced in July 1992 and continue until December 2012, with an option to extend the contract up to an additional 60 months (*Id.*). The contract is a base price plus escalation contract, with the prices ranging from 147.5[/mBtu to 150[/mBtu (Ohio Power Ex. 8, at 22). The annual tonnage requirement for most of the term of the contract is 2,500,000 tons (93-01, Comm. Ord. Ex. 1, at III-5; Tr. V, 67-8). The delivery schedule varies to take into account the inventory levels at the Mitchell plant and to permit the inventory to burn down (93-01, Tr. III, 57). Also, the contract permits Ohio Power to increase or decrease the base quantity of coal by 13 percent after 1994 (93-01, Tr. III, 64-5; Tr. V, 68). The contract has an estimated present value of $200 to $300 million, depending upon the value of sulfur dioxide emission allowances and the discount rate (93-01, Comm. Ord. Ex. 2, at 27).

Peabody agreed to deliver coal from the Martinka Mine (now known as the Tygart Mine) to the Mitchell plant through August 1994 (93-01, Comm. Ord. Ex. 2, at 26; Tr. III, 62-3). Thereafter, Peabody will deliver coal, which will comply with Ohio Power's Clean Air Act compliance plan, from other Peabody holdings or from other properties to the Mitchell plant (*Id.*; 93-01, Tr. II, 128-9). Also, Peabody assumed reclamation liabilities, water treatment liabilities, ultimate mine closure costs, and all post-sale operating costs (93-01, Comm. Ord. Ex. 2, at 26). The contract also contained minimum quantity requirements and a liquidated damages clause. Ohio Power avoided significant shut-down costs (estimated at $147 million) by coupling the sale of the Martinka Mine with a coal supply contract (93-01, Tr. III, 46; IEC Ex. 9).

In last year's audit proceeding, the Commission directed the m/p auditor to review the appropriateness of the divestiture of the Martinka Mine and the execution of the Peabody coal contract. Little reviewed the sale agreement, new supply contract, and FSD's economic evaluation of the 'integrated transaction'. Little concluded that the sale of the Martinka Mine was essentially a break-even transaction and that the sale and new contract were prudent because Ohio Power reduced the expected future cost of coal delivered to the Mitchell Plant (93-01, Comm. Ord. Ex. 2, at 4; Tr. I, 112). Furthermore, Little noted that the cost savings of the new contract will accrue to the benefit of the Ohio Power ratepayers and stockholders because it will bring Ohio Power's weighted average cost of fuel down, allow Ohio Power to amortize the investment in the Meigs mines, and, when the fixed cost of coal expires, the saving will flow to the ratepayer through lower expected costs (*Id.* at 4, 27; 93-01, Tr. II, 46-7). Little also stated that it felt that FSD's action in providing a maximum price to the bidders was not out of the ordinary and was helpful to the bidders so that they understood that FSD wanted a

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market-based price for the coal (93-01, Tr. II, 84, 86). Moreover, Little concluded that the Peabody offer was the lowest cost offer and stated that Ohio Power had a reasonable assessment of what the market price of coal to the Mitchell plant would be (93-01, Tr. II, 57, 61-2). On cross-examination, Little stated that it had no reservations regarding the sale of the Martinka Mine (93-01, Tr. I, 118).

*14 IEC questioned the thoroughness of Little's review of the integrated transaction, as well as the transaction's reasonableness. IEC alleged several reasons why the integrated transaction was unreasonable. Those reasons can be summarized as follows: (1) the cost of coal under the Peabody contract is excessive; (2) the coal contract perpetuates a fuel-sourcing strategy that will limit Ohio Power's ability to access spot coal purchases for years; (3) the divestiture was not properly accounted; (4) the contract has a substantial take-or-pay requirement for Ohio Power, in the form of liquidated damages; and (5) the integrated transaction is a risk and cost-shifting strategy used by Ohio Power to avoid regulatory review of the prudence and reasonableness of shutdown costs for the Martinka mine (93-01, IEC Brief at 8-47). Also, IEC argued that any gain recognized from the sale should be shared with the customers because past, present, and future affiliate coal costs are too high (93-01, Tr. V, 41-2). IEC suggested several regulatory options to the Commission (93-01, IEC Brief at 49-50; IEC Reply Brief at 3).

OCC also questioned the transaction. OCC argued that the certainty and finality of the integrated transaction were questionable because it is unclear whether the integrated transaction was the sole method by which the Martinka Mine could have been sold and because the financial auditor did not independently test the accounting entries (93-01, OCC Brief at 15-6). Moreover, OCC stated that the Clean Air Act eliminated the sole source for the Martinka mine coal and decreased the value of the mine, thus weakening any imprudence argument against Ohio Power (*Id.*). OCC agreed with IEC that whether the coal contract was excessive must be based upon a review of the reasonable market price for the types of coal purchased under the contract (*Id.* at 10). However, OCC found that the data, upon which IEC relied to determine that the market prices, was outdated (*Id.*).

Staff concurred with Little's findings. Staff believed the evidence demonstrated that the price sought by FSD was consistent with the range of prices Ohio Power received in early 1991 for low sulfur coal suitable for use at the Gavin plant and that the Peabody contract price is reasonable (93-01, Staff Brief at 8, 10). Also, staff noted that Ohio Power secured coal, which complies with the Clean Air Act, over the long-term from a reliable coal vendor before the market for such coal tightens (93-01, Staff Reply Brief at 4). Staff stated that IEC's witnesses lacked experience in coal markets, coal contracts, and coal mine valuation, thereby undermining the credibility and value of their testimony (*Id.* at 9). Because staff concurred with the accounting treatment made by Ohio Power for the Martinka divestiture, staff specifically expressed no opinion with regard to the proper regulatory treatment that should be accorded any gain which might result from the sale or with regard to the applicability of Commission precedent (93-01, Staff Brief at 6, Fn. 2). Accordingly, staff found that the integrated transaction will benefit Ohio Power ratepayers and urged the Commission to so find (*Id.*).

*15 Ohio Power contended that the sale of the Martinka Mine and the execution of the Peabody contract were reasonable and prudent actions on its part (93-01, Ohio Power Brief at 2). Ohio Power countered IEC's claim that the cost of coal under the Peabody contract is excessive with evidence that it did a market price analysis and compared the Peabody coal price with the 1991 bids Ohio Power received for comparable coal (93-01, IEC Ex. 5; Tr. III, 27). Ohio Power witness Paul Daley adjusted the 1991 bids for time, transportation costs, transportation penalties, and contract length (93-01, Ohio Power Ex. 3R at 7-9). As a result, Mr. Daley found the market price to range from 147.2 to 150 [/mBtu, while the price range under the Peabody contract is 147.8 to 150.3 [/mBtu (*Id.* at 9). Also, Ohio Power presented evidence that the mine may have particular value to Peabody because ownership of the mine enhanced the value of Peabody's ownership in the Guffey reserves,

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adjacent to the mine (93-01, Ohio Power Ex. 3R at 4). Ohio Power also noted that Peabody can market Martinka coal to cogeneration projects, industrial customers, the export market, and the metallurgical markets (*Id* .). Finally, Ohio Power argued that, even if the sale would result in a gain, that gain would not be shared with the customer; the gain should go to the stockholders (93-01, Ohio Power Brief at 14).

The Commission found that the record lacked sufficient evidence to determine the reasonableness of the price of coal under the Peabody contract.*Ohio Power Co.*, 93-01, *supra*, at 24.The Commission stated that, if the price of coal under the Peabody contract is reasonable, when compared to market prices, then no further investigation of the contract is needed, at least with respect to the price element as a successor of the Martinka contract price (*Id.*). Moreover, the Commission noted that, if it is determined that the Peabody contract price includes a premium related to the Martinka sale, further review would be required (*Id.*). The Commission identified several items which it felt required further examination. Specifically, the Commission directed the next m/p auditor to determine:

1) a range of fair market prices for coal of similar quality to that which was purchased by Ohio Power in the Peabody contract at the time the Peabody contract was entered into. This market analysis should be made to determine the price of coal without being integrated with a mine purchase agreement; 2) the industry standard with regard to the inclusion of 'changes in the law/environmental' clauses in long-term, high sulfur coal purchase transactions between non-affiliated entities; 3) what circumstances or considerations affecting long-term, high sulfur purchase transactions between non-affiliated parties usually determine which party, the seller or the buyer, is vested with the consequential risks and costs of 'changes in the law/environmental' requirements; 4) the reasonableness of the ratio between contract vs. spot purchases with the Peabody contract in place; 5) transportation options available to Ohio Power at the Mitchell Plant during the life of the Peabody contract; 6) the purpose and reasonableness of the apparently unusual liquidated damages clause of the Peabody contract; and 7) Ohio Power's flexibility, during the life of the Peabody contract, to respond to changing considerations.

***16** (*Id.* at 24-25).

In the instant proceeding, EVA reviewed the matters set forth above. In determining a range of fair market prices for coal, EVA reviewed eight similar long-term, compliance coal contracts executed by AEPSC and ten compliance coal contracts signed by Kentucky Utilities and East Kentucky Power Cooperative during 1990 through early 1992 (Comm. Ord. Ex. 2, at 2-5 to 2-11). EVA concluded that the range of fair market prices for similar quality coal to the specification 'A' coal [FN4] was $24.50/ton to 26.50/ton FOB rail (*Id.* at 2-11). EVA indicated that it was difficult to assess AEPSC's claim that the length and size of the Peabody contract required a price premium (*Id.* at 2-14). Nevertheless, EVA found that Ohio Power's decision to enter into a contract of this length and size was a direct result of the integration of the coal contract with the sale of the mine and, therefore, any price premium is attributable to the integrated nature of the transaction (*Id.*, at Tr. I, 85).

EVA further noted that the value of the difference between the contract price and the market price is approximately equal to Peabody's cash purchase price, plus the cost of Peabody's deferred payment (Comm Ord. Ex. 2, at 2-15). EVA stated that, in essence, Peabody paid $26 million to buy the coal mine, through the assumption of liabilities and a present value of $107 million for the sales contract (*Id.*). Additionally, EVA stated that, if the Commission includes that Peabody contract purchase price in the EFC rate, the ratepayer will be paying for Ohio Power's investment in Martinka through the coal contract (*Id.* at 2-18). However, EVA noted three benefits which the ratepayer will receive: (1) the difference between Martinka's cash operating costs and the Peabody contract price (a savings of approximately $22.3 million per year at Peabody maximum tonnage levels); (2) the avoided cost of $26 million in Martinka mine liabilities; and (3) the value of the sulfur dioxide emission allowances generated from 1995 to 2012 using the Peabody coal instead of the Martinka coal (approximately $163 million at Peabody maximum

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tonnage levels and a present value of $200/ton for the emission allowances) (*Id.*).

With regard to the 'changes in the law/environmental' clause and the liquidated damages clause, EVA concluded that it is standard practice for AEPSC to include 'changes in the law/environmental' clauses in new contracts without liquidated damages clauses restricting the right to reduce tonnage or to terminate the contract (Comm. Ord. Ex. 2, at 2-19). EVA noted that:

[t]his standard practice is a result of the current [coal] market conditions, where the producer has to accept the risk of these uncontrollable events in order to obtain a contract. The current coal market can generally be described as one in which there is an excess of production capacity, so producers are not making new large capital investments to serve new coal contracts . In this context, it is easy to understand the presence of these provisions in the Peabody contract. Peabody is making a major capital investment to purchase the Martinka Mine and the coal contract and is requiring [Ohio Power] to take the risk of new government laws that restrict the ability to use or produce the coal . EVA evaluated the economic impact of the liquidated damages clause on Peabody's income, if it is triggered . This value is virtually identical to EVA's estimate of Peabody's profit on performing the contract ($65.7 million) and to Peabody's cash purchase price ($62 million). These values are consistent and logical.

Id.

*17 Also, EVA concluded that Ohio Power had a very high percentage of its purchases under contract prior to the execution of the Peabody contract and continues to have a very high percentage (Comm. Ord. Ex. 2, at 2-20). The minimum tonnage requirements of the Peabody contract equal 72 to 98 percent of the projected burn at Mitchell (*Id.*). As for transportation options, EVA concluded that Ohio Power has expanded its transportation capability at the Mitchell plant and eliminated its prior take-or-pay obligation (*Id.*). Lastly, EVA concluded that Ohio Power has reduced its flexibility to respond to changing conditions because it has committed approximately 13 percent of its total system coal requirement to the Peabody contract (*Id.*). However, EVA found the Peabody coal very flexible because of its quality, origin, and ability to be economically shipped to other Ohio Power plants (*Id.*). EVA felt that the only options which Ohio Power had given up were the ability to buy spot coal and the ability to purchase high sulfur coal (*Id.*).

The parties spent the majority of their time and effort in this matter addressing the range of fair market prices of coal similar to that under the Peabody contract. Not surprisingly, there were several different price ranges advocated and much criticism of the manner in which the calculations were made. EVA, Mr. Daley, Mr. Quinlan, and Mr. Hill all presented analyses of the fair market prices. A summary is as follows:

Witness	*Market Price* Range for Spec. 'A' Coal	*Contract* Base Price
EVA	$24.50 - 26.50/ton FOB rail[5]	$29.05/ton
Daley	139.6 - 142.3[/mBtu FOB plant	147.5-150[/mBtu
Quinlan	$26.50 - 29.50/ton FOB mine	$29.05/ton
Hill	$25.00 - 26.00/ton FOB mine[6]	$29.05/ton

FN5 EVA also listed a market price for both types of specification 'B' coal as $22.00/ton and $24.00/ton (Comm. Ord. Ex. 2, at 2-15). EVA found the market price for the specification 'C' coal to be $25.00 (*Id.*).

FN6 Mr. Hill provided a range of fair market

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prices for each specification of coal to be delivered under the contract as well (IEC Ex. 1, at 8-25). He found the range of fair market prices for the two types of specification 'B' coal to be $23.00-25.00/ton and $21.00-24.00/ton (*Id.* at 18-24). He found the range of fair market prices of specification 'C' coal to be $22.00-24.50/ton (*Id.* at 24-5).

The Peabody contract price range for specification 'A' coal is $28.50 to $29.747/ton, depending upon the tonnage of coal delivered.

Ohio Power believes that the Commission should evaluate the integrated transaction as a whole and not determine the prudence of the coal contract in isolation (Ohio Power Brief at 3). Nevertheless, Ohio Power believes that the contract price is within a range of fair market prices for coal of similar quality to the coal from Peabody at the time in which the contract was entered and that the contract in all other respects is reasonable (*Id.* at 4; Ohio Power Reply Brief at 13).

*18 Ohio Power contended that, if the Commission were to find the contract price to be above market, it should still conclude that the integrated transaction as a whole was prudent and the company is entitled to recover the costs incurred under the coal contract (Ohio Power Brief at 4, 25-31; Ohio Power Reply Brief at 14-5). Ohio Power argued that this is particularly true because, after all, the coal contract would only have been consummated on an integrated basis (Ohio Power Brief at 25). Ohio Power noted that the ratepayers experience a fuel cost reduction of $22 million at maximum tonnage levels under the Peabody contract, avoid $26 million in Martinka mine liabilities, generate approximately $163 million with the consumption of fewer emission allowances, avoid significant mine shutdown costs, and reduce Ohio Power's reliance on affiliate coal (*Id.* at 26-7).

Ohio Power feels that Mr. Daley's bid-based method for determining a range of fair market prices is superior to the more 'judgmental' approaches taken by the others, but, as between those judgmental approaches, Mr. Quinlan's is the best (Ohio Power Brief at 5, Fn. 6 and at 21). Mr. Daley corrected and refined the analysis he presented in last year's audit proceeding to take into consideration the same tonnage as that of the Peabody contract and two adjustments to the transportation costs (Co. Ex. 8, at 18-9). Mr. Quinlan testified that he reviewed many of the contracts which EVA reviewed in preparing its analysis and he reviewed a 1991 study prepared for Allegheny Power System (Co. Ex. 9, at 5, 7). Mr. Quinlan indicated that a 1991 EVA study for Indianapolis Power Light, a 1991 projection by Resource Data International, and reports of spot prices in the months preceding the signing of the Peabody contract corroborated his estimates of the fair market prices (*Id.* at 8, 13-4).

Ohio Power leveled a large variety of reasons why the calculations made by EVA and Mr. Hill were improper and why their criticisms of the analyses of Mr. Daley and Mr. Quinlan were incorrect (Ohio Power Brief at 6-25; Ohio Power Reply Brief at 4-11). Ohio Power summarized that the difference between the conclusions reached boiled down to two considerations: (1) whether the bids, existing contracts, and/or reported prices should be adjusted to January 1992 dollars for comparison to the January 1992 base price of the Peabody contract and (2) whether such bids, existing contracts, and/or reported prices should be adjusted to reflect a premium associated with the larger volume, longer term of the Peabody contract (*Id.* at 24). Ohio Power argued that, if both adjustments are included in the estimates provided by EVA and Hill, then their estimates fall within the Peabody price range (*Id.*).

Regarding the 'changes in the law/environmental' clauses, Ohio Power stated that all of the company's non-affiliate coal contracts have similar clauses and that most utilities attempt to obtain similar clauses in their long-term contracts (Co. Ex. 10, at 5). As for the liquidated damages clause, Mr. Ebetino noted that Peabody required the clause because of the investments required by Peabody to fulfill the contract and its perceived risk that Ohio Power could terminate the contract virtually at will (*Id.* at 9). Mr. Ebetino stated that the Arch contract and five other contracts throughout the AEP system have a similar liquidated damages clause (*Id.*). Mr. Ebetino further testified that 'the contract is a compli-

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ance coal contract. I don't think we reasonably anticipate not being able to use that coal in the future' (Tr. IV, 52).

*19 With respect to the spot versus contract ratio with the Peabody contract in place, Mr. Ebetino stated that the quantity of contract coal is very reasonable for the Mitchell plant and the percent of contract coal only goes above the 80-85 percent target in 1998 (Co. Ex. 10, at 8). Ohio Power argued that EVA's higher percentage appears to be based upon an earlier burn forecast, which has been superseded (Ohio Power Brief at 34). Ohio Power agreed with EVA's conclusion that Ohio Power has expanded its transportation capability at the Mitchell plant (*Id.*). Lastly, Mr. Ebetino testified that the Peabody contract has all the flexibility that any other Ohio Power contract has, including the extra flexibility contained in agreements negotiated after the enactment of the Clean Air Act amendments of 1990 (Co. Ex. 10, at 10). Based upon the foregoing testimony of Ebetino and EVA, Ohio Power stated that the Commission should find that the Peabody contract is reasonable (Ohio Power Brief at 35).

IEC claimed that the specification 'A' and 'B' coal are above the fair market price, based upon all of its arguments in the last audit proceeding and, noting specifically, that the specification 'B' coal is purchased from third-party suppliers and re-priced upward (IEC Brief at 5-12; IEC Reply Brief at 5). This year, IEC presented the testimony of Mr. Hill, who also did an analysis of the fair market prices (IEC Ex. 1). Mr. Hill reviewed the 1991 coal solicitation, trade publications, other analysts' evaluations and his company files in determining a market price for coal similar to the Peabody coal (IEC Ex. 1, at 8, 11-12). Mr. Hill noted that, in his opinion, if AEP had issued a bid solicitation for low sulfur coal to the Mitchell plant, AEP might have received some bids at lower prices than those contained in the 1991 bid solicitation (IEC Ex. 1, at 12-3, 28).

IEC criticized the analyses conducted by Mr. Daley and Mr. Quinlan and countered the criticisms leveled against Mr. Hill's testimony (IEC Brief at 14-21, 30; IEC Reply Brief at 3-4, 12-18). IEC contended that the customer benefits identified by EVA are not truly beneficial, but rather they are hollow (*Id.* at 24-27; IEC Reply Brief at 7-9). IEC believes that the company has shifted the risk of loss on the Martinka investment to the ratepayers through the price of coal purchased from Peabody, represented by the amount of the above the market premium (IEC Reply Brief at 20). IEC concluded that the market price for specification 'A' coal ($29.05/ton) is $3.50/ton above market at the commencement of the contract and requested that the Commission re-price the Peabody coal purchases for EFC purposes to the market price (IEC Brief at 31). Then, IEC suggested that the Commission escalate the market price in accordance with the contract provisions or using the escalation factor developed by Mr. Daley, thereby removing the premium on a permanent basis from the contract price for EFC purposes (*Id.*). [FN7]

*20 IEC is also concerned that the spread between the market price and the Peabody price will grow wider over time (IEC Brief at 32; IEC Ex. 1, at 31). IEC pointed to Mr. Daley's testimony in which he noted that, after the first 13 years of the contract, the contract price might go above the market price (IEC Brief at 33; Tr. VI, 90). [FN8]

IEC feels that the liquidated damages clause imposes take-or-pay obligations on Ohio Power, which is not standard practice for Ohio Power (IEC Brief at 12-3). IEC stated that, of 47 AEP long-term coal contracts, the only contracts which contain a liquidated damages clause are those related to asset or lease buy-out contracts or renegotiation of contracts which defer delivery to the future (*Id.* at 13). IEC does not believe that Peabody required the clause to protect its investment in developing mining capacity, because Peabody has substantial facilities and is like any other producer, who does not require such clauses (*Id.*). Also, IEC pointed to Peabody's March 1991 bid, which did not require a liquidated damages clause (*Id.* at 13). Lastly, IEC argued that Section 4909.191, Revised Code, requires the Commission to consider each utility's fuel procurement practices and adjust the EFC rate by the amount which the company collected as a result of imprudent or unreasonable fuel procurement practices or policies (IEC Reply Brief at 6). According to IEC, if the utility's contract is

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not reasonable, it must be the result of either imprudent or unreasonable fuel procurement practices or policies, mandating Commission action (*Id.*).

OCC agreed with IEC that the ratepayers will pay for the sale of the Martinka mine, in the form of above-the-market prices in the Peabody contract (OCC Brief at 2, 16; OCC Reply Brief at 9). OCC supported the findings of EVA and Mr. Hill and criticized the analyses presented by Mr. Daley and Mr. Quinlan (OCC Brief at 3-11; OCC Reply Brief 2-8). However, OCC agreed with Ohio Power's adjustments to the EVA and Hill estimates so that their estimates are in January 1992 dollars, but disagreed with a time escalation of the 1991 bids utilized by Mr. Daley and the addition of a premium for the length of the contract (OCC Reply Brief at 3-5, 8). OCC pointed to several bid/price quotations received by AEP which show the Peabody contract price to be above market (OCC Brief at 11-13). OCC stated that the liquidated damages clause is unquestionably related to the integrated transaction since its value is identical to Peabody's profit from performing the contract and the cash purchase price (*Id.* at 14).

OCC sees the issue before the Commission as whether the cost of selling, closing, or writing off the affiliate mines should be passed through the EFC rate when these costs are not part of the acquisition and delivery costs of fuel under Sections 4905.01(E) and (F), Revised Code (OCC Brief at 16). OCC believes that the answer is no, ratepayers should not pay for a former affiliate mine (*Id.*;OCC Reply Brief at 11-2). Moreover, OCC stated that the Commission's decision in *In the Matter of the Regulation of the Electric Fuel Component Contained Within the Rate Schedule of Columbus Southern Power Company and Related Matters*, Case No. 88-102-EL-EFC (October 28, 1988) is decisive of the issue (OCC Brief at 17; OCC Reply Brief at 12). In *Columbus Southern Power* (CSP), *supra*, Simco, a wholly owned coal subsidiary of CSP, was sold to Peabody, resulting in a $2 million gain. AEP booked the gain below the line because the Simco property was a risk of Simco's only shareholder, CSP. OCC argued that the gain should have been passed to the ratepayers because they had been purchasing an interest in the assets through the cost of coal. The Commission disagreed with OCC, stating that the ratepayers had no interest or risks of ownership in the Simco property and finding that the treatment of the gain was appropriate. OCC stated that, therefore, whatever gains or losses occur with the final disposition of affiliate mines must be assigned to the owner of the mine, not the ratepayers. In the context of this matter, OCC urged the Commission to establish a base price reflecting the market value for the specification 'A' coal delivered under the Peabody contract, using EVA's prices with an appropriate escalation, and order that the specification 'A' coal will be adjusted in each EFC proceeding to reflect the appropriate figure (OCC Brief at 23; OCC Reply Brief at 13).

***21** Staff believes that, based upon the totality of the evidence, the integrated transaction is beneficial to the company and its customers (Staff Brief at 6-7, 10-11). Staff pointed out that the need for the coal contract was driven by the divestiture of the mine (*Id.* at 7). Staff contended that the Peabody contract price is within a reasonable range of the market price analyses and that the difference, which in and of itself does not render the Peabody price unreasonable, is attributable to the integrated nature of the transaction (*Id.* at 10). Staff believes that EVA's analysis is superior to the others because EVA relied upon actual and reasonably contemporaneous market transactions, not bids or forecasts (*Id.* at 9). Nevertheless, staff claimed that the true test of the reasonableness of the Peabody contract price will be determined over time (*Id.* at 10). The staff stated that the Commission is evaluating the reasonableness of the Peabody contract price during the audit period, not the reasonableness of the contract itself (*Id.* at 6). Staff noted that the Commission will review, in each fuel case, the reasonableness of the fuel costs under all coal supply agreements, including the Peabody contract (*Id.*).

As for the other Peabody contract terms, staff stated that the inclusion of the liquidated damages clause is understandable (Staff Brief at 12). Moreover, staff indicated that it does not advocate the execution of long-term contracts without price reopeners (as is the case with the Peabody contract), but the lack of such a provision in

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the Peabody contract does not render it unreasonable (*Id* .). Lastly, staff noted that Ohio Power has retained some flexibility (*Id.* at 13).

2. Decision

The Commission is not convinced that any one particular range of market prices is the definitive determination of the fair market price for coal of similar quality to the coal from Peabody at the time when the agreement was reached. Nevertheless, the Commission does find that the prices of the various specifications of coal under the Peabody contract are above market.

The Commission believes that, based upon the evidence presented in this proceeding that a fair market price range for coal of similar quality to the specification 'A' Peabody coal would have been $26.00 to $27.00 in July 1992. The Commission finds Mr. Daley's analysis to be biased on the high side (even before he added barging costs from the Gavin plant to the Mitchell plant, the CSX penalty, and the premium for the length of the contract). Mr. Daley relied upon bids which barge coal to the Gavin plant (Co. Ex. 8 at Exhibits 5 and 8). The weighted average price which he developed was based upon 16 bids still open in mid-1992 (93-01, Co. Ex. 3R). He did not limit the bids lowest bids supplying 2.5 million tons, the annual tonnage under the Peabody contract. Additionally, Mr. Daley escalated the bids and their transportation costs from 1991 dollars to 1992 dollars, even though it isn't clear that the bidders would have escalated the bids or transportation costs (Co. Ex. 8 at Exhibit 5; Tr. III, 100). We believe that it was very likely that some of the bids would have remained the same if the bidders had been asked to update their bids.

*22 Mr. Hill's analysis is helpful, but not the most reliable. Mr. Hill included data from executed contracts for coal which did not meet the sulfur and ash fusion temperature requirements of the Mitchell plant (IEC Ex. 1 at Exhibit 5; Tr. II, 15-6). Also, Mr. Hill relied upon some shorter-term contracts and a bid from a questionable supplier (Tr. II, 16-7). Additionally, Mr. Hill omitted possibly relevant data from his analysis because the data was not available publicly (Tr. V, 46, 56).

Mr. Quinlan relied heavily upon a 1991 study, based upon 1990 figures, which forecasted the cost of coal in 1995 dollars (Tr. III, 25, 61). He took the 1995 prices and converted them into 1992 dollars (Tr. III, 9, 79). The Commission fails to see how this portion of his analysis is a determination of the fair market price of coal in mid-1992. Mr. Quinlan also relied upon spot market prices to support his price range, but referenced the spot market prices from June 1992 through November 1993 for coal of a higher Btu quality than the Peabody coal (Co. Ex. 9 at Exhibit 4).

The Commission believes that EVA presented the most reliable analysis, as it relied upon contemporaneously executed contracts. However, EVA relied upon a few shorter-term contracts (5 and 6 years), which we believe contributes to finding a lower market price range. Also, EVA's market price range was premised upon a range of *baseprices* in several 1990 and 1991 contracts. EVA did calculate what the base prices would be in 1992 dollars, but did not accept those prices in establishing its market price range. If the prices were converted into 1992 dollars, which we believe is more appropriate, the range would apparently be $25.48 to $27.25/ton. As a result, we find EVA's market price range a bit low, but a good starting point.

The Commission also finds that the two bids which Peabody submitted in the March 1991 solicitation suggests that the fair market price of the specification 'A' coal is above market. In one bid in early 1991, Peabody offered 1.35 million tons of 12,274 Btu coal per year over ten years for $26.50/ton FOB rail (IEC Ex. 4; Tr. III, 146-9, Tr. VI, 78-82). The other bid was for coal at $26.50/ton FOB rail for ten years (Tr. III, 147-9). One year later, Peabody agreed to provide 2.5 million tons of 12,300 Btu coal per year for 20 years at $29.05/ton as part of the integrated transaction.

We find that the market price range for specification 'A' coal would have been $26.00/ton to $27.00/ton FOB mine in mid-1992. The Commission believes that several unique factors contained in the Peabody contract would tend to push a contract price higher, including such terms as the contract length, tonnage, and lack of a price reopener. Nevertheless, we do not believe that

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such terms would push a contract price to the level of the Peabody contract prices. Rather, we find that it is plausible that the price of specification 'A' coal would be at the high end of that market price range, near $27.00/ton, if a similar contract were entered into without an accompanying mine purchase agreement.

*23 As for the other specifications of coal, the parties did not focus upon them nearly as much. EVA and Mr. Hill presented uncontroverted evidence of the market prices of the specifications 'B' and 'C' coal. Also, IEC did present evidence and argue that the coal from third-party suppliers specification 'B' coal) will probably be re-priced upward by Peabody (IEC Exs. 2, 8, 9; Comm. Ord. Ex. 2, at 2-15; Tr. III, 138, Tr. IV, 125-7; 93-01, IEC Ex. 7). Also, IEC noted the fact that no one was interested in buying the mine without an accompanying coal contract (93-01, Tr. I, 112; Tr. II, 36-8; Tr. III, 53). Based upon the foregoing, the Commission finds that the prices of coal under the Peabody contract are above market.

In EFC proceedings, the Commission is charged with the responsibility of determining whether a utility's acquisition and delivery costs are fair, just, and reasonable *during the audit period.* As we noted in the opinion and order in 93-01, the reasonableness of the integrated transaction is not solely contingent upon whether the Peabody coal is at market only.

Indeed all of the parties to this case overstated the nature of the Commission's review in this proceeding and the significance of the same in future EFC proceedings. The Commission does not approve contracts, nor will it bind itself in this proceeding to determining the reasonableness of the Peabody contract for its entire term. To do so would totally shift the risk of this agreement departing from the market and the company's fuel purchasing practices in the future from the company to the ratepayer, a path which we expressly decline to go down and which we have declined in countless past proceedings. See, e.g., *In the Matter of the Regulation of the Electric Fuel Component Contained Within the Rate Schedule of Ohio Edison Company and Related Matters*, Case No. 81-05-EL-EFC (July 31, 1981).

On the other hand, a premium above market to reflect a buy-out is not *perse* unreasonable or unlawful. In fact, such an approach is well grounded in the Commission's approach to another mine buy-out situation, namely the Quarto mines. See, *In the Matter of the Regulation of the Electric Fuel Component of Ohio Edison Company and Related Matters*, Case No. 84-14-EL-EFC (January 29, 1985), aff'd, *Consumer's Counsel v. Pub. Util. Comm.* (1986) 24 Ohio St. 3d 149.In *Ohio Edison, supra*, the Commission authorized the recovery of deferred development costs of the Quarto mines through the EFC of Ohio Edison, costs which were based upon actual contract costs for operative and phased-down mines. The supreme court, in its opinion, *supra* , noted that the recovery of such costs related to the actual contract cost of procuring fuel (*Id.* at 152). The issue in this case is whether the premium was excessive for the cost of fuel during the audit period.

In examining this issue, we must look to what alternatives were available to the company during the audit period. There is no question that the Martinka costs were projected to be higher than the contract price at issue (Co. Ex. 8 at Exhibit 3). Although the company could have proceeded to procure a more market-based coal price, clearly such an action would have lead to having to immediately deal with the issue of the mine closure costs, including UMWA liabilities. The auditor found that the company's approach to selling the mine was reasonable under the circumstances and given the particular circumstances at hand (Tr. II, 45-6).

*24 The arguments of IEC and OCC seems to be centered around a finding that *any* premium over market is *perse* unreasonable and ought to be disallowed. As indicated above, such an approach is not consistent with applicable Commission and supreme court precedent. The evidence presented by EVA and the staff supports a finding that the sale of the mine and the premium paid during the audit period were not unreasonable.

That being said, the Commission shares a number of IEC's concerns about the length of the contract, the lack of a price reopener provision, and the liquidated damages clause. Depending upon how the market develops, which no one can know with certainty, these provisions

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may or may not become issues in the future. The Commission is loath to shift the risk to the ratepayer from such provisions given the fact that this mine disposition, unlike the resolution of the Meigs affiliate mine issues in *Ohio Power Co.*, Case No. 92-101-EL-EFC,*supra*, was not the subject of negotiation and stipulation let alone prior discussion with the Commission staff or the parties. As a result, we put Ohio Power on notice that it must administer this contract and negotiate such provisions and operations as necessary in the future, so as to ensure that the prices emanating from this contract remain reasonable taking into account all facts and circumstances present at the time. To the extent that this agreement results in prices which are unreasonable when compared to a market price range during a particular audit period, then nothing in this opinion and order shall be deemed as binding on the Commission in such future review. On the other hand, to the extent that the premium remains at the levels set forth in the record when compared to a market price range and barring unforeseen circumstances, the arrangement will not be disturbed.

D. *Clean Air Act Compliance and Emission Allowance Trading Issues*

1. Summary of the Evidence and Arguments of the Parties

Last year's m/p auditor raised several issues for consideration in the next audit proceeding which are related to Ohio Power's Clean Air Act compliance plan, approved by the Commission on November 25, 1992. [FN9]The Commission agreed that the issues should be reviewed and directed the next auditor to review them (*Ohio Power Company*, 93-01, *supra*, at 26). The issues are as follows:

1) a decision concerning where responsibility will rest within AEPSC concerning emission allowance trading; 2) steps to have Cardinal Unit 1 available for fuel switching; 3) any conclusions AEPSC may reach regarding the capabilities of the Westinghouse Dispatch Program to perform environmental dispatch; and 4) any conclusions AEPSC may reach regarding the importance of emission allowances in the terms of interchange and other bulk power market activities.

(*Id.* at 26).

EVA found that, during the audit period, AEPSC did not decide which area would be responsible for emission allowance (EA) trading, nor was the time frame for making the decision clear (Comm. Ord. Ex. 2, at 2-22). EVA felt that, wherever EA trading was located, the FSD, Finance, and System Transactions departments must all be actively involved (*Id.*). EVA found AEPSC's EA trading activity to be disjointed and recommended that AEPSC make a decision regarding the location of EA trading as soon as possible and develop the internal system necessary to integrate EA trading into the routine activities, including EA forecasts (*Id.* at 2-22 to 23, 3-43 to 3-44; Tr. I, 107-8).

***25** With regard to fuel-switching Cardinal Unit 1, EVA noted that, other than turning over the pile, there are essentially no additional steps required to have the unit ready (Comm. Ord. Ex. 2, at 2-23). EVA pointed out that the unit is scheduled for an outage in November 1994 and, thus, a turnover would have to be accomplished by the end of October (*Id.*). EVA felt that this could be accomplished if a decision was made by the beginning of the summer (*Id.*). Also, EVA reviewed five, Ohio Power low sulfur coal supply agreements and found that, if Cardinal Unit 1 was switched, the maximum tonnages under those five contract would represent 75 to 85 percent of Ohio Power's total low sulfur coal requirements (*Id.*). EVA further noted that, if Cardinal Unit 1 is fuel-switched, then the Windsor mine would have to be closed or sold (*Id.* at 2-24). However, EVA found no significant actions had been taken with respect to a sale of the mine (*Id.*).

Regarding environmental dispatch, EVA reported that AEPSC is evaluating the Westinghouse Dispatch Program for use in dispatching its system, along with other options (Comm. Ord. Ex. 2, at 2-24). Also, EVA stated that AEPSC had recognized the importance of EAs in power market activity and that AEPSC plans to price power with appropriate allowance values (*Id.*). Additionally, EVA stated that AEPSC is flexible as to whether EA costs are recovered in dollars or in other

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EAs (*Id.*).

EVA also reported on Ohio Power's activities in EA trading during the audit period (Comm. Ord. Ex. 2, at 3-40 to 3-44). AEPSC negotiated two transfer unit agreements, although one was later voided, and successfully bid on three private placement offers, none of which resulted in actual sales (*Id.* at 3-43). Additionally, Ohio Power received approximately $935,188 in proceeds from the sale of allowances by the Environmental Protection Agency (EPA) (*Id.*, Tr. II, 90-91; OCC Ex. 5). Ohio Power deferred the proceeds, pending a decision from the Commission as to the proper method of accounting (Tr. II, 91). Also, EVA encouraged AEPSC to develop a revised pooling agreement as soon as possible if a consensus is not reached between the various commissions which are considering the allocation of costs and allowances among the AEP operating companies (*Id.* at 3-40). EVA further recommended that AEPSC revisit the question of incremental cost dispatch if the pooling agreement is reopened (*Id.* at 1-12, 3-40). Moreover, EVA noted that AEPSC utilized two consultants during the audit period for its EA activities (*Id.* at 3-43). EVA believes that it would be beneficial for the direction of EA trading activity to be developed internally, rather than employing consultants (*Id.* at 1-11, 3-43; Tr. I, 106).

Ohio Power argued that it has fully complied with the Commission's expectations that it actively participate in the EA market as a means of reducing overall compliance costs (Ohio Power Brief at 43). Also, Ohio Power believes that it has established rational management procedures for the purchase, sale, transfer, and use of EAs and developed strategies for the most effective participation in the EA market (*Id.* at 45). Ohio Power requested that the Commission defer any action with regard to the $935,000 in proceeds because the Commission's regulatory policy for treatment of EA-related costs and proceeds has not been definitively established and because the AEP Regional Coordinating Committee is attempting to determine how the costs and benefits of the allowances should be allocated between the different AEP operating companies (Ohio Power Reply Brief at 29-30). Lastly, Ohio Power stated that the ratepayers will not be prejudiced by deferring the issues because carrying charges are being accrued, compensating the customers for the time value of the revenues in question (*Id.* at 30).

*26 IEC noted that, during the hearing, Mr. Fayne indicated that EA trading is located in the Controller's Department (IEC Brief at 52; Tr. II, 146). IEC criticized AEPSC's use of varying EA values for purposes of system planning, evaluating acid rain compliance options, and fuel purchasing decisions (IEC Brief at 53). Also, IEC claimed that AEPSC has hardly changed its approach to the EA market since it filed its environmental compliance plan in 1992, noting that the allowance management plan is still in draft form (*Id.*;Co. Ex. 7, at 3). IEC believes that Ohio Power has inferred that its ratepayers alone will be responsible for the costs of AEPSC's decision to hire a consultant (IEC Brief at 54; Tr. II, 126). IEC cautioned the Commission to monitor this intent, stating that Ohio Power ratepayers should not have to pay for such activity if it did not directly benefit the same ratepayers (IEC Brief at 54). Lastly, IEC argued that Ohio Power appears to be postponing its decisions of allowance trading to the time of the two-year review of its environmental compliance plan, despite the Commission's guidelines (*Id.*). IEC recommended that the Commission scrutinize several omissions (*Id.*).

OCC stated that the Commission should establish its policy as to the final disposition of the proceeds from allowance sales in this proceedings, in accordance with the Commission's determination in *In the Matter of the Commission's Investigation Into the Trading and Usage of, and the Accounting Treatment for, Emissions Allowances by Electric Utilities in Ohio* , Case No. 91-2155, Entry (March 25, 1993) (OCC Brief at 37). OCC stated that the Commission's current guidelines allow for the recovery of costs and the crediting of gains received through the EFC rate (*Id.* at 38). Therefore, OCC contended that the Commission should clarify that the proceeds from allowance sales should be passed to the ratepayers through the EFC rate when those proceeds are received (*Id.*). Therefore, OCC recommended that the Commission order Ohio Power to credit the ratepayers the amount of the proceeds Ohio Power received from

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the March 1993 EPA auction in the EFC rate to be determined in this proceeding (*Id.*). Also, OCC believes that the Commission should order the future financial auditors to determine any gains on the sale of EAs and verify their proper accounting (*Id.*).

Staff stated that it shares EVA's concern that AEP has not established a final mechanism for allowance trading (Staff Brief at 23). However, staff felt that, given the uncertainty of the market, AEPSC's actions to date, and the uncertainty surrounding inter-company allowance settlements, AEP's action to date have been reasonable (*Id.*). Nevertheless, staff concurred with EVA's recommendation that AEP internally develop the capability to direct its allowance trading activity (*Id.*).

2. Decision

a. Emissions Allowance Trading

Ohio Power indicated during the hearing that the EA trading responsibility rested with Mr. Fayne in the controller's department (Tr. II, 146). The record is unclear as to why EVA found otherwise, but EVA's primary concern that several departments be actively involved appears to be occurring already as well (Co. Ex. 7; Tr. II, 145). Also, EVA was rather vague when it concluded that AEPSC's activities in EA trading were disjointed. The Commission agrees with staff that AEPSC's actions to date have been reasonable, given the newness and uncertainty of the EA market and the inter-company settlement negotiations. The Commission further encourages AEPSC to actively participate in the EA market.

***27** At the present time, the Commission is not convinced that AEP should internally develop the capability to direct its allowance trading activity, in lieu of utilizing consultants. Rather, the Commission finds that AEPSC should evaluate the economics of the two options and present its conclusions in the upcoming, two-year review of its environmental compliance plan. Mr. Fayne testified that he thought that the costs of one of the consultants would most likely be flowed through to Ohio Power ratepayers (Tr. II, 126). He did not state or infer that Ohio Power ratepayers alone will pay for the consultants hired by AEPSC, as IEC alleges (*Id.*). Mr. Fayne stated that he did not know under what account the payment was being recorded (*Id.*). The Commission finds that, in light of its decision regarding the proceeds from the sale of bonus allowances below, the next financial auditor should review AEPSC's billings to Ohio Power to determine if Ohio Power was charged for any or all costs associated with AEPSC's decision to hire the two consultants and how Ohio Power recorded the payment.

We find that the issue of the distribution of the proceeds received from the EPA sale conducted in March 1993 should be deferred until the m/p auditor chosen to conduct the next review of Ohio Power's fuel procurement policies and practices has an opportunity to review the matter and to make its recommendations. The Commission notes that since these proceeds are accruing carrying charges, Ohio Power' customers would be compensated for any delay this procedure may cause. Lastly, the Commission notes that, incremental cost dispatch should be reviewed if the pooling agreement is reconsidered.

b. Cardinal Unit 1

In approving Ohio Power's compliance plan, we stated that 'the company should take steps to have Cardinal Unit 1 available for fuel switching in Phase I '.*Ohio Power Co.*, Case No. 92-790-EL-ECP,*supra* at 32.In our entry on rehearing in the same case, the Commission emphasized this point by noting that we had 'strongly suggested' Ohio Power take steps to fuel switch Cardinal 1 in Phase I.*Ohio Power Co., supra*, (January 14, 1993), at 5.

As noted above, EVA found that, other than turning over the coal pile, Cardinal would require no other preparations for commencing a switch to low sulfur coal. EVA pointed out, however, that the company had taken no significant action to prepare the Windsor mine for closing or sale, thus furthering the probability that it did not intend to comply with the Commission's suggestion to switch Cardinal 1 prior to Phase I.

Indeed, company witness Ebetino presented two scenarios which purport to justify Ohio Power's decision to

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delay the Cardinal 1 fuel switch until the beginning of Phase II (Co. Ex. 10, at 12; Ex. CAE-1). According to Mr. Ebetino, keeping the Windsor mine in operation (supplying 1.1 million tons per year) through 2000 would be more cost-effective, by $4.7 million (Case 1) to $34.7 million (Case 2), than a 1995 switch to compliance coal. The range of cost savings calculated by Mr. Ebetino assumed closing Windsor after 2000 and purchasing market-priced coal (Case 1) or long-term compliance coal (Case 2) from 2001 through 2009 (*Id.*). Based on this analysis, Ohio Power argued that a Phase I switch at Cardinal 1 is not justified (Ohio Power Brief at 49).

***28** EVA indicated that it found Mr. Ebetino's stand-alone study to be inappropriate, primarily because the dispatch order for Cardinal 1 will be different beginning January 1, 1995, as emission allowance values will begin to be incorporated into the dispatch decision-making process (Tr. I, 72, 203). EVA also stated that the analysis assumed continuing improvements of productivity at the Windsor Mine, despite the fact that there will be a large reduction in production at the mine in January 1995 (*Id.* at 73, 204). EVA further noted that Mr. Ebetino's analysis only considered two alternatives, although in reality there are a number of options (*Id.*).

IEC and OCC also dispute the company's findings. IEC argued that it is inappropriate to analyze Cardinal 1 on a stand-alone basis because emission allowances must also be taken into account, thus affecting the amount of fuel used at Cardinal 1 as well as the resulting cost of fuel-switching the unit (IEC Reply Brief at 22). IEC also pointed out that a system-wide analysis must be employed to be consistent with Ohio Power's environmental compliance plan case (IEC Brief at 44). IEC recommended that the Commission direct Ohio Power to perform a new fuel-switch analysis of Cardinal 1 which considers: a Phase I fuel-switch based on the AEP system as a whole, alternatives using compliance coals and non-affiliate high sulfur coals, exclusion of Windsor mine closing costs, and high and low sulfur prices which reflect the company's best estimate of contract and spot prices in 1995 and 2001 (*Id.* at 45; IEC Reply Brief at 24).

OCC holds similar views of this issue. OCC also claimed that a system-wide analysis is essential for determining least-cost compliance (OCC Brief at 33-4). OCC further argued that Mr. Ebetino failed to consider market prices for high sulfur coal, which are lower than the affiliate coal purchased from Windsor (*Id.* at 34). Finally, OCC contended that the limited study performed by Mr. Ebetino improperly includes Windsor mine closing costs, thus inflating the cost of a Phase I fuel-switch (*Id.*). OCC requested that the Commission direct the company to continue to analyze the Cardinal 1 fuel-switch by incorporating these criticisms (*Id.* at 36). OCC suggested that this issue should again be addressed in Ohio Power's two-year environmental compliance plan review, later this fall (OCC Reply Brief at 15-6).

The staff, while in general agreement with the criticisms leveled by IEC and OCC, is most concerned by Ohio Power's failure to consider alternative, non-affiliate, high sulfur coal in its analysis (Staff Brief at 19). According to the staff, a comparison of relatively high cost affiliate coal from Windsor with non-affiliate high sulfur coal would result in cost savings of over $4.5 million to ratepayers in 1995 alone (*Id.* at 20). The staff agreed with OCC that the two-year environmental compliance plan review case would be the best forum for considering an additional analysis by the company of this issue (*Id.* at 20-1).

***29** We agree with the staff and intervenors that Ohio Power's failure to provide a more comprehensive analysis of a Cardinal 1 fuel-switch severely limits the usefulness of the company's conclusions. As pointed out in the intervenors' post-hearing briefs, Ohio Power's stand-alone study is inconsistent with the system-wide analysis employed in the environmental compliance plan case. It is inappropriate to treat the Cardinal 1 fuel-switch as a stand-alone issue because of the effect that the inclusion of emission allowances would have on dispatch decisions. Based on a system-wide analysis, the inclusion of emission allowances will cause higher sulfur coal plants to be dispatched at a higher cost than lower sulfur plants, thereby providing a more realistic view of the true cost of switching Cardinal 1 in Phase I.

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We also question Ohio Power's decision to look only at high sulfur coal from Windsor, rather than alternatively evaluating other lower cost sources of high sulfur coal. The staff noted that such an analysis could, perhaps, yield additional savings not reflected in the company's study (Staff Brief at 19-20). Finally, the inclusion of mine closing costs in the company's analysis is an issue which requires further consideration.

We are extremely disturbed with Ohio Power's purported confusion as to the Commission's intention with regard to the issue of fuel switching Cardinal 1 and even moreso by Mr. Ebetino's failure to provide the results of his stand-alone cost study to the auditors in time for their review (Tr. I, 70-71, 201). In fact, the auditor indicated that the company had provided no sufficient explanation for its delay on this matter (Tr. I, 203).

As to the Commission's intention in its decision in *Ohio Power Co.*, Case No. 92-790-EL-ECP,*supra*, whatever confusion there may have been with regard to the Commission's language in its original opinion was clarified on rehearing, wherein the Commission stated in a footnote:

[i]n subsequent fuel cases, where the Commission intends to review developments in the allowance trading market and each utility's participation therein, the Commission will *expect Ohio Power to demonstrate* a reduced revenue requirement *at least equal to* the total revenue requirement benefit identified in this case resulting from a Cardinal fuel switch, which affects both fuel cases and the bank of SO2 allowances. (Emphasis added.)

The company did not seek further clarification of that footnote in subsequent proceedings. Clearly, this case was a 'subsequent fuel case' within the meaning of that footnote.

In the environmental compliance plan case, the testimony indicated that a fuel switch at Cardinal 1 was an extremely economical means of compliance, with or without recovery of the mine closure costs. In the Commission's rehearing entry, it set forth in the above footnote an evidentiary standard which the company would be held to in 'subsequent fuel cases'. We find that the company in this case failed to meet its burden of proof under that standard and, inexplicably, failed to submit *any* empirical analysis of fuel switching Cardinal 1 until well after the close of the auditor's review. This finding does *not* mean that the Commission would not reconsider the standard set forth in the entry on rehearing in Case No. 92-790-EL-ECP based upon new evidence. This finding only means that the company has failed to meet its burden of proof in this case based upon this record. As a result, although we intend to look at this issue again in the two-year review of the ECP case and in subsequent fuel cases, absent clear and convincing evidence as to why the numbers in the ECP case concerning the economics of fuel switching Cardinal 1 in 1995 are no longer valid, our standard remains in effect. Consequently, the company remains at risk for potential disallowances effective at the commencement of Phase I of the Clean Air Act for having failed to undertake the least cost strategy for compliance with the Clean Air Act Amendments of 1990, as they relate to Cardinal 1.

*30 The company's actions in this regard will be reviewed by the auditor in the next Ohio Power fuel case. In the two-year review proceeding, Ohio Power should present an analysis which looks at Cardinal 1 in the context of the entire AEP system and which compares both compliance coal and non-affiliate, high-sulfur coal, based upon best estimates and actual bids for compliance coal. That study should be presented to the parties and to the staff in sufficient time to permit thorough review and discovery concerning same. We reiterate again that the company has to make a far better presentation on this issue than that which was done in this case to justify a change in the evidentiary standard and/or to avoid future disallowances associated with Cardinal 1.

IV. *Miscellaneous Issues*

A. *Buy-out of Dragline Leases*

During the audit period, COCCO bought out the lease of its largest dragline, the 'Big Muskie' (Co. Ex. 8, at 7). COCCO retired the 'Big Muskie' and reflected the expense (a net loss of $15.3 million) in the cost of coal charged to Ohio Power (adding $5.88/ton to the per-ton

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cost) (*Id.*;Tr. III, 118-9). Ohio Power alleges that the dragline was idled in 1991 and, with the adoption of the company's environmental compliance plan, the dragline was no longer needed and, thus, retired (Ohio Power Reply Brief at 18; Tr. III, 118-9, 123-4; Tr. IV, 8, 10). Once the buy-out expense was incurred, COCCO had to reflect the expense in that same fiscal year (Tr. III, 165-6). Additionally, Ohio Power notes that the COCCO-Ohio Power contract required COCCO to charge the expense as part of its cost of coal (Ohio Power Reply Brief at 19).

COCCO plans to retire a second dragline, the 8750, in 1994 as a result of Ohio Power's environmental compliance plan as well (Co. Ex. 8, at 8; Tr. III, 123-4, 168; Tr. IV, 11). The 'write-off' is projected to be over $21.733 million, resulting in an added cost of $13.58/ton to the price of coal (Co. Ex. 8, at 8; Tr. III, 120). Ohio Power plans to reflect the full expense of the write-off in the first 11 months of 1994, as opposed to over the full year, because Ohio Power believes that is consistent with a prior EVA recommendation and/or Commission order that the cost normalization process occur within the last year of the stipulation period (Ohio Power Reply Brief at 20; Tr. III, 122-3, 166-7).

Ohio Power alleged that the additional cost to COCCO coal is required by their contract and Ohio Power's treatment of the expense is proper (Ohio Power Reply Brief at 19-20). Also, Ohio Power contended that its plans to reflect the expense of the 8750 retirement by November 30, 1994 is consistent with past practice (Ohio Power Reply Brief at 20). Ohio Power also believes that the ratepayers will benefit because any loss to the company at the end of the stipulation period will be greater than if the expense were spread over twelve months (*Id.*).

IEC argued that Ohio Power delayed the decision to write-off the Big Muskie (IEC Brief at 47). IEC believes that, if the write-off had occurred in 1991 at the time the dragline was idled, the differential between affiliate and non-affiliate coal prices would have been even greater and led to a greater ratepayer benefit (*Id.*). Also, IEC stated that any loss associated with the idling of the Big Muskie should have been recorded below the line, in accordance with proper accounting for losses on the disposition of assets (*Id.* at 48). Next, IEC claimed that, through the 1993 write-off, Ohio Power has effectively utilized the 1992 stipulation to recover COCCO investment and limited the intended purpose of the stipulation (*Id.*). Therefore, IEC recommended that the Commission order a reconciliation adjustment to recognize the write-off under the previous stipulation and the $15.3 million, indicated as the possible amount of Meigs investment that could have been written off at the end of the first three-year period of the stipulation (*Id.* 48-9). As for the 8750 dragline, IEC believes that the $21.733 million loss must be taken below the line and not be transferred to the ratepayers, since Ohio Power's proposed treatment is in violation of the stipulation as well. In the alternative, IEC recommended that the Commission direct that the amortization begin after the idling occurs (mid-1994) and be taken in equal amounts over the remaining months of 1994, with any amounts not recovered by November 30, 1994 written-off below the line (Id. at 49, Fn. 12). IEC stated that the proposed write-off at COCCO and the overproduction at Windsor lead IEC to conclude that negotiations with Ohio Power regarding regulatory treatment of the Windsor and Muskingum mines will be difficult to commence. Lastly, IEC believes that the Commission has all it needs before it to determine the treatment of both draglines and that Commission precedent (*Columbus Southern Power* , *supra*) dictates that Ohio Power bear the loss on the disposition of the draglines, not the ratepayers.

***31** OCC argued that the write-off costs are not proper costs for inclusion in the EFC (OCC Brief at 25-26). OCC believes that the Commission's decision in *Columbus Souther Power*, *supra* , is analogous and the ratepayers do not bear the risk of ownership of the COCCO assets (*Id.* at 26). OCC noted that the write-offs of both draglines have the effect of diminishing Ohio Power's ability to accelerate recovery of the Meigs investment under the 1992 stipulation (*Id.* at 24; Tr. III, 124). OCC recommended that next m/p auditor investigate the write-offs, determine how much they affected the price of COCCO coal, the propriety of the write-off occurring during the 12-month and 11-month periods, and how the

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balance from the four-station cap will be affected (OCC Brief at 26).

The Commission finds that COCCO's lease buy-out expense for the Big Muskie dragline is one of the costs Ohio Power is obligated to pay as part of the cost of coal it purchases from COCCO. The company's contract with COCCO includes costs associated with the termination of leased or rental property which COCCO may be required to pay pursuant to any lease of equipment in its mining operation (PWD Exhibit No. 10-A of Co. Ex. 7, in Case No. 92-01-EL-EFC). There is no evidence of record that the lease buy-out cost for Big Muskie was improperly incurred. The dragline was idled in 1991 due to several factors, including the fact that the dragline was no longer needed to mine coal because of Ohio Power's compliance plan to switch Muskingum River Unit 5 to low sulfur coal, the cost of maintaining and repairing the dragline, the high coal inventories at Muskingum River plant, and EVA's recommendation to retire the dragline (Co. Ex. 8, at 7; Tr. IV, 8-11).

We have considered the argument made by OCC and IEC that the buy-out costs should be COCCO's loss and not passed through to Ohio Power's ratepayers. We disagree with this argument. We find that the issue is not a question of a 'below or above the line asset' as OCC and IEC have argued. The dragline in question is not an asset of the utility, but rather, it is equipment leased by COCCO. Therefore, the concept of above or below the line assets is not applicable. The dragline lease buy-out is a cost of coal production that is properly includable in the cost of coal, absent a showing of imprudence on the part of Ohio Power or its mining affiliate.

Having found that the Big Muskie dragline lease buy-out was a proper coal expense to be passed through the EFC, we must now decide how that expense should be recovered. IEC argues that, if the Big Muskie dragline is a proper expense, then it should have been included as an expense under the previously-approved price cap stipulation that ended in November of 1991 because the equipment was idled in January of 1991. We agree with IEC's reasoning. To permit the company to include this expense in 1993 would circumvent the purpose and integrity of the stipulation in effect when the equipment was idled. We are not persuaded by the company's argument that it was proper to wait until the Commission reached a determination on the company's compliance plan before retiring the equipment in 1993. The company's compliance plans for the Muskingum River units did not vary among the options being proposed for system-wide compliance to influence when the dragline should have been retired. Under normal circumstances, retiring the equipment in 1993 after the company's ECP plan was approved would not have been such a serious concern. However, because affiliate coal price caps have been in effect, it is critical that expenses be recognized in the most appropriate period so as not to diminish or circumvent the intent of the price cap stipulations previously approved by the Commission. Therefore, the Commission will require, for regulatory purposes, that the Big Muskie be expensed as a cost of affiliate coal in 1991 ending with the last month of the previous stipulation. Ending with November 1991 is consistent with EVA's recommendation in *Ohio Power Co.*, Case No. 91-01-EL-EFC and our approval of the stipulation in that case.

***32** The effect of our decision is that there should have been an even greater affiliate/non-affiliate price differential under the previous stipulation, and greater ratepayer benefit. Accordingly, a reconciliation adjustment to recognize the $15.3 lease buy-out under the previous stipulation is in order. Our decision will not affect the EFC rate being adopted in this proceeding. However, it will affect how the EFC components were, or are to be, calculated under the current price cap stipulation and will increase the dollars available to recover the Meigs investment. The next EFC m/p auditor should review the company's calculation of the reconciliation adjustment being ordered by the Commission.

With regard to the 8750 dragline which is to be retired in 1994, we note that this is a matter outside the review period of the audits conducted in this case. The Commission will, therefore, direct the next m/p auditor to review the appropriateness of the retirement of this dragline, as well as the appropriate accounting treatment if the dragline is in fact retired.

B. *Compliance with the 1992 Stipulation*

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OCC recommended in its brief that the next m/p auditor review Ohio Power's actions since the execution of the 1992 stipulation. (OCC Brief at 31-2). OCC worries that, although Ohio Power had approximately $11.8 million in its 'pot' at the end of the audit period which can be used to accelerate the recovery of the Meigs investment, there could be nothing left at the end of November 1994 (*Id.*). The financial auditor identified two 'contingent losses' which could affect the amount available to accelerate the Meigs investment (Tr. I, 26). They are the loss from the flood at the Meigs Mine No. 31 and the retirement of a dragline at COCCO (*Id.*). Mr. Ebetino noted that it was not unexpected that the cap would have a positive balance in the first couple years (Tr. IV, 17). OCC believes that the Commission must consider for every year in which the stipulation is in effect whether Ohio Power acted prudently in accelerating the recovery of the Meigs investment (OCC Brief at 31). Thus, OCC recommended that the next auditor determine what actions by Ohio Power have reduced or hindered the Meigs investment recovery and, given whatever balance may exist, the most prudent course of action for Meigs recovery (*Id.*). OCC also requested that the Commission order all m/p auditors performing audits from December 1994 forward to detail and evaluate the recovery of the Meigs investment on a year-to-year basis throughout the time in which the cap at the Gavin station is in effect (*Id.* at 32).

Ohio Power stated that the Commission found the stipulation to be reasonable and therefore, it should conclude that the effects of the stipulation are reasonable (Ohio Power Brief at 37). However, Ohio Power clarified that it will not know the amount available for accelerating the Meigs investment until the end of the three-year period, at which time it will make the appropriate acceleration (Ohio Power Reply Brief at 21). Moreover, Ohio Power stated that it expects next year's financial auditor to review the close-out of the first three-year period under the stipulation (*Id.* at 20, fn. 21). Ohio Power believes that the financial auditor, rather than the m/p auditor as proposed by OCC, would be more appropriate to conduct such a review (*Id.*). Ohio Power does not believe that this is an issue for the Commission's consideration here (*Id.* at 21).

*33 Pursuant to the terms of the stipulation, Ohio Power will not know what amount, if any, will be available for accelerating the Meigs investment until after November 30, 1994. In that respect, the Commission agrees with Ohio Power that OCC is jumping ahead. Both OCC and Ohio Power believe that next year's audit proceeding should include a review of the close of the first three-year period and the Commission agrees. The financial auditor should review whether Ohio Power acted prudently and in accordance with the terms of the stipulation from an accounting standpoint and the m/p auditor should review the same from a policy standpoint.

C. *Company-Owned Life Insurance for Martinka Employees*

EVA indicated that the sale of the Martinka mine affects certain life insurance liabilities and medical liabilities, which could change the nominal loss on the sale into a gain (Comm. Ord. Ex. 2, at 2-2; Tr. I, 82-4). During the course of the hearing, EVA expressed some confusion about the nature of the life insurance program (Tr. II, 74). Mr. Campbell explained the corporate-owned life insurance program, indicating that AEP purchased life insurance in 1990 for all Ohio employees in all subsidiaries (Tr. II, 152-56). The policies generate cash and income benefits to the company over time (*Id.* at 156). Although it would seem that there would be a 'gain' created as a result of the sale of the Martinka mine, the value of the life insurance is unaffected by the sale (*Id.*). Moreover, it is not appropriate to include a value for the reduction in the life insurance liability under current accounting rules (*Id.* at 10, 155; Tr. I, 31). Therefore, the company did properly account for this item (Ohio Power Reply Brief at 36; IEC Reply Brief at 14).

Ohio Power, therefore, contended that there is no basis for the Commission to take any action (Ohio Power Brief at 36). Staff stated that the issue has raised other questions which should be addressed (Staff Brief at 14). Specifically, staff believes that there are questions concerning the extent to which the insurance was obtained with ratepayer funds, the extent to which shareholder funds have or will create this 'asset', and the administration of the proceeds (*Id.*). Staff recommended that the

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next financial auditor examine and the company provide testimony concerning the status and operation of the post-employment benefits and associated insurance (*Id.* at 15). However, staff further stated that this issue should not prevent recognition of the Martinka costs in the current EFC (*Id.*).

The Commission finds that staff's recommendation should be adopted. Mr. Campbell stated that AEP purchased the policies for several operating companies and billed the Martinka division of SOCCO the premium expense, which was included in the cost of fuel billed to Ohio Power (Tr. II, 158-9). Accordingly, the next financial auditor should examine whether the cost of the insurance were reflected in the cost of Martinka coal anytime between its purchase in 1990 and the sale of the Mine in 1992 and the appropriateness of what appears to be a life insurance 'asset'. Also, Ohio Power should provide testimony regarding the status and operation of the insurance program in the next audit proceeding.

***34** V. *Future Actions*

As this may be the last full EFC hearing for this company prior to the implementation of the Clean Air Act Amendments of 1990, a few observations are in order. First, the EFC statutes both in letter and in spirit require the Commission to ensure that its policies promote the efficient acquisition of fuel. This can be done, over time by bringing the forces of competition to bear in the acquisition of fuel. As noted herein, the Commission will not be inclined to insulate the company, over a substantial period of time, from the forces of competition holding down the price of fuel. The Commission will also not be amenable to agreements which continue over time to shift all risk to the ratepayer and to insulate the company from market forces and other drivers of efficiency in fuel procurement. We are clearly entering into a more competitive age in the sale of electricity both at the wholesale and, potentially, at the retail level. The company must work to devise solutions to its high fuel costs which bring the disciplines of competition and market forces to bear, along with a potential sharing of past costs deemed prudent to the extent same could be part of a stipulated settlement package.

Guaranties of full recovery irrespective of market conditions are antithetical to the concept of risk for which the company is compensated through rate of return by this Commission. By a similar token, early and frequent communication with the Commission staff and the intervenors on these issues is far preferable to the delays, incomplete studies, and less than full disclosure to the auditors which was prevalent in this proceeding. We trust that the company will take a more open approach in working with its customers in the future on these issues. By the same token, the company's customers must be open to solutions which, although not ideal, recognize that some reasonable transition from the affiliate operations is in order. Better communication on all sides is needed to ensure reasonable results.

As we move to a post-Clean Air Act environment, it is important that the company continue to encourage and promote diversity of supplies. As noted earlier, the Commission has, in past EFC cases, repeatedly emphasized that it values a diverse portfolio which includes a diversity of suppliers, as well as an appropriate mix of spot and contract purchases. This will become even more important in this post-Clean Air Act environment if fuel costs are to remain reasonable and if the Ohio coal industry is to have a chance to survive. We would not want to see concentration of the market in one or two large, low sulfur (or high sulfur) coal suppliers, since it was this very concentration and manipulation of prices in the mid-1970's which were, in part, responsible for the company's decision to develop the affiliate mines. A diversity of coal suppliers, both in Ohio for high sulfur supplies and in surrounding regions for low sulfur supplies, is essential to ensure that the market remains competitive so that low cost fuel and reasonable energy costs in general are available to offset the burdens which Ohio faces from the implementation of the Clean Air Act Amendments of 1990.

***35** VI. *The EFC Rate*

The EFC rate will cover the six-month current period of June 1, 1994 through November 30, 1994. The EFC rate will consist of a fuel component calculated pursuant to Rule 4901:1-14-04, O.A.C., a reconciliation adjustment (RA) calculated pursuant to Rule 4901:1-11-06, O.A.C.,

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a system loss adjustment (SLA) calculated pursuant to Rule 4901:1-11-07, O.A.C., and an Ohio coal research and development (OCRD) component.

The EFC rate proposed by the company has been derived from five months of projected data and one month of actual data for the six-month base period of December 1, 1993, through May 31, 1994, and pursuant to the stipulation approved by the Commission in the 1992 EFC proceedings. The EFC rate proposed by Ohio Power is used by the company to compute the fuel charges rendered to jurisdictional customers during the six-month current period of June 1, 1994, through November 30, 1994. Based on the actual and projected data, the company has calculated a fuel component of 1.575708[/kWh; an RA rate of 0.017007 [/kWh, which included a reconciliation of (0.033206)[/kWh for over recovery of EFC revenues and a reconciliation of 0.050213[/kWh for Commission ordered adjustments; and an SLA of (0.047008)[/kWh, using a twelve-month rolling average of losses method (Company Ex. 11, at 7-9). In addition to the rate components above, the company has included in its calculations of the EFC rate a (0.004627)[/kWh for the recovery of OCRD costs (*Id.* at 7). Based upon the above, the company has calculated an EFC rate of 1.541080[/kWh (*Id.* at 9).

The Commission finds that Ohio Power's proposed EFC rate will be put into effect. We realize the our decision regarding the Big Muskie dragline should necessitate an adjustment in a component of the EFC rate and in the amount by which the Meigs investment will be accelerated. However, because the price of coal is predetermined in accordance with the 1992 stipulation, the adjustment may be made in the next proceeding. The financial auditor should review Ohio Power's calculations to ensure that the adjustment is properly applied. Ohio Power should file the EFC tariff rider setting forth the EFC rate no later than May 27, 1994. The tariff rider should become effective with the company's June 1994 cycle 1 billing and remain in effect until otherwise ordered by the Commission.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

1) Ohio Power is an electric light company within the meaning of Section 4905.03(A)(4), Revised Code, and, as such, is a public utility subject to the jurisdiction and supervision of the Commission. Ohio Power is also an electric utility within the meaning of Rule 4901:1-11-01(L), O.A.C. 2) Section 4905.301, Revised Code, requires the Commission to review each electric utility's EFC at a hearing annually. By finding and order issued June 24, 1993, the Commission initiated the mid-year adjustment and annual audit adjustment proceedings to review Ohio Power's EFC and related matters. 3) On November 10, 1993, the Commission found that Ohio Power had timely filed the requisite data submissions and approved an EFC rate of 1.583368[/kWh to become effective with the December 1993 Cycle 1 billing on November 29, 1993. The Commission noted that the establishment of the mid-year EFC adjustment would be subject to full review in Ohio Power's annual EFC hearing. 4) Notice of the annual EFC hearing proceeding was published in accordance with requirements of Section 4909.191(A), Revised Code, and Rule 4901:1-11-11(C), O.A.C. 5) The financial and m/p audits were performed in compliance with Section 4905.66(B), Revised Code, and the provisions of Rule 4901:1-11-10, O.A.C. 6) The financial auditor found that Ohio Power's EFC rate was properly calculated and properly applied to customers' bills. 7) The m/p auditor made numerous findings, including: Ohio Power should develop a plan to address the problems with the Muskingum and Windsor mines, Ohio Power should commence negotiations with the relevant parties regarding the regulatory treatment for the Windsor and Muskingum mines, AEPSC should develop internal capabilities for directing its allowance trading activity, the next m/p auditor should monitor the Sands Hill contract and the several aspects of the flooding of Meigs Mine No. 31, AEPSC should evaluate whether to take advantage of alternative work schedules, and Ohio Power should continue to minimize capital expenditures and least commitments for the Muskingum and Windsor mines. EVA also evaluated the list of items regarding the sale of the Martinka Mine and the execution of the Peabody coal supply contract and a list of items regarding compliance with the Clean Air Act. 8) The Commission finds that the purchase of Peabody coal during the

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audit period was reasonable under the circumstances presented in this record. Such purchases will continue to be reviewed on an ongoing basis in future proceedings. 9) The Commission finds that Ohio Power should present an analysis of the Cardinal 1 fuel-switch issue in the upcoming two-year environmental compliance plan review proceeding and in future EFC proceedings. 10) The Commission finds that the loss resulting from the buy-out of the Big Muskie dragline lease should have been expensed during the period of the last stipulated price cap. 11) The next financial and m/p auditors should review those matters set forth in this Opinion and Order. 12) Ohio Power should report upon those issues set forth in this Opinion and Order. 13) The EFC rate for the period June 1, 1994, through November 30, 1994 should be 1.541080[/kWh.

ORDER:

***36** It is, therefore,

ORDERED, That the financial and m/p auditors for the company's next EFC audit proceeding review those matters set forth in this Opinion and Order. It is, further,

ORDERED, That the EFC rate to be charged by Ohio Power during the six-month period beginning June 1, 1994 be 1.541080[/kWh, subject to reconciliation in future EFC rates to reflect the difference between the stipulated predetermined price and the fuel component used in the adopted EFC rate and to reflect the Commission's decision regarding the loss from the buy-out of the Big Muskie dragline. It is, further,

ORDERED, That Ohio Power file its EFC tariff rider incorporating the EFC rate for the next current period no later than May 27, 1994. It is, further,

ORDERED, That the EFC rider become effective with the company's June 1993 Cycle 1 billing and remain in effect until otherwise ordered by the Commission. It is, further,

ORDERED, That a copy of this Opinion and Order be served upon all parties of record. Entered in the Journal MAY 25 1994 A True Copy

DISSENTING OPINION OF COMMISSIONER RICHARD M. FANELLY

I concur with the finding of the majority that the initial price of the Peabody contract exceeds market price for comparable fuel. However, I dissent from the majority's conclusion that the Peabody contract price nevertheless should be recoverable from EFC customers.

Throughout its two decades of production as an Ohio Power for-profit subsidiary, the Martinka mine has experienced fuel costs, paid by EFC customers, in excess of comparable market prices. The succeeding Peabody contract will apparently stretch two into four decades of above-market fuel costs at the Mitchell power plant.

Based on the record of fuel costs from the mine, on Ohio Power's failure to resolve this matter at a much earlier date when it was evident that market prices were clearly experiencing a long term downward trend, on the evidence in this case that Martinka could not ever produce coal economically due to unfavorable mining conditions, and on the Company's apparent preference to litigate and game a weak multi-jurisdictional regulatory system rather than focus on the interest of its customers, I have concluded that Ohio Power should not be permitted, through the succeeding Peabody contract, to recover from EFC customers the Martinka mine equity investment. Accordingly, I would credit against the annual Peabody contract price a sum equal to the twenty year levelized amortization of the June 30, 1992 equity investment in the Martinka mine with a carrying charge calculated in a manner consistent with the equity return included in the cost of Martinka coal. However, for any subsequent annual period in which Ohio Power demonstrates to the satisfaction of the Commission that the Peabody contract price is at or below comparable market prices I would waive the credit outlined above. All remaining assets and liabilities pertaining to Martinka should be treated permanently below the line.

***37** I believe it is important that my position regarding long term contracts and my decision in this case be understood correctly. Certainty and predictability are necessary components of sound, effective regulation. Long term supply contracts are essential for stable and

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cost effective electric utility operations. If reasonable and appropriate when effective, long term contracts should be honored provided they are meticulously administered and their continued efficacy is periodically scrutinized and demonstrated. Due to the absence of an arms length relationship, contracts with affiliates or controlled entities must be held to a more strict standard, one which at a minimum imposes a performance based risk on equity, or on other below the line effects, in order to avoid conflicting incentives. My decision in this case does not intend to suggest, even indirectly, that buy-out, buy-down costs associated with terminating an uneconomic contract or other arrangement should not be fully recoverable from customers when net benefits therefrom can be demonstrated. In fact, this consideration causes me to propose only a limited disallowance, further subject to a market price test, not the entire 'premium' identified by the M/P Auditor, whose testimony I found most persuasive relative to comparable market price. My decision in this case was compelled by the specific factors noted above, by affiliation, and by the price record of Martinka coal from first production through June, 1992. In my view, the majority citation to Quarto merely reinforces the timing aspect of the efficacy consideration.

I am dissatisfied with the structure and terms of the Peabody contract. It is not bifurcated into a price for the replacement fuel and a price reflective of the buy-out cost, as found in the Arch-Donaldson contract. More important, the Peabody contract fails to contain a periodic price re-opener provision relative to the replacement fuel supply. However, the Peabody contract predates the Commission's policy statement relative to periodic price re-negotiation in long term contracts. Since I have concluded that being at or near market is more rational than trying to outguess the market, particularly in circumstances where a bad guess is riskless, future long term contracts not containing such provisions will have a substantial prudence barrier to satisfy, in my judgment; or should be subject to at least a cumulative market price test.

In addition, I disagree with the majority's treatment of the Sands Hill contract. In my view, the record in this case raises legitimate concerns relative to the proportion of fuel under long term contract. If this aspect of the appropriateness of the Sands Hill contract is not reserved in this case, then I have difficulty understanding on what grounds the Commission could question the proportion of fuel under long term contract in a future EFC proceeding, assuming no other pertinent long term contracts are executed and all existing pertinent long term contracts are reduced to minimum levels consistent with least cost purchasing objectives. The Company's response that it might reduce production at Meigs, thereby freeing more of the Gavin burn for the spot market, is not sufficiently definitive nor adequately assessable to justify acceptance at this time of the Sands Hill contract and the liabilities flowing therefrom. Reducing Meigs production is an available option that is unaffected by the existence of the Sands Hill contract. I support the Staff's recommendation of further review and evaluation with respect to this contract. Richard M. Fanelly Entered in the Journal MAY 25 1994 A True Copy

*38 FOOTNOTES

FN1 Ohio Power is a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP). Another AEP subsidiary, American Electric Power Service Corporation (AEPSC), acts as fuel agent for Ohio Power. Fuel procurement is handled by AEPSC's Fuel Supply Department (FSD).

FN2 The contract dedicated the coal reserves exclusively to the contract (Comm. Ord. Ex. 2, at 2-26). Also, the contract stated that, if the contract terminated prior to the exhaustion of the reserves, the buyer was obligated to purchase the mine at the greater of the fair market value or the net book plus the assumption of all liabilities (*Id.*). The contract was a 'cost-plus' contract, wherein the buyer paid all of Donaldson's operating costs, plus a G&A expense, the financing cost of Donaldson's debt, and a profit margin (*Id.* at 2-26 to 2-27).

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FN3 Peabody purchased all assets, except for the Cove North land and its mineral rights (93-01, Comm. Ord. Ex. 2, at 26; Tr. III, 54, 56). IEC urged the Commission to find that the costs associated with the Cove North reserves and deferred royalties still on SOCCO's books may not be recovered from ratepayers in the future and that the disposition of the assets be recorded below the line (IEC Brief at 37-8). The Commission finds that IEC's recommendation is premature at this time. Nevertheless, the Commission will review the disposition and/or nondisposition of the properties in the future. Ohio Power should report to the Commission what transpires with the Cove North reserves.

FN4 The contract specifies that specification 'A' coal will be the type of coal delivered in the greatest quantity.

FN7 Alternatively, IEC suggested the application of the average of the changes in Ohio Power's other non-mine, purchase-related low sulfur, long-term contracts that were entered into at approximately the same time as the Peabody contract (IEC Brief at 32). Moreover, IEC stated that, if the Commission determines that the coal prices is currently at market, the Commission should advise the company that the Peabody price will be evaluated in every EFC proceeding and re-priced if it exceeds market (IEC Reply Brief at 21, Fn. 9).

FN8 The company noted that, if the contract price rose above market price during the last third of the contract term, the 'crossover' would be 'canceled out by the contract price being below market for the prior majority of the contract's term' (Ohio Power Reply Brief at 7; Tr. VI, 90-1). Moreover, if the crossover occurs, Ohio Power will permit the contract to expire at the end of the term, but if the crossover does not occur, the company could exercise its unilateral right to extend the contract for an additional five years (*Id.*).

FN9 See, *In the Matter of the Application of Ohio Power Company for Approval of an Environmental Compliance Plan Pursuant to Chapter 4913, Revised Code*, Case No. 92-790-EL-ECP (November 25, 1992), aff'd, *Indus. Energy Consumers of Ohio Power Co. v. Pub. Util. Comm.* (1994), 68 Ohio St. 3d 547.

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4903.10 Application for rehearing.

After any order has been made by the public utilities commission, any party who has entered an appearance in person or by counsel in the proceeding may apply for a rehearing in respect to any matters determined in the proceeding. Such application shall be filed within thirty days after the entry of the order upon the journal of the commission. Notwithstanding the preceding paragraph, in any uncontested proceeding or, by leave of the commission first had in any other proceeding, any affected person, firm, or corporation may make an application for a rehearing within thirty days after the entry of any final order upon the journal of the commission. Leave to file an application for rehearing shall not be granted to any person, firm, or corporation who did not enter an appearance in the proceeding unless the commission first finds:

(A) The applicant's failure to enter an appearance prior to the entry upon the journal of the commission of the order complained of was due to just cause; and,

(B) The interests of the applicant were not adequately considered in the proceeding. Every applicant for rehearing or for leave to file an application for rehearing shall give due notice of the filing of such application to all parties who have entered an appearance in the proceeding in the manner and form prescribed by the commission. Such application shall be in writing and shall set forth specifically the ground or grounds on which the applicant considers the order to be unreasonable or unlawful. No party shall in any court urge or rely on any ground for reversal, vacation, or modification not so set forth in the application. Where such application for rehearing has been filed before the effective date of the order as to which a rehearing is sought, the effective date of such order, unless otherwise ordered by the commission, shall be postponed or stayed pending disposition of the matter by the commission or by operation of law. In all other cases the making of such an application shall not excuse any person from complying with the order, or operate to stay or postpone the enforcement thereof, without a special order of the commission. Where such application for rehearing has been filed, the commission may grant and hold such rehearing on the matter specified in such application, if in its judgment sufficient reason therefor is made to appear. Notice of such rehearing shall be given by regular mail to all parties who have entered an appearance in the proceeding. If the commission does not grant or deny such application for rehearing within thirty days from the date of filing thereof, it is denied by operation of law. If the commission grants such rehearing, it shall specify in the notice of such granting the purpose for which it is granted. The commission shall also specify the scope of the additional evidence, if any, that will be taken, but it shall not upon such rehearing take any evidence that, with reasonable diligence, could have been offered upon the original hearing. If, after such rehearing, the commission is of the opinion that the original order or any part thereof is in any respect unjust or unwarranted, or should be changed, the commission may abrogate or modify the same; otherwise such order shall be affirmed. An order made after such rehearing, abrogating or modifying the original order, shall have the same effect as an original order, but shall not affect any right or the enforcement of any right arising from or by virtue of the original order prior to the receipt of notice by the affected party of the filing of the application for rehearing. **No cause of action arising out of any order of the commission, other than in support of the order, shall accrue in any court to any person, firm, or corporation unless such person, firm, or corporation has made a proper application to the commission for a rehearing.**

4903.11 Proceeding deemed commenced.

No proceeding to reverse, vacate, or modify a final order of the public utilities commission is commenced unless the notice of appeal is filed within sixty days after the date of denial of the application for rehearing by operation of law or of the entry upon the journal of the commission of the order denying an application for rehearing or, if a rehearing is had, of the order made after such rehearing. An order denying an application for rehearing or an order made after a rehearing shall be served forthwith by regular mail upon all parties who have entered an appearance in the proceeding.

4928.01 Competitive retail electric service definitions.

(A) As used in this chapter:

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

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

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

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

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

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

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

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

(9) "Electric services company" means an electric light company that is engaged on a for-profit or not-for-profit basis in the business of supplying or arranging for the supply of only a competitive retail electric service in this state. "Electric services company" includes a power marketer, power broker, aggregator, or independent power producer but excludes an electric cooperative, municipal electric utility, governmental aggregator, or billing and collection agent.

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

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

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

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

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

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

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

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

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

(19) "Mercantile customer" means a commercial or industrial customer if the electricity consumed is for nonresidential use and the customer consumes more than seven hundred thousand kilowatt hours per year or is part of a national account involving multiple facilities in one or more states.

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

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

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

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

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

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

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

(27) "Retail electric service" means any service involved in supplying or arranging for the supply of electricity to ultimate consumers in this state, from the point of generation to the point of consumption. For the purposes of this chapter, retail electric service includes one or more of the following "service components" : generation service, aggregation service, power marketing

service, power brokerage service, transmission service, distribution service, ancillary service, metering service, and billing and collection service.

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

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

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

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

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

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

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

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

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

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

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

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

(b) Any distributed generation system consisting of customer cogeneration of electricity and thermal output simultaneously;

(c) Clean coal technology that includes a carbon-based product that is chemically altered before combustion to demonstrate a reduction, as expressed as ash, in emissions of nitrous oxide, mercury, arsenic, chlorine, sulfur dioxide, or sulfur trioxide in accordance with the American society of testing and materials standard D1757A or a reduction of metal oxide emissions in accordance with standard D5142 of that society, or clean coal technology that includes the

design capability to control or prevent the emission of carbon dioxide, which design capability the commission shall adopt by rule and shall be based on economically feasible best available technology or, in the absence of a determined best available technology, shall be of the highest level of economically feasible design capability for which there exists generally accepted scientific opinion;

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

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

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

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

(35) "Renewable energy resource" means solar photovoltaic or solar thermal energy, wind energy, power produced by a hydroelectric facility, geothermal energy, fuel derived from solid wastes, as defined in section 3734.01 of the Revised Code, through fractionation, biological decomposition, or other process that does not principally involve combustion, biomass energy, biologically derived methane gas, or energy derived from nontreated by-products of the pulping process or wood manufacturing process, including bark, wood chips, sawdust, and lignin in spent pulping liquors. "Renewable energy resource" includes, but is not limited to, any fuel cell used in the generation of electricity, including, but not limited to, a proton exchange membrane fuel cell, phosphoric acid fuel cell, molten carbonate fuel cell, or solid oxide fuel cell; wind turbine located in the state's territorial waters of Lake Erie; methane gas emitted from an abandoned coal mine; storage facility that will promote the better utilization of a renewable energy resource that primarily generates off peak; or distributed generation system used by a customer to generate electricity from any such energy. As used in division (A)(35) of this section, "hydroelectric facility" means a hydroelectric generating facility that is located at a dam on a river, or on any water discharged to a river, that is within or bordering this state or within or bordering an adjoining state and meets all of the following standards:

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

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

state that the river has impaired water quality under Section 303(d) of the "Clean Water Act of 1977," 114 Stat. 870, 33 U.S.C. 1313.

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

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

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

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

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

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

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

4928.143 Application for approval of electric security plan - testing.

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

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

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

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

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

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

(c) The establishment of a nonbypassable surcharge for the life of an electric generating facility that is owned or operated by the electric distribution utility, was sourced through a competitive bid process subject to any such rules as the commission adopts under division (B)(2)(b) of this section, and is newly used and useful on or after January 1, 2009, which surcharge shall cover all

costs of the utility specified in the application, excluding costs recovered through a surcharge under division (B)(2)(b) of this section. However, no surcharge shall be authorized unless the commission first determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility. Additionally, if a surcharge is authorized for a facility pursuant to plan approval under division (C) of this section and as a condition of the continuation of the surcharge, the electric distribution utility shall dedicate to Ohio consumers the capacity and energy and the rate associated with the cost of that facility. Before the commission authorizes any surcharge pursuant to this division, it may consider, as applicable, the effects of any decommissioning, deratings, and retirements.

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

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

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

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

(h) Provisions regarding the utility's distribution service, including, without limitation and notwithstanding any provision of Title XLIX of the Revised Code to the contrary, provisions regarding single issue ratemaking, a revenue decoupling mechanism or any other incentive ratemaking, and provisions regarding distribution infrastructure and modernization incentives for the electric distribution utility. The latter may include a long-term energy delivery infrastructure modernization plan for that utility or any plan providing for the utility's recovery of costs, including lost revenue, shared savings, and avoided costs, and a just and reasonable rate of return on such infrastructure modernization. As part of its determination as to whether to allow in an electric distribution utility's electric security plan inclusion of any provision described in division (B)(2)(h) of this section, the commission shall examine the reliability of the electric distribution utility's distribution system and ensure that customers' and the electric distribution utility's expectations are aligned and that the electric distribution utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system.

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

(C)(1) The burden of proof in the proceeding shall be on the electric distribution utility. The commission shall issue an order under this division for an initial application under this section not later than one hundred fifty days after the application's filing date and, for any subsequent application by the utility under this section, not later than two hundred seventy-five days after the application's filing date. Subject to division (D) of this section, the commission by order shall approve or modify and approve an application filed under division (A) of this section if it finds that the electric security plan so approved, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code. Additionally, if the commission so approves an application that contains a surcharge under division (B)(2)(b) or (c) of this section, the commission shall ensure that the benefits derived for any purpose for which the surcharge is established are reserved and made available to those that bear the surcharge. Otherwise, the commission by order shall disapprove the application.

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

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

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

(E) If an electric security plan approved under division (C) of this section, except one withdrawn by the utility as authorized under that division, has a term, exclusive of phase-ins or deferrals, that exceeds three years from the effective date of the plan, the commission shall test the plan in the fourth year, and if applicable, every fourth year thereafter, to determine whether the plan,

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

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

4901:1-35-03 Filing and contents of applications.

Each electric utility in this state filing an application for a standard service offer (SSO) in the form of an electric security plan (ESP), a market-rate offer (MRO), or both, shall comply with the requirements set forth in this rule.

(A) SSO applications shall be case captioned as (XX-XXX-EL-SSO). Twenty copies plus an original of the application shall be filed. The application must include a complete set of direct testimony of the electric utility personnel or other expert witnesses. This testimony shall be in question and answer format and shall be in support of the electric utility's proposed application. This testimony shall fully support all schedules and significant issues identified by the electric utility.

(B) An SSO application that contains a proposal for an MRO shall comply with the requirements set forth below.

(1) The following electric utility requirements are to be demonstrated in a separate section of the standard service offer SSO application proposing a market-rate offer MRO:

(a) The electric utility shall establish one of the following: that it, or its transmission affiliate, belongs to at least one regional transmission organization (RTO) that has been approved by the federal energy regulatory commission; or, if the electric utility or its transmission affiliate does not belong to an RTO, then the electric utility shall demonstrate that alternative conditions exist with regard to the transmission system, which include non-pancaked rates, open access by generation suppliers, and full interconnection with the distribution grid.

(b) The electric utility shall establish one of the following: its RTO retains an independent market-monitor function and has the ability to identify any potential for a market participant or the electric utility to exercise market power in any energy, capacity, and/or ancillary service markets by virtue of access to the RTO and the market participant's data and personnel and has the ability to effectively mitigate the conduct of the market participants so as to prevent or preclude the exercise of such market power by any market participant or the electric utility; or the electric utility shall demonstrate that an equivalent function exists which can monitor, identify, and mitigate conduct associated with the exercise of such market power.

(c) The electric utility shall demonstrate that an independent and reliable source of electricity pricing information for any energy product or service necessary for a winning bidder to fulfill the contractual obligations resulting from the competitive bidding process (CBP) is publicly available. The information may be offered through a pay subscription service, but the pay subscription service shall be available under standard pricing, terms, and conditions to any person requesting a subscription. The published information shall be representative of prices and changes in prices in the electric utility's electricity market, and shall identify pricing of on-peak and off-peak energy products that represent contracts for delivery, encompassing a time frame beginning at least two years from the date of the publication. The published information shall be updated on at least a monthly basis.

(2) Prior to establishing an MRO under division (A) of section 4928.142 of the Revised Code, an electric utility shall file a plan for a CBP with the commission. The electric utility shall provide justification of its proposed CBP plan, considering alternative possible methods of procurement. Each CBP plan that is to be used to establish an MRO shall include the following:

(a) A complete description of the CBP plan and testimony explaining and supporting each aspect of the CBP plan. The description shall include a discussion of any relationship between the wholesale procurement process and the retail rate design that may be proposed in the CBP plan. The description shall include a discussion of alternative methods of procurement that were considered and the rationale for selection of the CBP plan being presented. The description shall also include an explanation of every proposed non-avoidable charge, if any, and why the charge is proposed to be non-avoidable.

(b) Pro forma financial projections of the effect of the CBP plan's implementation, including implementation of division (D) of section 4928.142 of the Revised Code, upon generation, transmission, and distribution of the electric utility, for the duration of the CBP plan.

(c) Projected generation, transmission, and distribution rate impacts by customer class and rate schedules for the duration of the CBP plan. The electric utility shall clearly indicate how projected bid clearing prices used for this purpose were derived.

(d) Detailed descriptions of how the CBP plan ensures an open, fair, and transparent competitive solicitation that is consistent with and advances the policy of this state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code.

(e) Detailed descriptions of the customer load(s) to be served by the winning bidder(s), and any known factors that may affect such customer loads. The descriptions shall include, but not be limited to, load subdivisions defined for bidding purposes, load and rate class descriptions, customer load profiles that include historical hourly load data for each load and rate class for at least the two most recent years, applicable tariffs, historical shopping data, and plans for meeting targets pertaining to load reductions, energy efficiency, renewable energy, advanced energy, and advanced energy technologies. If customers will be served pursuant to time-differentiated or dynamic pricing, the descriptions shall include a summary of available data regarding the price elasticity of the load. Any fixed load provides to be served by winning bidder(s) shall be described.

(f) Detailed descriptions of the generation and related services that are to be provided by the winning bidder(s). The descriptions shall include, at a minimum, capacity, energy, transmission, ancillary and resource adequacy services, and the term during which generation and related services are to be provided. The descriptions shall clearly indicate which services are to be provided by the winning bidder(s) and which services are to be provided by the electric utility.

(g) Draft copies of all forms, contracts, or agreements that must be executed during or upon completion of the CBP.

(h) A clear description of the proposed methodology by which all bids would be evaluated, in sufficient detail so that bidders and other observers can ascertain the evaluated result of any bids or potential bids.

(i) The CBP plan shall include a discussion of time-differentiated pricing, dynamic retail pricing, and other alternative retail rate options that were considered in the development of the CBP plan. A clear description of the rate structure ultimately chosen by the electric utility, the electric utility's rationale for selection of the chosen rate structure, and the methodology by which the electric utility proposes to convert the winning bid(s) to retail rates of the electric utility shall be included in the CBP plan.

(j) The first application for a market rate offer by an electric utility that, as of July 31, 2008, directly owned, in whole or in part, operating electric generation facilities that had been used and useful in this state shall include a description of the electric utility's proposed blending of the CBP rates for the first five years of the market rate offer pursuant to division (D) of section 4928.142 of the Revised Code. The proposed blending shall show the generation service price(s) that will be blended with the CBP determined rates, and any descriptions, formulas, and/or tables necessary to show how the blending will be accomplished. The proposed blending shall show all adjustments, to be made on a quarterly basis, included in the generation service price(s) that the electric utility proposes for changes in costs of fuel, purchased power, portfolio requirements, and environmental compliance incurred during the blending period. The electric utility shall provide its best current estimate of anticipated adjustment amounts for the duration of the blending period, and compare the projected adjusted generation service prices under the CBP plan to the projected adjusted generation service prices under its proposed electric security plan.

(k) The electric utility's application to establish a CBP shall include such information as necessary to demonstrate whether or not, as of July 31, 2008, the electric utility directly owned, in whole or in part, operating electric generation facilities that had been used and useful in the state of Ohio.

(l) The CBP plan shall provide for funding of a consultant that may be selected by the commission to assess and report to the commission on the design of the solicitation, the oversight of the bidding process, the clarity of the product definition, the fairness, openness, and transparency of the solicitation and bidding process, the market factors that could affect the solicitation, and other relevant criteria as directed by the commission. Recovery of the cost of such consultant(s) may be included by the electric utility in its CBP plan.

(m) The CBP plan shall include a discussion of generation service procurement options that were considered in development of the CBP plan, including but not limited to, portfolio approaches, staggered procurement, forward procurement, electric utility participation in day-ahead and/or real-time balancing markets, and spot market purchases and sales. The CBP plan shall also include the rationale for selection of any or all of the procurement options.

(n) The electric utility shall show, as a part of its CBP plan, any relationship between the CBP plan and the electric utility's plans to comply with alternative energy portfolio requirements of section 4928.64 of the Revised Code, and energy efficiency requirements and peak demand

reduction requirements of section 4928.66 of the Revised Code. The initial filing of a CBP plan shall include a detailed account of how the plan is consistent with and advances the policy of this state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code. Following the initial filing, subsequent filings shall include a discussion of how the state policy continues to be advanced by the plan.

(o) An explanation of known and anticipated obstacles that may create difficulties or barriers for the adoption of the proposed bidding process.

(3) The electric utility shall provide a description of its corporate separation plan, adopted pursuant to section 4928.17 of the Revised Code, including but not limited to, the current status of the corporate separation plan, a detailed list of all waivers previously issued by the commission to the electric utility regarding its corporate separation plan, and a timeline of any anticipated revisions or amendments to its current corporate separation plan on file with the commission pursuant to Chapter 4901:1-37 of the Administrative Code.

(4) A description of how the electric utility proposes to address governmental aggregation programs and implementation of divisions (I) and (K) of section 4928.20 of the Revised Code.

(C) An SSO application that contains a proposal for an ESP shall comply with the requirements set forth below.

(1) A complete description of the ESP and testimony explaining and supporting each aspect of the ESP.

(2) Pro forma financial projections of the effect of the ESP's implementation upon the electric utility for the duration of the ESP, together with testimony and work papers sufficient to provide an understanding of the assumptions made and methodologies used in deriving the pro forma projections.

(3) Projected rate impacts by customer class/rate schedules for the duration of the ESP, including post-ESP impacts of deferrals, if any.

(4) The electric utility shall provide a description of its corporate separation plan, adopted pursuant to section 4928.17 of the Revised Code, including, but not limited to, the current status of the corporate separation plan, a detailed list of all waivers previously issued by the commission to the electric utility regarding its corporate separation plan, and a timeline of any anticipated revisions or amendments to its current corporate separation plan on file with the commission pursuant to Chapter 4901:1-37 of the Administrative Code.

(5) Division (A)(3) of section 4928.31 of the Revised Code required each electric utility to file an operational support plan as a part of its electric transition plan. Each electric utility shall provide a statement as to whether its operational support plan has been implemented and whether there are any outstanding problems with the implementation.

(6) A description of how the electric utility proposes to address governmental aggregation programs and implementation of divisions (I), (J), and (K) of section 4928.20 of the Revised Code.

(7) A description of the effect on large-scale governmental aggregation of any unavoidable generation charge proposed to be established in the ESP.

(8) The initial filing for an ESP shall include a detailed account of how the ESP is consistent with and advances the policy of this state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code. Following the initial filing, subsequent filings shall include how the state policy is advanced by the ESP.

(9) Specific information

Division (B)(2) of section 4928.143 of the Revised Code authorizes the provision or inclusion in an ESP of a number of features or mechanisms. To the extent that an electric utility includes any of these features in its ESP, it shall file the corresponding information in its application.

(a) Division (B)(2)(a) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for the automatic recovery of fuel, purchased power, and certain other specified costs. An application including such provisions shall include, at a minimum, the information described below:

(i) The type of cost the electric utility is seeking recovery for under division (B)(2) of section 4928.143 of the Revised Code including a summary and detailed description of such cost. The description shall include the plant(s) that the cost pertains to as well as a narrative pertaining to the electric utility's procurement policies and procedures regarding such cost.

(ii) The electric utility shall include in the application any benefits available to the electric utility as a result of or in connection with such costs including but not limited to profits from emission allowance sales and profits from resold coal contracts.

(iii) The specific means by which these costs will be recovered by the electric utility. In this specification, the electric utility must clearly distinguish whether these costs are to be recovered from all distribution customers or only from the customers taking service under the ESP.

(iv) A complete set of work papers supporting the cost must be filed with the application. Work papers must include, but are not limited to, all pertinent documents prepared by the electric utility for the application and a narrative and other support of assumptions made in completing the work papers.

(b) Divisions (B)(2)(b) and (B)(2)(c) of section 4928.143 of the Revised Code, authorize an electric utility to include unavoidable surcharges for construction, generation, or environmental expenditures for electric generation facilities owned or operated by the electric utility. Any plan which seeks to impose surcharge under these provisions shall include the following sections, as appropriate:

(i) The application must include a description of the projected costs of the proposed facility. The need for the proposed facility must have already been reviewed and determined by the commission through an integrated resource planning process filed pursuant to rule 4901:5-5-05 of the Administrative Code.

(ii) The application must also include a proposed process, subject to modification and approval by the commission, for the competitive bidding of the construction of the facility unless the commission has previously approved a process for competitive bidding, which would be applicable to that specific facility.

(iii) An application which provides for the recovery of a reasonable allowance for construction work in progress shall include a detailed description of the actual costs as of a date certain for which the applicant seeks recovery, a detailed description of the impact upon rates of the proposed surcharge, and a demonstration that such a construction work in progress allowance is consistent with the applicable limitations of division (A) of section 4909.15 of the Revised Code.

(iv) An application which provides recovery of a surcharge for an electric generation facility shall include a detailed description of the actual costs, as of a date certain, for which the applicant seeks recovery and a detailed description of the impact upon rates of the proposed surcharge.

(v) An application which provides for recovery of a surcharge for an electric generation facility shall include the proposed terms for the capacity, energy, and associated rates for the life of the facility.

(c) Division (B)(2)(d) of section 4928.143 of the Revised Code authorizes an electric utility to include terms, conditions, or charges related to retail shopping by customers. Any application which includes such terms, conditions or charges, shall include, at a minimum, the following information:

(i) A listing of all components of the ESP which would have the effect of preventing, limiting, inhibiting, or promoting customer shopping for retail electric generation service. Such components would include, but are not limited to, terms and conditions relating to shopping or to returning to the standard service offer and any unavoidable charges. For each such component, an explanation of the component and a descriptive rationale and, to the extent possible, a quantitative justification shall be provided.

(ii) A description and quantification or estimation of any charges, other than those associated with generation expansion or environmental investment under divisions (B)(2)(b) and (B)(2)(c) of section 4928.143 of the Revised Code, which will be deferred for future recovery, together with the carrying costs, amortization periods, and avoidability of such charges.

(iii) A listing, description, and quantitative justification of any unavoidable charges for standby, back-up, or supplemental power.

(d) Division (B)(2)(e) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for automatic increases or decreases in any component of the standard service offer price. Pursuant to this authority, if the ESP proposes automatic increases or decreases to be implemented during the life of the plan for any component of the standard service offer, other than those covered by division (B)(2)(a) of section 4928.143 of the Revised Code, the electric utility must provide in its application a description of the component, the proposed means for changing the component, and the proposed means for verifying the reasonableness of the change.

(e) Division (B)(2)(f) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for the securitization of authorized phase-in recovery of the standard service offer price. If a phase-in deferred asset is proposed to be securitized, the electric utility shall provide, at the time of an application for securitization, a description of the securitization instrument and an accounting of that securitization, including the deferred cash flow due to the phase-in, carrying charges, and the incremental cost of the securitization. The electric utility will also describe any efforts to minimize the incremental cost of the securitization. The electric utility shall provide all documentation associated with securitization, including but not limited to, a summary sheet of terms and conditions. The electric utility shall also provide a comparison of costs associated with securitization with the costs associated with other forms of financing to demonstrate that securitization is the least cost strategy.

(f) Division (B)(2)(g) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions relating to transmission and other specified related services. Moreover, division (A)(2) of section 4928.05 of the Revised Code states that, notwithstanding Chapters 4905. and 4909. of the Revised Code, commission authority under this chapter shall include the authority to provide for the recovery, through a reconcilable rider on an electric distribution utility's distribution rates, of all transmission and transmission-related costs (net of transmission related revenues), including ancillary and net congestion costs, imposed on or charged to the utility by the federal energy regulatory commission or a regional transmission organization, independent transmission operator, or similar organization approved by the federal energy regulatory commission.

Any utility which seeks to create or modify its transmission cost recovery rider in its ESP shall file the rider in accordance with the requirements delineated in Chapter 4901:1-36 of the Administrative Code.

(g) Division (B)(2)(h) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for alternative regulation mechanisms or programs, including infrastructure and modernization incentives, relating to distribution service as part of an ESP. While a number of mechanisms may be combined within a plan, for each specific mechanism or program, the electric utility shall provide a detailed description, with supporting data and information, to allow appropriate evaluation of each proposal, including how the proposal addresses any cost savings to the electric utility, avoids duplicative cost recovery, and aligns electric utility and consumer interests. In general, and to the extent applicable, the electric utility shall also include, for each separate mechanism or program, quantification of the estimated impact on rates over the term of any proposed modernization plan. Any application for an infrastructure modernization plan shall include the following specific requirements:

(i) A description of the infrastructure modernization plan, including but not limited to, the electric utility's existing infrastructure, its existing asset management system and related capabilities, the type of technology and reason chosen, the portion of service territory affected, the percentage of customers directly impacted (non-rate impact), and the implementation schedule by geographic location and/or type of activity. A description of any communication infrastructure included in the infrastructure modernization plan and any metering, distribution automation, or other applications that may be supported by this communication infrastructure also shall be included.

(ii) A description of the benefits of the infrastructure modernization plan (in total and by activity or type), including but not limited to the following as they may apply to the plan: the impacts on current reliability, the number of circuits impacted, the number of customers impacted, the timing of impacts, whether the impact is on the frequency or duration of outages, whether the infrastructure modernization plan addresses primary outage causes, what problems are addressed by the infrastructure modernization plan, the resulting dollar savings and additional costs, the activities affected and related accounts, the timing of savings, other customer benefits, and societal benefits. Through metrics and milestones, the infrastructure modernization plan shall include a description of how the performance and outcomes of the plan will be measured.

(iii) A detailed description of the costs of the infrastructure modernization plan, including a breakdown of capital costs and operating and maintenance expenses net of any related savings, the revenue requirement, including recovery of stranded investment related to replacement of un-depreciated plant with new technology, the impact on customer bills, service disruptions associated with plan implementation, and description of (and dollar value of) equipment being made obsolescent by the plan and reason for early plant retirement. The infrastructure modernization plan shall also include a description of efforts made to mitigate such stranded investment.

(iv) A detailed description of any proposed cost recovery mechanism, including the components of any regulatory asset created by the infrastructure modernization plan, the reporting structure and schedule, and the proposed process for approval of cost recovery and increase in rates.

(v) A detailed explanation of how the infrastructure modernization plan aligns customer and electric utility reliability and power quality expectations by customer class.

(h) Division (B)(2)(i) of section 4928.143 of the Revised Code authorizes an electric utility to include provisions for economic development, job retention, and energy efficiency programs. Pursuant to this section, the electric utility shall provide a complete description of the proposal, together with cost-benefit analysis or other quantitative justification, and quantification of the program's projected impact on rates.

(10) Additional required information

Divisions (E) and (F) of section 4928.143 of the Revised Code provide for tests of the ESP with respect to significantly excessive earnings. Division (E) of section 4928.143 of the Revised Code is applicable only if an ESP has a term exceeding three years, and would require an earnings

determination to be made in the fourth year. Division (F) of section 4928.143 of the Revised Code applies to any ESP and examines earnings after each year. In each case, the burden of proof for demonstrating that the return on equity is not significantly excessive is borne by the electric utility.

(a) For the annual review pursuant to division (F) of section 4928.143 of the Revised Code, the electric utility shall provide testimony and analysis demonstrating the return on equity that was earned during the year and the returns on equity earned during the same period by publicly traded companies that face comparable business and financial risks as the electric utility. In addition, the electric utility shall provide the following information:

(i) The federal energy regulatory commission form 1 (FERC form 1) in its entirety for the annual period under review. The electric utility may seek protection of any confidential or proprietary data if necessary. If the FERC form 1 is not available, the electric utility shall provide balance sheet and income statement information of at least the level of detail as required by FERC form 1.

(ii) The latest securities and exchange commission form 10-K in its entirety. The electric utility may seek protection of any confidential or proprietary data if necessary.

(iii) Capital budget requirements for future committed investments in Ohio for each annual period remaining in the ESP.

(b) For demonstration under division (E) of section 4928.143 of the Revised Code, the electric utility shall also provide, in addition to the requirements under division (F) of section 4928.143 of the Revised Code, calculations of its projected return on equity for each remaining year of the ESP. The electric utility shall support these calculations by providing projected balance sheet and income statement information for the remainder of the ESP, together with testimony and work papers detailing the methodologies, adjustments, and assumptions used in making these projections.

(D) The first application for an SSO filed after the effective date of section 4928.141 of the Revised Code by each electric utility shall include an ESP and shall be filed at least one hundred fifty days before the electric utility proposes to have such SSO in effect. The first application may also include a proposal for an MRO. First applications that are filed with the commission prior to the initial effective date of this rule and that are determined by the commission to be not in substantive compliance with this rule shall be amended or refiled at the direction of the commission. The commission shall endeavor to make a determination on an amended or refiled ESP application, which substantively conforms to the requirements of this rule, within one hundred fifty days of the filing of the amended or refiled application.

(E) Subsequent applications for an SSO may include an ESP and/or MRO; however, an ESP may not be proposed once the electric utility has implemented an MRO approved by the commission.

(F) The SSO application shall include a section demonstrating that its current corporate separation plan is in compliance with section 4928.17 of the Revised Code, Chapter 4901:1-37 of

the Administrative Code, and consistent with the policy of the state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code. If any waivers of the corporate separation plan have been granted and are to be continued, the applicant shall justify the continued need for those waivers.

(G) A complete set of work papers must be filed with the application. Work papers must include, but are not limited to, all pertinent documents prepared by the electric utility for the application and a narrative or other support of assumptions made in the work papers. Work papers shall be marked, organized, and indexed according to schedules to which they relate. Data contained in the work papers should be footnoted so as to identify the source document used.

(H) All schedules, tariff sheets, and work papers prepared by, or at the direction of, the electric utility for the application and included in the application must be available in spreadsheet, word processing, or an electronic non-image-based format, with formulas intact, compatible with personal computers. The electronic form does not have to be filed with the application but must be made available within two business days to staff and any intervening party that requests it.