IN THE SUPREME COURT OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of an Electric Security Plan; an Amendment to Its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets.	)	Case No. 2009-2298 On Appeal from the Public Utilities Commission of Ohio, Case No. 08-917-EL-SSO
In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan.	)	
(*Columbus Southern Power Company v. The Public Utilities Commission of Ohio*)	)	

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TABLE OF CONTENTS

TABLE OF CONTENTS cont'd.

APPX. NO.

PUCO Cases:

TABLE OF AUTHORITIES

Page

Case:

PUCO Cases:

STATUTES:

OHIO ADMINISTRATIVE CODE PROVISIONS:

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MERIT BRIEF OF INTERVENING APPELLEE
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL

I. INTRODUCTION

On May 1, 2008, the Governor signed S.B. 221, which brought sweeping changes to the electric industry in Ohio. Under this legislation, the Public Utilities Commission of Ohio ("Commission" or "PUCO") determines the appropriate pricing for electric generation services under standard service offers in the form of either electric security plans ("ESPs") or market rate offers proposed by Ohio's electric utilities. The case below involved an ESP application under R.C. 4928.143 by the Columbus Southern Power Company ("CSP" or "the Company"), filed on July 31, 2008. As part of its ESP application, the Company sought authority to sell or transfer the Waterford Energy Center and Darby Electric Generating Center (collectively, "Facilities") within its ESP, under R.C. 4928.17(E). As noted by CSP witness J.

Craig Baker, however, the Company has no present plans to sell or transfer these Facilities. (CSP Supp. 4).[1]

On March 18, 2009, the Commission issued an Opinion and Order ("Order") that modified and approved the Company's ESP. (CSP Appx. 31). In so doing, the Commission characterized CSP's request for transfer of the Facilities as premature, and directed CSP to file an application for PUCO approval to transfer the Facilities at such time when the Company establishes a plan to transfer them. (CSP Appx. 83). In the Order, the PUCO allowed CSP to collect from customers the jurisdictional costs associated with maintaining and operating the Facilities. The PUCO ruled that any of these jurisdictional expenses not recovered in the fuel adjustment clause should be recoverable in the non-fuel adjustment clause portion of the generation rates. (CSP Appx. 83). The Company claims that the costs associated with the Facilities total approximately $51 million per year, totaling $153 million over the three-year term of the ESP. (CSP Supp. 7-8).

In an entry on rehearing issued on July 23, 2009 ("July 23 Entry"), the PUCO granted the rehearing application of the Industrial Energy Users ("IEU") and reversed its decision permitting CSP to collect costs associated with the Facilities from customers. (CSP Appx. 148-149). The Commission found that CSP had not demonstrated that its current revenue is inadequate to cover the costs associated with the Facilities, and had not demonstrated that those costs should be collected from Ohio customers through the non-fuel portion of the generation rate. (CSP Appx. 148-149). Although CSP filed its own application for rehearing

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[1] In this brief, OCC will use the following citation forms: citations to the appendix to CSP's brief will be cited "CSP Appx."; citations to the supplement to CSP's brief will be cited "CSP Supp."; citations to the appendix to OCC's brief will be cited "OCC Appx."; citations to the supplement to OCC's brief will be cited "OCC Supp."

of the Order, the Company did not seek rehearing of the PUCO's decision that the request for transfer authority was premature.

On July 31, 2009, CSP filed an application for rehearing of the July 23 Entry. In this application for rehearing, CSP did not ask the Commission for authority to collect the costs associated with the Facilities. Instead, the Company sought PUCO authority to transfer the Facilities. (CSP Appx. 350-354). The Commission denied CSP's application for rehearing on November 4, 2009 ("November 4 Entry"). (CSP Appx. 175-177).

The Company appealed the July 23 Entry and the November 4 Entry to this Court.

II. STANDARD OF REVIEW

R.C. 4903.13[2] governs this Court's review of PUCO Orders. It provides in pertinent part: "A final order made by the public utilities commission shall be reversed, vacated, or modified by the supreme court on appeal, if, upon consideration of the record, such court is of the opinion that such order was unlawful or unreasonable***." The Court has interpreted this standard as one turning upon whether the issue presents a question of law or a question of fact.

As to questions of fact, the Court has held that it will not reverse the PUCO unless the PUCO's findings are manifestly against the weight of the evidence or are so clearly unsupported by the record as to show misapprehension, mistake or willful disregard of duty.[3] The appellant bears the burden of proof.[4] This burden is difficult to sustain because the Court

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[2] (CSP Appx. 1).

[3] *Cleveland Elec. Illuminating Co. v. Pub. Util. Comm.* (1975), 42 Ohio St.2d 403, 330 N.E.2d 1, ¶ 8 of the syllabus, certiorari denied (1975), 423 U.S. 986, 96 S.Ct. 393, 46 L.Ed.302.

[4] See *Monongahela Power Co. v. Pub. Util. Comm*, 104 Ohio St. 3d 571, 578, 2004-Ohio-6896, 820 N.E.2d 921.

has consistently found it proper to defer to the Commission's judgment in matters that require the Commission to apply its specialized expertise and discretion with regard to factual matters.[5] CSP claims that the PUCO's denial of the transfer authority in conjunction with its denial of cost collection from customers was unreasonable.[6]

As to questions of law, this Court has complete, independent power of review.[7] Accordingly legal issues are subject to a more intensive examination than are factual questions.

In this appeal, although CSP attempts to frame the issues as issues of law, they are not. The Company's arguments that the PUCO erred in not approving CSP's premature request to transfer the facilities at some unnamed future time involves a question of whether the Commission, in its exercise of discretion under R.C. 4928.17 and R.C. 4928.143 (C)(1), acted reasonably. This is not an issue of law.

The Company's arguments that it was unreasonable for the PUCO, on rehearing, to reverse its decision and deny the Company authority to collect $153 million in costs for the Facilities from customers, when it had denied the Company the ability at this time to transfer the units, is also a question of fact. The Court is being asked to determine whether the PUCO acted reasonably in exercising its discretion under R.C. 4928.143(C)(1) to disprove that portion of the ESP plan which included expenses for the Facilities.

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[5] Id., 104 Ohio St. 3d 578.

[6] CSP Brief at 13-14.

[7] *Office of Consumers' Counsel v. Pub. Util. Comm.* (1979), 58 Ohio St.2d 108, 110, 12 O.O.3d 115, 388 N.E.2d 1370.

It is in this context that the Court must carry out its review of the Commission's orders.

III. STATEMENT OF FACTS

On July 31, 2008, CSP filed an ESP application with the PUCO. (OCC Supp. 1-21). In conjunction with its ESP application, CSP requested authority to sell or transfer the Facilities, which the Company had acquired during the previous three years. (OCC Supp. 14-15). CSP alleges that the Facilities were never included in its rate base for ratemaking purposes. (OCC Supp. 14). In the application, CSP stated that it had "no immediate plan to sell or transfer those facilities and, if authorized to do so, will notify the Commission prior to any such transaction." (OCC Supp. 15).

After a process that included an evidentiary hearing, the Commission issued an order on March 18, 2009, that modified and approved the Company's ESP. In the Order, the Commission also determined that CSP's request to transfer the Facilities was premature, and directed CSP to file an application to transfer the Facilities when it wished to actually sell or transfer them, pursuant to the PUCO's enabling rules adopted in accordance with R.C. 4928.17. (CSP Appx. 83). The PUCO allowed CSP to collect from customers the jurisdictional expenses of the facilities ($51 million per year) that were not recovered in the fuel adjustment clause through the non-fuel portion of the generation rate. (CSP Appx. 83).

On April 16, 2009, IEU applied for rehearing of the Commission's decision. IEU argued that the PUCO did not adequately justify the decision (violating R.C. 4903.09) and that CSP had not demonstrated a need for additional revenues beyond those embedded in the current rates. (CSP Appx. 203-205). On rehearing, the PUCO, on July 23, 2009, reversed its decision concerning the collection of costs associated with the Facilities. The Commission found that CSP had not demonstrated that its current revenue is inadequate to cover the costs associated with the Facilities, and had not shown that those costs should be collected from Ohio customers through the non-fuel portion of the generation rate. (CSP Appx. 148-149). The PUCO directed the Company to modify its ESP and remove the annual recovery of $51 million of expenses, including carrying charges, related to the Facilities. (CSP Appx. 148-149).

On July 31, 2009, CSP applied for rehearing of the PUCO's July 23 Entry. In its application, CSP argued that "[i]f the Commission were going to revoke the rate authorization it provided in the Opinion and Order it also should have reconsidered its ruling as it related to authority to sell or transfer the Waterford and Darby facilities and granted CSP the authority it sought under §4928.17 (E), Ohio Rev. Code, regarding Waterford and Darby." (CSP Appx. 352). CSP also complained that because the generation rates in effect on the effective date of S.B. 221 did not include recovery of costs associated with maintaining and operating the Facilities, "CSP is unlawfully put in the position of being required to retain these facilities but not being permitted to make any adjustment to the rate plan rate to recover costs of maintaining and operating those units or recover a return on the investment in those plants." (CSP Appx. 352-353). The relief CSP requested was for the Commission to "grant[] CSP the authority it sought in the proceeding to sell or transfer Waterford and Darby." (CSP Appx. 353). CSP did not ask for rehearing of the PUCO's decision barring the Company from collecting from customers the $153 million in costs associated with the Facilities' operations.

On November 4, 2009, the Commission denied CSP's application for rehearing. (CSP Appx. 175-177). In the November 4 Entry, the Commission noted that it did not prohibit the Company from selling or transferring the Facilities. Instead, the Commission's decision "was based on the Companies' testimony that there was not a 'present plan to exercise' the authority to sell or transfer the Darby or Waterford plants and the Staff's observation that the transfer or sale of the facilities could have a potential financial and policy impact at the time of the transfer." (Citations omitted.) (CSP Appx. 177). The Commission directed CSP to file a plan, for Commission consideration under R.C. 4928.17(E), to sell or transfer the Facilities when CSP has established such a plan. (CSP Appx. 177).

On December 22, 2009, CSP appealed the PUCO's decision to this Court. In its Notice of Appeal (CSP Appx. 24-30), CSP presented the following allegations of error:[8]

1. The Commission unlawfully and unreasonably denied CSP the authority to sell or transfer certain generating assets (Waterford Energy Center and Darby Electric Generating Center) as part of CSP's proposed Electric Security Plan.

2. The Commission unlawfully and unreasonably denied CSP the authority to recover, as part of its Electric Security Plan, costs associated with its ownership of the Waterford Energy Center and Darby Electric Generating Station.

3. If the Commission were going to require CSP to retain the Waterford Energy Center and Darby Electric Generating Station, "then the Commission should also allow [CSP] to recover Ohio customers' jurisdictional share of any costs associated with maintaining and operating such facilities." (Opinion and Order, p. 52). The Commission's failure to either authorize the sale or transfer of those generating assets or to authorize recovery of costs from customers is unlawful and unreasonable.

[8] CSP Appx. 26.

IV. ARGUMENT

Proposition of Law No. 1

Where appellants fail to raise specific grounds for rehearing before the Commission, the Court lacks jurisdiction to consider those arguments.

R.C. 4903.10 provides that "[a]fter 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." (OCC Appx. 1). The application must be filed within 30 days "of the entry of the order upon journal of the commission." (OCC Appx. 1). Further, under R.C. 4903.10 "[s]uch 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." (OCC Appx. 1). R.C. 4903.10 also provides that "[n]o 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." (OCC Appx. 1).

Another provision of the Revised Code, R.C. 4903.13, sets forth the right of appeal and the obligations of parties seeking an appeal from a decision of the PUCO. Under R.C. 4903.13, a party to a Commission proceeding may appeal, but must set forth "the order appealed from and the errors complained of." (CSP Appx. 1). These statutes together authorize a mandatory process for appealing PUCO orders and prescribe the conditions and procedure under which appeals may be sought.

This Court has ruled that if an appellant fails to raise specific grounds for rehearing before the PUCO, the Court lacks jurisdiction to consider those arguments.[9] Therefore, under R.C. 4903.10, an appellant that does not raise an issue in its application for rehearing has failed to preserve the issue on appeal, and the Court has refused to hear arguments on such issues.[10] This process assures that parties do not engage in unfair tactics by raising issues for the first time before the Court – issues that could have been addressed earlier by the Commission.[11] This process thus ensures that the PUCO has the opportunity to thoroughly address matters under its jurisdiction, and helps to maintain the integrity of the appeal process. In this case, CSP failed to adhere to these statutes, and its belated claims of error should not be heard.

In its Notice of Appeal, CSP introduced two claimed errors on which the Company failed to apply for rehearing at the PUCO. These alleged errors are: (1) that the Commission unlawfully and unreasonably denied CSP the authority to recover, as part of its Electric Security Plan, costs associated with its ownership of Waterford and Darby; and (2) that the

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[9] *Consumers' Counsel v. Pub. Util. Comm.*, 114 Ohio St.3d 340, 349, 2007-Ohio-4276, 872 N.E.2d 269, ¶40, citing *Consumers' Counsel v. Pub. Util. Comm.* (1994), 70 Ohio St.3d 244, 247, 638 N.E.2d 550; *Travis v. Pub. Util. Comm.* (1931), 123 Ohio St. 355, 9 Ohio Law Abs. 443, 175 N.E. 586, ¶6 of the syllabus.

[10] See, e.g., *Consumers' Counsel v. Pub. Util. Comm.*, 114 Ohio St. 3d at 349, 872 N.E.2d 269, ¶40; *Ohio Partners for Affordable Energy v. Pub. Util. Comm.*, 115 Ohio St.3d 208, 2007-Ohio-4790, 874 N.E.2d 764, ¶16.

[11] See *City of Cincinnati v. Pub. Util. Comm.* (1949), 151 Ohio St. 353, 376-377, 39 O.O. 188, 86 N.E.2d 10 (characterizing Section 614-46a, General Code, the predecessor to R.C. 4903.10, as the General Assembly recognizing that it should guard against such unfair tactics). Jurisdictional issues, however, are an exception to this rule. See *Time Warner AxS v. Pub. Util. Comm.* (1996), 75 Ohio St.3d 229, 233, 661 N.E.2d 1097, reconsideration denied (1996), 75 Ohio St.3d 1453, 663 N.E.2d 333, citing to *Gates Mills Investment Co. v. Parks* (1971), 25 Ohio St.2d 16, 20, 54 O.O.2d 157, 266 N.E.2d 552. None of the issues discussed herein qualify as jurisdictional issues, however.

Commission's failure to either authorize the sale or transfer of Waterford and Darby or to authorize recovery of costs from customers is unlawful and unreasonable. (CSP Appx. 26).

In its brief, CSP restated these two allegations of error and combined them into one proposition of law: "When the Public Utilities Commission of Ohio considers an application for approval to sell or transfer generating assets which never have been included in the electric distribution utility's plant-in-service for rate making purposes at the same time it considers the utility's Electric Security Plan application, it is unlawful for the Commission to deny the authority to sell or transfer those assets and at the same time refuse to allow, as part of the Electric Security Plan, an adjustment for costs associated with maintaining and operating those same assets."[12] CSP asks this Court to "direct the Commission to either authorize the sale or transfer of the Waterford and Darby facilities, or authorize the revenue recovery associated with those facilities as the Commission originally authorized."[13]

A review of CSP's two applications for rehearing, filed on April 17, 2009 and July 31, 2009, reveals that the Company has not complied with the statute governing appeals. In its April 17, 2009 application for rehearing of the Order in which the PUCO denied CSP authority to transfer the Facilities, CSP did not seek rehearing of the PUCO's decision. (CSP Appx. 182-244). The Company did not ask the PUCO to reverse its decision regarding transfer authority until the July 31 application for rehearing – more than 30 days after the decision – and even then, CSP did not allege that the denial of transfer authority was unlawful or unreasonable. Thus, the Company failed to preserve the PUCO's denial of transfer authority as an issue for appeal to this Court.

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[12] CSP Brief at 8.

[13] Id. at 15.

After the PUCO's July 23 Entry preventing CSP from collecting from customers costs associated with operating the Facilities, CSP filed an application for rehearing on July 31, 2009. Although CSP did assert that "[i]t is unreasonable to force CSP to keep these generating units and not be able to recover any costs associated with these units" (CSP Appx. 352), the Company did *not* ask the Commission to reverse its July 23 decision and allow CSP to collect from customers the costs associated with the Facilities. Instead, the Company focused on having the ability to sell the units: "[W]ith the cost recovery provision of the Opinion and Order being revoked on rehearing, the fair and reasonable course of action now is to authorize CSP to sell or transfer those units." (CSP Appx. 352-353. See also CSP Appx. 353 ("On rehearing the Commission should rectify this unlawful situation by granting CSP the authority it sought in the proceeding to sell or transfer Waterford and Darby."). The Company thus failed to preserve the issue of collecting costs associated with the Facilities from customers for appeal to this Court.

In addition, CSP raised an issue in its brief that was not presented to the PUCO for consideration in the proceeding below and was not included in the Notice of Appeal. On brief, CSP argued that the PUCO "inexplicably reverted to the traditional rate making concepts contained in R.C. Chapter 4909."[14] The Company asserted that "reference to the adequacy of current revenues is uniquely based in the traditional cost-of-service/rate of return on investment rate making concepts of R.C. Chapter 4909. It has no place in evaluating a proposed, or in this case, Commission-modified ESP under R.C. 4928.143."[15]

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[14] Id. at 12.

[15] Id. at 13.

Based on this premise, CSP contended that "[t]he Commission's reliance on traditional rate making concepts to reverse its earlier position was unlawful."[16]

CSP, however, never brought this issue before the PUCO in the case below. In its July 31 application for rehearing, CSP characterized the PUCO's original decision, denying transfer authority but allowing cost collection from customers, as "a fair balance***." (CSP Appx. 352). The Company complained that the July 23 Entry "completely upset the balance" of the Order, and decried that the PUCO's reversal of that portion of the Order was "unreasonable***." (CSP Appx. 352). CSP did not argue in its application for rehearing that the PUCO had acted beyond its statutory authority by applying traditional ratemaking principles in the July 23 Entry. Thus, the Company failed to preserve this issue for appeal to this Court.

The Company cannot appeal PUCO actions for which it has not sought rehearing under R.C. 4903.10. The words of R.C. 4903.10 are clear in this regard: "No cause of action arising out of any order of the commission, other than in support of the order, shall accrue to any person, firm, or corporation unless such person, firm or corporation has made a proper application to the commission for a rehearing." The Company did not apply for rehearing of the PUCO's decision to deny it the ability to collect costs associated with the Facilities from customers, and thus the Court should not overturn the PUCO's decision. And because the Company's application for rehearing of the PUCO's denial of transfer authority was not filed

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[16] Id.

within 30 days of the Order in which the decision was made, as required by R.C. 4903.10, the Court should also dismiss CSP's claim concern the denial of transfer authority.[17]

Proposition of Law No. 2

The Commission may require an electric distribution utility to separately apply for authority to sell or transfer facilities, in accordance with R.C. 4928.17 and the enabling rules of the Ohio Administrative Code.

Even if the issue of transfer authority was properly raised in the Company's July 31 application for rehearing, the Court should find that the PUCO acted reasonably in exercising its discretion under R.C. 4928.17. (CSP Appx. 20-21). In passing S.B. 221, the General Assembly revised portions of Chapter 4928, including R.C. 4928.17(E). The subsection now requires electric distribution utilities ("EDUs") to seek PUCO approval of the transfer of generation assets, which prior to S.B. 221 was not necessary. Specifically, R.C. 4928.17(E) provides that "[n]o electric distribution utility shall sell or transfer any generating asset it wholly or partly owns at any time without obtaining prior commission approval." (CSP Appx. 21). The statute does not include a standard for approving a request for such a transfer,[18] though the recently adopted enabling rules provide standards.

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[17] See *Office of Consumers' Counsel v. Pub. Util. Comm.*, 70 Ohio St.3d at 248 (OCC's failure to raise an issue in its application for rehearing was ruled fatal to its claim of error.); *Ohio Consumers' Counsel v. Pub. Util. Comm.*, 114 Ohio St.3d 340, 2007-Ohio-4276, 872 N.E.2d 269, ¶40 (finding that OCC waived its right to raise an issue by not setting it forth in the application for rehearing); *Forest Hills Utility Co. v. Pub. Util. Comm.* (1972), 31 Ohio St.2d 46, 52, 60 O.O.2d 32, 285 N.E.2d 702, 707 (Court would not consider issue that was not raised in the application for rehearing, but must adhere to R.C. 4903.10 and the decisions of the court, citing *Agin v. Pub. Util. Comm.* (1967), 12 Ohio St.2d 97, 98, 41 O.O.2d 406, 232 N.E.2d 828, 829).

[18] On July 2, 2008, the Commission put out for comment in Case No. 08-777-EL-ORD a proposed rule that the Commission will approve an application for transfer of generation assets only if "the commission is satisfied that the sale or transfer is just, reasonable, and in the public interest***." (OCC Appx. 48). The Commission adopted Ohio Adm. Code 4901:1-37-09(E), effective April 2, 2009. (CSP Appx. 355).

The rules, in particular, Ohio Adm. Code 4901:1-37-09 (CSP Appx. 355), require a separation application, setting forth the object and purpose, and the terms of the transfer. In addition, the electric utility is required to demonstrate how the transfer will affect the current and future standard service offer, and demonstrate how the proposed transfer will affect the public interest. The utility must also state the fair market value and the book value of the property to be transferred. The separation application required under Ohio Adm. Code 4901:1-37-09 does not mention the transfer occurring outside the process provided, such as being encompassed as part of an EDU's standard service offer filing.

In its brief, CSP presented no direct argument as to why the Commission's denial of the Company's authority to sell or transfer the facilities, at some unspecified time in the future and to some unknown entity, was unreasonable. Instead, the Company attempted to bundle the PUCO's denial of transfer authority with its denial of the collection of the Facilities' costs from customers. The Company argued: "Withholding authority to sell or transfer these facilities, while at the same time withholding authority to recover the costs associated with these facilities, is unlawful and unreasonable."[19] As noted in Proposition of Law No. 1, CSP did not ask the PUCO, in any application for rehearing, to reinstate the Company's ability to collect the costs associated with the Facilities, and thus the cost recovery issue is not properly before this Court.

[19] CSP Brief at 13-14.

The Company's argument against the PUCO's decision is based on fact rather than law. The Company cited no statutory or other authority that would make the Commission's action unlawful. Rather, CSP's position is based on its perceived unfairness of the PUCO's denial of cost collection in conjunction with its finding that transfer authority was premature. The Company wrongly challenges the PUCO's use of its discretion in applying the law to the facts of the case.

A review of the law and of the PUCO's Order shows that the Commission acted reasonably and lawfully to deny the Company carte blanche authority to sell or transfer the Facilities to some unnamed entity at some unspecified future time. The power to approve or deny the transfer of generation assets, placed on the Commission by R.C. 4928.17(E), does not include a specific standard upon which the Commission must base its determination. The statute is also silent as to whether the Commission can approve such a request if it is included in an ESP filing.

In the Order, the Commission examined the record and took a prudent course in dealing with CSP's request. Noting that the PUCO Staff had testified that the transfers could have a potential financial and policy impact, the Commission determined that approval of the transfer was premature. (CSP Appx. 82-83). The Commission determined that a separation application should be filed at the time CSP wishes to sell or transfer the facilities, in accordance with PUCO rules. (CSP Appx. 83).

In its 08-777 decision, consistent with the General Assembly's directive in R.C. 4928.06(A) (OCC Appx. 5), the Commission established a standard for reviewing applications to transfer generation assets; the applicant must show that the transfer is just, reasonable and in the public interest. (OCC Appx. 117). The Company did not challenge this standard, either in the rulemaking proceeding or at the Court. The Company also did not attempt to address the potential policy and financial implications associated with the transfer in its ESP proceeding. The record in the PUCO proceeding below lacks any foundation for the Commission to find that a future transfer of the Facilities could, at the time of the Order, be just, reasonable and in the public interest, as the PUCO has deemed necessary under Ohio Adm. Code 4901:1-37-09.

To aid in its determination whether the transfer of a generation asset is just, reasonable and in the public interest, the Commission adopted enabling rules establishing a process for applications to transfer generation facilities. (OCC Appx. at 117). The process, set forth in Ohio Adm. Code 4901:1-37-09(C), requires applicants to do the following: "(1) Clearly set forth the object and purpose of the sale or transfer, and the terms and conditions of the same; (2) Demonstrate how the sale or transfer will affect the current and future standard service offer established pursuant to section 4928.141 of the Revised Code; (3) Demonstrate how the proposed sale or transfer will affect the public interest; [and] (4) State the fair market value and book value of all property to be transferred from the electric utility, and state how the fair market value was determined." (CSP Appx. 355).

Although these rules were not in effect when CSP filed its ESP application, the Commission wisely determined that the request should be considered as a separation application, applying the standards adopted, when the Company actually has concrete plans for the transfer. Indeed, CSP was well aware of the Commission's drafting of enabling rules that were to apply to applications to transfer generating assets as the PUCO first proposed draft rules for comment on July 2, 2008 – more than three weeks before CSP filed its ESP application.[20]

In fact, it would have been unlawful and unreasonable for the Commission to grant the Company the transfer authority it sought in its ESP case. The ESP application filed by CSP provided no basis for the Commission to make the sort of determination that it had already deemed, in the 08-777 proceeding, to be necessary for transfer applications. Based on the vague and premature nature of CSP's request, the Commission acted lawfully and reasonably in denying CSP's request to transfer the Facilities. The PUCO exercised its authority to deny the application to transfer, which was well within its discretion under R.C. 4928.17(E).

Proposition of Law No. 3

The Commission may lawfully modify an electric security plan under R.C. 4928.143(C)(1) either in its initial order or on rehearing.

CSP argues that the PUCO acted unlawfully in revoking the Company's ability to collect costs associated with the Facilities from customers. CSP asserts that the PUCO failed to follow the statutory standard in R.C. 4928.143(C) (CSP Appx. 17), which requires the Commission to approve an ESP if it finds the ESP to be more favorable in the aggregate than a market rate offer ("MRO") under R.C. 4928.142.[21] The Company contends that "[t]he Commission's responsibility on rehearing was to determine if its initial order was in error. In any event, the Commission's reversal on rehearing made no mention of the statutory test."[22] CSP is wrong.

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[20] PUCO Case No. 08-777-EL-ORD, Entry (July 2, 2008). (OCC Appx. 7-58).

[21] CSP Brief at 13.

[22] Id.

First, CSP stated the wrong standard for modifying a PUCO order on rehearing. Rather than determining whether the initial order "was in error," the Commission may modify or abrogate an order on rehearing if it is "of the opinion that the original order or any part thereof is in any respect unjust or unwarranted, or should be changed***."[23] The ESP statute, R.C. 4928.143, does not alter this standard. (CSP Appx. 15-19). That statute, in particular subsection (C)(1) (CSP Appx. 17), gives the Commission authority to "approve or modify and approve an application." Thus, the PUCO had statutory authority to modify the CSP ESP application, either in its original Order or on rehearing, as it did here.

The Commission here took into account IEU's arguments on rehearing, which included that there was no record evidence to support including $153 million in costs related to the facilities. These arguments relate to the burden of proof in the ESP proceeding which is placed squarely upon the applicant, CSP, under R.C. 4928.143(C)(1). Whether a party has met the burden of proof, is a question of fact, not law.

CSP seems to dismiss the notion that it must prove anything other than that the plan is more favorable in the aggregate than an MRO. In order, however, to determine whether an ESP's "pricing and other terms and conditions, including any deferrals and any future recovery of deferrals, are more favorable in the aggregate as compared to the expected results that would otherwise apply under an MRO," the Commission must individually examine each part of the ESP, in light of the policy objectives of R.C. 4928.02 (OCC Appx. 3-4). The PUCO took this exact approach in the FirstEnergy ESP and MRO proceedings.

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[23] R.C. 4903.10(B). (OCC Appx. 1).

In November 2008, the Commission, in analyzing FirstEnergy's application for a standard service offer through a MRO, emphasized the need to examine FirstEnergy's application in light of R.C. 4928.02:

> Chapter 4928 of the Revised Code provides a roadmap of regulation in which specific provisions were put forth to advance state policies of ensuring access to adequate, reliable, and reasonably priced electric service in the context of significant economic and environmental challenges. In reviewing the Companies' application for an MRO, the commission is aware of the challenges facing Ohioans and the electric power industry and will be guided by the policies of the state as established by the General Assembly in Section 4928.02, Revised Code, as amended by Amended Substitute Senate bill No. 221 (SB 221), effective July 31, 2008.
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> ***
>
> In determining whether an MRO meets the requirements of Section 4828.142(A) and (B), Revised Code the Commission must read those provisions together with the policies of this state as set forth in Section 4928.02, Revised Code. Accordingly, the policy provisions of Section 4928.02, Revised Code, will guide the Commission in its implementation of the statutory requirements of Section 4928.142(A) and (B), Revised Code.[24]

Moreover, despite arguments that R.C. 4928.02 is merely a redundant standard once the requirements of "more favorable in the aggregate" standard has been met, the Commission determined otherwise: "The Commission notes that Section 4928.06, Revised Code, makes the policy specified in Section 4928.02, Revised Code, more than a statement of general policy objectives. Section 4928.06(A), Revised Code, imposes on the Commission a specific duty to 'ensure the policy specified in section 4928.02 of the Revised Code is effectuated.'"[25]

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[24] *In the Matter of the Application of Ohio Edison Company, the Cleveland Electric Illuminating Company, and the Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications Associated with Reconciliation Mechanism, and Tariffs for Generation Service*, Case No. 08-936-EL-SSO, Opinion and Order (Nov. 25, 2008) ("First Energy MRO Order") at 6-7. (OCC Appx. 207-208).

[25] Id. at 13. (OCC Appx. 214).

The Commission dismissed as well arguments that R.C. 4928.02 does not impose any obligations or duties upon utilities.[26] In doing so the Commission relied upon the Ohio Supreme Court holding in *Elyria Foundry*,[27] where the Court held that the Commission may not approve a rate plan that violates the policy provisions of R.C. 4928.02. Accordingly, the Commission opined that an electric utility should be deemed to have met the "more favorable in the aggregate" standard "only to the extent that the electric utility's proposed MRO is consistent with the policies set forth in section 4928.02, Revised Code."[28]

Less than a month later, the Commission cemented its interpretation that each piece of the standard service offer must be examined in light of the policy objectives of R.C. 4928.02. This Commission did so in addressing FirstEnergy's ESP, not its MRO application: "Chapter 4928 of the Revised Code provides an integrated system of regulation in which specific provisions were designed to advance state policies of ensuring access to adequate, reliable, and reasonably priced electric service in the context of significant economic and environmental challenges."[29]

Rather than ignoring the state policies enumerated in R.C. 4928.02, the Commission embraced the policies in order to give meaning to R.C. 4928.143: "The Commission believes that the state policy codified by the General Assembly in Chapter 4928, Revised Code, sets

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[26] Id.

[27] *Elyria Foundry v. Pub. Util. Comm.*, 114 Ohio St. 3d 305; 2007-Ohio-4164; 871 N.E.2d 1176.

[28] First Energy MRO Order at 14. (OCC Appx. 215).

[29] *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan,* Case No. 08-935-EL-SSO, Opinion and Order (December 19, 2008) ("First Energy ESP Order") at 8. (OCC Appx. 138).

forth important objectives which the Commission must keep in mind when considering all cases filed pursuant to that chapter of the code. Therefore, in determining whether the ESP meets the requirements of Section 4928.143, Revised Code, the Commission takes into consideration the policy provisions of Section 4928.02, Revised Code, and we use these policies as a guide in our implementation of Section 4928.143, Revised Code."[30]

Indeed the Commission remained true to its words as can be seen throughout the FirstEnergy ESP Order. For instance, in recognition of the need to ensure reasonably priced service (under R.C. 4928.02(A)), the Commission reduced the base generation rates of FirstEnergy, "mindful of the significant economic difficulties facing residents in Ohio at this time."[31] The Commission also eliminated other provisions in FirstEnergy's ESP plan that significantly increased costs to customers; the deferred generation cost rider was eliminated, saving customers approximately $500 million in carrying costs. There the Commission concluded that this savings will help promote the competitiveness of Ohio in the global economy,[32] a state policy enumerated in R.C. 4928.02(N) (OCC Appx. 4).

In evaluating the distribution service improvement rider, although the Commission noted that the rider was permissible under R.C. 4929.143(B)(2)(h), it nonetheless found that the "sound policy goals" of R.C. 4928.02 required the rider to be limited to "prudently incurred costs."[33] Since FirstEnergy's rider was not cost based, the Commission found it should not be approved unless it is shown "to comply with both the intent and scope of the

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[30] Id. at 12. (OCC Appx. 142).

[31] Id. at 17. (OCC Appx. 147).

[32] Id. at 25. (OCC Appx. 155).

[33] Id. at 41. (OCC Appx. 171).

statute (R.C. 4928.02)." With respect to First Energy's capital improvement program for its distribution system, the Commission ordered FirstEnergy to work to develop a program that "advances state policy."[34]

When the legal standard of review of the provisions of the ESP is correctly applied, there is further justification for the PUCO's denial of the facilities' costs. The Commission's actions were consistent with a number of policies in R.C. 4928.02, including (B), (H), and (I) (OCC Appx. 3-4).

Second, CSP wrongly asserted that the PUCO "made no mention" of the standard contained in R.C. 4928.143(C). The PUCO stated in its July 23 Entry, "[w]ith regard to the MRO versus ESP comparison, our analysis did not end with the rehearing requests. Upon review of the record in this case and all arguments raised on rehearing, the Commission does in fact find that the ESP, including deferrals and future recovery of deferrals, as modified by the Order and as further modified by this entry, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code."[35] The Commission also included the following additional support for its finding: "The Commission notes that, with this entry, it is further modifying AEP-Ohio's ESP to reduce the rate impacts on customers. The Commission believes that the modifications made in this entry increase the value of the Companies' ESP."[36]

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[34] Id at 41-42. (OCC App 171-172).

[35] July 23 Entry at 51. (CSP Appx. 164).

[36] Id. (CSP Appx. 164).

Contrary to CSP's assertion, the PUCO acted in accordance with R.C. 4928.143(C)(1), where it has the discretion to modify an ESP application. The Commission acted lawfully, and its decision should be upheld.

V. CONCLUSION

The Commission's denial of CSP's request, as part of the Company's ESP, for authority to transfer the Facilities was lawful. The Court should not overturn the Commission's ruling. In addition, CSP did not seek rehearing at the PUCO regarding the Commission's decision to deny the Company authority to collect from customers costs associated with the Facilities. Thus, the Court lacks jurisdiction over that issue and should dismiss CSP's claims concerning collection of costs associated with the Facilities.

Respectfully submitted,

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IN THE SUPREME COURT OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of an Electric Security Plan; an Amendment to Its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets.	)	Case No. 2009-2298 On Appeal from the Public Utilities Commission of Ohio, Case No. 08-917-EL-SSO
In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan.	)	
(*Columbus Southern Power Company v. The Public Utilities Commission of Ohio*)	)	

APPENDIX

4903.09 Written opinions filed by commission in all contested cases.

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

Effective Date: 10-26-1953

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.

Effective Date: 09-29-1997

4928.02 State policy.

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

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

(B) Ensure the availability of unbundled and comparable retail electric service that provides consumers with the supplier, price, terms, conditions, and quality options they elect to meet their respective needs;

(C) Ensure diversity of electricity supplies and suppliers, by giving consumers effective choices over the selection of those supplies and suppliers and by encouraging the development of distributed and small generation facilities;

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

(E) Encourage cost-effective and efficient access to information regarding the operation of the transmission and distribution systems of electric utilities in order to promote both effective customer choice of retail electric service and the development of performance standards and targets for service quality for all consumers, including annual achievement reports written in plain language;

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

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

(H) Ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa, including by prohibiting the recovery of any generation-related costs through distribution or transmission rates;

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

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

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

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

(M) Encourage the education of small business owners in this state regarding the use of, and encourage the use of, energy efficiency programs and alternative energy resources in their businesses;

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

Effective Date: 10-05-1999; 2008 SB221 07-31-2008

4928.06 Commission to ensure competitive retail electric service.

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

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

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

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

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

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

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

(4) Other indicators of market power, which may include market share, growth in market share, ease of entry, and the affiliation of suppliers of services. The burden of proof shall be on any entity

requesting, under division (B) or (C) of this section, a determination by the commission of the existence of or a lack of effective competition or reasonably available alternatives.

(E)(1) Beginning on the starting date of competitive retail electric service, the commission has authority under Chapters 4901. to 4909. of the Revised Code, and shall exercise that authority, to resolve abuses of market power by any electric utility that interfere with effective competition in the provision of retail electric service.

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

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

Effective Date: 10-05-1999

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Adoption of Rules for Standard Service Offer, Corporate Separation, Reasonable Arrangements, and Transmission Riders for Electric Utilities Pursuant to Sections 4928.14, 4928.17, and 4905.31, Revised Code, as amended by Amended Substitute Senate Bill No. 221.	)	Case No. 08-777-EL-ORD

ENTRY

The Commission finds:

(1) On July 7, 1999, the governor of the state of Ohio signed Amended Substitute Senate Bill No. 3 (SB 3). That legislation, among many things, established a starting date for competitive retail electric service in the state of Ohio and provided for the establishment of market development periods (MDP) for each electric utility. After the MDP, pursuant to Section 4928.14(A), Revised Code, as originally enacted into law, each electric utility was required to provide consumers, on a comparable and nondiscriminatory basis within its certified territory, a market-based standard service offer (MBSSO) to maintain essential electric service to consumers, including a firm supply of electric generation service. Pursuant to Section 4928.14(B), Revised Code, each electric utility was required to offer customers within its certified territory an option to purchase competitive retail electric service after its MDP ends, the price of which is to be determined through a competitive bidding process (CBP).

(2) On December 17, 2003, the Commission issued a Finding and Order in Case No. 01-2164-EL-ORD which adopted, with certain modifications, staff's proposed rules for processing applications to establish the MBSSO and CBP in Chapter 4901:1-35-01, Ohio Administrative Code (O.A.C.).

(3) On May 1, 2008, the governor signed into law Amended Substitute Senate Bill No. 221 (SB 221) amending various provisions of SB 3. Among those amendments were changes to Section 4928.14, Revised Code, to establish a standard service offer (SSO); Section 4905.31, Revised Code, to approve

reasonable arrangements and utility schedules; and Section 4928.17, Revised Code, to establish corporate separation plans. 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). The SSO shall serve as the electric utility's default SSO. Electric utilities may apply simultaneously under both options; however, at a minimum, the first SSO application must include an application for an ESP. The amendments to Section 4905.31, Revised Code, modify the applicability of reasonable arrangements and the amendments to Section 4928.17, Revised Code, impose additional requirements on electric utilities relating to the transfer of assets.

(4) The staff of the Commission has proposed a complete rewrite of Chapter 4901:1-35, O.A.C., and its incorporated appendices, which include procedural requirements for filing applications for an MRO and ESP as well as filing requirements for such applications in accordance with SB 221. The staff is also proposing Chapter 4901:1-36 to establish procedures for the implementation of transmission riders and Chapter 4901:1-38 to establish procedures for approving reasonable arrangements between the electric utility and customers. Further, the staff is proposing to rescind Rule 4901:1-20-16, O.A.C., and revise and place the existing Commission requirements in a stand-alone Chapter 4901:1-37 to address electric utility corporate separation between affiliated entities, as well as new SB 221 requirements.

(5) The Commission requests comments from interested persons to assist in the review of staff's proposed Chapters 4901:1-35 through 4901:1-38. Comments should be filed in this docket by July 22, 2008, and reply comments should be filed by August 1, 2008. Filed comments may be viewed on the Commission's web site by going to www.puc.ohio.gov/PUCO, clicking on DIS, and inserting the case number, 08-777, in the case look-up search box. If any entity filing comments requires a paper copy of the comments filed, it shall file a notice of its request in this docket. The other commenters shall serve a copy of the comments upon the requesting party via email or hard-copy to the address provided.

(6) The Commission notes that the rules and appendices attached to this entry are over 40 pages. While the Commission finds that a hard copy of this entry should be served upon all stakeholders, we believe that, rather than mail hard copies of the rules and appendices to the stakeholders, it would be prudent and more efficient to provide a web address where the attachment can be accessed. Accordingly, interested entities can access the attachment by going to the Commission's web site at www.puco.ohio.gov/PUCO/Rules, and clicking on the link to Staff's Proposed Rules for Electric Utility Standard Service Offer, Corporate Separation, Reasonable Arrangements, and Transmission Riders to implement Senate Bill 221. If an entity has questions regarding how to access the attachment or does not have access to the internet, it may contact the Commission's Docketing Division at (614) 466-4095, Monday through Friday between the hours of 7:30 a.m. and 5:30 p.m.

(7) To assist the Commission in its evaluation of Staff's proposed rules, the Commission requests that interested parties file with their comments responses to the following questions.

(a) Should the rules on the competitive bidding process (Proposed O.A.C. §4901:1-35-03, Appendix A, Part (B)) provide for consideration of alternative products and approaches to conducting competitive bidding?

(b) Should the Commission require consideration of the value of lost load in ensuring that customers' and the electric utility's expectations are aligned as required by Section 4928.143(B)(2)(h), Revised Code?

(c) Should the Commission by rule invite an electric utility to identify in an ESP specific long-term objectives (e.g., objectives related to the implementation of state policies or meeting standards contained in S.B. 221), together with milestones and metrics for measuring progress? If so, are there specific topics which should be addressed?

(d) With respect to an energy efficiency schedule based on a reduction in electricity consumption (Proposed O.A.C. §4901:1-38-04 (B)), how should the rules define the baseline level of customer energy consumption from which a reduction would be measured?

(e) Should special arrangements provided for in Chapter 4901:1-38 be applicable only to customers of an electric utility providing service pursuant to an electric security plan?

(f) Should there be a cap on the level of incentives for special arrangements authorized pursuant to Chapter 4901:1-38?

It is, therefore,

ORDERED, That public comments on the staff's proposed rules be filed in accordance with finding (5). It is, further,

ORDERED, That entities access the rules and appendices at the above internet site or contact the Commission's Docketing Division. It is further, ORDERED, That a copy of this entry, without the attachments, be served upon electric utility companies regulated by the Commission, competitive retail electric service providers certified by the Commission, the Office of the Ohio Consumers' Counsel, and all interested parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Paul A. Centolella

Ronda Hartman Fergus

Valerie A. Lemmie

Cheryl L. Roberto

RRG:ct

Entered in the Journal
JUL 0 2 2008

Reneé J. Jenkins
Secretary

Chapter 4901:1-35

Electric Utility Standard Service Offer

4901:1-35-01 Definitions.

(A) "Application" means an application for standard service offer pursuant to this chapter.

(B) "Commission" means the public utilities commission of Ohio.

(C) "Competitive bidding process" means a bidding process established pursuant to section 4928.142 of the Revised Code.

(D) "Electric utility" has the same meaning as in division (A)(11) of section 4928.01 of the Revised Code.

(E) "Electric security plan" means an electric utility plan for the supply and pricing of electric generation service pursuant to section 4928.143 of the Revised Code.

(F) "Market development period" has the meaning set forth in division (A)(17) of section 4928.01 of the Revised Code.

(G) "Market-rate offer" means an electric utility plan for the supply and pricing of electric generation service pursuant to section 4928.142 of the Revised Code.

(H) "Person"has the same meaning as in division (A)(24) of section 4928.01 of the Revised Code.

(I) "Rate plan" means an electric utility's standard service offer approved by the commission prior to January 1, 2009 that established rates for electric service at the expiration of an electric utility's market development period.

(J) "Standard service offer" means an electric utility offer to provide consumers, on a comparable and nondiscriminatory basis within its certified territory, all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service.

(K) "Staff" means the staff of the commission or its authorized representative.

4901:1-35-02 Purpose and scope.

(A) Pursuant to division (A) of section 4928.141 of the Revised Code, beginning January 1, 2009, each electric utility in this state shall provide consumers, on a comparable and nondiscriminatory basis within its certified territory, a standard service offer (SSO) of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service. Pursuant to this chapter, an electric utility shall file an application for commission approval of an SSO. Such application shall be in the form of an electric security plan or market rate offer pursuant to sections 4928.142 and 4928.143 of the Revised Code. The purpose of this chapter is to establish rules for the form and process under which an electric utility shall file an application for an SSO and the commission's review of that application.

(B) The commission may waive any requirement of Chapter 4901:1-35 of the Administrative Code for good cause shown.

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 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 of appendix A to this rule. An SSO application that contains a proposal for an ESP shall comply with the requirements of appendix B to this rule.

(C) The first application for an SSO 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 effective date of this rule and that are determined by the commission to be not in substantive compliance with this rule, shall be refiled at the direction of the commission. The commission shall endeavor to make a determination on an application that substantively conforms to the requirements of this rule within one hundred fifty days of the filing of such complete application.

(D) 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. An SSO application that contains a proposal for an

MRO shall comply with the requirements of appendix A to this rule. An SSO application that contains a proposal for an ESP shall comply with the requirements of appendix B to this rule.

(E) 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 achieves 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.

(F) A complete set of work papers must be filed with the application. Work papers must include, but are not limited to, any and all 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.

(G) All schedules, tariff sheets, and work papers included in the application must be available in spreadsheet, word processing, or an electronic non-image-based format 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.

4901:1-35-04 Service of application.

(A) Concurrent with the filing of a standard service offer (SSO) application and the filing of any waiver requests, the electric utility shall provide notice of proposed filings to each party in its most recent SSO or, if this is its first SSO filing, then its last rate plan proceeding. At a minimum, that notice shall state that a copy of the application and any waiver requests are available through the electric utility's and commission's web sites, available at the electric utility's main office, available at the commission's offices, and any other sites at which the electric utility will maintain a copy of the application and any waiver requests.

(B) The electric utility shall provide copies of the application upon request, without cost, and within a reasonable period of time.

4901:1-35-05 Technical conference.

Upon filing of a standard service offer (SSO) application, the commission, legal director, deputy legal director, or attorney examiner shall schedule a technical conference. The purpose of the technical conference is to allow interested persons an opportunity to better understand the electric utility's application. The electric utility will have the necessary personnel in attendance at this conference so as to explain, among other things, the structure of the filing, the work papers, the data sources, and the manner in which methodologies were devised. The conference will be held at the commission offices, unless the commission, legal director, deputy legal director, or attorney examiner determines otherwise.

4901:1-35-06 Hearings.

(A) After the filing of a standard service offer application that conforms with the commission's rules, the commission shall set the matter for hearing and shall publish notice of the hearing one time in a newspaper of general circulation in each county in the electric utility's certified territory. At such hearing, the burden of proof to show that the proposals in the application are just and reasonable and achieve the policy of the state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code shall be upon the electric utility.

(B) Interested persons wishing to participate in the hearing shall file a motion to intervene no later than thirty days after the issuance of the entry scheduling the hearing, unless ordered otherwise by the commission, legal director, deputy legal director, or attorney examiner. This rule does not prohibit the filing of a motion to intervene and conducting discovery prior to the issuance of an entry scheduling a hearing.

4901:1-35-07 Discoverable agreements.

Upon submission of an appropriate discovery request during a proceeding establishing a standard service offer, an electric utility shall make available to the requesting party every contract or agreement that is between the electric utility or any of its affiliates and a party to the proceeding, consumer, electric service company, or political subdivision and that is relevant to the proceeding, subject to such protection for proprietary or confidential information as is determined appropriate by the commission.

4901:1-35-08 Competitive bidding process requirements and use of independent third party.

(A) An electric utility proposing a market-rate offer in its standard service offer application, pursuant to section 4928.142 of the Revised Code, shall propose a plan for a competitive bidding process (CBP). The CBP plan shall comply with the requirements set forth in appendix A to rule 4901:1-35-03 of this chapter. The electric utility shall use an independent third party to design an open, fair, and transparent bid solicitation; to administer the bidding process; and to oversee the entire procedure to assure that the CBP complies with the CBP plan. The independent third party shall be accountable to the commission for all design, process, and oversight decisions. Any modifications or additions to the CBP made by the independent third party shall be submitted to staff prior to implementation. The independent third party shall incorporate into the solicitation such measures as the Commission or its staff may prescribe, and shall incorporate into the bidding process any direction the Commission may provide.

(B) Immediately upon the completion of the bidding process, the independent third party shall submit a report to the commission summarizing the results of the CBP. The report shall include, but not be limited to, the following items:

(1) A description of the conduct of the bidding process, including a discussion of any aspects of the process that could have adversely affected the outcome.

(2) The level(s) of oversubscription for each product.

(3) The number of bidders for each product.

(4) The percentage of each product that was bid upon by persons other than the electric utility.

(5) The independent third party's evaluation of the submitted bids.

(6) The independent third party's final recommendation of the least cost winning bidder(s).

(7) A listing of the retail rates that would result from the least cost winning bids, along with any descriptions, formulas, and/or tables necessary to demonstrate how the conversion from winning bid(s) to retail rates was accomplished.

(C) The electric utility shall provide access to staff and any consultant hired by the commission to assist in review of the CBP of any and all data, information, and communications pertaining to the bidding process, on a real time basis, regardless of the confidential nature of such data and information.

(D) The commission shall make the final selection of the least-cost winning bidder(s) of the CBP. The commission may rely upon the information provided in the independent third party's report in making its selection of the least-cost winning bidder(s) of the CBP.

4901:1-35-09 Electric security plan fuel and purchased power adjustments.

(A) Each electric utility for which the commission has approved an electric security plan (ESP) which includes automatic adjustments under division (B)(2)(a) of section 4928.143 of the Revised Code shall file for such adjustments in accordance with the provisions of this rule.

(B) The electric utility shall calculate a proposed quarterly adjustment based on projected costs by filing an application four times per year. The staff shall review the quarterly filing for completeness and computational accuracy. If staff raises no issues prior to the date the quarterly adjustment is to become effective, the rates shall become effective on that date. Although rates are to be adjusted and provided on a quarterly basis, the cost information shall be summarized monthly.

(C) On an annual basis, the prudence of the costs incurred and recovered through quarterly adjustments shall be reviewed in a separate proceeding outside of the automatic recovery provision of the electric utility's ESP. The process and timeframes for that separate proceeding shall be set by order of the commission, the legal director, deputy legal director, or attorney examiner.

(D) The commission may order that consultants be hired, with the costs billed to the electric utility, to conduct prudence and/or financial reviews of the costs incurred and recovered through the quarterly adjustments.

4901:1-35-10 Annual review of electric security plan.

(A) Within ninety days after the end of each annual period of an electric utility's electric security plan (ESP), the electric utility shall make a separate filing with the commission demonstrating whether or not any rate adjustments authorized by the commission as part of the electric utility's ESP resulted in excessive earnings during the review period as measured by division (F) of section

4928.143 of the Revised Code. The electric utility's filing shall include the information set forth in appendix B to rule 4901:1-35-03 of this chapter as it relates to excessive earnings.

(B) Any person may file comments to the electric utility's filing made pursuant to paragraph (A) of this rule within thirty days of the filing.

(C) Based upon the above filings, if the commission finds that there are reasonable grounds that such adjustments, in the aggregate, may have resulted in significant excess earnings for the electric utility, the commission may set the matter for hearing.

4901:1-35-11 Competitive bidding process ongoing review and reporting requirements.

(A) The initial MRO implemented by each electric utility subject to the provisions of division (D) of section 4928.142 of the Revised Code shall include a blended price for electric generation services.

(B) Once a competitive bidding process (CBP) plan subject to a price blending period is approved by the commission pursuant to section 4928.142 of the Revised Code, the electric utility shall file its proposed adjustments to the standard service offer (SSO) portion of the blended rates of its CBP in a filing to the commission on a quarterly basis (quarterly filing) for the duration of the price blending period of the CBP plan, on specific dates to be determined by the commission.

(1) The quarterly filing shall include a separate listing of each cost or cost component including costs for fuel, purchased power, portfolio requirements, and environmental compliance, in comparison with the costs or cost components included in the most recent SSO and the previously existing level of each cost. Any offsetting benefits, as defined in division (D) of section 4928.142 of the Revised Code, obtained in the specified cost areas shall be listed separately and be used to reduce the cost levels requested for recovery. Rates are to be adjusted on a quarterly basis. The cost information shall consist of monthly data submitted on a quarterly basis.

(2) The quarterly filing shall include any descriptions, formulas, and/or tables necessary to show how the adjusted cost levels are translated into blended CBP rates.

(3) The electric utility shall provide projections, in its quarterly filing, of any impacts that the proposed adjustments will have on its return on common equity.

(4) The staff shall review the quarterly filing for completeness and computational accuracy. If the staff raises no issues prior to the date the quarterly adjustment is to become effective, the rates shall become effective on that date.

(5) On an annual basis, or other basis as determined by the commission, the prudence of the costs incurred and recovered through quarterly adjustments to the electric utility's SSO portion of the blended rates shall be reviewed. The commission shall determine the frequency of the review and shall establish a schedule for the review process. The commission may order that consultants be hired, with the cost to be billed to the company, to conduct prudence and/or financial reviews of the costs incurred and recovered through the quarterly adjustments.

(C) If the CBP plan is approved by the commission subject to a price blending period, approximately one year after filing the CBP plan, and annually thereafter for the duration of the price blending period of the CBP plan, on dates to be determined by the commission, the electric utility shall file an annual status report on its CBP.

(1) The annual status report shall provide a general statement about the operation of the CBP to date. The annual status report shall also provide a summary of generation service obtained via the CBP during the period under review, and impacts of the cost of the CBP service and the resulting blended rates on the electric utility's customers.

(2) The annual status report shall describe any defaults and/or other difficulties encountered in obtaining generation service from winning bidder(s) of the CBP, and describe in detail actions taken by the electric utility to remedy such situations.

(3) The annual status report shall describe the condition and significant developments of the wholesale electric generation and transmission market during the year covered by the report, and any developments in those markets anticipated and/or known for the following year.

(4) The annual status report shall describe the financial condition of the electric utility, its current return on common equity, and the return on common equity of publicly traded companies that face comparable business and financial risk. The electric utility shall show that its earnings under the price

blending period have not been significantly excessive as compared with similarly situated companies. Information submitted by the electric utility shall include, but not be limited to, balance sheet information, income statement information, and capital budget requirements for future investments in Ohio. This information should be provided for generation, transmission, and distribution for the electric utility and its affiliates, as well as functionalized as to distribution, transmission, and generation activities. Additionally, the electric utility shall provide testimony and analysis demonstrating the return on equity that was earned by publicly traded companies that face comparable business and financial risks as the electric utility.

(5) If in an emergency situation the electric utility claims that its financial integrity is threatened by the operation of the CBP price blending period, it shall demonstrate its claim through information and data filed in its annual status report.

(6) The electric utility shall discuss, in its annual status report, upcoming solicitations to be conducted pursuant to its approved CBP plan. Any deviations or modifications of the approved CBP plan being requested by the electric utility shall be described in detail, with specific rationale provided for every such deviation or modification requested.

(7) The annual status report shall describe the blended phase-in rates projected to be charged to its customers under the continuation of the CBP plan, as modified pursuant to paragraph (B)(6) of this rule. The rate projections shall show the existing and projected generation service price(s) blended with the CBP determined rates and projected CBP determined rates, and any descriptions, formulas, and/or tables necessary to show how the blending is accomplished. The projected blended phase-in rates shall be compared in the annual status report to the existing blended phase-in rates.

(8) The annual report shall include a status report of the market conditions necessary and prerequisite for a utility to propose an MRO - namely, whether prices for each service necessary for a winning bidder to fulfill its contractual obligations resulting from the CBP are published for at least two years in the future, whether the electric utility or its affiliate still belongs to an RTO, and whether the RTOs market monitoring function has mitigation authority over the transactions resulting from the CBP.

(9) The commission, legal director, deputy legal director, or attorney examiner shall determine the level of review required for any information, plans, or

requests set forth in the annual status report, and set any necessary schedules through an entry.

(D) If the CBP plan is approved by the commission without the requirement of a price blending period, or after the expiration of any such required price blending period, on an annual basis, on dates to be determined by the commission, the electric utility shall file an annual CBP report with the commission.

(1) The annual CBP report shall provide a general statement about the operation of the CBP to date. The annual CBP report shall also provide a summary of generation service obtained via the CBP during the period under review, and impacts of the cost of the CBP on the electric utility's customers' rates.

(2) The annual CBP report shall describe any defaults or other difficulties encountered in obtaining generation service from winning bidder(s) of the CBP, and describe in detail actions taken by the electric utility to remedy such situations.

(3) The annual CBP report shall describe the condition and significant developments of the wholesale electric generation and transmission market during the year covered by the report, and any developments in those markets anticipated or known for the following year.

(4) The electric utility shall discuss, in its annual CBP report, upcoming solicitations to be conducted pursuant to its approved CBP plan. Any deviations or modifications of the approved CBP plan being requested by the electric utility shall be described in detail, with specific rationale provided for every such deviation or modification requested.

(5) The commission, legal director, deputy legal director, or attorney examiner shall determine the level of review required for any information, plans, or requests set forth in the annual CBP report, and set any necessary schedules through an entry.

Appendix A

Requirements for Market-Rate Offers

(A) 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):

(1) 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.

(2) The electric utility shall establish one of the following: that its RTO retains an independent market monitor that has the ability to identify any potential for a market participant to exercise market power in any energy, capacity, and/or ancillary service markets necessary for a winning bidder to fulfill the contractual obligations resulting from the CBP, whether such market is administered by the RTO or whether it is a bilateral market necessary for a winning bidder to fulfill the contractual obligations resulting from the CBP, by virtue of access to the RTO and the market participant's data and personnel, and that has the authority to mitigate the conduct of the market participants so as to prevent or preclude the exercise of market power by any market participant; or, if no such market monitor exists, the electric utility shall demonstrate that an equivalent function exists which can monitor, identify, and mitigate conduct associated with the exercise of market power.

(3) The electric utility shall demonstrate that an independent and reliable source of electricity pricing information for any product or service necessary for a winning bidder to fulfill the contractual obligations resulting from the CBP is publicly available. The information may be offered through a pay subscription service, but the pay subscription service shall be available to any person requesting it, and the information shall be sufficiently reliable and available for use in a proceeding before the commission. The published information shall be relevant to 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.

(B) 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 competitive bidding process (CBP) with the commission. Each CBP plan that is to be used to establish an MRO shall include the following:

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

(2) Pro forma financial projections of the effect of the CBP plan's implementation upon generation, transmission, and distribution of the electric utility or its affiliates for the duration of the CBP plan.

(3) Projected generation, transmission, and distribution rate impacts by customer class and rate schedules for the duration of the CBP plan.

(4) Provisions for an open, fair, and transparent competitive solicitation of the generation services necessary to serve the customer load that is the subject of the CBP.

(5) Detailed descriptions of the customer load(s) to be served by the winning bidder(s), and any known factors that may affect customer loads. The descriptions shall include, at a minimum, 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 behavior, and plans for meeting targets pertaining to load reductions, energy efficiency, renewable energy, advanced energy, and advanced energy technologies.

(6) 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.

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

(8) 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.

(9) A clear description of the methodology by which the electric utility proposes to convert the winning bid(s) to retail rates of the electric utility.

(10) If applicable, a description of the electric utility's proposed blending of the CBP rates 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.

(11) 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.

(12) 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.

(13) The electric utility may propose, as part of its CBP plan, a portfolio approach to the procurement of SSO generation supply, including such aspects as staggered procurements and spot solicitations during peak periods.

(14) The initial filing of a CBP plan shall include a detailed account of how the plan achieves 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 plan.

(C) 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.

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

Appendix B

Requirements for Electric Security Plans

Each filing for an electric security plan (ESP) shall include the following:

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

(B) Pro forma financial projections of the effect of the ESP's implementation upon the electric utility for the duration of the ESP.

(C) Projected rate impacts by customer class/rate schedules for the duration of the ESP.

(D) 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.

(E) Division (A)(2) 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.

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

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

(H) The initial filing for an ESP shall include a detailed account of how the ESP achieves 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.

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 should 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:

(1) 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.

(2) The electric utility shall include in the application, as an offset, 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.

(3) Demonstration by the electric utility that the cost as defined was prudently incurred as required under division (B)(2) of section 4928.143 of the Revised Code.

(4) 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.

(5) A complete set of work papers supporting the cost must be filed with the application. Work papers must include, but are not limited to, any and all 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 expenditures or environmental expenditures of generation resources. Any plan which seeks to impose surcharge under these provisions shall include the following sections, as appropriate:

(1) The application must include a description of the projected costs of the proposed facility and an integrated resource plan, demonstrating the need for the proposed facility, which has been previously approved by the commission.

(2) 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 the process for competitive bidding of that specific facility.

(3) 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 and a detailed description of the impact upon rates of the proposed surcharge.

(4) 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.

(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:

(1) A listing of all components of the ESP which would have the effect of preventing, limiting, inhibiting, or incentivizing 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 or a quantitative justification shall be provided.

(2) A listing and description 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.

(3) 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 being securitized, the electric utility shall provide 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, including ancillary and 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, 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 must provide a narrative explanation and information to allow appropriate evaluation of the proposal. In general, and to the extent applicable, the electric utility should include, for each separate mechanism or program, quantification of the estimated impact on rates over time and on the electric utility's finances over time. Specific requirements for infrastructure modernization plans include the following:

(1) The application shall include a description of the infrastructure modernization plan, including but not limited to, 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.

(2) The application shall include a description of the benefits of the infrastructure modernization plan (in total and by activity or type), including but not limited to, 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.

(3) The application shall include a detailed description of the costs of the infrastructure modernization plan, including a breakdown of capital costs and operating and maintenance expenses, 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.

(4) The application shall include 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.

(5) The application shall include 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.

Additional Required Information

(A) Divisions (E) and (F) of section 4928.143 of the Revised Code provide for tests of the ESP with respect to 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 earnings are not excessive is borne by the electric utility. For this demonstration, at a minimum, the electric utility shall provide the following information for the total electric utility as well as functionalized as to distribution, transmission, and generation activities:

(1) Balance sheet information.

(2) Income statement information.

(3) Capital budget requirements for future committed investments in Ohio.

(B) The electric utility shall provide testimony and analysis demonstrating the return on equity that was earned during the same period by publicly traded companies that face comparable business and financial risks as the electric utility.

Chapter 4901:1-36

Transmission Cost Recovery

4901:1-36-01 Definitions.

(A) "Application" means an application for a transmission cost recovery rider pursuant to this chapter.

(B) "Commission" means the public utilities commission of Ohio.

(C) "Electric utility" has the same meaning as in division (A)(11) of section 4928.01 of the Revised Code.

(D) "Staff" means the staff of the commission or its authorized representative.

4901:1-36-02 Purpose and scope.

(A) This chapter authorizes an electric utility to recover, through a reconcilable rider on the electric utility's rates, all transmission and transmission-related costs, including ancillary and 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.

(B) The commission may waive any requirement of Chapter 4901:1-36 of the Administrative Code for good cause shown.

4901:1-36-03 Application.

(A) Each electric utility which seeks recovery of transmission and transmission-related costs shall file an application with the commission for a transmission cost recovery rider. The initial application shall include all information set forth in the appendix to this rule.

(B) Each electric utility with an approved transmission cost recovery rider shall update the rider on an annual basis pursuant to a schedule set forth by commission order. Each application to update the transmission cost recovery rider shall include all information set forth in the appendix to this rule.

(C) The commission may order that consultants be hired, with the costs billed to the electric utility, to conduct prudence and/or financial reviews of the costs incurred and recovered through the transmission cost recovery rider.

(D) Each annual application to update the transmission cost recovery rider shall be made seventy-five days prior to the proposed effective date of the updated rider.

(E) If at anytime during the period between annual update filings, the electric utility or staff determines that costs are or will be substantially different than the projected amounts included in their previous application, the electric utility shall file an interim application to adjust the transmission cost recovery rider in order to avoid excessive carrying costs and to minimize rate impacts for the following update filing.

(F) Affected parties may file detailed comments on any issue concerning any application filed under this rule within thirty days of the date of the filing of the application.

4901:1-36-04 Limitations.

(A) The transmission cost recovery rider costs shall be reconcilable on an annual basis, with carrying charges to be applied to both over and under recovery of costs.

(B) The transmission cost recovery rider shall be avoidable by all customers who choose alternative generation suppliers.

(C) The transmission cost recovery rider shall include only federal energy regulatory commission approved transmission, ancillary service, and other regional transmission organization related charges that the electric utility is not recovering in any other schedule or rider included in the electric utility's tariff on file with the commission.

4901:1-36-05 Hearings.

Unless otherwise ordered by the commission, the legal director, the deputy legal director, or the attorney examiner, the commission shall approve the application or set the matter for hearing within seventy-five days after the filing of a complete application under this chapter.

4901:1-36-06 Additional information.

On a biennial basis, the electric utility shall provide additional information in its annual application detailing the electric utility's policies and procedures for minimizing any costs in the transmission cost recovery rider where the electric utility has control over such costs.

Appendix

Schedule I.D.	Schedule Name and Required Data
A-1	Copy of proposed tariff schedules
A-2	Copy of redlined current tariff schedules
B-1	Summary of Total Projected Transmission Costs Provide the total forecasted cost for each cost component. Provide all costs, including, but not limited to, costs related to network integration transmission service, ancillary service, regional transmission organization, and reconciliation adjustment. Indicate whether each component is energy or demand related.
B-2	Summary of Current verses Proposed Transmission Revenues Provide a table that includes billing determinants for each class applied to current transmission cost recovery rider rates and proposed transmission cost recovery rider rates, including current and proposed class revenues, and the dollar and percentage differences.
B-3	Summary of Current and Proposed Rates For each rate class provide the current transmission cost recovery rider rate and proposed transmission cost recovery rider rate, the dollar difference, and percentage change.
B-4	Graphs For each cost component provide a bar graph of quarterly actual transmission cost recovery rider costs beginning January 06. Also include the original projected cost for each quarter. Also include the next period projections on the graph.
B-5	Typical Bill Comparisons Provide a typical bill comparison for each rate schedule affected by the proposed adjustments to the transmission cost recovery rider.
C-1	Projected Transmission Cost Recovery Rider Costs For each cost component include the monthly projected transmission cost recovery rider cost.
C-2	For each rate schedule provide the monthly projected cost.
C-3	Provide the projected transmission cost recovery rider rate calculations. Provide all necessary support for the rate calculations, including support for demand and energy allocators.
D-1	Reconciliation Adjustment Provide actual transmission cost recovery rider costs for each component used to calculate the reconciliation adjustment.
D-2	Provide monthly revenues collected from each rate schedule.
D-3	Provide monthly over and under recovery amounts.
D-3a…z	Include all additional and necessary schedules for support, including, but not limited to: *Carrying cost calculation. *Reconciliation of throughput to company financial records. *Reconciliation of one month's bill from RTO to Financial Records of the company.

Chapter 4901:1-37

Corporate Separation

NEW CHAPTER
(rescind 4901:1-20-16)

4901:1-37-01 Definitions.

(A) "Affiliates" are companies that are related to each other due to common ownership or control. The affiliate standards shall also apply to any internal merchant function of the electric utility whereby the electric utility provides a competitive service.

(B) "Commission" means the public utilities commission of Ohio.

(C) "Competitive retail electric service provider" means a provider of a competitive retail electric service as defined in division (A)(4) of section 4928.01 of the Revised Code.

(D) "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.

(E) "Electric utility" has the same meaning as in division (A)(11) of section 4928.01 of the Revised Code.

(F) "Employees" are all full-time or part-time employees of an electric utility or its affiliates, as well as consultants, independent contractors, or any other persons performing various duties or obligations on behalf of or for an electric utility or its affiliate.

(G) "Fully allocated costs" are the sum of direct costs plus an appropriate share of indirect costs. For purposes of these rules, the term "fully allocated costs" shall have the same meaning as the term "fully loaded embedded costs" as that term appears in division (A)(3) of section 4928.17 of the Revised Code.

(H) "Staff" means the staff of the commission or its authorized representative.

4901:1-37-02 Purpose and scope.

(A) The purpose of this chapter is to require all of the state's electric utilities to meet the same standards so a competitive advantage is not gained solely because of corporate affiliation.

(B) This chapter is intended to create competitive equality, prevent unfair competitive advantage, and prohibit the abuse of market power in furtherance of the policy of the state of Ohio embodied in section 4928.02 of the Revised Code.

(C) The commission may waive any requirement of Chapter 4901:1-37 of the Administrative Code for good cause shown.

(D) To ensure compliance with this chapter, examination of the books and records of affiliates may be necessary.

(E) Violations of this chapter shall be subject to section 4928.18 of the Revised Code.

(F) The electric utility has the burden of proof to demonstrate compliance with this chapter.

4901:1-37-03 Applicability.

(A) The provisions of this chapter shall apply to the activities of the electric utility and its transactions, or other arrangements, with its affiliates.

(B) The provisions of this chapter shall apply to any shared services of the electric utilities with any affiliates.

(C) The provisions of this chapter shall also apply to the sale or transfer of generating assets.

4901:1-37-04 General provisions.

(A) Structural safeguards.

(1) Each electric utility and its affiliates that provide services to customers within the electric utility's service territory shall function independently of each other.

(2) Each electric utility and its affiliates that provide services to customers within the electric utility's service territory shall not share facilities and services if such sharing in any way violates paragraph (D) of this rule.

(3) Cross-subsidies between an electric utility and its affiliates are prohibited. An electric utility's operating employees and those of its affiliates shall work/function independently of each other.

(4) An electric utility may not share employees and/or facilities with any affiliate, if the sharing, in any way, violates paragraph (D) of this rule.

(5) An electric utility shall ensure that all shared employees appropriately record and charge their time based on fully allocated costs.

(6) *Transactions made in accordance with rules or regulations approved by* the federal energy regulatory commission, securities and exchange commission, and the commission, which rules the electric utility shall maintain in its cost allocation manual (CAM) and file with the commission, shall provide a rebuttable presumption of compliance with the costing principles contained in this chapter.

(B) Separate accounting.

Each electric utility and its affiliates shall maintain, in accordance with generally accepted accounting principles and an applicable uniform system of accounts, books, records, and accounts that are separate from the books, records, and accounts of its affiliates.

(C) Financial arrangements.

(1) Unless otherwise approved by the commission, the financial arrangements of an electric utility are subject to the following restrictions:

(a) Any indebtedness incurred by an affiliate shall be without recourse to the electric utility.

(b) An electric utility shall not enter into any agreement with terms under which the electric utility is obligated to commit funds to maintain the financial viability of an affiliate.

(c) An electric utility shall not make any investment in an affiliate under any circumstances in which the electric utility would be liable for the debts and/or liabilities of the affiliate incurred as a result of actions or omissions of an affiliate.

(d) An electric utility shall not issue any security for the purpose of financing the acquisition, ownership, or operation of an affiliate.

(e) An electric utility shall not assume any obligation or liability as a guarantor, endorser, surety, or otherwise with respect to any security of an affiliate.

(f) An electric utility shall not pledge, mortgage, or use as collateral any assets of the electric utility for the benefit of an affiliate.

(D) Code of conduct.

(1) The electric utility shall not release any proprietary customer information (e.g., individual customer load profiles or billing histories) to an affiliate, or otherwise, without the prior authorization of the customer, except as required by a regulatory agency or court of law.

(2) On or after the effective date of the chapter, the electric utility shall make customer lists, which include name, address, and telephone number, available on a nondiscriminatory basis to all nonaffiliated and affiliated certified retail electric service providers transacting business in its service territory, unless otherwise directed by the customer. This provision does not apply to customer-specific information, obtained with proper authorization, necessary to fulfill the terms of a contract, or information relating to the provision of general and administrative support services.

(3) Employees of the electric utility's affiliates shall not have access to any information about the electric utility's transmission or distribution systems (e.g., system operations, capability, price, curtailments, and ancillary services) that is not contemporaneously and in the same form and manner available to a nonaffiliated competitor of retail electric service.

(4) An electric utility shall treat as confidential all information obtained from a competitive retail electric service provider, both affiliated and nonaffiliated, and shall not release such information, unless a competitive retail electric service provider provides authorization to do so or unless the information was or thereafter becomes available to the public other than as a result of disclosure by the electric utility.

(5) The electric utility shall not tie (or allow an affiliate to tie) or otherwise condition the provision of the electric utility's regulated services, discounts, rebates, fee waivers, or any other waivers of the electric utility's ordinary terms and conditions of service, including but not limited to tariff provisions, to the taking of any goods and/or services from the electric utility's affiliates.

(6) The electric utility shall ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa.

(7) The electric utility, upon request from a customer, shall provide a complete list of all competitive retail electric service providers operating on the system, but shall not endorse any competitive retail electric service providers or indicate that any competitive retail electric service provider will receive preference because of an affiliate relationship.

(7) The electric utility shall ensure retail electric service consumers protection against unreasonable sales practices, market deficiencies, and market power.

(8) Employees of the electric utility or persons representing the electric utility shall not indicate a preference for an affiliated electric services company.

(10) The electric utility shall provide comparable access to products and services related to tariffed products and services and specifically comply with the following:

(a) An electric utility shall be prohibited from unduly discriminating in the offering of its products and/or services.

(b) The electric utility shall apply all tariff provisions in the same manner to the same or similarly situated entities, regardless of any affiliation or nonaffiliation.

(c) The electric utility shall not, through a tariff provision, a contract, or otherwise, give its affiliates preference over nonaffiliated competitors of retail electric service or their customers in matters relating to any product and/or service.

(d) The electric utility shall strictly follow all tariff provisions.

(e) Except to the extent allowed by state law, the electric utility shall not be permitted to provide discounts, rebates, or fee waivers for any retail electric service.

(11) Shared representatives or shared employees of the electric utility and affiliated electric services company shall clearly disclose upon whose behalf their public representations are being made.

(E) Emergency.

(1) Notwithstanding the foregoing, in a declared emergency situation, an electric utility may take actions necessary to ensure public safety and system reliability.

(2) The electric utility shall maintain a log of all such actions that do not comply with this chapter, and such log shall be subject to review by the commission and its staff.

4901:1-37-05 Application.

(A) Consistent with section 4928.17 of the Revised Code, an electric utility that provides in this state, either directly or through an affiliate, a noncompetitive retail electric service and a competitive retail electric service (or a noncompetitive retail electric service and a product or service other than retail electric service) shall file with the commission an application for approval of a proposed corporate separation plan.

(B) The proposed corporate separation plan shall, at a minimum, include the following:

(1) Provisions that maintain structural safeguards.

(2) Provisions that maintain separate accounting.

(3) Identify and describe the financial arrangements between the electric utility and all affiliates.

(4) A code of conduct policy that complies with this chapter and that employees of the electric utility and affiliates must follow.

(5) Identify and describe any joint advertising and/or joint marketing activities between the electric utility and an affiliate that the electric utility intends to utilize, including when and where the name and logo of the electric utility will be utilized, and explain how such activities will comply with this chapter.

(6) Provisions related to maintaining a cost allocation manual (CAM).

(7) A description and timeline of all planned education and training, throughout the holding company structure, to ensure that electric utility and affiliate employees know and can implement the policies and procedures of this rule. The information shall be maintained on the electric utilities' public website.

(8) A copy of a policy statement to be signed by electric utility and affiliate employees who have access to any nonpublic electric utility information, which indicates that they are aware of, have read, and will follow all policies and procedures regarding limitation on the use of nonpublic electric utility information. The statement will include a provision stating that failure to observe these limitations will result in appropriate disciplinary action.

(9) A description of the internal compliance monitoring procedures and the methods for corrective action for compliance with this chapter.

(10) Each electric utility shall name a compliance officer who will be the contact for the commission and staff on corporate separation matters. The compliance officer shall certify that the approved corporation separation plan is up to date and in compliance with the commission's rules and orders. The electric utility shall notify the commission and staff of changes in the compliance officer.

(11) A detailed description outlining how the electric utility and its affiliates will comply with this chapter. The format shall identify the provision and then provide the description.

(12) A detailed listing of the electric utility's electric services and the electric utility's transmission and distribution affiliates' electric services.

(13) The electric utility shall establish a complaint procedure for issues concerning compliance with this chapter, which, at a minimum, shall include the following:

(a) All complaints, whether written or verbal, shall be referred to the legal counsel of the utility or their designee.

(b) The legal counsel shall orally acknowledge the complaint within five working days of its receipt.

(c) The legal counsel shall prepare a written statement of the complaint that shall contain the name of the complainant and a detailed factual report of the complaint, including all relevant dates, companies involved, employees involved, and the specific claim.

(d) The legal counsel shall communicate the results of the preliminary investigation to the complainant in writing within thirty days after the complaint was received, including a description of any course of action that was taken.

(e) The legal counsel shall keep a file in the CAM, in accordance with rule 4901:1-37-08 of this chapter, of the written statements of the complaints and resulting investigations required by paragraphs (B)(13)(c) and (d) of this rule for a period of not less than three years.

(f) This complaint procedure shall not in any way limit the rights of a party to file a formal complaint with the commission.

4901:1-37-06 Revisions and amendments.

(A) All proposed revisions and/or amendments to the electric utility's approved corporate separation plan shall be filed with the commission, and a copy of the filing shall be provided simultaneously to the director of the utilities department.

(B) Except for proposals related to the sale or transfer of assets filed pursuant to rule 4901:1-37-09 of this chapter, if a filing to revise and/or amend the electric utility's corporate separation plan is not acted upon by the commission within sixty days after it is filed, the modified corporate separation plan shall be deemed approved on the sixty-first day after filing.

4901:1-37-07 Access to books and records.

(A) The electric utility shall maintain records sufficient to demonstrate compliance with this chapter, and shall produce, upon the request of staff, all books, accounts, and/or other pertinent records kept by an electric utility or its affiliates as they may relate to the businesses for which corporate separation is required under section 4928.17 of the Revised Code, including those required under section 4928.145 of the Revised Code.

(B) The staff may investigate such electric utility and/or affiliate operations and the interrelationship of those operations at the staff's discretion. In addition, the employees and officers of the electric utility and its affiliates shall be made available for informational interviews, at a mutually agreed time and place, as required by the staff to ensure proper separations are being followed.

(C) If such employees, officers, books, and records cannot be reasonably made available to the staff in the state of Ohio, then upon request of the staff, the appropriate electric utility or affiliate shall reimburse the commission for reasonable travel expenses incurred.

4901:1-37-08 Cost allocation manual (CAM).

(A) Each electric utility that receives products and/or services from an affiliate and/or that provides products and/or services to an affiliate shall maintain information in the CAM, documenting how costs are allocated between the electric utility and affiliates and the regulated and nonregulated operations.

(B) The CAM will be maintained by the electric utility.

(C) The CAM is intended to ensure the commission that no cross-subsidization is occurring between the electric utility and its affiliates.

(D) The CAM will include:

(1) An organization chart of the holding company, depicting all affiliates, as well as a description of activities in which the affiliates are involved.

(2) A description of all assets, services, and products provided to and from the electric utility and its affiliates.

(3) All documentation including written agreements, accounting bulletins, procedures, work order manuals, or related documents, which govern how costs are allocated between affiliates.

(4) A copy of the job description of each shared employee.

(5) A list of names and job summaries for shared consultants and shared independent contractors.

(6) A copy of all transferred employees' (from the electric utility to an affiliate or vice versa) previous and new job descriptions.

(7) A log of all complaints brought to the utility regarding this chapter.

(8) A copy of the minutes of each board of directors meeting, where it shall be maintained for a minimum of three years.

(E) The method for charging costs and transferring assets shall be based on fully allocated costs.

(F) The costs should be traceable to the books of the applicable corporate entity.

(G) The electric utility and affiliates shall maintain all underlying affiliate transaction information for a minimum of three years.

(H) Following approval of a corporate separation plan, an electric utility shall provide the director of the utilities department (or their designee) with a summary of any changes in the CAM at least every twelve months.

(I) The compliance officer designated by the electric utility will act as the contact for the staff when staff seeks data regarding affiliate transactions, personnel transfers, and the sharing of employees.

(J) The staff may perform an audit of the CAM in order to ensure compliance with this rule.

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

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

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

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

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

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

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

(D) Upon the filing of such application, the commission may fix a time and place for a hearing if the application appears to be unjust, unreasonable, or not in the public interest.

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

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

Chapter 4901:1-38

Special Arrangements

4901:1-38-01 Definitions.

(A) "Affidavit" means a written declaration made under oath before a notary public or other authorized officer.

(B) "Commission" means the public utilities commission of Ohio.

(C) "Delta revenue" means the deviation resulting from the difference in rate levels between the otherwise applicable rate schedule and the result of any economic development schedule, energy efficiency schedule, or unique arrangement.

(D) "Economic Development," for the purpose of this chapter, includes, but is not limited to, incremental job creation, job retention, incremental capital investment, incremental or retained load, and incremental or retained benefits (e.g., local and state tax dollars, employment from business opportunities related to the core business of the customer).

(E) "Electric utility" has the same meaning as in division (A)(11) of section 4928.01 of the Revised Code.

(F) "Energy efficiency production facilities" means any customer that manufactures or assembles products that promote the more efficient use of energy (i.e., increase the ratio of energy end use services (i.e., heat, light and drive power) derived from a device or process to energy inputs necessary to derive such end use services as compared with other devices or processes that are commonly installed to derive the same energy use services); or, any customer that manufactures, assembles or distributes products that are used in the production of clean, renewable energy.

(G) "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.

(H) "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 the electric utility.

(I) "Staff" means the staff of the commission or its authorized representative.

4901:1-38-02 Purpose and scope.

(A) The purpose of this chapter is to facilitate the state's effectiveness in the global economy, to promote job growth and retention in the state, to ensure the availability of reasonably priced electric service, to promote energy efficiency and to provide means of giving appropriate incentives to technologies that can adapt successfully to environmental mandates in furtherance of the policy of the state of Ohio embodied in section 4928.02 of the Revised Code.

(B) The commission may waive any requirement of Chapter 4901:1-38 of the Administrative Code for good cause shown.

4901:1-38-03 Economic development schedule.

(A) Each electric utility shall file an application for commission approval for an economic development schedule applicable to new or expanding customers.

(1) The filing shall include a standard application form for customers.

(2) Each customer applying for the schedule must meet the criteria set forth in paragraphs (a) to (h) below and must submit to the electric utility verifiable information detailing how the criteria are met, and must provide an affidavit from a company official as to the veracity of the information provided.

(a) Eligible projects must be for non-retail purposes.

(b) At least twenty-five new, full-time jobs must be created within three years of initial operations.

(c) The average hourly base wage rate of the new, full-time jobs must be at least one hundred fifty per cent of federal minimum wage.

(d) The project must have a fixed asset investment in land, building, machinery/equipment, and infrastructure of at least five hundred thousand dollars.

(e) The applicant must demonstrate financial viability.

(f) The applicant must identify local (city, county), state, or federal support in the form of tax abatements or credits, jobs programs, or other incentives.

(g) The applicant must identify potential secondary and tertiary benefits resulting from its project including, but not limited to, local/state tax dollars and related employment or business opportunities resulting from the location of the facility.

(h) The applicant must agree to maintain operations at the project site for at least twice the term of the incentives.

(B) Each electric utility shall file an application for an economic development schedule for the retention of existing customers likely to cease, reduce operations, or relocate the operations out of state.

(1) The filing shall include a standard application form for customers.

(2) Each customer applying with the utility for the schedule must meet the criteria set forth in paragraphs (a) to (g) below, must submit to the electric utility verifiable information detailing how the criteria are met, and must provide an affidavit from a company official as to the veracity of the information provided.

(a) Eligible projects must be for non-retail purposes.

(b) The number of full-time jobs to be retained must be at least twenty-five.

(c) The average billing load (in kilowatts to be retained) must be at least two hundred fifty kilowatts.

(d) The electricity-intensity of the operations (i.e., the ratio of the cost of electricity to the total operational expenses) must be at least ten per cent.

(e) The customer must demonstrate that the cost of electricity is a "major factor" in its decision to cease, reduce, or relocate its facilities to an out-of-state site. In-state relocations are not eligible. If the customer has the potential to relocate to an out-of-state site, the site(s) must be identified, along with the expected costs of electricity at the site(s) and the expected costs of other significant expenses including, but not limited to, labor and taxes.

(f) The customer must identify any other local, state, or federal assistance sought and/or received in order to maintain its current operations.

(g) The customer must agree to maintain its current operations for the term of the incentives.

(C) Customer information provided to demonstrate eligibility under paragraphs (A) and (B) of this rule shall remain confidential by the electric utility. Nonetheless, the name and address of customers eligible for the schedules shall be public information.

(D) The staff shall have access to all customer and electric utility information related to service provided pursuant to these schedules for periodic and random audits.

4901:1-38-04 Energy efficiency schedule.

(A) Each electric utility shall file an application for commission approval for an energy efficiency schedule applicable to energy efficiency production facilities with loads not more than one thousand kilowatts.

(1) The filing shall include a standard application form for customers.

(2) Each customer applying with the utility for the schedule must meet the criteria set forth in paragraphs (a) to (h) below and must submit to the electric utility verifiable information detailing how the criteria are met, and must provide an affidavit from a company official as to the veracity of the information provided.

(a) The customer must be an energy efficiency production facility as defined in this chapter.

(b) At least ten new, full-time jobs must be created within three years of initial operations.

(c) The average hourly base wage rate of the new, full-time jobs must be at least one hundred fifty per cent of federal minimum wage.

(d) The load must be for no more than one thousand kilowatts.

(e) The project must have a fixed asset investment in land, building, machinery/equipment, and infrastructure of at least two hundred fifty thousand dollars.

(f) The applicant must demonstrate financial viability.

(g) The applicant must identify local (city, county), state, or federal support in the form of tax abatements or credits, jobs programs, or other incentives.

(h) The applicant must agree to maintain operations at the project site for at least twice the term of the incentives.

(B) The electric utility shall file an application for an energy efficiency schedule that recognizes the efforts by a customer with loads not more than one thousand kilowatts to reduce its electricity consumption per unit of production.

(1) The filing shall include a standard application form for customers.

(2) Each customer applying with the utility for the schedule must meet the criteria set forth in paragraphs (a) to (e) below and must submit to the electric utility verifiable information detailing how the criteria are met, and must provide an affidavit from a company official as to the veracity of the information provided.

(a) Eligible projects must be for manufacturing.

(b) The average billing load must be no more that one thousand kilowatts.

(c) The customer must identify its capital investments and expenses related to energy efficient measures.

(d) The customer must provide sufficient financial data to illustrate that it has reduced its electricity consumption per unit of production.

(e) The customer must agree that the electric utility may count the reduction in electricity consumption attributable to its investments and expenses toward its energy efficiency targets as set forth in section 4928.66 of the Revised Code.

(C) Customer information provided to demonstrate eligibility under paragraphs (A) and (B) of this rule shall remain confidential by the electric utility. Nonetheless, the name and address of customers eligible for the schedules shall be public information.

(D) The staff shall have access to all customer and electric utility information related to service provided pursuant to these schedules for periodic and random audits.

4901:1-38-05 Unique arrangements.

(A) Notwithstanding rules 4901:1-38-03 and 4901:1-38-04 of this chapter, an electric utility may file an application pursuant to section 4905.31 of the Revised Code for commission approval of a reasonable arrangement with one or more of its customers, consumers, or employees.

(1) An electric utility filing an application for commission approval of a reasonable arrangement with one or more of its customers, consumers, or employees bears the burden of proof as to the reasonableness of the arrangement and shall submit to the commission verifiable information detailing the rationale for the arrangement.

(2) Upon the filing of such application, the commission may fix a time and place for a hearing if the application appears to be unjust or unreasonable.

(3) The arrangement is subject to change, alteration, or modification by the commission.

(B) A mercantile customer, or a group of mercantile customers, of an electric utility may apply to the commission for a reasonable arrangement with the electric utility.

(1) Each customer applying for an arrangement bears the burden of proof as to the reasonableness of the arrangement and shall submit to the commission and the electric utility verifiable information detailing the rationale for the arrangement.

(2) The customer shall provide an affidavit from a company official as to the veracity of the information provided.

(3) Upon the filing of such application, the commission may fix a time and place for a hearing if the application appears to be unjust or unreasonable.

(4) The arrangement is subject to change, alteration, or modification by the commission.

(C) Reasonable arrangements must reflect terms and conditions for circumstances for which the electric utility's tariffs have not already provided.

4901:1-38-06 Reporting requirements.

(A) Each customer served under any schedule or unique arrangement established pursuant to this chapter must submit an annual report to the electric utility no later than April 30th of each year. The format of that report shall be determined by the electric utility and staff such that a determination of the compliance with the eligibility criteria can be determined.

(B) The burden of proof to demonstrate on-going compliance with the schedule or unique arrangement lies with the customer. The electric utility shall summarize the reports provided by customers under paragraph (A) of this rule and submit such summary to staff for review and audit no later than June 15th of each year.

4901:1-38-07 Level of incentives.

(A) The level of the incentives associated with any schedule or unique arrangement established pursuant to this chapter shall be determined as part of the commission's review and approval of the applications filed pursuant to this chapter.

(B) Incentives may be based on, but not limited to:

(1) Demand discounts.

(2) Percentages of total bills, or portions of bills.

(3) Direct contributions.

(4) Reflections of cost savings to the electric utility.

(5) Shared savings.

(6) Some combination of the required criteria.

(C) Upon commission approval of an application, the schedule or arrangement, as approved, shall be:

(1) Posted on the commission's docketing information system.

(2) Accessible through the commission's web page.

(3) Under the supervision and regulation of the commission, and subject to change, alteration, or modification by the commission.

(D) No customer shall be provided incentives from more than one schedule or arrangement approved by the commission pursuant to this chapter.

4901:1-38-08 Revenue recovery.

(A) Each electric utility may apply for a rider for the recovery of certain costs associated with its delta revenue in accordance with the following:

(1) The rider is subject to commission approval.

(2) The rider may be updated, by application to the commission, semi-annually by the electric utility. All data submitted in support of the rider update is subject to commission review and audit.

(3) The approval of the request for revenue recovery, including the level of such recovery, is at the commission's discretion and the application is subject to change, alteration or modification by the commission.

(4) Upon the filing of such application, the commission may fix a time and place for a hearing if the application appears to be unjust or unreasonable.

(B) The electric utility may request recovery of administrative costs related to the programs as part of the rider. Such request is subject to audit, review and approval by the commission.

(C) Any special arrangement in which incentives are given based upon cost savings to the electric utility (including, but not limited to, nonfirm arrangements, on/off peak pricing, seasonal rates, time-of-day rates, real-time-pricing rates) are not subject to the delta revenue recovery mechanism.

(D) The amount of the revenue recovery rider shall be spread to all customers in proportion to the current revenue distribution between and among classes, subject to change, alteration, or modification by the commission.

4901:1-38-09 Failure to comply.

(A) If the customer being provided with service pursuant to a schedule or unique arrangement established pursuant to this chapter fails to substantially comply with any of the criteria for eligibility, the electric utility after reasonable notice to the customer shall terminate the arrangement unless otherwise ordered by the commission.

(B) The commission may also direct the electric utility to charge the customer for all or part of the incentives previously provided by the electric utility.

(C) If the customer is required to pay for all or part of the incentives previously provided, such amounts shall be reflected in the calculation of the revenue recovery rider established pursuant to rule 4901:1-38-08 of this chapter.

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Adoption of Rules for Standard Service Offer, Corporate Separation, Reasonable Arrangements, and Transmission Riders for Electric Utilities Pursuant to Sections 4928.14, 4928.17, and 4905.31, Revised Code, as amended by Amended Substitute Senate Bill No. 221.	)	Case No. 08-777-EL-ORD

FINDING AND ORDER

The Commission finds:

BACKGROUND:

On July 7, 1999, the governor of the state of Ohio signed Amended Substitute Senate Bill No. 3 (SB 3). That legislation, among many things, established a starting date for competitive retail electric service in the state of Ohio and provided for the establishment of market development periods (MDP) for each electric utility. After the MDP, pursuant to Section 4928.14(A), Revised Code, as originally enacted into law, each electric utility was required to provide consumers, on a comparable and nondiscriminatory basis within its certified territory, a market-based standard service offer (MBSSO) to maintain essential electric service to consumers, including a firm supply of electric generation service. Pursuant to Section 4928.14(B), Revised Code, each electric utility was required to offer customers within its certified territory an option to purchase competitive retail electric service after its MDP ends, the price of which is to be determined through a competitive bidding process (CBP). On December 17, 2003, the Commission issued a Finding and Order in Case No. 01-2164-EL-ORD which adopted, with certain modifications, staff's proposed rules for processing applications to establish the MBSSO and CBP in Chapter 4901:1-35-01, Ohio Administrative Code (O.A.C.).

On May 1, 2008, the governor signed into law Amended Substitute Senate Bill No. 221 (SB 221) amending various provisions of SB 3. Among those amendments were changes to Section 4928.14, Revised Code, to establish a standard service offer (SSO); Section 4905.31, Revised Code, to approve reasonable arrangements and utility schedules; and Section 4928.17, Revised Code, to establish corporate separation plans. 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). The SSO shall serve as the electric utility's default SSO. Electric utilities may apply simultaneously under both options; however, at a minimum, the first SSO application must include an application for an ESP. The amendments to Section 4905.31, Revised Code, modify the applicability of reasonable arrangements and the amendments to Section 4928.17, Revised Code, impose additional requirements on electric utilities relating to the transfer of assets.

The staff of the Commission (Staff) has proposed a complete rewrite of Chapter 4901:1-35, O.A.C., and its incorporated appendices, which include procedural requirements for filing applications for an MRO and ESP as well as filing requirements for such applications in accordance with SB 221. The Staff has also proposed Chapter 4901:1-36 to establish procedures for the implementation of transmission riders and Chapter 4901:1-38 to establish procedures for approving reasonable arrangements between the electric utility and customers. Further, the Staff is proposing to rescind Rule 4901:1-20-16, O.A.C., and revise and place the existing Commission requirements in a stand-alone Chapter 4901:1-37 to address electric utility corporate separation between affiliated entities, as well as new SB 221 requirements.

On July 2, 2008, the Commission issued an entry requesting comments from interested persons to assist in the review of Staff's proposed Chapters 4901:1-35 through 4901:1-38. Comments and/or reply comments were filed in this docket by the following parties:

Ohio Hospital Association
Ohio Home Builders Association, Inc.
The Greater Cincinnati Health Council
City of Cleveland
Kraft Foods Global, Inc.
Alliance for Real Energy Options
Columbus Southern Power Company and Ohio Power Company (AEP Ohio)
Ohio Energy Group, Chemistry Technology Council, Ohio Cast Metals Association, Ohio Hospital's Association, Ohio Aggregates and Industrial Minerals Association and Ohio Manufacturers' Association (OEG)
Ohio Consumer and Environmental Advocates (OCEA)
Duke Energy Ohio, Inc. (Duke)
Ohio Environmental Council
Kroger Company, Inc.
Nucor Steel Marion, Inc.
City of Cincinnati
Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company (FirstEnergy)
Council of Small Enterprises
Dayton Power and Light Company
Ohio Farm Bureau Federation
Ohio Association of School Business Officials, the Ohio School Boards Association and The Buckeye Association of School Administrators

Northeast Ohio Public Energy Council
Ormet Primary Aluminum Company
Recycled Energy Development, LLC
Industrial Energy Users-Ohio (IEU)

DISCUSSION:

After reviewing the Staff's proposal, initial comments, and reply comments, the Commission will adopt new Chapters 4901:1-35, 4901:1-36, 4901:1-37, and 4901:1-38 as attached to the order. Further, the Commission will rescind existing Chapter 4901:1-35 and Rule 4901:1-20-16, O.A.C. In this order, we will only address the more salient comments. In some respects, we agree with certain comments and have incorporated them into our rules without specifically addressing such changes in this Finding and Order. To the extent that a comment was raised and is not addressed in this order or incorporated into our adopted rules, it has been rejected.

Chapter 4901:1-35:

The Commission has made several changes to Staff's proposed Chapter 4901:1-35, based upon our review of the comments and our interpretations of SB 221. With regard to Rule 4901:1-35-01,[1] Definitions, the Commission has modified Staff's proposed definition in Rule 4901:1-35-01(E) "electric security plan," to recognize that such plans may relate to matters other than electric generation service as provided for in Section 4928.143, Revised Code.

With respect to Rule 03, Filing and Content of Application, the Commission has reorganized the structure of this rule. OCEA believes that the appendices should be incorporated into the rules rather than as appendices so that they are readily obtainable to interested persons. Inasmuch as a good deal of Appendices A and B to this rule, which involve the content of SSO applications, are substantive directives to the electric utilities, the Commission has decided to delete the appendices and incorporate the requirements of the appendices into Rules 03(B) and (C) of this chapter. Rule 03(B) now contains the requirement formerly set forth in Appendix A and Rule 03(C) now contains the requirements formerly set forth in Appendix B. The Commission has also modified language in Rule 03 to reflect that provisions of an SSO application must be "consistent with" instead of "achieve" the policies of the state as set forth in divisions (A) to (N) of Section 4928.02, Revised Code, recognizing the need for flexibility in attempting to satisfy those policies.

1 Hereafter, the Commission will refer to specific rules by their last two numbers instead of the full code section being discussed in each subsection of the Finding and Order.

With regard to former Appendix A, AEP Ohio and FirstEnergy indicated that items (A)(2) and (A)(3) go beyond the scope of SB 221. We disagree. The language as originally proposed by Staff is useful in describing the requirements necessary to fulfill the meaning of SB 221, and we are retaining it largely in the form in which it was proposed. OCEA proposes an extensive addition to both Appendix A and Appendix B, that would provide a list of items that an electric utility must consider in developing a generation supply procurement plan. Although we find OCEA's suggestion to be overly proscriptive, we agree that the electric utility should demonstrate its consideration of alternatives in development of its CBP plan. We have therefore amended section (B) of former Appendix A accordingly.

The Commission has received various comments and proposed revisions with regard to former Appendix B, Requirements for Electric Security Plans, and Rule 10, Annual Review of Electric Security Plans. Many parties found that the original language in the "Additional Requirements Information" section of Appendix B did not clearly make the proper distinctions between the two different situations calling for an earnings review, and we have re-written this section to clarify this matter. In terms of substantive recommendations, the OEG has proposed extending the comment period from the proposed 30 days to 60 days, to enable consideration of the information contained in the Federal Energy Regulatory Commission (FERC) Form 1 which is generally available at the end of April. Also, all of the electric utilities objected to the requirement that they provide information on a functionalized basis, although these objections were not identical in nature. In consideration of these objections, we recognized that the income statement and balance sheet information which was being sought is satisfactorily contained in the FERC Form 1 and the Securities and Exchange Commission (SEC) 10-K. Therefore, we are changing the date for the submission of the filing for the annual review from April 1 to May 15. Further, proposed Rule 4901:1-35-10 and former Appendix B have been revised based on the comments discussed above.

Among the general requirements for ESPs in former Appendix B, first section provision (B) requires that an electric utility provide pro forma financial projections of the effect of the ESP's implementation upon the utility. The OCEA and the OEG filed comments suggesting that this requirement include supporting material, workpapers, and explanations of assumptions used. The comments of AEP Ohio, however, argue that the requirement of pro forma financial information is without basis in statute and constitutes improper prospective evaluations of the significantly excessive earnings test and should thus be deleted.

We agree with OCEA and OEG that any quantitative projection can be understood and be useful only if the basis for the projection is also available and have added this requirement. We reject AEP Ohio's characterization of this information as constituting an excess earnings test. An ESP is quite complex, with many aspects to be decided, and these decisions should be made in the context of all available information. The Commission, throughout its history, has been charged with consideration and balancing of the competing interests of various stakeholders, a process which requires knowledge and understanding of the possible effects of decisions on various parties. AEP Ohio's argument would have the Commission, and the public, flying blind in this regard, and could jeopardize the sense of fairness and legitimacy of the process. We would also observe that none of the other electric utilities objected to this provision or interpreted it as an excess earnings test.

Former Appendix B, second section titled Specific Information, paragraph (B) provides requirements for a utility which is seeking to include unavoidable surcharges for certain expenditures pursuant to division (B)(2)(b) and (B)(2)(c) of Section 4928.143, Revised Code. Duke proposes "a bidding process appropriate for the dedication to load of existing assets, rather than newly constructed assets." We disagree with this proposal. We believe that the impetus for these provisions of SB 221 was a concern that the market might not provide sufficient means for the creation of additional generation resources which might be needed in the future. Existing resources are already available to Ohio consumers through the market. Consequently, we will not include Duke's recommendation into these rules.

One last area of former Appendix B that the Commission finds worthy of discussion is the second section titled Specific Information, paragraph (G). OCEA has made a large number of recommendations as preconditions for cost recovery. Many of these provisions go beyond informational filing requirements and have the effect of predetermining the outcome of the Commission's review. However, we agree with OCEA that proposed sub-section (G)(3) should include a description of the utility's efforts to mitigate stranded investment with respect to its modernization plan, and we have therefore added such language at the end of the corresponding provision in Rule 03.

Based on the comments, the Commission finds that each electric utility should submit with its SSO application a proposed notice for newspaper publication describing the application and the rate impacts. Such requirement has been added to Rule 04(B).

Chapter 4901:1-36, Transmission Cost Recovery

The Commission has made some minor changes to proposed Chapter 4901:1-36. Among the changes, the Commission revised Rule 03 based on the comments of Duke and FirstEnergy. They requested that the Commission clarify that the costs of consultants retained by the Staff be recoverable through the transmission cost recovery rider. The Commission has amended this rule accordingly. With respect to Rule 04, IEU recommended that the Commission include a requirement in this rule that electric utilities must include offsetting benefits in the calculation of the rider. The Commission agrees with this recommendation and revised the rule.

Chapter 4901:1-37, Corporate Separation Rules

As for proposed Chapter 4901:1-37, which establishes corporate separation rules, numerous comments focused on general corporate separation prohibitions and the reporting requirements of the electric utility (including the information maintained in the electric utility's cost allocation manual), and recommended modifications to the proposed rules to expand the existing provisions and provide additional detail. However, most of these comments merely repeated, rephrased, or relocated the existing requirements or provisions set forth in Staff's proposed rules. Accordingly, the Commission reviewed the recommendations and has clarified or expanded Staff's proposed rules where necessary.

Similarly, comments were filed that recommended an expansion of the complaint procedures and remedies set forth in Staff's proposed rules. The Commission finds that such an expansion is unnecessary. Section 4928.18 of the Revised Code clearly enumerates the appropriate complaint process concerning violations of corporate separation plans established pursuant to section 4928.17 of the Revised Code and the Commission's rules and orders, as well as applicable remedies. Additionally, Rule 02(E) of Staff's proposed rules reference the pertinent statutory provision for violations of Chapter 4901:1-37, O.A.C.

OCEA proposed modifications to proposed Rule 09, that would require mandatory hearings regarding all applications to sell or transfer an electric utility's generating asset that it wholly or partly owns. With the exception of those transactions which would alter the jurisdiction of the Commission over a generation asset, the Commission agrees with Staff that the decision to hold an evidentiary hearing should be discretionary, decided on a case-by-case basis. The Commission may receive applications that are classified as a transfer in ownership, but that may not necessarily require a hearing. Under OCEA's proposal, a slight change in the percentage of ownership of a small generating asset among two electric utilities would trigger a hearing, regardless of whether there is participation, or even interest, by other parties in the proceeding. Such a result is unnecessary and burdensome on the parties involved, Staff, and the Commission.

Throughout the rules, OCEA requests that all parties receive the same access as Staff to the books, accounts, and records of the electric utility and affiliates. While the Commission does not believe any modifications to the proposed rules are warranted, the Commission notes that the proposed rules do not limit a party's right to discovery in a pending proceeding pursuant to the Commission's rules of practice.

With the adoption of the new corporate separation chapter, the Commission clarifies that each electric utility must file, within sixty days of the effective date of this chapter, an application for approval of its proposed corporate separation plan as outlined in proposed Rule 05. Upon approval of its corporate separation plan, the electric utility shall file the plan in its "TRF" docket, and maintain a current version of its approved plan in that docket.

Chapter 4901:1-38, Reasonable Arrangements

The last chapter being considered in the docket is Chapter 4901:1-38, Reasonable Arrangements. The Commission has made various revisions to this chapter after considering the comments that have been filed. The Commission has determined that it is necessary to approve all reasonable arrangements entered into between the electric utility and one or more of its customers. Accordingly, all references to standard schedules have been removed and the chapter has been modified accordingly.

With respect to proposed Rules 03(A)(2)(d) and 04(A)(2)(e) regarding eligibility requirements for customers to be served under economic development and energy efficiency arrangements, some commenters requested that the Commission remove the criterion for fixed asset investment. The Commission recognizes that the primary focus of these arrangements is to create jobs. Since it is possible that jobs can be created without additional investments in fixed assets, the criterion requiring a fixed asset investment in land, buildings, machinery/equipment, and infrastructure has been removed. In addition, certain commenters have expressed a concern that the criterion that the customer must have an electric intensity of at least 10% as set forth in proposed Rule 03(B)(2)(d) is unrealistic. The Commission finds that this criterion is not necessary on a stand-alone basis because such considerations can be incorporated into the demonstration that the cost of electricity is a major factor in the decision to cease, reduce, or relocate operations.

With respect to proposed Rule 04(A), the criterion that the energy efficiency arrangements be applicable to facilities with loads of not more than one thousand kilowatts has been removed. The Commission agrees with those commenters that believe that there should be no load maximum load for eligibility. The Commission has also determined that division (B) of proposed Rule 04 should be deleted. The rule required the electric utility to file an application for an energy efficiency schedule that recognized the efforts by a customer to reduce its electricity consumption per unit of production. There was uncertainty as to how the baseline would be established and how the ratio of electricity consumption to unit of output would be measured, monitored, and valued. Several parties commented that there was no basis for this rule in SB 221 and that it should be deleted. Parties commented that a third-party specialist would be required to do the evaluations. OCC argues that such a schedule would dilute the value of the other energy efficiency provisions of SB 221. The Commission finds that the rule is problematic and should not be implemented as proposed in the rules for comment.

The Commission also received comments regarding proposed Rule 07(D). The proposed rule set forth that no customer shall be provided incentives from more than one arrangement under this chapter. Commenters did not see the necessity for this provision and believe it should be eliminated. The Commission has determined that it can look at each arrangement on a case-by-case basis and deleted this provision.

Lastly, based upon comments received, the Commission has revised proposed Rule 08 which addresses cost recovery for the delta revenue related to reasonable arrangements. With respect to division (C) of Rule 08, rather than disallow any delta revenue recovery of arrangements which are based upon cost savings to the electric utility, the rule has been modified to reflect that any such cost savings be reflected as an offset to the recovery of delta revenues. Also some comments recommended that the Commission revise paragraph (A)(3) of this rule to reflect that the recovery of delta revenue is not up to Commission discretion. We disagree, Section 4905.31(E), Revised Code, provides for the filing of an application to recover costs incurred and revenue forgone; however, filings still must be approved by the Commission as set forth in Section 4905.31, Revised Code. Accordingly, we will not adopt the recommendations on this point.

CONCLUSION:

The Commission finds that the rules proposed by Staff should be approved as modified by this order. Attached is a copy of the rules adopted.

The Commission notes that the rules being approved by this order are over 40 pages. While the Commission finds that a hard copy of this entry should be served upon all stakeholders, we believe that, rather than mail hard copies of the rules to the stakeholders, it would be prudent and more efficient to provide a web address where the attachment can be accessed. Accordingly, interested entities can access the attachment by going to the Commission's web site at www.puco.ohio.gov/PUCO/Rules, and clicking on the link to Staff's Proposed Rules for Electric Utility Standard Service Offer, Corporate Separation, Reasonable Arrangements, and Transmission Riders to implement Senate Bill 221. If an entity has questions regarding how to access the attachment or does not have access to the internet, it may contact the Commission's Docketing Division at (614) 466-4095, Monday through Friday between the hours of 7:30 a.m. and 5:30 p.m.

ORDER:

It is, therefore,

ORDERED, That the attached rules are hereby adopted. It is, further,

ORDERED, That existing Chapter 4901:1-35, O.A.C., and Rule 4901:1-20-16, O.A.C., are rescinded. It is, further, ORDERED, That attached new Chapters 4901:1-35, 4901:1-36, 4901:1-37, and 4901:1-38 should be filed with the Joint Committee on Agency Rule Review, the Secretary of State, and the Legislative Service Commission in accordance with divisions (D) and (E) of Section 111.15, Revised Code. It is, further,

ORDERED, That the final rules be effective on the earliest day permitted by law. Unless otherwise ordered by the Commission, the review date for Chapters 4901:1-35, 4901:1-36, 4901:1-37, and 4901:1-38 shall be September 30, 2013. It is, further,

ORDERED, That a copy of this entry, without the attachments, be served upon all parties filing comments in this docket and all interested parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Paul A. Centolella

Ronda Hartman Fergus

Valerie A. Lemmie

Cheryl L. Roberto

KWB:ct

Entered in the Journal
SEP 17 2008

Reneé J. Jenkins
Secretary

Chapter 4901:1-35

Electric Utility Standard Service Offer

4901:1-35-01 **Definitions.**

(A) "Application" means an application for standard service offer pursuant to this chapter.

(B) "Commission" means the public utilities commission of Ohio.

(C) "Competitive bidding process" means a bidding process established pursuant to section 4928.142 of the Revised Code.

(D) "Dynamic Retail Pricing" means a retail rate design which includes prices that can change based on changes in wholesale electricity prices, power system conditions, or the marginal cost of providing electric service.

(E) "Electric utility" shall have the meaning set forth in division (A)(11) of section 4928.01 of the Revised Code.

(F) "Electric security plan" means an electric utility plan for the supply and pricing of electric generation service including other related matters pursuant to section 4928.143 of the Revised Code.

(G) "First application for a market rate offer" means the application filed under section 4928.142 of the Revised Code by an electric utility that has not previously implemented an approved market-rate offer.

(H) "Market development period" shall have the meaning set forth in division (A)(17) of section 4928.01 of the Revised Code.

(I) "Market-rate offer" means an electric utility plan for the supply and pricing of electric generation service pursuant to section 4928.142 of the Revised Code.

(J) "Person" shall have the meaning set forth in division (A)(24) of section 4928.01 of the Revised Code.

(K) "Rate plan" means an electric utility's standard service offer approved by the commission prior to January 1, 2009, that established rates for electric service at the expiration of an electric utility's market development period.

(L) "Standard service offer" means an electric utility offer to provide consumers, on a comparable and nondiscriminatory basis within its certified territory, all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service.

(M) "Staff" means the staff of the commission or its authorized representatives.

(N) "Time Differentiated Pricing" means a retail rate design which includes differing prices based upon the time that electricity is used in order to reflect differences in expected costs or wholesale electricity prices in different time periods.

4901:1-35-02 **Purpose and scope.**

(A) Pursuant to division (A) of section 4928.141 of the Revised Code, beginning January 1, 2009, each electric utility in this state shall provide consumers, on a comparable and nondiscriminatory basis within its certified territory, a standard service offer (SSO) of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service. Pursuant to this chapter, an electric utility shall file an application for commission approval of an SSO. Such application shall be in the form of an electric security plan or market rate offer pursuant to sections 4928.142 and 4928.143 of the Revised Code. The purpose of this chapter is to establish rules for the form and process under which an electric utility shall file an application for an SSO and the commission's review of that application.

(B) The commission may waive any requirement of Chapter 4901:1-35 of the Administrative Code for good cause shown.

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: that its RTO retains an independent market monitor that 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, whether such market is administered by the RTO or whether it is a bilateral market, by virtue of access to the RTO and the market participant's data and personnel, and that has the authority and 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, if no such market monitor exists, 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 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 to any person requesting it, and the information shall be sufficiently reliable and available for use in a proceeding before the commission. 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 or its affiliates, to the extent that impacts on affiliates are ascertainable by 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 profiles 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.

(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 (J) 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) and (J) 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, as an offset, 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) Demonstration by the electric utility that the cost as defined was prudently incurred as required under division (B)(2) of section 4928.143 of the Revised Code. Demonstration that a significant change in such costs was prudently incurred shall include, but not be limited to, an analysis comparing the electric utility's resource and/or environmental compliance strategy with supply and demand-side alternatives.

(iv) 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.

(v) 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 the process for competitive bidding of 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 being 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 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 application for an ESP that substantively conforms to the requirements of this rule within one hundred fifty days of the filing of such complete 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, any and all 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.

4901:1-35-04 **Service of application.**

(A) Concurrent with the filing of a standard service offer (SSO) application and the filing of any waiver requests, the electric utility shall provide notice of filings to each party in its most recent SSO proceeding or, if this is its first SSO filing after the effective date of section 4928.141 of the Revised Code, then its last rate plan proceeding. At a minimum, that notice shall state that a copy of the application and all waiver requests are available through the electric utility's and commission's web sites, available at the electric utility's main office, available at the commission's offices, and any other sites at which the electric utility will maintain a copy of the application and all waiver requests.

(B) The electric utility shall also submit with its SSO application a proposed notice for newspaper publication that fully discloses the substance of the application, including projected rate impacts, and that prominently states that any person may request to become a party to the proceeding.

(C) The electric utility shall provide electronic copies of the application upon request, without cost, and transmit the application within five business days, or make a hard copy available for review at the electric utility's business office. Upon request, electronic copies shall be provided in spreadsheet, word processing, or an electronic non-image-based format, with formulas intact, compatible with personal computers.

4901:1-35-05 **Technical conference.**

Upon filing of a standard service offer application, the commission, legal director, deputy legal director, or attorney examiner shall schedule a technical conference. The purpose of the technical conference is to allow interested persons an opportunity to better understand the electric utility's application. The electric utility will have the necessary personnel in attendance at this conference so as to explain, among other things, the structure of the filing, the work papers, he data sources, and the manner in which methodologies were devised. The conference will be held at the commission offices, unless the commission, legal director, deputy legal director, or attorney examiner determines otherwise.

4901:1-35-06 **Hearings.**

(A) After the filing of a standard service offer application that conforms to the commission's rules, the commission shall set the matter for hearing and shall cause notice of the hearing to be published one time in a newspaper of general circulation in each county in the electric utility's certified territory. At such hearing, the burden of proof to show that the proposals in the application are just and reasonable and are consistent with the policy of the state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code shall be upon the electric utility.

(B) Interested persons wishing to participate in the hearing shall file a motion to intervene no later than forty-five days after the issuance of the entry scheduling the hearing, unless ordered otherwise by the commission, legal director, deputy legal director, or attorney examiner. This rule does not prohibit the filing of a motion to intervene and conducting discovery prior to the issuance of an entry scheduling a hearing.

4901:1-35-07 **Discoverable agreements.**

Upon submission of an appropriate discovery request during a proceeding establishing a standard service offer, an electric utility shall make available to the requesting party every contract or agreement that is between the electric utility or any of its affiliates and a party to the proceeding, consumer, electric service company, or political subdivision and that is relevant to the proceeding, subject to such protection for proprietary or confidential information as is determined appropriate by the commission.

4901:1-35-08 **Competitive bidding process requirements and use of independent third party.**

(A) An electric utility proposing a market-rate offer in its standard service offer application, pursuant to section 4928.142 of the Revised Code, shall propose a plan for a competitive bidding process (CBP). The CBP plan shall comply with the requirements set forth in paragraph (B) of rule 4901:1-35-03 of the Administrative Code. The electric utility shall use an independent third party to design an open, fair, and transparent competitive solicitation; to administer the bidding process; and to oversee the entire procedure to assure that the CBP complies with the CBP plan. The independent third party shall be accountable to the commission for all design, process, and oversight decisions. The independent third party shall incorporate into the solicitation such measures as the commission may prescribe, and shall incorporate into the bidding process any direction the commission may provide. Any modifications or additions to the approved CBP plan requested by the independent third party shall be submitted to the commission for review prior to implementation.

(B) Within twenty-four hours after the completion of the bidding process, the independent third party shall submit a report to the commission summarizing the results of the CBP. The report shall include, but not be limited to, the following items:

(1) A description of the conduct of the bidding process, including a discussion of any aspects of the process that the independent third party believes may have adversely affected the outcome.

(2) The level(s) of oversubscription for each product.

(3) The number of bidders for each product.

(4) The percentage of each product that was bid upon by persons other than the electric utility.

(5) The independent third party's evaluation of the submitted bids, including the bidders' generation source and financial capabilities to perform.

(6) The independent third party's final recommendation of the least cost winning bidder(s).

(7) A listing of the retail rates that would result from the least cost winning bids, along with any descriptions, formulas, and/or tables necessary to demonstrate how the conversion from winning bid(s) to retail rates was accomplished under the conversion process approved by the commission in the electric utility's CBP plan.

(C) The electric utility shall provide access to staff and any consultant hired by the commission to assist in review of the CBP of any and all data, information, and communications pertaining to the bidding process, on a real time basis, regardless of the confidential nature of such data and information.

(D) The commission shall make the final selection of the least-cost winning bidder(s) of the CBP. The commission may rely upon the information provided in the independent third party's report in making its selection of the least-cost winning bidder(s) of the CBP.

4901:1-35-09 **Electric security plan fuel and purchased power adjustments.**

(A) Each electric utility for which the commission has approved an electric security plan (ESP) which includes automatic adjustments under division (B)(2)(a) of section 4928.143 of the Revised Code shall file for such adjustments in accordance with the provisions of this rule.

(B) The electric utility shall calculate a proposed quarterly adjustment based on projected costs and reconciliation requirements by filing an application four times per year. The staff shall review the quarterly filing for completeness and computational accuracy. If staff raises no issues prior to the date the quarterly adjustment is to become effective, the rates shall become effective on that date. Although rates are to be adjusted and provided on a quarterly basis, the cost information shall be summarized monthly.

(C) On an annual basis, the prudence of the costs incurred and recovered through quarterly adjustments shall be reviewed in a separate proceeding outside of the automatic recovery provision of the electric utility's ESP. The process and timeframes for that separate proceeding shall be set by order of the commission, the legal director, deputy legal director, or attorney examiner.

(D) The commission may order that consultants be hired, with the costs billed to the electric utility, to conduct prudence and/or financial reviews of the costs incurred and recovered through the quarterly adjustments.

4901:1-35-10 **Annual review of electric security plan.**

By May fifteenth of each year, the electric utility shall make a separate filing with the commission demonstrating whether or not any rate adjustments authorized by the commission as part of the electric utility's electric security plan resulted in significantly excessive earnings during the review period as measured by division (F) of section 4928.143 of the Revised Code. The process and timeframes for that proceeding shall be set by order of the commission, the legal director, or attorney examiner. The electric utility's filing shall include the information set forth in paragraph (C) of rule 4901:1-35-03 of the Administrative Code as it relates to excessive earnings.

4901:1-35-11 Competitive bidding process ongoing review and reporting requirements.

(A) The initial market rate offer (MRO), and subsequent offers, implemented by each 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 blended price for electric generation services for the first five years of the MRO, or some other period determined by the commission under section 4928.142 of the Revised Code.

(B) Once a competitive bidding process (CBP) plan subject to a price blending period is approved by the commission pursuant to section 4928.142 of the Revised Code, the electric utility shall file its proposed adjustments to the standard service offer (SSO) portion of the blended rates of its CBP in a filing to the commission on a quarterly basis (quarterly filing) for the duration of the price blending period of the CBP plan, on specific dates to be determined by the commission.

(1) The quarterly filing shall include a separate listing of each cost or cost component including costs for fuel, purchased power, alternative portfolio requirements, and environmental compliance, in comparison with the costs or cost components included in the most recent SSO and the previously existing level of each cost. Any offsetting benefits, as defined in division (D) of section 4928.142 of the Revised Code, obtained directly or as a result of expenditures in the specified cost areas shall be listed separately and be used to reduce the cost levels requested for recovery. Rates are to be adjusted on a quarterly basis. Such adjustments may include, or be made pursuant to, the application of incentive factors or formulas that the commission determined to be reasonable in its approval of the CBP plan. The cost information shall consist of monthly data submitted on a quarterly basis.

(2) The quarterly filing shall include any descriptions, formulas, and/or tables necessary to show how the adjusted cost levels are translated into blended CBP rates.

(3) The electric utility shall provide projections, in its quarterly filing, of any impacts that the proposed adjustments will have on its return on common equity.

(4) The staff shall review the quarterly filing for completeness, computational accuracy, and consistency with prior commission determinations regarding the adjustments. If the staff raises no issues prior to the date the quarterly adjustment is to become effective, the rates shall become effective on that date.

(5) On an annual basis, or other basis as determined by the commission, the prudence of the costs incurred and recovered through quarterly adjustments to the electric utility's SSO portion of the blended rates shall be reviewed. The commission shall determine the frequency of the review and shall establish a schedule for the review process. The commission may order that consultants be hired, with the cost to be billed to the company, to conduct prudence and/or financial reviews of the costs incurred and recovered through the quarterly adjustments. The cost to the electric utility of the

commission's use of such consultants may be included by the electric utility in its quarterly rate adjustment filing.

(C) If the CBP plan is approved by the commission subject to a price blending period, approximately one year after filing the CBP plan, and annually thereafter for the duration of the price blending period of the CBP plan, on dates to be determined by the commission, the electric utility shall file an annual report on its CBP.

(1) The annual report shall provide a general statement about the operation of the CBP to date. The annual status report shall also provide a summary of generation service obtained via the CBP during the period under review, and impacts of the cost of the CBP service and the resulting blended rates on the electric utility's customers.

(2) The annual report shall describe any defaults and/or other difficulties encountered in obtaining generation service from winning bidder(s) of the CBP, and describe in detail actions taken by the electric utility to remedy such situations.

(3) The annual report shall describe the condition and significant developments of the wholesale electric generation and transmission market during the year covered by the report, and any developments in those markets anticipated and/or known for the following year.

(4) The annual report shall describe the financial condition of the electric utility, its current and projected return on common equity, and the return on common equity of publicly traded companies that face comparable business and financial risk. The electric utility shall show that its earnings under the price blending period will not be significantly excessive as compared with similarly situated companies. Information submitted by the electric utility to demonstrate its projected earnings shall include, but not be limited to, balance sheet information, income statement information, and capital budget requirements for future investments in Ohio. This information should be provided separately for generation, transmission, and distribution for the electric utility and its affiliates. Additionally, the electric utility shall provide testimony and analysis demonstrating the return on equity earned by publicly traded companies that face comparable business and financial risks as the electric utility.

(5) If in an emergency situation the electric utility claims that its financial integrity is threatened by the operation of the CBP price blending period, it shall demonstrate its claim through information and data filed in its annual report. The electric utility has the burden of proof in any such claim of threatened financial integrity.

(6) The electric utility shall discuss, in its annual report, upcoming solicitations to be conducted pursuant to its approved CBP plan. Any deviations or modifications of the approved CBP plan being requested by the electric utility shall be described in detail, with specific rationale provided for every such deviation or modification requested.

(7) The annual report shall describe the blended phase-in rates projected to be charged to its customers under the continuation of the CBP plan, as modified pursuant to paragraph (C)(6) of this rule. The rate projections shall show the existing and projected generation service price(s) blended with the CBP determined rates and projected CBP determined rates, and any descriptions, formulas, and/or tables necessary to show how the blending is accomplished. The projected blended phase-in rates shall be compared in the annual report to the existing blended phase-in rates.

(8) The annual report shall describe the operation to date of any time-differentiated and dynamic rate designs implemented under the CBP, the approaches used to communicate price and usage information to consumers, and observed price elasticity.

(9) The annual report shall include a status report of the market conditions relevant to the continued operation of the electric utility's MRO, including but not limited to information about the existence of published source(s) of electric market pricing information, whether the electric utility or its affiliate still belongs to an regional transmission organization (RTO), and whether the RTO's market monitoring function has mitigation authority over the transactions resulting from the CBP.

(10) The commission, legal director, deputy legal director, or attorney examiner shall determine the level of review required for any information, plans, or requests set forth in the annual report, and set any necessary schedules through an entry.

(D) If the CBP plan is approved by the commission without the requirement of a price blending period, or after the expiration of any such required price blending period, on an annual basis, on dates to be determined by the commission, the electric utility shall file an annual report with the commission.

(1) The annual report shall provide a general statement about the operation of the CBP to date. The annual report shall also provide a summary of generation service obtained via the CBP during the period under review, and impacts of the cost of the CBP on the electric utility's customers' rates.

(2) The annual report shall describe any defaults or other difficulties encountered in obtaining generation service from winning bidder(s) of the CBP, and describe in detail actions taken by the electric utility to remedy such situations.

(3) The annual report shall describe the condition and significant developments of the wholesale electric generation and transmission market during the year covered by the report, and any developments in those markets anticipated or known for the following year.

(4) The electric utility shall discuss, in its annual report, upcoming solicitations to be conducted pursuant to its approved CBP plan. Any deviations or modifications of the approved CBP plan being requested by the electric utility shall be described in detail, with specific rationale provided for every such deviation or modification requested.

(5) The annual report shall describe the operation to date of any time-differentiated and dynamic rate designs implemented under the CBP, the approaches used to communicate price and usage information to consumers, and observed price elasticity.

(6) The commission, legal director, deputy legal director, or attorney examiner shall determine the level of review required for any information, plans, or requests set forth in the annual report, and set any necessary schedules through an entry.

Chapter 4901:1-36

Transmission Cost Recovery

4901:1-36-01 **Definitions.**

(A) "Application" means an application for a transmission cost recovery rider pursuant to this chapter.

(B) "Commission" means the public utilities commission of Ohio.

(C) "Electric utility" shall have the meaning set forth in division (A)(11) of section 4928.01 of the Revised Code.

(D) "Staff" means the staff of the commission or its authorized representative.

4901:1-36-02 **Purpose and scope.**

(A) This chapter authorizes an electric utility to recover, through a reconcilable rider on the electric utility's distribution rates, all transmission and transmission-related costs, including ancillary and congestion costs, imposed on or charged to the utility, net of financial transmission rights and other transmission-related revenues credited to the electric 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.

(B) The commission may waive any requirement of Chapter 4901:1-36 of the Administrative Code for good cause shown.

4901:1-36-03 **Application.**

(A) Each electric utility which seeks recovery of transmission and transmission-related costs shall file an application with the Commission for a transmission cost recovery rider. The initial application shall include all information set forth in the appendix to this rule.

(B) Each electric utility with an approved transmission cost recovery rider shall update the rider on an annual basis pursuant to a schedule set forth by commission order. Each application to update the transmission cost recovery rider shall include all information set forth in the appendix to this rule.

(C) The commission may order that consultants be hired, with the costs billed to the electric utility and recoverable through the rider, to conduct prudence and/or financial reviews of the costs incurred and recovered through the transmission cost recovery rider.

(D) Each annual application to update the transmission cost recovery rider should be made not less than seventy-five days prior to the proposed effective date of the updated rider.

(E) If at anytime during the period between annual update filings, the electric utility or staff determines that costs are or will be substantially different than the projected amounts included in their previous application, the electric utility should file, on its own initiative or by order of the commission, an interim application to adjust the transmission cost recovery rider in order to avoid excessive carrying costs and to minimize rate impacts for the following update filing.

(F) Affected parties may file detailed comments on any issues concerning any application filed under this rule within forty days of the date of the filing of the application.

Appendix to Rule 4901:1-36-03

Schedule I.D.	Schedule Name and Required Data
A-1	**Copy of proposed tariff schedules**
A-2	**Copy of redlined current tariff schedules**
B-1	**Summary of Total Projected Transmission Costs/Revenues** Provide the total forecasted cost/revenue for each cost component. Include all costs and related revenues, network integration transmission service, ancillary service, regional transmission organization related, and reconciliation adjustment. Indicate whether each component is energy or demand related
B-2	**Summary of Current verses Proposed Transmission Revenues** Provide table that includes billing determinants for each class applied to current transmission cost recovery rider rates and proposed transmission cost recovery rider rates, including current and proposed class revenues, and the dollar and percentage difference
B-3	**Summary of Current and Proposed Rates** For each rate class provide the current transmission cost recovery rider rate and proposed transmission cost recovery rider rate, the dollar difference and percentage change.
B-4	**Graphs** For each cost/revenue component provide a bar graph of quarterly actual transmission cost recovery rider costs beginning January 06. Also include the original projected cost for each quarter. Also include the next period projections on the graph.
B-5	**Typical Bill Comparisons** Provide a typical bill comparison for each rate schedule affected by the proposed adjustments to the transmission cost recovery rider.
C-1	**Projected Transmission Cost Recovery Rider Costs/Revenues** For each cost/revenue component include the monthly projected transmission cost recovery rider costs/revenues.
C-2	For each rate schedule provide the monthly projected cost.
C-3	Provide the projected transmission cost recovery rider rate calculations. Provide all necessary support for the rate calculations, including support for demand and energy allocators.
D-1	**Reconciliation Adjustment** Provide actual transmission cost recovery rider costs for each component used to calculate reconciliation adjustment.
D-2	Provide monthly revenues collected from each rate schedule.
D-3	Provide monthly over and under recovery.
D-3a…z	Include all additional and necessary schedules for support, including, but not limited to: *Carrying cost calculation. *Reconciliation of throughput to Company financial records. *Reconciliation of one month's bill from RTO to Financial Records of the company

4901:1-36-04 **Limitations.**

(A) The transmission cost recovery rider costs are reconcilable on an annual basis, with carrying charges to be applied to both over- and under-recovery of costs.

(B) The transmission cost recovery rider shall be avoidable by all customers who choose alternative generation suppliers and the electric utility no longer bears the responsibility of providing generation and transmission service to the customers.

(C) The transmission cost recovery rider shall include transmission and transmission-related costs and off-setting revenues, including ancillary and congestion-related costs and revenues, charged or credited 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 and such costs and revenues are not included in any other schedule or rider in the electric utility's tariff on file with the commission.

4901:1-36-05 **Hearings.**

Unless otherwise ordered by the commission, the legal director, the deputy legal director, or the attorney examiner, the commission shall approve the application or set the matter for hearing within seventy-five days after the filing of a complete application under this chapter. Proposed rates will become effective on the seventh-fifth day subject to reconciliation adjustments following any hearing, if necessary, or in its subsequent filing.

4901:1-36-06 **Additional information.**

On a biennial basis, the electric utility shall provide additional information detailing the electric utility's policies and procedures for minimizing any costs in the transmission cost recovery rider where the electric utility has control over such costs.

Chapter 4901:1-37

Corporate Separation

4901:1-37-01 **Definitions.**

(A) "Affiliates" are companies that are related to each other due to common ownership or control. The affiliate standards shall also apply to any internal merchant function of the electric utility whereby the electric utility provides a competitive service.

(B) "Commission" means the public utilities commission of Ohio.

(C) Competitive retail electric service provider means a provider of a competitive retail electric service as defined in division (A)(4) of section 4928.01 of the Revised Code.

(D) Electric services company shall have the meaning set forth in division (A)(9) of section 4928.01 of the Revised Code.

(E) Electric utility shall have the meaning set forth in division (A)(11) of section 4928.01 of the Revised Code.

(F) Employees are all full- or part-time employees of an electric utility or its affiliates, as well as consultants, independent contractors, or any other persons performing various duties or obligations on behalf of or for an electric utility or its affiliate.

(G) Fully allocated costs are the sum of direct costs plus an appropriate share of indirect costs. For purposes of these rules, the term fully allocated costs shall have the same meaning as the term fully loaded embedded costs as that term appears in division (A)(3) of section 4928.17 of the Revised Code.

(H) "Person" shall have the meaning set forth in division (A)(24) of section 4928.01 of the Revised Code.

(I) "Staff" means the staff of the commission or its authorized representative.

4901:1-37-02 **Purpose and scope.**

(A) The purpose of this chapter is to require all of the state's electric utilities to meet the same standards so a competitive advantage is not gained solely because of corporate affiliation.

(B) This chapter is intended to create competitive equality, prevent unfair competitive advantage, prohibit the abuse of market power and effectuate the policy of the state of Ohio embodied in section 4928.02 of the Revised Code.

(C) The commission may waive any requirement of Chapter 4901:1-37 of the Administrative Code for good cause shown.

(D) To ensure compliance with this chapter, examination of the books and records of affiliates may be necessary.

(E) Violations of this chapter shall be subject to section 4928.18 of the Revised Code. The electric utility has the burden of proof to demonstrate compliance with this chapter.

4901:1-37-03 **Applicability.**

(A) The provisions of this chapter shall be applicable in accordance with sections 4928.17 and 4928.18 of the Revised Code and apply to:

(1) The activities of the electric utility and its transactions or other arrangements with its affiliates.

(2) Any shared services of the electric utilities with any affiliates.

(3) The sale or transfer of generating assets.

(B) Nothing in this chapter is to be construed as prohibiting or otherwise impeding an electric utility's ability to conduct activities pursuant to rules 4901:1-38-03 to 4901:1-38-05 of the Administrative Code.

4901:1-37-04 **General provisions.**

(A) Structural safeguards.

(1) Each electric utility and its affiliates that provide services to customers within the electric utility's service territory shall function independently of each other.

(2) Each electric utility and its affiliates that provide services to customers within the electric utility's service territory shall not share facilities and services if such sharing in any way violates paragraph (D) of this rule.

(3) Cross-subsidies between an electric utility and its affiliates are prohibited. An electric utility's operating employees and those of its affiliates shall function independently of each other.

(4) An electric utility may not share employees and/or facilities with any affiliate, if the sharing, in any way, violates paragraph (D) of this rule.

(5) An electric utility shall ensure that all shared employees appropriately record and charge their time based on fully allocated costs.

(6) Transactions made in accordance with rules, regulations, or service agreements approved by the federal energy regulatory commission, securities and exchange commission, and the commission, which rules the electric utility shall maintain in its cost allocation manual (CAM) and file with the commission, shall provide a rebuttable presumption of compliance with the costing principles contained in this chapter.

(B) Separate accounting.

Each electric utility and its affiliates shall maintain, in accordance with generally accepted accounting principles and an applicable uniform system of accounts, books, records, and accounts that are separate from the books, records, and accounts of its affiliates.

(C) Financial arrangements.

Unless otherwise approved by the commission, the financial arrangements of an electric utility are subject to the following restrictions:

(1) Any indebtedness incurred by an affiliate shall be without recourse to the electric utility.

(2) An electric utility shall not enter into any agreement with terms under which the electric utility is obligated to commit funds to maintain the financial viability of an affiliate.

(3) An electric utility shall not make any investment in an affiliate under any circumstances in which the electric utility would be liable for the debts and/or liabilities of the affiliate incurred as a result of actions or omissions of an affiliate.

(4) An electric utility shall not issue any security for the purpose of financing the acquisition, ownership, or operation of an affiliate.

(5) An electric utility shall not assume any obligation or liability as a guarantor, endorser, surety, or otherwise with respect to any security of an affiliate.

(6) An electric utility shall not pledge, mortgage, or use as collateral any assets of the electric utility for the benefit of an affiliate.

(D) Code of Conduct.

(1) The electric utility shall not release any proprietary customer information (e.g., individual customer load profiles or billing histories) to an affiliate, or otherwise, without the prior authorization of the customer, except as required by a regulatory agency or court of law.

(2) On or after the effective date of this chapter, the electric utility shall make customer lists, which include name, address, and telephone number, available on a nondiscriminatory basis to all nonaffiliated and affiliated certified retail electric service providers transacting business in its service territory, unless otherwise directed by the customer. This provision does not apply to customer-specific information, obtained with proper authorization, necessary to fulfill the terms of a contract, or information relating to the provision of general and administrative support services.

(3) Employees of the electric utility's affiliates shall not have access to any information about the electric utility's transmission or distribution systems (e.g., system operations, capability, price, curtailments, and ancillary services) that is not contemporaneously available, readily accessible, and in the same form and manner available to nonaffiliated competitors providing retail electric service.

(4) An electric utility shall treat as confidential all information obtained from a competitive retail electric service provider, both affiliated and nonaffiliated, and shall not release such information, unless a competitive retail electric service provider provides authorization to do so or unless the information was or thereafter becomes available to the public other than as a result of disclosure by the electric utility.

(5) The electric utility shall not tie (or allow an affiliate to tie), as defined by state and federal antitrust laws, or otherwise condition the provision of the electric utility's regulated services, discounts, rebates, fee waivers, or any other waivers of the electric utility's ordinary terms and conditions of service, including but not limited to tariff provisions, to the taking of any goods and/or services from the electric utility's affiliates.

(6) The electric utility shall ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail

electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa.

(7) The electric utility, upon request from a customer, shall provide a complete list of all competitive retail electric service providers operating on the system, but shall not endorse any competitive retail electric service providers, indicate that an electric services company is an affiliate, or indicate that any competitive retail electric service provider will receive preference because of an affiliate relationship.

(8) The electric utility shall use reasonable efforts to ensure retail electric service consumers protection against unreasonable sales practices, market deficiencies, and market power and the electric utility's compliance officer shall promptly report any such unreasonable sales practices, market deficiencies, and market power to the director of the utilities department (or their designee).

(9) Employees of the electric utility or persons representing the electric utility shall not indicate a preference for an affiliated electric services company.

(10) The electric utility shall provide comparable access to products and services related to tariffed products and services and specifically comply with the following:

(a) An electric utility shall be prohibited from unduly discriminating in the offering of its products and/or services.

(b) The electric utility shall apply all tariff provisions in the same manner to the same or similarly situated entities, regardless of any affiliation or nonaffiliation.

(c) The electric utility shall not, through a tariff provision, a contract, or otherwise, give its affiliates or customers of affiliates preferential treatment or advantages over nonaffiliated competitors of retail electric service or their customers in matters relating to any product and/or service.

(d) The electric utility shall strictly follow all tariff provisions.

(e) Except to the extent allowed by any applicable law, regulation, or commission order, the electric utility shall not be permitted to provide discounts, rebates, or fee waivers for any retail electric service.

(11) Shared representatives or shared employees of the electric utility and affiliated electric services company shall clearly disclose upon whose behalf their public representations are being made when such representations concern the entity's provision of electric services.

(E) Emergency.

(1) Notwithstanding the foregoing, in a declared emergency situation, an electric utility may take actions necessary to ensure public safety and system reliability.

(2) The electric utility shall maintain a log of all such actions that do not comply with this chapter, and such log shall be subject to review by the commission and its staff.

4901:1-37-05 **Application.**

(A) Consistent with section 4928.17 of the Revised Code, an electric utility that provides in this state, either directly or through an affiliate, a noncompetitive retail electric service and a competitive retail electric service (or a noncompetitive retail electric service and a product or service other than retail electric service) shall file with the commission an application for approval of a proposed corporate separation plan. The application shall include a narrative describing how the plan ensures competitive equality, prevents unfair competitive advantage, prohibits the abuse of market power, and effectuates the policy of the state of Ohio embodied in section 4928.02 of the Revised Code.

(B) The proposed corporate separation plan shall be a stand alone document that, at a minimum, includes the following:

(1) Provisions that maintain structural safeguards.

(2) Provisions that maintain separate accounting.

(3) A list of all current affiliates identifying each affiliate's product(s) and/or service(s) that it provides.

(4) A list identifying and describing the financial arrangements between the electric utility and all affiliates.

(5) A code of conduct policy that complies with this chapter and that employees of the electric utility and affiliates must follow.

(6) A description of any joint advertising and/or joint marketing activities between the electric utility and an affiliate that the electric utility intends to utilize, including when and where the name and logo of the electric utility will be utilized, and explain how such activities will comply with this chapter.

(7) Provisions related to maintaining a cost allocation manual (CAM).

(8) A description and timeline of all planned education and training, throughout the holding company structure, to ensure that electric utility and affiliate employees know and can implement the policies and procedures of this rule. The information shall be maintained on the electric utilities' public web site.

(9) A copy of a policy statement to be signed by electric utility and affiliate employees who have access to any nonpublic electric utility information, which indicates that they are aware of, have read, and will follow all policies and procedures regarding limitation on the use of nonpublic electric utility information. The statement will include a provision stating that failure to observe these limitations will result in appropriate disciplinary action.

(10) A description of the internal compliance monitoring procedures and the methods for corrective action for compliance with this chapter.

(11) A designation of the electric utility's compliance officer who will be the contact for the commission and staff on corporate separation matters. The compliance officer shall certify that the approved corporation separation plan is up to date and in compliance with the commission's rules and orders. The electric utility shall notify the commission and the director of the utilities department (or their designee) of changes in the compliance officer.

(12) A detailed description outlining how the electric utility and its affiliates will comply with this chapter. The format shall identify the provision and then provide the description.

(13) A detailed listing of the electric utility's electric services and the electric utility's transmission and distribution affiliates' electric services.

(14) A complaint procedure to address issues concerning compliance with this chapter, which, at a minimum, shall include the following:

(a) All complaints, whether written or verbal, shall be referred to the compliance officer designated by the electric utility to handle corporate separation matters or the compliance officer's designee.

(b) The complaint shall be acknowledged within five working days of its receipt.

(c) A written statement of the complaint shall be prepared and include the name of the complainant, a detailed factual report of the complaint, all relevant dates, the entities involved, the employees involved, and the specific claim.

(d) The results of the preliminary investigation shall be provided to the complainant in writing within thirty days after the complaint was received, including a description of any course of action that was taken.

(e) The written statements of the complaints and resulting investigations required by paragraphs (B)(14)(c) and (B)(14)(d) of this rule shall be kept in the CAM, in accordance with rule 4901:1-37-08 of the Administrative Code for a period of not less than three years.

(f) This complaint procedure shall not in any way limit the rights of any person to file a formal complaint with the commission.

(C) Each electric utility shall file its approved corporate separation plan in its tariff docket.

4901:1-37-06 **Revisions and amendments.**

(A) All proposed revisions and/or amendments to the electric utility's approved corporate separation plan shall be filed with the commission, and a copy of the filing shall be provided simultaneously to the director of the utilities department (or their designee).

(B) Except for proposals related to the sale or transfer of assets filed pursuant to rule 4901:1-37-09 of this chapter, if a filing to revise and/or amend the electric utility's corporate separation plan is not acted upon by the commission within sixty days after it is filed, the modified corporate separation plan shall be deemed approved on the sixty-first day after filing.

(C) Each electric utility shall file any modified corporate separation plan in its tariff docket upon approval of such plan.

4901:1-37-07 **Access to books and records.**

(A) The electric utility shall maintain records sufficient to demonstrate compliance with this chapter, and shall produce, upon the request of staff, all books, accounts, and/or other pertinent records kept by an electric utility or its affiliates as they may relate to the businesses for which corporate separation is required under section 4928.17 of the Revised Code, including those required under section 4928.145 of the Revised Code.

(B) The staff may investigate such electric utility and/or affiliate operations and the interrelationship of those operations at the staff's discretion. In addition, the employees and officers of the electric utility and its affiliates shall be made available for informational interviews, at a mutually agreed time and place, as required by the staff to ensure proper separations are being followed.

(C) If such employees, officers, books, and records cannot be reasonably made available to the staff in the state of Ohio, then upon request of the staff, the appropriate electric utility or affiliate shall reimburse the commission for reasonable travel expenses incurred.

4901:1-37-08 Cost allocation manual (CAM).

(A) Each electric utility that receives products and/or services from an affiliate and/or that provides products and/or services to an affiliate shall maintain information in the CAM, documenting how costs are allocated between the electric utility and affiliates and the regulated and nonregulated operations.

(B) The CAM will be maintained by the electric utility.

(C) The CAM is intended to ensure the commission that no cross-subsidization is occurring between the electric utility and its affiliates.

(D) The CAM will include:

(1) An organization chart of the holding company, depicting all affiliates, as well as a description of activities in which the affiliates are involved.

(2) A description of all assets, services, and products provided to and from the electric utility and its affiliates.

(3) All documentation including written agreements, accounting bulletins, procedures, work order manuals, or related documents, which govern how costs are allocated between affiliates.

(4) A copy of the job description of each shared employee.

(5) A list of names and job summaries for shared consultants and shared independent contractors.

(6) A copy of all transferred employees' (from the electric utility to an affiliate or vice versa) previous and new job descriptions.

(7) A log detailing each instance in which the electric utility exercised discretion in the application of its tariff provisions.

(8) A log of all complaints brought to the electric utility regarding this chapter.

(9) A copy of the minutes of each board of directors meeting, where it shall be maintained for a minimum of three years.

(E) The method for charging costs and transferring assets shall be based on fully allocated costs.

(F) The costs should be traceable to the books of the applicable corporate entity.

(G) The electric utility and affiliates shall maintain all underlying affiliate transaction information for a minimum of three years.

(H) Following approval of a corporate separation plan, an electric utility shall provide the director of the utilities department (or their designee) with a summary of any changes in the CAM at least every twelve months.

(I) The compliance officer designated by the electric utility will act as the contact for the staff when staff seeks data regarding affiliate transactions, personnel transfers, and the sharing of employees.

(J) The staff may perform an audit of the CAM in order to ensure compliance with this rule.

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

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

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

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

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

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

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

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

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

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

Chapter 4901:1-38

Reasonable Arrangements

4901:1-38-01 **Definitions.**

(A) "Affidavit" means a written declaration made under oath before a notary public or other authorized officer.

(B) "Commission" means the public utilities commission of Ohio.

(C) "Delta revenue" means the deviation resulting from the difference in rate levels between the otherwise applicable rate schedule and the result of any reasonable arrangement approved by the commission.

(D) "Electric utility" shall have the meaning set forth in division (A)(11) of section 4928.01 of the Revised Code.

(E) "Energy efficiency production facilities" means any customer that manufactures or assembles products that promote the more efficient use of energy (i.e., increase the ratio of energy end use services (i.e., heat, light, and drive power) derived from a device or process to energy inputs necessary to derive such end use services as compared with other devices or processes that are commonly installed to derive the same energy use services); or, any customer that manufactures, assembles or distributes products that are used in the production of clean, renewable energy.

(F) "Mercantile customer" shall have the meaning set forth in division (A)(19) of section 4928.01 of the Revised Code.

(G) "Nonfirm electric service" means electric service provided pursuant to a schedule filed under section 4905.30 or 4928.141 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 the electric utility.

(H) "Staff" means the staff of the commission or its authorized representative.

4901:1-38-02 **Purpose and scope.**

(A) The purpose of this chapter is to facilitate the state's effectiveness in the global economy, to promote job growth and retention in the state, to ensure the availability of reasonably priced electric service, to promote energy efficiency and to provide a means of giving appropriate incentives to technologies that can adapt successfully to environmental mandates in furtherance of the policy of the state of Ohio embodied in section 4928.02 of the Revised Code.

(B) The commission may waive any requirement of Chapter 4901:1-38 of the Administrative Code for good cause shown.

4901:1-38-03 **Economic development arrangements.**

(A) An electric utility, mercantile customer, or group of mercantile customers of an electric utility may file an application for commission approval for an economic development arrangement between the electric utility and a new or expanding customer or group of customers.

(1) Each customer requesting to take service pursuant to an economic development arrangement with the electric utility shall describe the general status of the customer in the community and how such arrangement furthers the policy of the state of Ohio embodied in section 4928.02 of the Revised Code.

(2) Each customer requesting to take service pursuant to an economic development arrangement with the electric utility shall, at a minimum, meet the following criteria, submit to the electric utility and the commission verifiable information detailing how the criteria are met, and provide an affidavit from a company official as to the veracity of the information provided:

(a) Eligible projects shall be for non-retail purposes.

(b) At least twenty-five new, full-time or full-time equivalent jobs shall be created within three years of initial operations.

(c) The average hourly base wage rate of the new, full-time or full-time equivalent jobs shall be at least one hundred fifty per cent of the federal minimum wage.

(d) The customer shall demonstrate financial viability.

(e) The customer shall identify local (city, county), state, or federal support in the form of tax abatements or credits, jobs programs, or other incentives.

(f) The customer shall identify potential secondary and tertiary benefits resulting from its project including, but not limited to, local/state tax dollars and related employment or business opportunities resulting from the location of the facility.

(g) The customer shall agree to maintain operations at the project site for the term of the incentives.

(3) An electric utility and/or mercantile customer or group of mercantile customers filing an application for commission approval of an economic development arrangement bears the burden of proof as to the reasonableness of the arrangement requested and shall submit to the commission verifiable information detailing the rationale for the arrangement.

(B) An electric utility, mercantile customer, or group of mercantile customers of an electric utility may file an application for an economic development arrangement between the electric utility and its customer or group of customers for the retention of an existing customer(s) likely to cease, reduce, or relocate its operations out of state.

(1) Each customer requesting to take service pursuant to an economic development arrangement with the electric utility shall describe the general status of the customer in the community and how such arrangement furthers the policy of the state of Ohio embodied in section 4928.02 of the Revised Code.

(2) Each customer requesting to take service pursuant to an economic development arrangement with the electric utility shall, at a minimum, meet the following criteria, submit to the electric utility verifiable information detailing how the criteria are met, and provide an affidavit from a company official as to the veracity of the information provided:

(a) Eligible projects shall be for non-retail purposes.

(b) The number of full-time or full-time equivalent jobs to be retained shall be at least twenty-five.

(c) The average billing load (in kilowatts to be retained) shall be at least two hundred fifty kilowatts.

(d) The customer shall demonstrate that the cost of electricity is a major factor in its decision to cease, reduce, or relocate its operations to an out-of-state site. In-state relocations are not eligible. If the customer has the potential to relocate to an out-of-state site, the site(s) shall be identified, along with the expected costs of electricity at the site(s) and the expected costs of other significant expenses including, but not limited to, labor and taxes.

(e) The customer shall identify any other local, state, or federal assistance sought and/or received in order to maintain its current operations.

(f) The customer shall agree to maintain its current operations for the term of the incentives.

(3) An electric utility and/or mercantile customer or group of mercantile customers filing an application for commission approval of an economic development arrangement bears the burden of proof as to the reasonableness of the arrangement requested and shall submit to the commission verifiable information detailing the rationale for the arrangement.

(C) Upon the filing of an economic development application, the commission may fix a time and place for a hearing if the application appears to be unjust or unreasonable.

(1) The economic development arrangement shall be subject to change, alteration, or modification by the commission.

(2) The staff shall have access to all customer and electric utility information related to service provided pursuant to the economic development arrangements.

(D) Customer information provided to demonstrate eligibility under paragraphs (A) and (B) of this rule shall be treated by the electric utility as confidential.

4901:1-38-04 **Energy efficiency arrangements.**

(A) An electric utility, mercantile customer, or group of mercantile customers of an electric utility may file an application for commission approval for an energy efficiency arrangement between the electric utility and its customer or group of customers that have new or expanded energy efficiency production facilities.

(1) Each customer requesting to take service pursuant to an energy efficiency arrangement with the electric utility shall describe the general status of the customer in the community and how such arrangement furthers the policy of the state of Ohio embodied in section 4928.02 of the Revised Code.

(2) Each customer requesting to take service pursuant to an energy efficiency arrangement with the electric utility shall meet the following criteria, submit to the electric utility verifiable information detailing how the criteria are met, and provide an affidavit from a company official as to the veracity of the information provided:

(a) The customer shall be an energy efficiency production facility as defined in this chapter.

(b) At least ten new, full-time or full-time equivalent jobs shall be created within three years of initial operations.

(c) The average hourly base wage rate of the new, full-time, or full-time equivalent jobs shall be at least one hundred fifty per cent of federal minimum wage.

(d) The customer shall demonstrate financial viability.

(e) The customer shall identify local (city, county), state, or federal support in the form of tax abatements or credits, jobs programs, or other incentives.

(f) The customer shall agree to maintain operations at the project site for the term of the incentives.

(3) An electric utility and/or mercantile customer or group of mercantile customers filing an application for commission approval of an energy efficiency arrangement bears the burden of proof as to the reasonableness of the arrangement requested and shall submit to the commission verifiable information detailing the rationale for the arrangement.

(B) Upon the filing of an energy efficiency application, the commission may fix a time and place for a hearing if the application appears to be unjust or unreasonable.

(1) The energy efficiency arrangement shall be subject to change, alteration, or modification by the commission.

(2) The staff shall have access to all customer and electric utility information related to service provided pursuant to the energy efficiency arrangements.

(C) Customer information provided to demonstrate eligibility under paragraph (A) of this rule shall be treated by the electric utility as confidential.

4901:1-38-05 **Unique arrangements.**

(A) Notwithstanding rules 4901:1-38-03 and 4901:1-38-04 of the Administrative Code, an electric utility may file an application pursuant to section 4905.31 of the Revised Code for commission approval of a unique arrangement with one or more of its customers, consumers, or employees.

(1) An electric utility filing an application for commission approval of a unique arrangement with one or more of its customers, consumers, or employees bears the burden of proof as to the reasonableness of the arrangement and shall submit to the commission verifiable information detailing the rationale for the arrangement.

(2) Upon the filing of an application for a unique arrangement, the commission may fix a time and place for a hearing if the application appears to be unjust or unreasonable.

(3) The unique arrangement shall be subject to change, alteration, or modification by the commission.

(B) A mercantile customer, or a group of mercantile customers, of an electric utility may apply to the commission for a unique arrangement with the electric utility.

(1) Each customer applying for a unique arrangement bears the burden of proof as to the reasonableness of the arrangement and shall submit to the commission and the electric utility verifiable information detailing the rationale for the arrangement.

(2) The customer shall provide an affidavit from a company official as to the veracity of the information provided.

(3) Upon the filing of an application for a unique arrangement, the commission may fix a time and place for a hearing if the application appears to be unjust or unreasonable.

(4) The unique arrangement shall be subject to change, alteration, or modification by the commission.

(C) Each applicant applying for approval of a unique arrangement between an electric utility and one or more of its customers, consumers, or employees shall describe how such arrangement furthers the policy of the state of Ohio embodied in section 4928.02 of the Revised Code.

(D) Unique arrangements shall reflect terms and conditions for circumstances for which the electric utility's tariffs have not already provided.

4901:1-38-06 **Reporting requirements.**

(A) Each customer served under any reasonable arrangement established pursuant to this chapter shall submit an annual report to the electric utility and staff no later than April thirtieth of each year. The format of that report shall be determined by staff such that a determination of the compliance with the eligibility criteria can be determined, the value of any incentives received by the customer(s) is identified, and the potential impact on other customers can be calculated.

(B) The burden of proof to demonstrate ongoing compliance with the reasonable arrangement lies with the customer(s). The electric utility shall summarize the reports provided by customers under paragraph (A) of this rule and submit such summary to staff for review and audit no later than June fifteenth of each year.

4901:1-38-07 **Level of incentives.**

(A) The level of the incentives associated with any reasonable arrangement established pursuant to this chapter shall be determined as part of the commission's review and approval of the applications filed pursuant to this chapter. Incentives shall only be applicable to the service(s) taken from the electric utility by the customer receiving the incentives.

(B) Incentives may be based on, but not limited to:

(1) Demand discounts.

(2) Percentages of total bills, or portions of bills.

(3) Direct contributions.

(4) Reflections of cost savings to the electric utility.

(5) Shared savings.

(6) Some combination of the required criteria.

(C) Upon commission approval of an application, the reasonable arrangement, as approved, shall be:

(1) Posted on the commission's docketing information system.

(2) Accessible through the commission's web site.

(3) Under the supervision and regulation of the commission, and subject to change, alteration, or modification by the commission.

4901:1-38-08 **Revenue recovery.**

(A) Each electric utility that is serving customers pursuant to approved reasonable arrangements, may apply for a rider for the recovery of certain costs associated with its delta revenue for serving those customers pursuant to reasonable arrangements in accordance with the following:

(1) The approval of the request for revenue recovery, including the level of such recovery, shall be at the commission's discretion.

(2) The electric utility may request recovery of direct incremental administrative costs related to the programs as part of the rider. Such request shall be subject to audit, review, and approval by the commission.

(3) For reasonable arrangements in which incentives are given based upon cost savings to the electric utility (including, but not limited to, nonfirm arrangements, on/off peak pricing, seasonal rates, time-of-day rates, real-time-pricing rates), the cost savings shall be an offset to the recovery of the delta revenues.

(4) The amount of the revenue recovery rider shall be spread to all customers in proportion to the current revenue distribution between and among classes, subject to change, alteration, or modification by the commission. The electric utility shall file the projected impact of the proposed rider on all customers, by customer class.

(5) The rider shall be updated and reconciled, by application to the commission, semiannually. All data submitted in support of the rider update shall be subject to commission review and audit.

(B) If it appears to the commission that the proposals in the application may be unjust and unreasonable, the commission shall set the matter for hearing.

(1) At such hearing, the burden of proof to show that the revenue recovery rider proposal in the application is just and reasonable shall be upon the electric utility.

(2) The revenue recovery rider shall be subject to change, alteration, or modification by the commission.

(3) The staff shall have access to all customer and electric utility information related to service provided pursuant to the reasonable arrangements that created the delta revenue triggering the electric utility's application to recover the costs associated with said delta revenue.

4901:1-38-09 **Failure to comply.**

(A) If the customer being provided with service pursuant to a reasonable arrangement established pursuant to this chapter fails to substantially comply with any of the criteria for eligibility, the electric utility, after reasonable notice to the customer, shall terminate the arrangement unless otherwise ordered by the commission.

(B) The commission may also direct the electric utility to charge the customer for all or part of the incentives previously provided by the electric utility.

(C) If the customer is required to pay for all or part of the incentives previously provided, the recovered amounts shall be reflected in the calculation of the revenue recovery rider established pursuant to rule 4901:1-38-08 of the Administrative Code.

71

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code in the Form of an Electric Security Plan.	)	Case No. 08-935-EL-SSO

OPINION AND ORDER

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

APPEARANCES:

James W. Burk, Arthur E. Korkosz, Mark A. Hayden, Ebony L. Miller, FirstEnergy Service Company, 76 South Main Street, Akron, Ohio 44308, Jones Day, by David A. Kutik, North Point, 901 Lakeside Avenue, Cleveland, Ohio 44114-1190, and Calfee, Halter & Griswold, LLP, by James F. Lang and Laura C. McBride, 1400 KeyBank Center, 800 Superior Avenue, Cleveland, Ohio 44114, on behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company.

Sheryl Creed Maxfield, First Assistant Attorney General of the State of Ohio, by Duane W. Luckey, Section Chief, and William L. Wright, Thomas W. McNamee, and John H. Jones, Assistant Attorneys General, 180 East Broad Street, Columbus, Ohio 43215, on behalf of the Staff of the Public Utilities Commission of Ohio.

Janine L. Migden-Ostrander, Ohio Consumers' Counsel, by Jeffrey L. Small, Jacqueline Lake Roberts, Richard C. Reese, and Gregory J. Poulos, Assistant Consumers' Counsel, 10 West Broad Street, Columbus, Ohio 43215-3485, on behalf of the residential utility consumers of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company.

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

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

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

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

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

Bell & Royer Co., LPA, by Barth E. Royer, 33 South Grant Avenue, Columbus, Ohio 43215-3927, and Gary A. Jefferies, Dominion Resources Services, Inc., 501 Martindale Street, Suite 400, Pittsburgh, Pennsylvania 15212-5817, on behalf of Dominion Retail, Inc.

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

Robert J. Triozzi, Director of Law, and Steven Beeler, Assistant Director of Law, City of Cleveland, and Schottenstein, Zox & Dunn Co., LPA, by Gregory H. Dunn, Christopher L. Miller, and Andre T. Porter, 250 West Street, Columbus, Ohio 43215, on behalf of the city of Cleveland.

Brickfield, Burchette, Ritts & Stone, P.C., by Damon E. Xenopoulos, 1025 Thomas Jefferson Street, N.W., 8th Floor, West Tower, Washington, D.C. 20007, on behalf of OmniSource Corporation.

Bell & Royer Co., LPA, by Barth E. Royer, 33 South Grant Avenue, Columbus, Ohio 43215-3927, and Nolan Moser and Trent A. Dougherty, Ohio Environmental Council, 1207 Grandview Avenue, Suite 201, Columbus, Ohio 43212-3449, on behalf of Ohio Environmental Council.

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

The Legal Aid Society of Cleveland, by Joseph P. Meissner, 1223 West 6th Street, Cleveland, Ohio 44113, on behalf of The Neighborhood Environmental Coalition, The Empowerment Center of Greater Cleveland, United Clevelanders Against Poverty, Cleveland Housing Network, and The Consumers for Fair Utility Rates.

Leslie A. Kovacik, city of Toledo, 420 Madison Avenue, Suite 100, Toledo Ohio 43604-1219; Lance M. Keiffer, Lucas County, 711 Adams Street, 2nd Floor, Toledo, Ohio 43624-1680; Marsh & McAdams, by Sheilah H. McAdams, city of Maumee, 204 West Wayne Street, Maumee, Ohio 43537; Ballenger & Moore, by Brian J. Ballenger, city of Northwood, 3401 Woodville Road, Suite C, Toledo, Ohio 43619; Paul S. Goldberg and Phillip D. Wurster, city of Oregon, 5330 Seaman Road, Oregon, Ohio 43616; James E. Moan, city of Sylvania, 4930 Holland-Sylvania Road, Sylvania, Ohio 43560; Leatherman, Witzler, by Paul Skaff, city of Holland, 353 Elm Street, Perrysburg, Ohio 43551; and Thomas R. Hayes, Lake Township, 3315 Centennial Road, Suite A-2, Sylvania, Ohio 43560, on behalf of Northwest Ohio Aggregation Group.

Henry W. Eckhart, 50 West Broad Street, Suite 2117, Columbus, Ohio 43215, on behalf of the Natural Resources Defense Council.

Craig G. Goodman, 3333 K. Street, N.W., Suite 110, Washington, D.C. 20007, on behalf of National Energy Marketers Association.

Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff and Stephen M. Howard, 52 East Gay Street, Columbus, Ohio 43216-1008, and Bobby Singh, 300 West Wilson Bridge Road, Suite 350, Worthington, Ohio 43085, on behalf of Integrys Energy Services, Inc.

Sean W. Vollman and David A Muntean, 161 South High Street, Suite 202, Akron, Ohio 44308, on behalf of the city of Akron.

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

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

Bailey Cavalieri, LLC, by Dane Stinson, 10 West Broad Street, Suite 2100, Columbus, Ohio 43215-3422, and F. Mitchell Dutton, FPL Energy Power Marketing, Inc., 700 Universe Boulevard, Juno Beach, Florida 33408, on behalf of FPL Energy Power Marketing, Inc., and Gexa Energy Holdings, LLC.

Henry W. Eckhart, 50 West Broad Street, Suite 2117, Columbus, Ohio 43215, on behalf of the Sierra Club, Ohio Chapter.

Bricker & Eckler, LLP, by Glenn S. Krassen, 1375 East Ninth Street, Suite 1500, Cleveland, Ohio 44114, and E. Brett Breitschwerdt, 100 South Third Street, Columbus, Ohio 43215, on behalf of Northeast Ohio Public Energy Council.

Larry Gearhardt, 280 North High Street, P.O. Box 182383, Columbus, Ohio 43218-2383, on behalf of Ohio Farm Bureau Federation.

Bricker & Eckler, LLP, by Sally W. Bloomfield and Terrence O'Donnell, 100 South Third Street, Columbus, Ohio 43215, on behalf of American Wind Energy Association, Wind on the Wires, and Ohio Advanced Energy.

Theodore S. Robinson, 2121 Murray Avenue, Pittsburgh, Pennsylvania 15217, on behalf of Citizens Power, Inc.

McDermott, Will & Emery, LLP, by Douglas M. Mancino, 2049 Century Park East, Suite 3800, Los Angeles, California, 90067-3218, and Grace C. Wung, 600 Thirteenth Street, N.W., Washington, D.C. 20005, on behalf of Wal-Mart Stores East, LP, and Sam's East, Inc., LP, Macy's, Inc., and BJ's Wholesale Club, Inc.

Craig I. Smith, 2824 Coventry Road, Cleveland, Ohio 44120, on behalf of Material Sciences Corporation.

Bricker & Eckler, LLP, by Glenn S. Krassen, 1375 East Ninth Street, Suite 1500, Cleveland, Ohio 44114, and E. Brett Breitschwerdt, 100 South Third Street, Columbus, Ohio 43215, on behalf of Ohio Schools Council.

McDermott, Will & Emery, LLP, by Douglas M. Mancino, 2049 Century Park East, Suite 3800, Los Angeles, California 90067-3218, and Gregory K. Lawrence, 28 State Street, Boston, Massachusetts 02109, on behalf of Morgan Stanley Capital Group, Inc.

Tucker, Ellis & West, LLP, by Nicholas C. York and Eric D. Weldele, 1225 Huntington Center, 41 South High Street, Columbus, Ohio 43215-6197, and Steve Millard, 100 Public Square, Suite 201, Cleveland, Ohio 44113, on behalf of Council of Smaller Enterprises.

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

OPINION:

I. HISTORY OF PROCEEDINGS

On July 31, 2008, Ohio Edison Company (OE), The Cleveland Electric Illuminating Company (CEI), and The Toledo Edison Company (TE) (FirstEnergy or the Companies) filed an application for a standard service offer (SSO) pursuant to Section 4928.141, Revised Code. This application is for an electric security plan (ESP) in accordance with Section 4928.143, Revised Code. Contemporaneously, in Case No. 08-936-EL-SSO, FirstEnergy filed a separate application for a market rate offer (MRO) in accordance with Section 4928.142, Revised Code.

On August 18, 2008, a technical conference was held regarding FirstEnergy's applications. Subsequently, by entry dated September 5, 2008, the attorney examiner set this matter for hearing on October 16, 2008. By entry issued September 9, 2008, the Commission scheduled nine local public hearings in this matter.

On August 29, 2008, the Ohio Consumers' Counsel (OCC) filed a motion for bifurcated hearings in Case No. 08-936-EL-SSO, and a motion to consolidate Case No. 08-936-EL-SSO with Case No. 08-935-EL-SSO. On September 8, 2008, FirstEnergy filed a memorandum contra OCC's motions. The city of Cleveland (Cleveland) filed a motion for bifurcated hearings and a memorandum in support of OCC's motion on September 9, 2008. OCC filed a reply to FirstEnergy's memorandum contra on September 11, 2008. The motions to bifurcate the hearings and OCC's motion to consolidate the cases were denied by the attorney examiner on September 12, 2008.

The following parties were granted intervention by entries dated September 15, 2008, and December 16, 2008: Ohio Energy Group (OEG); OCC; Kroger Company (Kroger); Ohio Environmental Council (OEC); Industrial Energy Users-Ohio (IEU-Ohio); Ohio Partners for Affordable Energy (OPAE); Nucor Steel Marion, Inc. (Nucor); Northwest Ohio Aggregation Coalition (NOAC); Constellation NewEnergy and Constellation Energy Commodities Group, Inc. (Constellation); Dominion Retail, Inc. (Dominion); Ohio Hospital Association (OHA); Neighborhood Environmental Coalition, The Empowerment Center of Greater Cleveland, United Clevelanders Against Poverty, Cleveland Housing Network, and The Consumers for Fair Utility Rates (Citizens' Coalition); Natural Resources Defense Council (NRDC); Sierra Club; National Energy Marketers Association (NEMA); Integrys Energy Service, Inc. (Integrys); Direct Energy Services, LLC (Direct Energy); city of Akron; Ohio Manufacturers' Association (OMA); FPL Energy Power Marketing, Inc and Gexa Energy Holdings, LLC (FPL); Cleveland; Northeast Ohio Public Energy Council (NOPEC); Ohio Farm Bureau Federation (OFBF); American Wind Association, Wind on Wires, and Ohio Advance Energy; Citizens Power, Inc. (Citizens); Omnisource Corporation (OmniSource); Material Sciences Corporation (Material Sciences); Ohio Schools Council (OSC); Council of Smaller Enterprises (COSE); Morgan Stanley Capital Group; Wal-Mart Stores East, LP and Sam's East, Inc., Macy's, Inc., and BJ's Wholesale Club, Inc. (Commercial Group); and Ohio Association of School Business Officials, Ohio School Boards Association, and Buckeye Association of School Administrators (OASBO/OSBA/BASA).

The hearing in this proceeding commenced on October 16, 2008, and concluded on October 31, 2008. Eight witnesses testified on behalf of FirstEnergy, 21 witnesses testified on behalf of various intervenors, and nine witnesses testified on behalf of the Staff. At the local public hearings held in this matter 106 witnesses testified. Briefs and reply briefs were filed on November 21, 2008, and December 12, 2008, respectively.

II. DISCUSSION

A. Applicable Law

Chapter 4928 of the Revised Code provides an integrated system of regulation in which specific provisions were designed to advance state policies of ensuring access to adequate, reliable, and reasonably priced electric service in the context of significant economic and environmental challenges. In reviewing FirstEnergy's application, the Commission is cognizant of the challenges facing Ohioans and the electric power industry and will be guided by the policies of the state as established by the General Assembly in Section 4928.02, Revised Code, as amended by SB 221.

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

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

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

(3) Ensure diversity of electric supplies and suppliers.

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

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

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

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

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

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

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

In addition, SB 221 amended Section 4928.14, Revised Code, which now provides that on January 1, 2009, electric utilities must provide consumers with an SSO, consisting of either an MRO or an ESP. The SSO is to serve as the electric utility's default SSO. The law provides that electric utilities may apply simultaneously for both an MRO and an ESP; however, at a minimum, the first SSO application must include an application for an ESP. Section 4928.141, Revised Code, specifically provides that an SSO shall exclude any previously authorized allowances for transition costs, with such exclusion being effective on and after the date that the allowance is scheduled to end under the electric utility's rate plan. In the event an SSO is not authorized by January 1, 2009, Section 4928.141, Revised Code, provides that the current rate plan of an electric utility shall continue until an SSO is authorized under either Section 4928.142 or 4928.143, Revised Code.

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

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

As stated previously, contemporaneous with the filing of this ESP, FirstEnergy filed an application for an MRO. The statute provides that the Commission is required to approve, or modify and approve the ESP, if the ESP, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code. In addition, the Commission must reject an ESP that contains a surcharge for CWIP or for new generation facilities if the benefits derived for any purpose for which the surcharge is established are not reserved or made available to those that bear the surcharge.

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

By finding and order issued September 17, 2008, in Case No. 08-777-EL-ORD (*SSO Rules Case*), the Commission adopted new rules concerning SSO, corporate separation, and reasonable arrangements for electric utilities pursuant to Sections 4928.06, 4928.14, 4928.17, and 4905.31, Revised Code.

B. Summary of the Local Public Hearings

Nine local public hearings were held in order to allow FirstEnergy's customers the opportunity to express their opinions regarding the issues in this proceedings. The hearings were held in the following cities: September 24, 2008, at 6:30 p.m., Springfield; September 25, 2008, at 12:00 p.m., Cleveland; September 25, 2008, at 6:30 p.m., Cleveland Heights; October 1, 2008, at 6:30 p.m., Sandusky; October 2, 2008, at 12:30 p.m., Toledo; October 2, 2008, at 6:30 p.m., Maumee; October 7, 2008, at 6:30 p.m., Akron; October 14, 2008, at 6:30 p.m., Austintown; and October 15, 2008, at 6:30 p.m., Geneva. At those hearings, public testimony was heard from eight customers in Springfield, 15 customers in Cleveland, five customers in Cleveland Heights, six customers in Sandusky, 20 customers in Toledo, 23 customers in Maumee, nine customers in Akron, 15 customers in Austintown, and five customers in Geneva. In addition to the public testimony, several dozen letters were filed in the case docket by customers stating concern about the application.

The principal concern expressed by customers, both at the public hearings and in letters, was over the increases in customer rates that would result from approval of the application. Witnesses stated that any increase in rates would negatively impact low-income customers, the elderly, and those on fixed incomes. Customers cited the recent downturn in the economy as the primary source of their apprehension. It was noted by many at the hearings that customers are also facing increases in other utility charges, gasoline, food, and medical expenses and that the proposed increase would cause undue hardship. In addition, numerous school officials testified at the local hearings expressing their concerns over FirstEnergy's elimination of the Energy for Education II program effective January 1, 2009.

C. State Policy - Section 4928.02, Revised Code

FirstEnergy maintains that the proposed ESP is consistent with the policy of the state as delineated in Section 4928.02(A) through (N), Revised Code. According to the Companies, the ESP promotes the availability of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service. In addition, the Companies believe that the ESP advances DSM, time-differentiated pricing, advanced metering infrastructure, energy efficiency programs, and the development of performance standards and targets for service quality. Furthermore, FirstEnergy states that the ESP promotes the state's economy and improves the environment. The Companies note that the General Assembly determined that an ESP supports the policies set forth in Section 4928.02, Revised Code, if it is more favorable in the aggregate when compared to the expected results of an MRO (Co. Ex. 1 at 4-5, 7).

OPAE submits that the proposed ESP fails to take into consideration and protect at-risk populations, as required by statute. According to OPAE, the rates proposed in the ESP do not consider the impact of rate increases on low-income households or those struggling to pay their bills (OPAE Br. at 8).

Dominion notes that Section 4928.02, Revised Code, provides that it is the policy of the state to encourage and promote the development of effective retail electric competition. However, Dominion maintains that this policy cannot be effectuated if the SSO price against which the competitive suppliers must compete is based on something other than the cost for the electric utility to provide SSO generation service. While Dominion understands the concern for near-term rate stability, it opines that customers are not well served if costs are deferred for future recovery. Further, Dominion believes that the proposed riders in the ESP, which can produce automatic increases in bills, dispels any illusion that the ESP, as proposed, offers any rate certainty for customers (Dom. Br. at 4-5). OEG contends that the rate increases under the ESP do not consider the state policy to facilitate Ohio's competitiveness in the global economy (OEG Ex. 1 at 16).

FPL states that, although the statute ultimately requires that an ESP be approved if it is more favorable in the aggregate than an MRO, the statute does not permit the approval of an ESP, even one that is more favorable than an MRO, if any component part of the ESP is unreasonable or unlawful. Furthermore, FPL, NOAC, and NOPEC note that the pro-competitive policies enumerated in Sections 4928.143(B) and 4928.20(I) through (K), Revised Code, require that an ESP encourage and promote large-scale governmental aggregation (FPL Br. at 7-8; NOAC/NOPEC Br. at 5). In addition, FPL points out that Section 4928.20(K), Revised Code, requires that the Commission consider the effect on large-scale governmental aggregation of any unavoidable generation charges. FPL maintains that provisions of the ESP that runs afoul of these policies are unreasonable and unlawful, and must be modified or the ESP must not be approved (FPL Br. at 5, 11).

FirstEnergy submits that, contrary to the views of the intervenors, Section 4928.02, Revised Code, does not impose requirements on an ESP and the ESP should not be modified or rejected because it does not satisfy the policies of the state. According to FirstEnergy, the "more favorable in the aggregate" test set forth in Section 4928.143, Revised Code, does not include a reference to the state policies set forth in Section 4928.02, Revised Code, and the Commission has no authority to expand the criteria in Section 4928.142, Revised Code (Co. Reply Br. at 16).

The Commission believes that the state policy codified by the General Assembly in Chapter 4928, Revised Code, sets forth important objectives which the Commission must keep in mind when considering all cases filed pursuant to that chapter of the code. Therefore, in determining whether the ESP meets the requirements of Section 4928.143, Revised Code, the Commission takes into consideration the policy provisions of Section 4928.02, Revised Code, and we use these policies as a guide in our implementation of Section 4928.143, Revised Code. The Commission has reviewed the ESP proposal presented by FirstEnergy, as well as the issues raised by the various intervenors, and we believe that, with the modifications set forth herein, we have appropriately reached a conclusion advancing the public's interest.

D. Application Overview and Term of the Plan

In their application, the Companies are requesting authority to establish an SSO in the form of an ESP pursuant to the provisions of Sections 4928.141 and 4928.143, Revised Code. The proposed ESP is to be effective for a three-year period commencing January 1, 2009, unless the Commission determines, after hearing, that the ESP should be terminated effective January 1, 2011. According to the ESP, if the Commission does not issue a decision terminating the ESP by December 31, 2009, then the ESP could continue through December 31, 2011. If the Commission terminates the ESP effective January 1, 2011, the Companies propose that certain obligations provided for in the ESP would likewise terminate, including the Economic Development Rider (Rider EDR) (Co. Ex. 9a at 1, 32-33; Co. Ex. 5 at 3).

According to the Companies, notwithstanding various adjustments included in the ESP, the overall increases in total customer rates, including generation, transmission, and distribution, would be an average of 5.32 percent in 2009, 4.01 percent in 2010, and 5.9 percent in 2011 (Co. Ex. 9a at 5; Co. Ex. 1 at 12). FirstEnergy notes that the first year increase is attributable to an increase in distribution rates, not generation rates (Co. Br. at 2).

The Companies submit that, upon termination of the generation prices under the ESP, the generation prices will be determined pursuant to a competitive bid process in accordance with an approved MRO process. Likewise, the Companies state that they may also implement any approved MRO and conduct a competitive bid if the Commission rejects this application for an ESP (Co. Ex. 9a at 34).

With regard to the term of the ESP, IEU-Ohio believes that three years is too short. According to IEU-Ohio, having rate stability only for three years will make it difficult to satisfy the state's policy objectives and for industrial and other customers to make the business case to invest in and maintain their Ohio operations. Further, IEU-Ohio maintains that a longer term plan will provide more tools to help mitigate the significant immediate increases driven by fuel costs (IEU-Ohio Br. at 14).

The Commission believes that FirstEnergy's proposal allowing the Commission to terminate the plan, if the Commission finds it necessary, effective January 1, 2011, is appropriate, in light of the concern about the current state of the economy and the numerous uncertainties facing both the Companies and the consumers in the future. The Commission believes that it is essential that the plan we approve be one that initially requires revenue neutrality for the Companies, provides future revenue certainty for the Companies, and affords rate predictability for the customers. Accordingly, we find that the ESP should be in place for three years, with the option for the Commission to terminate the plan effective January 1, 2011.

E. Base Generation Rates (Rider GEN) and Generation Phase-in Credit (Rider GPI)

In the ESP, the Companies propose a three-year SSO fixed base generation rate (Rider GEN) for customers who choose to receive generation service from the Companies (Co. Ex. 9a at 5; Co. Ex. 5 at 4). However, the Companies propose to phase-in each year's price by means of the Generation Phase-in Credits Rider (Rider GPI), with recovery of the amounts for the phase-in credits over a period not to exceed ten years through the Deferred Generation Rider (Rider DGC) (Co. Ex. 9a at 10, Att. A at 2; Co. Ex. 5 at 8). According to the Companies, this phase-in approach yields a reduction in generation pricing greater than ten percent during the ESP period; thus, mitigating the impact on customers as pricing is transitioned to more closely reflect market pricing. Pursuant to the ESP, the Companies' proposal is as follows:

	Proposed Average Base Generation Price per kWh (Rider GEN)	Proposed Phase-in Price per kWh (Rider GPI)
2009	$0.075	$0.0675
2010	$0.080	$0.0715
2011	$0.085	$0.0755

The Companies further explain that the generation charges and phase-in credits will be seasonally and voltage adjusted for all three years in the retail tariffs (Co. Ex. 9a at 10; Co. Ex. 5 at 7-9).

According to the Companies, on average, their proposal would represent an increase in the customer's total bill of 0.06 percent in 2009, 4.01 percent in 2010, and 5.79 percent in 2011 (Co. Ex. 9a at 5). Kroger recommends that the ESP be modified to ensure that the overall increase attributable to increased generation charges be as close to these levels cited by the Companies as possible (Kroger Ex. 1 at 8).

OCC states, and Material Sciences agrees, that the generation rates proposed by the Companies in the ESP are excessive and, if a more appropriate rate is developed, then Rider GPI would not be necessary (OCC Ex. 3 at 36; Mat. Sci. Br. at 13). OHA states that the proposed generation rates are arbitrary and unreasonable (OHA Br. at 9). The Competitive Suppliers[1] aver that FirstEnergy is not really discounting the cost of generation through Rider GPI, only delaying the collection with carrying costs, which has the effect of increasing the total cost of generation which customers have to pay (Comp. Supp. Br. at 17). IEU-Ohio states that, while Section 4828.144, Revised Code, permits the phase-in of rates, it limits the resulting surcharges that amortize the cost of the phase-in such that they must apply during the term of the ESP. However, IEU-Ohio points out that the deferral aspects of the ESP have an impact beyond the three-year term of the ESP (IEU-Ohio Br. at 13).

FPL, which has executed a letter of intent to provide electric supply to NOPEC during the term of the ESP (FPL Br. at 1), argues that the ESP contains numerous anticompetitive provisions that would prevent competitive suppliers from entering the market and FPL from serving NOPEC's customers. For example, FPL states that the net pricing disadvantage to competitive suppliers if Rider GPI and the Minimum Default Service Rider (Rider MDS) are approved is 26 percent (FPL Ex. 1 at 10-11, 15; FPL Br. at 3). According to FPL, because of the onerous effect of Riders GPI and MDS, the NOPEC letter of intent contains two conditions precedent to FPL's execution of the agreement, namely, the approved ESP must extend the full amount of any Rider GPI to large-scale governmental aggregations and Rider MDS must be made avoidable for large-scale governmental aggregations (FPL Br. at 4).

FPL advocates that Rider GPI, as proposed in the ESP, violates the legislative mandate to encourage and promote large-scale governmental aggregation and, therefore, it must be modified (FPL Br. at 5). NOAC and NOPEC argue that Rider GPI and the deferral it accomplishes create a barrier to competition and a subsidy from one group of consumers to another. NOAC and NOPEC point out that Rider GPI applies only to

1 Constellation and Integrys submitted joint exhibits and filed a joint initial brief; therefore, when referring to the arguments in these documents, these parties will be referred to as the Competitive Suppliers.

consumers who accept Rider GEN from the Companies. In order to provide savings to a consumer, a large-scale governmental aggregator would need to be able to purchase generation at a price lower than Rider GEN less the ten percent Rider GPI credit; thus, Rider GPI is a significant barrier to competition. NOAC and NOPEC recommend that the ESP be modified to provide a governmental aggregation generation credit that would be made available to customers served by a large-scale governmental aggregation that is equivalent to Rider GPI. Further, they offer that the generation costs deferred through both Rider GPI and the governmental aggregation credit should be included in Rider DGC beginning in 2011 (NOAC/NOPEC Jt. Ex. 1 at 6, 8-9). FPL supports this proposal by NOAC and NOPEC (FPL Ex. 1 at 10-11, 15). The Competitive Suppliers agree that the playing field can be leveled if FirstEnergy gives each shopping customer a credit equal to the generation deferral (Comp. Supp. Ex. 1 at 14). The Consumer Advocates believe that alternative treatment for generation deferrals, which would deal with the anticompetitive effects of the proposed deferrals, should remain a secondary consideration and that the primary goal should be the elimination of the deferrals (Con. Adv. Br.[2] at 20).

In response to the criticisms of the phase-in and the deferrals proposed in the ESP, FirstEnergy points out that Section 4928.144, Revised Code, expressly authorized the phase-in of generation prices, along with other deferrals. In addition, FirstEnergy notes that, with the exception of governmental aggregation programs as set forth in Section 4928.20(I), Revised Code, Section 4928.144, Revised Code, also directs that the deferrals plus carrying charges be collected through an unavoidable surcharge on rates of an electric distribution utility (Co. Br. at 33).

Staff notes that Section 4928.63(C)(3), Revised Code, provides that electric utilities may be excused from complying with the annual alternative energy portfolio standards if their annual compliance exceeds a certain level. Staff believes that the reduction of the base generation prices through the use of deferrals could potentially impact the implementation of this statutory provision. Therefore, Staff recommends that the Commission reinforce that no part of any deferred generation-related amounts should include alternative energy portfolio standard related compliance costs (Staff Ex. 1 at 4-5; Staff Br. at 18).

With regard to Rider GEN and the proposed base generation rates, the Commission notes that, at the hearing, FirstEnergy's witness Warvell acknowledged that the generation rates proposed by FirstEnergy were not based upon cost, but were based solely on the judgment of FirstEnergy's management (Tr. I at 64, 167-168). Mr. Warvell testified that it is FirstEnergy's understanding that the two objectives for an ESP are for the rates to be below the rate which could be obtained through an MRO and for rates to be stabilized (Tr. I at 26, 48). Further, FirstEnergy presented testimony at the hearing indicating that the

2 OCC, Cleveland, NRDC, NOAC, and Citizens Coalition filed a joint initial brief; therefore, when referring to the arguments in this document these parties will be referred to as the Consumer Advocates.

generation rates proposed by FirstEnergy are below the rates which could be obtained through an MRO (Co. Ex. 1 at 18, Att. 1 at 1). However, this testimony was based upon the market information available to FirstEnergy on July 15, 2008, immediately prior to the filing of its application on July 31, 2008 (Tr. I at 102-103; Tr. III at 13).

The record in this proceeding demonstrates that, after the filing of the application by FirstEnergy, there was a significant decline in prices in the relevant energy markets (Tr. I at 99-103, 184-184). FirstEnergy's witness Jones acknowledged a decline in energy prices between July 15, 2008, and the date of the hearing, but he stated that he had not calculated the impact of that decline in his testimony (Tr. III at 85). Because the decline occurred after the filing of the application by FirstEnergy, this decline was not reflected in the prices proposed by FirstEnergy. Therefore, if the Commission is to accept the two objectives for the ESP proposed by FirstEnergy, that the rates for the ESP should be below the prices which could be obtained through an MRO and that rates should be stabilized, it is necessary to reduce the average base generation rates contained in FirstEnergy's application.

The Commission finds that the record supports a reduction in the proposed base generation rates of approximately 10 percent for 2009, with additional reductions thereafter, in order to reflect the market decline between the date of the filing of the application and the hearing. A comparison of the forward prices used by OEG witness Kollen, using October 10, 2008, market data, with forward prices used by FirstEnergy's witness Jones using July 15, 2008, market data, indicates a decline of approximately 12 percent (OEG Ex. 2-A, Exhibit LK-8A; Co. Ex. 6, Exhibits 8-10). As previously noted, FirstEnergy's witness Jones testified that he had not calculated the impact of the market decline (Tr. 111 at 85). Moreover, OCC's witness Yankel testified that prices had declined by approximately 10 percent (OCC Ex. 3 at 5; OCC Ex. 8; OCC Ex. 9; OCC Ex. 10; Tr. VI at 182-185). Further, Kroger's witness Higgins recommended that the Commission reduce the base generation rates to $0.0675 per kWh for 2009; this recommendation would reduce base generation rates by approximately 10 percent (Kroger Ex. 1 at 3, 8). Therefore, the Commission concludes that it is appropriate to reduce the average base generation rates proposed in FirstEnergy's application to $0.0675 per kWh for 2009, $0.0695 per kWh for 2010, and $0.071 per kWh in 2011. Accordingly, the Commission finds that FirstEnergy's proposed ESP should be modified in order to reflect these reductions.

Turning now to Rider GPI, the Commission acknowledges that Section 4928.144, Revised Code, authorizes the Commission to order an electric utility to phase-in any rate established under Section 4928.143, Revised Code, in order to ensure rate stability to customers. FirstEnergy has proposed a generation phase-in credit under which the Companies would defer a portion of the base generation costs and recover these deferrals, with carrying costs, through Rider DGC. In its application, FirstEnergy proposed a generation phase-in credit in the amount of $0.0075 per kWh for 2009, $0.0085 per kWh for

2010, and $0.0095 per kWh for 2011. The Commission believes that, with the modifications to the average base generation rates, no such deferrals would be necessary. The Commission notes that the aggregate cost of the deferrals, including carrying costs, proposed by FirstEnergy amounts to nearly $2 billion, which would need to be recovered from ratepayers in the future (Co. Ex. 9a, Att. A; Co. Ex. 5 at 8; Tr. 11 at 280-282). Although there would be short-term benefits to such a deferral in the form of lower billed generation rates, the need for recovery of nearly $2 billion in deferred generation rates and carrying costs has the potential to damage Ohio's competitiveness in the global economy over the long-term as new businesses may be deterred from locating in Ohio in the future. Accordingly, the Commission finds that Rider GPI should be eliminated from the ESP.

Moreover, the Commission is mindful of the significant economic difficulties facing residents in Ohio at this time, as reflected in the record of the nine local public hearings held in this proceeding. Thus, we note that the average base generation rate for 2009, as approved in this order, represents no increase in electric rates for residential customers served by the Companies.

1. <u>Generation Procurement</u>

According to the Companies, integral to the ESP is an arrangement with FirstEnergy Solutions (FES) for generation supply. Under this arrangement, the Companies explain that there would be additional benefits to customers. Among these benefits would be an addition of 1,000 megawatts (MW) of capacity through either new or upgraded generation, maintaining generation in service that would otherwise be shutdown, and/or additional generation. Furthermore, the Companies state that FES will commit up to $45 million over the term of the plan toward environmental remediation and reclamation (Co. Ex. 9a at 7, 17).

OEG contends that the generation rate proposed in the ESP is not reasonable, stating that FirstEnergy has failed to show that the prices for purchased power from FES are prudent (OEG Ex. 2 at 19; Tr. I at 26). In addition, OEG alleges that the proposed rates are not consistent with the policy of the state set forth in Section 4928.02, Revised Code (OEG Br. at 14). OEG further states that the base generation rates proposed in the ESP are in excess of the market prices; stating that, based on September 19, 2008, forward prices, the wholesale market price to serve the Companies' load would be $63.45, $65.23, and $66.15 per MWh, for 2009, 2010, and 2011 respectively; compared to FES's offer price proposed in the ESP of $75, $80, and $85 per MWh, respectively, for the same years (OEG Ex. 2 at 4, 11, 19). OPAE agrees that the lack of transparency concerning the contractual terms with FES and the lack of justification for the proposed generation prices are fatal flaws in the ESP (OPAE Ex. 1 at 15). In addition, OCC asserts that the forecasted rates developed by the Companies to determine the market price benchmarks for generation are highly inflated; thus, giving a false impression of the value of the rates being proposed in the ESP. Based on data from July 15, 2008, and taking in consideration adjustments for load shaping and distribution losses, OCC calculates that the more realistic forward market prices would be $55.65, $54.78, and $53.87 per MWh for 2009, 2010, and 2011, respectively (OCC Ex. 3 at 12; Con. Adv. Br. at 12).

OEG recommends an active portfolio as an alternative, whereby the Companies would issue requests for proposal for all facets of wholesale generation supply sufficient to meet their provider of last resort (POLR) requirements. OEG proposes that these purchases should only be made at transparent and verifiable Federal Energy Regulatory Commission (FERC) regulated wholesale market rates. According to OEG, the goal would be to obtain the least cost portfolio of wholesale generating resources, which would include a mix of fixed block wholesale contracts, spot purchases, and sales contracts, to supply those customers who do not shop. OEG also states that the Companies should retain the POLR responsibility, rather than outsourcing it to the wholesale generation suppliers. To the extent costs are prudently incurred, OEG states that the Companies should be permitted to recover all of their competitively bid generation supply cost, including the costs for the risk. OEG believes that this method will significantly reduce the cost of wholesale generation (OEG Ex. 1 at 8-11; OEG Ex. 2 at 14, 17, 21). OHA supports OEG's proposed procurement process (OHA Br. at 12).

OPAE proposes that FirstEnergy be required to evaluate options to assure generation supply to its customer classes. OPAE believes that the analysis should start with an examination of the Companies' current and future load and load shapes for each customer class. OPAE advocates that the Companies should then evaluate how they can manage this load shape and meet their needs under a variety of potential scenarios that would evaluate the cost of effective energy efficiency and demand response products compared to purchasing traditional generation supply at the lowest price (OPAE Ex. 1 at 16-17).

OCC and OPAE recommend that FirstEnergy's proposed cost recovery for new generation sources, including the contract with FES for an additional 1,000 MW, or for long-term power purchase contracts identified in the ESP not be approved, because of the lack of resource planning information provided by FirstEnergy in its application. OCC and OPAE agree that approval should depend on the Companies' demonstration that such resources are least-cost as determined in a formal long-term forecast and integrated resource planning process (OCC Ex. 1 at 20; OPAE Ex. 1 at 18).

In light of the Commission's determination in this order that the average base generation rates proposed by the Companies must be reduced to an appropriate level, as well as other modifications to the ESP set forth in this order, we find that the issues raised by several of the intervenors regarding the FirstEnergy's proposed procurement of generation from FES have been taken into consideration and addressed. As for FES's commitments to provide 1,000 MW of capacity and to provide $45 million toward environmental remediation and reclamation, the Commission agrees with OCC and OPAE that these commitments should be eliminated (OCC Ex. 1 at 20; OPAE Ex. 1 at 18).

2. Section 199 Tax Deduction

IEU-Ohio points out that, pursuant to Section 199 of the Internal Revenue Service Code, a deduction against federal taxable income is available for qualified production activities income, which includes the production of electricity. IEU-Ohio states that the Companies have not reflected the Section 199 tax benefits in the base generation prices proposed in the ESP. According to IEU-Ohio, to the extent that the Section 199 deduction associated with the generation supplied by FES to the Companies can be utilized in FirstEnergy's consolidated tax return, it is appropriate for that tax benefit to be reflected in the generation rates. IEU-Ohio argues that, if the Companies are not able to demonstrate that the price of generation is net of Section 199 tax benefits, they should not be allowed to pass along the costs of new taxes associated with generation (IEU-Ohio Ex. 1 at 5-7).

The Commission acknowledges that, as pointed out by IEU-Ohio, the generation supplied by FES to the Companies may qualify for the Section 199 deduction. In previous cases, the Commission has recognized the possibility of the applicability of this deduction and has required other electric utilities to make adjustments reflecting this deduction. *See Columbus Southern Power Company and Ohio Power Company*, Case No. 07-63-EL-UNC (October 3, 2007). Thus, the Commission agrees that applicable Section 199 deductions should be taken into consideration. That being said, we believe that the modifications set forth in this order adequately account for the possibility of any applicable Section 199 tax deductions.

3. Generation Rate Design

Under the ESP, generation charges, which are seasonally and voltage adjusted, are levied on all customer classes on a per kilowatt hour (kWh) basis. According to FirstEnergy, there are two main considerations that form the basis for the proposed generation rate design in the ESP. First, the ESP proposal uses the rate classifications developed by the Companies in Case Co. 07-551-EL-AIR (*FirstEnergy Distribution Rate Case*). Second, according to the Companies, the proposed rate design incorporates the concept of gradualism in the transition from historic rate levels and structures to the proposed rate classifications and components of the ESP in order to mitigate customer impacts. FirstEnergy explains that the base distribution rates in the ESP utilize the Companies' updated filing in the *FirstEnergy Distribution Rate Case*; however, the ESP proposal incorporates the following changes to that update: (1) a single rate block structure for residential customers; (2) the revenue distribution and the rate design set forth in the stipulation and recommendation filed in the *FirstEnergy Distribution Rate Case* on February 11, 2008; (3) tariffs that produce the distribution increase pursuant to the terms of the ESP; (4) removal of the DSM Rider and incorporating the same charge in

Demand Side Management and Energy Efficiency Rider (Rider DSE); and (5) to be consistent with the riders proposed in the ESP, the seasonal price change in the billing and payment section of the electric service regulations was modified (Co. Ex. 4 at 5-6).

Staff states that the Companies' proposed voltage-based rate design is reasonable (Staff Ex. 5 at 4). The Commercial Group supports the Companies' proposal for seasonal and voltage level adjustments to its generation cost, as well as the optional time-of-day differentiated generation service price option. However, the Commercial Group states that the Companies should investigate whether a pricing option based on the functional cost of generation, i.e., capacity and energy pricing elements, would provide more accurate price signals (Com. Gr. Ex. 1 at 7). Nucor also recommends that the time-of-day proposal be modified to include two separate pricing periods; for example, peak and shoulder pricing periods (Nucor Ex. 3 at 30).

IEU-Ohio argues that the proposed per kWh rate design is not appropriate for large customers because it provides no price signal that the customer's load factor contributes to the cost of providing electricity (IEU-Ohio Ex. 1 at 9). Kroger agrees that the elimination of any rate differentiation based on load factor causes substantial negative impacts on higher-load factor, non-residential customers (Kroger Ex. 1 at 9). IEU-Ohio believes that the elimination of the demand charge would change the customer's load shape and increase the customer's peak demand (Tr. VIII at 86; IEU-Ohio Br. at 31). According to IEU-Ohio, not only does the load factor affect variable costs, but a higher load factor means that the fixed costs are spread over a greater quantity of usage, thus lowering the overall average costs per kWh. IEU-Ohio alleges that designing generation charges to be entirely kWh based implicitly suggests that such costs are entirely variable, which IEU-Ohio does not accept; however, if the generation costs are entirely variable, IEU-Ohio opines that there is no need for shopping customers to pay for default or standby service (IEU-Ohio Ex. 1 at 9-10). The Companies disagree that the removal of the demand charges from retail rates will cause a change in customers' load profiles (Co. Ex. 20 at 18).

IEU-Ohio recommends that, once the generation revenue requirement has been established for the transmission, sub-transmission, and primary rate schedules, the generation rider should be structured as a two-part rate consisting of both demand and energy components. Since there is no cost-of-service study, IEU-Ohio recommends a demand charge of $14 per kW and that the remainder of the revenue requirement be collected through seasonally differentiated kWh charges (IEU-Ohio Ex. 1 at 10; IEU-Ohio Br. at 30). IEU-Ohio also proposes that partial service and cogeneration schedules should be included as part of the ESP. IEU-Ohio points out that cogeneration is one option that can be used to fulfill the alternative energy resource portfolio obligations in SB 221 (IEU-Ohio Ex. 1 at 13).

OEG maintains that the ESP rate proposals fail to adequately mitigate the increase to large industrial customers. According to OEG, the increases for the Companies' largest industrial manufacturing firms range from 25 percent to 34 percent, compared to the retail average increases in the five percent range for the other customer classes (OEG Ex. 1 at 16-20). OEG recommends that the increases proposed under the ESP be modified using the following rate mitigation plan principles: residential rates should reflect the increases and not be charged any costs for rate mitigation or, if alternative wholesale generation rates are approved, residential rates should be adjusted with the residential class sharing the costs; no rate schedule should receive an increase greater than two times the average increase; and no rate schedule should receive a rate decrease if other schedules get an increase. OEG recommends its mitigation plan be accomplished via the charges and credits contained in the Companies' Rider EDR. According to OEG, its mitigation plan: moderates the full effect of wholesale cost increase to the industrial class by increasing Rider EDR on non-residential customers; provides incentives to industrial customers to remain on the SSO; and benefits all non-shopping customers by minimizing the retail risk premium that must be added to the wholesale generation price (OEG Ex. 1 at 20-24). Nucor supports OEG's rate mitigation proposal (Nucor Br. at 20). OSC points out that the effect of applying OEG mitigation plan principles to the eight rate schedules proposed by the Companies would be to further increase the rates confronting schools under the ESP (OSC Reply Br. at 5).

Nucor further advocates that, regardless of whether the ESP is a cost-of-service proposal or a market-based proposal, the rates between the classes should reflect cost-of-service differentials (Nucor Br. at 17). Nucor argues that large industrial customers under transmission rate schedules and most lighting customers will get significant rate increases. Nucor offers that transmission customers will receive increases of between 14 and 34 percent, and, for some transmission customers served under interruptible rates, like Nucor, the increase will approach or exceed 50 percent. Nucor does not believe that such charges are cost-based; rather, such disparate increases for high-load factor transmission customers and off-peak lighting classes are attributable to the fact that FirstEnergy has not properly reflected the cost of generation capacity in the rates for customer classes. According to Nucor, with the exception of voltage differentials, the ESP generation rates do not recognize cost differences to serve specific classes, e.g., loads characterized by timing, duration, and load factor. Nucor and Kroger agree that the time-of-use price differentials in the ESP do not address class-specific cost differences (Nucor Ex. 3 at 9-11; Kroger Ex. 1 at 11). Nucor alleges that the result is generation rates that create interclass subsidies and large rate increases for selected classes (Nucor Ex. 3 at 11). Nucor recommends that the generation rates be modified to reflect the class-specific cost differences and that FirstEnergy develop class allocation factors which would first be adjusted to the proposed uniform generation rate, followed by the time-of-use, and voltage adjustments (Nucor Ex. 3 at 14-15). Kroger recommends that, for rate schedules for high-load factor customers, the existing generation-related rate components should be amalgamated into a single base generation charge, and then a rate schedule specific rider should be applied to this base charge to recover the requisite change in generation revenue authorized in the ESP (Kroger Ex. 1 at 11-12). Nucor advocates that, if its class allocation factor proposal is not adopted, then FirstEnergy should be required to retain all existing rates and to apply an across-the-board generation increase to FirstEnergy's existing rates (Nucor Br. at 21).

The Commercial Group offers that the Companies' generation cost deferrals and Rider GPI should also track costs based on customer class (voltage level), season, and time-of-day period costs (Com. Gr. Ex. 1 at 7). OHA states that the rate design should be reflective of the manner in which costs are incurred, on a reserved capacity basis (OHA Br. at 18).

OCC disagrees with the proposal in the ESP that eliminates the demand components for non-residential customers. OCC maintains that demand components in generation rates for large customers reduce the bid price. Further, OCC suggests that elimination of demand charges from non-residential generation tariffs will encourage an inefficient demand for, and use of, generation resources. OCC submits that the Companies' interruptible load response programs (Economic Load Response Program [Rider ELR] and Optional Load Response Program [Rider OLR]) and the seasonality factors do not provide enough control over the growth demand (OCC Ex. 1 at 22-24). Further, OCC states that, until the Companies can provide justification why an inverted rate block structure is appropriate for residential customers, residential customers under Rider 88 should be given a flat-rate (OCC Ex. 3 at 32).

NRDC states that that there are good public policy reasons for ensuring that the Companies are made whole for the revenue they forgo as a result of energy efficiency programs; however, the Companies' lost revenue adjustment proposed in the ESP does nothing to remove the Companies' incentive to increase kWh sales. NRDC submits that the disincentive toward energy efficiency could be removed if revenue decoupling is adopted in FirstEnergy's service territory (NRDC Ex. 1 at 10-11).

It is the Commission's understanding that the Companies are requesting that the rate design and tariff structure developed by the Companies in the *FirstEnergy Distribution Rate Case* also be adopted in this case for the generation service. However, the Commission will not be determining the substantive issues of the *FirstEnergy Distribution Rate Case* in this case. Moreover, based upon the issues raised by the intervenors in this proceeding, the Commission finds that FirstEnergy has not demonstrated that the proposed rate design and tariff structure properly allocates the cost of providing generation service to the appropriate customers. Therefore, we decline to implement a new generation rate design and tariff structure at this time. Instead, the Commission finds that FirstEnergy should file new tariffs adjusting its current rate design and tariff structure to implement the new base generation rates approved by the Commission in the ESP. These proposed tariffs should maintain the current rate relationships between customer classes and among the rate schedules within each customer class.

In addition, the Commission agrees that the issues raised by various intervenors regarding the inclusion of demand components in the generation rate design must be addressed. To that end, the Commission finds that FirstEnergy should work with Staff, and other stakeholders, to develop a means of transitioning FirstEnergy's generation rate schedules to a more appropriate rate structure which takes into consideration of time-varying generation costs of serving different customers and classifications of customers with homogenous loads and/or generation cost profiles, considers customer load factor, incorporates seasonal generation cost differentials, and, where adequate metering is available, provides customers with time-differentiated and dynamic pricing options. Further, as part of our approval of this ESP, the Commission will modify the ESP to authorize FirstEnergy to make periodic, revenue-neutral, Rider GEN tariff filings, subject to Commission review and approval, to implement a revised new rate design on a gradual basis consistent with its collaborative effort with Staff. Accordingly, the ESP, as proposed, should be modified consistent with our determination herein.

F. Generation Riders and Programs

1. Deferred Generation Cost (Rider DGC)

As stated previously, the Companies propose that approximately ten percent of the generation price during the three-year ESP period be deferred, with carrying charges, and recovered in the future through Rider DGC. Rider DGC would be an unavoidable rider for all customers, with the exception of certain governmental aggregation customers, consistent with Section 4928.20(I), Revised Code (Co. Ex. 9a at 5, 11; Co. Ex. 5 at 9). The Companies estimated that, in the aggregate, the deferred amounts would be $430 million in 2009, $490 million in 2010, and $550 million in 2011 (Co. Ex. 9a, Att. A; Co. Ex. 5 at 8). The Companies set forth two options for the recovery of the deferred costs in Rider DGC (Co. Ex. 9a, Att. A at 2).

The first option assumes no securitization and would allow the Companies to begin recovering the costs and carrying costs deferred pursuant to the generation rate increase phase-in effective with services rendered on and after January 1, 2011, through implementation of Rider DGC averaging $0.002009 per kWh. It is projected that, under the first option, Rider DGC would increase in 2013 and decrease in 2021. Pursuant to option one, Rider DGC would be reconciled semiannually and it would not continue beyond December 31, 2022 (Co. Ex. 9a at 11-13, Att. A at 2-3; Co. Ex. 2 at 12).

The second option would allow the Companies, with the Commission's approval, to securitize, at least on an annual basis, the accumulated balance of the deferred generation charges, together with the associated carrying charges and the related securitization transaction costs, effective with services rendered on and after January 1, 2010, through implementation of Rider DGC averaging $0.000893 per kWh. The Companies explain that, in accordance with this option, each year's generation phase-in costs may be securitized in separate transactions, as authorized by Sections 4928.143(B)(2)(f) and 4928.144, Revised Code, by issuing bonds with scheduled final maturities not to exceed ten years. It is projected that, under the second option, Rider DGC would increase in 2011 and 2012, and decrease in 2020 and 2021. Pursuant to option two, Rider DGC would be reconciled semiannually, as well as on a non-routine basis, and it would not continue beyond December 31, 2021 (Co. Ex. 9a at 11-14, Att. A at 3-9; Co. Ex. 2 at 13; Co. Ex. 1 at 25).

The Commercial Group states that, whichever deferral mechanism is employed, it should provide full recovery of the deferrals to the Companies, but at the lowest possible cost to retail customers. Therefore, if the first option, without securitization, is adopted, the Commercial Group recommends that the carrying charge include all deferred tax offsets associated with unrecovered generation prices and carry net of tax balance at the Companies' cost of long-term debt. If the second securitization option is adopted, the Commercial Group recommends a special securitization proceeding be held to consider the economic benefits of the use of such bonds (Com. Gr. Ex. 1 at 8).

Dominion submits that all riders designed to recover generation-related costs, such as Rider DGC, must be made avoidable for shopping customers if there is to be any hope for retail competition (Dom. Br. at 6). Similarly, the Competitive Suppliers state that this rider should be avoidable because it is inappropriate to require customers who take generation supply service from a competitive provider to be forced to pay for costs properly attributable to the generation portion of FirstEnergy's SSO rates (Comp. Supp. Ex. 1 at 8-9 and Ex. 3 at 8). In addition, the Competitive Suppliers state that this deferral masks the true cost of the ESP generation and artificially suppresses conservation by reducing the value of using less electricity (Comp. Supp. Br. at 16).

Staff, OHA, and Kroger are opposed to the generation deferrals requested by the Companies (Staff Ex. 6 at 3; OHA Br. at 15; Kroger Ex. 1 at 8). Kroger does not favor a program in which customers accumulate a very substantial debt owed, with interest, to FirstEnergy (Kroger Ex. 1 at 8). Staff believes deferrals present too many difficulties and distortions. While Staff notes that it is not opposed to smoothing out the rate shock problem, Staff does not recommend a process which extends the collection through an unavoidable charge beyond the ESP period (Staff Ex. 6 at 3). Rather than deferrals, Staff recommends that a rate structure coupled with a reconciliation adjustment will generate sufficient revenues for FirstEnergy to recover the costs of providing an SSO, while at the same time earning a fair return on its investment. Staff offers that, through an annual or semi-annual true-up mechanism, generation rates could be adjusted either up or down, but no higher than the generation rates proposed by the Companies, to reflect the actual cost of power acquisition (Staff Br. at 8-10). FPL states that, while rejection of Rider GPI would satisfy its interest, so would the development of a levelized SSO as proposed by Staff, therefore, FPL supports Staff's proposal (FPL Br. at 16).

NOAC and NOPEC aver that Section 4928.20(I), Revised Code, provides that large-scale governmental aggregation participants only pay the portion of Rider DGC that represents the benefits the participants received; however, the ESP does not say that. Therefore, NOAC and NOPEC state that the ESP lacks any detail on how this statutory requirement will be implemented and this uncertainty is an impediment to large-scale governmental aggregation. However, NOAC and NOPEC point out that the initial barrier of Rider GPI makes it unlikely that a governmental aggregator would secure power supplies at a low enough price to provide the opportunity for avoidance of Rider DGC (NOAC/NOPEC Jt. Ex. 1 at 7-8).

As stated previously, the Commission has determined that there should be no deferral of generation rates as proposed by FirstEnergy. Therefore, there is no need for Rider DGC. Accordingly, FirstEnergy's ESP should be modified to eliminate this rider. Elimination of this rider will save customers, in the long-term, approximately $500 million in carrying costs (Tr. 11 at 280, 282). The Commission believes that this savings will help promote, in the long-term, the competitiveness of Ohio in the global economy.

2. <u>Capacity Cost Adjustment (Rider CCA)</u>

Pursuant to the ESP, the Capacity Cost Adjustment Rider (Rider CCA) would be an avoidable rider that would account for the capacity purchases made by FES which are required to meet the applicable standards of FERC, North American Electric Reliability Corporation (NERC), Midwest Independent Transmission System Operator, Inc. (MISO), or others for planning reserve margin requirements for the Companies' retail load. Purchases made for the period May 1 through September 30 of each calendar year of the plan would be recoverable through Rider CCA. Furthermore, in accordance with the ESP, the Commission may elect to increase the generation rate phase-in amounts, to the extent of any charges for planning reserves under Rider CCA, but only to the extent such charges exceed 1.5 percent of the then existing average annual total rates of the Companies (Co. Ex. 9a at 18; Co. Ex. 5 at 12-13).

OEG states that it is not opposed to Rider CCA to the extent it applies to firm POLR load. However, OEG argues that it is the responsibility of FirstEnergy to obtain sufficient annual planning reserves, based on their firm load, not interruptible load. OEG submits, and Nucor agrees, that it is inappropriate to charge Rider CCA to interruptible load (OEG Ex. 1 at 32; Nucor Br. at 54).

As noted previously, OCC recommends that demand components for non-residential customers be part of the ESP. However, if such components are not part of the ESP, OCC recommends that Rider CCA be rejected and that the Companies bear the risk of their rate design in the event that capacity is insufficient (OCC Ex. 1 at 24; OCC Ex. 3 at 37).

FPL advocates that Rider CCA, as proposed in the ESP, violates the legislative mandate to encourage and promote large-scale governmental aggregation and, therefore, it must be modified (FPL Br. at 5). FPL states that the ESP fails to provide transparency on how FirstEnergy will determine its capacity charges. Therefore, FPL believes that, in order to ensure a level playing field for competitive suppliers, FES should procure capacity in the market needed to meet the planning reserve requirements for all customers for the entire term of the ESP and that associated costs should be recovered through an unavoidable rider (FPL Ex. 1 at 17). In the alternative, FPL recommends that FirstEnergy provide an estimate of the MISO designated network resource capacity it plans to make available to meet planning reserve requirements and a reasonable forecast of Rider CCA, in order to provide pricing transparency (FPL Br. at 29). In response, FirstEnergy states that the process contemplated for Rider CCA does provide transparency in that the cost estimates and actual costs incurred will be reviewed and approved by the Commission (Co. Reply Br. at 51).

The Commission understands that Rider CCA, as proposed by the Companies, is an avoidable rider and that the purpose of this rider is to account for capacity purchases during the summer months in order to meet applicable planning reserve margin requirements. The availability to consumers of adequate, reliable, safe, and efficient electric service is one of the cornerstones of the state electric policy set forth in Section 4928.02, Revised Code. In balancing these important needs of consumers with the issues raised by several of the intervenors, the Commission believes that Rider CCA is a reasonable mechanism that will advance the state policy. However, the evidence in the record demonstrates that FirstEnergy is required to obtain sufficient annual planning reserves based upon their firm load and not their interruptible load (OEG Ex. 1 at 32; Tr. II at 33-34, 40-41). Therefore, the Commission agrees that FirstEnergy should not be permitted to charge customers Rider CCA for their interruptible load and that Rider CCA should be modified to apply only to firm load. Accordingly, the Commission finds that Rider CCA should be approved, as an avoidable rider and it should not be charged to FirstEnergy's interruptible customers.

3. <u>Minimum Default Service Rider (Rider MDS)</u>

Pursuant to the ESP, Rider MDS would be an unavoidable rider that would compensate the Companies for the administrative costs and hedging costs associated with committing to obtain adequate generation resources to supply the entire retail customer load, recognizing the risk and costs of customers switching to an alternative generation supplier. The Companies propose that Rider MDS be equal to 1.0 cent per kWh (Co. Ex. 9a at 14; Co. Ex. 5 at 10-11). According to the Companies, Rider MDS is permitted by Section 4928.143(B)(2)(d), Revised Code. The Companies explain that the minimum default service charge is included in the base generation charge in Rider GEN for non-shopping customers and separately charged to shopping customers through Rider MDS; however, the minimum default service charge is not subject to the generation phase-in deferral referenced above for the base generation charge (Co. Ex. 9a at 10, 14; Co. Ex. 5 at 8). According to FirstEnergy, without this unavoidable charge, the base generation charges in the ESP would need to be increased (Co. Ex. 5 at 12).

The Competitive Suppliers state, and Dominion agrees, that Rider MDS should be avoidable because it is inappropriate to require customers who take generation supply service from a competitive provider to be forced to pay for cost properly attributable to the generation portion of FirstEnergy's SSO rates (Comp. Supp. Ex. 1 at 8-9 and Ex. 3 at 8; Dom. Br. at 6).

IEU-Ohio, Nucor, NOAC, NOPEC, OCC, Cleveland, OHA, and FPL argue that Rider MDS is not reasonable or appropriate, and that the Companies have not provided cost support for this level of charges (IEU-Ohio Ex. 1 at 7; Nucor Ex. 3 at 31; NOAC/NOPEC Jt. Ex. 1 at 12-13; OCC Ex. 3 at 34; Cleve. Ex. 1 at 4; OHA Br. at 15; FPL Ex. 1 at 13). Nucor, NOAC, and NOPEC state that this rider will hinder the development of competitive markets for retail generation service. NOAC and NOPEC maintain that this unavoidable charge will greatly impede and likely destroy large-scale governmental aggregation (Nucor Ex. 3 at 31; NOAC/NOPEC Jt. Ex. 1 at 12, 18). FPL, NOAC, and NOPEC assert that Rider MDS should either be disallowed or made avoidable for large-scale governmental aggregations (FPL Br. at 5; NOAC/NOPEC Br. at 27). Moreover, IEU-Ohio contends that, if Rider MDS is intended to compensate FirstEnergy for hedging costs associated with serving its entire retail load, it is not clear what additional costs would result from shopping customers returning which would justify Standby Charges for Generation Rider (Rider SBC) (IEU-Ohio Ex. 1 at 7). Likewise, FPL believes that Rider SBC is designed to protect against the Companies' concern regarding risk. FPL asserts that, if Rider MDS is allowed as an unavoidable charge then, to ensure a level playing field, a pro-rated portion of the rider revenues should be made available to competitive suppliers serving large-scale government aggregations to mitigate any costs incurred due to shopping risk (FPL Ex. 1 at 13-14). Another alternative mentioned by NOAC and NOPEC is that Rider MDS could be made avoidable upon prior notice by a large-scale governmental aggregation that it will take competitive electric retail service from a third-party supplier (NOAC/NOPEC Br. at 34-35).

OEG contends that, to the extent the ESP can be modified to eliminate the Companies' volumetric risk to provide POLR services to some ESP customers, then those customers should not be charged the costs of that risk. Therefore, OEG recommends that

Rider MDS be waived for ESP customers who either: (1) agree to forgo their right to shop during the term of the ESP; or (2) agree to not take service under the ESP and, in the event that they return to POLR service, agree to accept market-based rates (OEG Ex. 1 at 26). Nucor supports OEG's proposal (Nucor Br. at 53). IEU-Ohio agrees with the second part of OEG's recommendation (IEU-Ohio Br. at 25).

FirstEnergy states that the criticisms from the intervenors that Rider MDS is not cost-based are misdirected. According to FirstEnergy, an ESP is not a cost-based vehicle and, therefore, such a calculation is not a prerequisite. FirstEnergy contends that it is only able to offer the fixed base generation prices set forth in the ESP if it can be compensated for the risks arising from a customer's ability to shop via Rider MDS (Co. Br. at 49). Furthermore, in response to proposals by various parties that Rider MDS be made avoidable under certain circumstances, i.e., the customer agreeing not to shop, FirstEnergy points out that these proposals do not eliminate shopping or the risks associated with the Companies' POLR supply obligation which Rider MDS is intended to cover (Co. Reply Br. at 40-41).

The Commission agrees with the intervenors who question the purpose of Rider MDS. We do not believe that the record supports the imposition of Rider MDS, especially in light of the possibility that the impact of Rider MDS would impede shopping. Therefore, the Commission finds that Rider MDS should not be approved. Accordingly, the Commission finds that FirstEnergy's proposed ESP should be modified to eliminate Rider MDS.

4. <u>Standby Charges for Generation (Rider SBC)</u>

Pursuant to the ESP, Rider SBC would be an avoidable rider that would compensate the Companies for the risk of customers coming back to the electric utility during times of rising prices. The proposed Rider SBC is 1.5 cents per kWh in 2009, 2.0 cents per kWh in 2010, and 2.5 cents per kWh in 2011 (Co. Ex. 9a at 15-16). Pursuant to the ESP, customers, either individually or as part of a governmental aggregation group, who switch to an alternative generation supplier may elect to waive standby charges (Co. Ex. 9a at 16). If the customer pays the standby charge while taking generation service from an alternative supplier, the customer will have the right to return to the Companies' SSO price, provided the customer remains with the electric utility for a period not less than 12 months or the remainder of the ESP (Co. Ex. 5 at 21). If a customer chooses not to pay the standby charges, should they return to the Companies for generation service during the ESP period, they would do so at the market pricing for generation; for returning non-governmental customers who do not pay the standby charges, they will pay the higher of the SSO market pricing or the SSO pricing otherwise applicable to such customers. Customers who do not pay Rider SBC have no minimum stay provision if they return to the electric utility (Co. Ex. 9a at 16).

Staff believes that a minimum stay provision discourages market development. Therefore, Staff recommends that, for residential and small commercial customers who pay the standby charge and then choose to return to the Companies' SSO price, no minimum stay requirement should be imposed. However, if a minimum stay is approved, Staff recommends that it apply only to residential and small commercial customers who return in the summer (May 16th through September 15th) (Staff Ex. 8 at 10). The Competitive Suppliers submit that Rider SBC should be modified so that it does not act as a penalty for customers who return to the SSO (Comp. Supp. Br. at 22).

IEU-Ohio and Cleveland maintain that Rider SBC is arbitrary and unreasonable (IEU-Ohio Ex. 1 at 7; Cleve. Ex. 1 at 5). As discussed previously, IEU-Ohio insists that, if Rider MDS is intended to compensate for hedging costs associated with serving its entire retail load, it is not clear what additional costs would result from shopping customers returning which would justify Rider SBC (IEU-Ohio Ex. 1 at 7). While IEU-Ohio believes it is reasonable for the Companies to recover the costs of hedging risk, IEU-Ohio believes that, initially, Rider SBC should be set at $0 and then the Companies could file periodic requests to update the rate to reflect actual, prudently incurred hedging costs (IEU-Ohio Br. at 25-26).

The Commission believes that Rider SBC complies with the provisions of Section 4928.20(J), Revised Code, which requires that customers of aggregations be permitted to avoid charges for standby power by agreeing not to return to the rate provided under the ESP; instead such customers would pay a market rate in the event of a return to electric utility service. It is also important to note that this rider is entirely optional to individual customers. The record reflects that Rider SBC, as proposed, is not based upon cost (Tr. I at 90-91). The Commission finds that FirstEnergy's proposed ESP should be modified such that Rider SBC will be based upon the actual, prudently-incurred costs to FirstEnergy of hedging against the risk of customers returning to the SSO (Tr. 1 at 92-93). Therefore, while the Commission will accept FirstEnergy's proposed rate of $0.015 per kWh, this rate will be subject to Commission review and reconciliation on a quarterly basis to insure that it reflects the Companies' actual prudently-incurred costs. Further, the Commission agrees with Staff witness Turkenton that there should be no minimum stay for returning residential and small commercial customers (Staff Ex. 8 at 10). Next, we believe that the definitions should be clarified such that the market pricing for generation applicable to customers who choose not to pay Rider SBC and then return to the Companies for generation service will be based on the quarterly forward wholesale on-peak and off-peak price multiplied by 120. Accordingly, the Commission finds that Rider SBC should be approved as modified herein.

5. Adjustments to the Base Generation Charges - Fuel Transportation Surcharge, Environmental Control, and New Taxes (Rider FTE) and Fuel Cost Adjustment (Rider FCA)

Pursuant to the ESP, Fuel Transportation Surcharge, Environmental Control, and New Taxes Rider (Rider FTE) and Fuel Cost Adjustment Rider (Rider FCA) would be avoidable riders that would constitute adjustments to the base generation charges proposed in the ESP. These riders would be averaged over the three Companies' sales in aggregate, would be adjusted on a quarterly basis, and the adjustment would include a reconciliation component for the balance of the actual recoverable costs, including interest (Co. Ex. 9a at 14-15, Att. B; Co. Ex. 5 at 14, 16).

(a) Rider FTE

Specifically, Rider FTE would be effective beginning January 1, 2009. The Companies explain that Rider FTE would recover two categories of costs. First, it would recover increases in fuel transportation surcharges imposed by shippers in excess of a baseline level of $30 million in 2009, $20 million in 2010, and $10 million in 2011. Second, Rider FTE would recover costs associated with new alternative/renewable-type requirements (other than those required in SB 221), new taxes, and new environmental laws or interpretations of existing laws effective after January 1, 2008, to the extent such costs exceed $50 million during the ESP and are related to the generation assets of FES (Co. Ex. 9a at 14-15, Att. B; Co. Ex. 5 at 13-14). OCC recommends that Rider FTE be rejected (OCC Ex. 3 at 38).

With regard to the fuel transportation portion of Rider FTE, Staff points out that the baseline levels for this portion of the rider, $30, $20, and $10 million, were determined by the Companies based on the judgment of the Companies' management and are reflective of the risk the Companies were willing to take during the ESP period (Staff Ex. 8 at 5). Based upon the fact that the ESP could terminate early, prior to when the recovery of the bulk of any fuel transportation costs would be sought, and, given the fact that no specific fuel transportation forecast or analysis has been provided by the Companies, Staff recommends that the fuel transportation portion of Rider FTE not be approved (Staff Ex. 8 at 6). However, if the Commission were to approve the fuel transportation portion of Rider FTE, Staff recommends that, consistent with SB 221, the Staff be able to audit all current renegotiated and any new contracts to ensure that any such surcharges in the contracts were warranted and prudent (Staff Ex. 8 at 6).

Further, with regard to the fuel transportation portion of Rider FTE, FPL advocates that the charge should be based on actual historical costs. In order to ensure a level playing field, FPL states that FirstEnergy must develop a transparent charge to cover these fuel transportation surcharges (FPL Ex. 1 at 22). In response to the concern that the costs for the fuel transportation portion be transparent, the Companies believe that this concern is unfounded because the Companies have already provided supporting information for the costs for 2006 and 2007, as well as a budget forecast for the term of the ESP, to the Staff and, under the ESP, the Commission will have the opportunity to audit and review these costs (Co. Br. at 28).

Staff supports the approval of the second portion of Rider FTE pertaining to new alternative/renewable-type requirements (other than those required in SB 221), new taxes, and new environmental laws or interpretations of existing laws. Staff agrees that initially this portion of Rider FTE should be funded at $0 and used as placeholder in the event costs exceed $50 million during the ESP. Moreover, Staff recommends that, since many of these costs are unknown at this time, the Companies should be required to consult with Staff regarding the types of costs to be included in the rider. Overall, Staff recommends that Rider FTE be subject to audits by Staff and reviewed in a separate annual proceeding outside of the automatic recovery provision of the ESP (Staff Ex. 8 at 7-8). In response, FirstEnergy clarifies that, as proposed, the Commission would review all costs that may be included in recovery for Rider FTE (Tr. 11 at 135-136, 150; Co. Reply Br. at 53).

Upon consideration of the evidence in the record, the Commission finds that the fuel transportation portion of Rider FTE should not be approved. With regard to the new alternative/renewable-type requirements (other than those required in SB 221), new taxes, and new environmental laws or interpretations of existing laws portion of rider FTE, we agree with Staff that it should be funded at $0 and that the Companies may file a request for recovery to the extent that such costs are above the baseline $50 million during the ESP. In addition, we find that the Companies should consult with Staff regarding the types of costs to be included in this rider and that this rider should be subject to audits by Staff. Accordingly, FirstEnergy's Rider FTE, as proposed in the ESP, should be modified as set forth herein.

(b) Rider FCA

According to the Companies, Rider FCA would be effective for services rendered beginning January 1, 2011. Given the uncertainty of fuel prices more that two years out, the Companies have proposed Rider FCA to recover the costs of fuel in 2011 above the level of fuel costs incurred in 2010 (Co. Ex. 9a at 14-15, Att. B; Co. Ex. 5 at 15).

Staff recommends, and OCC agrees, that Rider FCA should not be approved given the uncertainty surrounding whether the Companies' proposed ESP will ultimately be a two-year or three-year plan, and because the Companies have not provided a forecast of the 2011 Rider FCA fuel costs on which to base an opinion (Staff Ex. 8 at 4; OCC Ex. 3 at 38).

In light of the significant reductions ordered by the Commission to the proposed base generation rate for 2011, we find that Rider FCA should be approved as proposed by FirstEnergy. However, the Commission directs FirstEnergy to provide Staff with a fullydocumented forecast of fuel costs for 2011 within ninety days after the issuance of this order.

6. Non-distribution Service Uncollectible Rider (Rider NDU) and PIPP Uncollectible Rider (Rider PUR)

Pursuant to the ESP, the Non-distribution Service Uncollectible Rider (Rider NDU) would be an unavoidable rider that would compensate the Companies for the risk of customer non-payment for non-distribution service and would be initially set at the average rate of .0403 cents per kWh for each of the Companies. This rider would be reconciled annually to reflect actual uncollectible non-distribution costs (Co. Ex. 9a at 15).

The Companies propose that, to provide for recovery of uncollectible expense associated with percentage of income payment plan (PIPP) customers, to the extent such an expense is incurred by the Companies as a result of modification of the state policy after July 31, 2008, PIPP Uncollectible Rider (Rider PUR) would be implemented. Rider PUR would be an unavoidable rider and would be initially set at 0.00 cents per kWh. This rider would be updated and reconciled on an annual basis (Co. Ex. 9a at 15). The Companies explain that Rider PUR is a placeholder for additional costs if the state makes changes that require them to bear uncollectible costs for PIPP customers (Co. Br. at 53).

In support of the proposal that Riders NDU and PUR be unavoidable by shopping customers, FirstEnergy submits that both of the riders promote social objectives and, therefore, it is appropriate for the Companies to recover the totality of the uncollectible accounts. FirstEnergy states that, in contrast to the Companies, which serve as the default service provider, competitive retail electric service (CRES) providers can establish their own credit rules to minimize uncollectible accounts (Co. Ex. 4 at 12-14).

Staff recommends, and the Competitive Suppliers agree, that Rider NDU should be avoidable for customers who shop because a customer who is not receiving generation service from FirstEnergy should not be responsible for generation-related costs incurred by FirstEnergy (Staff Ex. 5 at 8; Comp. Supp. Ex. 1 at 9 and Ex. 3 at 8).

The Commercial Group opposes approval of Rider NDU stating that a rider that allows the Companies to pass on such costs removes all incentive for the Companies to manage this expense (Comm. Gr. Ex. 1 at 13). In addition, the Commercial Group notes that Rider NDU will be allocated to customers on a cents per kWh basis; they believe that an energy allocation of the costs is inappropriate because none of the costs proposed to be recovered varies with the customers' usage and such allocation will improperly allocate costs to the high-load factor customers (Com. Gr. Ex. 1 at 3). OPAE also recommends that Riders NDU and PUR be rejected stating that uncollectible expenses are already reflected in FirstEnergy's base rates and these riders would allow for double recovery (OPAE Ex. 1 at 32).

NOAC, NOPEC, and FPL believe that an unavoidable Rider NDU creates an unfair competitive subsidy for the Companies. To eliminate this subsidy, NOAC, NOPEC, and FPL propose that the Companies be required to purchase 100 percent of the receivables from any CRES provider billing through the Companies (NOAC/NOPEC Jt. Ex. 1 at 20-21; FPL Ex. 1 at 20). Integrys agrees that, if FirstEnergy insists on providing an unavoidable charge through Rider NDU, it should be required to provide a purchase of receivables program for competitive suppliers with a zero percent discount rate (Comp. Supp. Ex. 3 at 11). In the alternative, FPL recommends that Rider NDU should be made avoidable (FPL Br. at 39). The Consumer Advocates agree that FirstEnergy should either purchase the receivables from competitive suppliers or the rider should be avoidable (Con. Adv. Br. at 13).

With regard to Rider NDU, we acknowledge FirstEnergy's perspective that the recovery of uncollectibles supports a social objective; however, we cannot ignore the fact that the competitive suppliers have uncollectibles of their own that they must face. Taking this into consideration, the Commission finds that the arguments presented by some of the parties that Rider NDU should be avoidable by shopping customers are reasonable; therefore, this proposal should be adopted in the ESP and Rider NDU should be avoidable. We would note that this conclusion is consistent with our recent decision in *In re FirstEnergy*, Case No. 08-936-EL-SSO, Opinion & Order (November 25, 2008). Accordingly, the Commission finds that Rider NDU should be modified to reflect that it will be avoidable for shopping customers. Finally, with regard to Rider PUR, the Commission finds that it should be approved as proposed by FirstEnergy. The Commission notes, however, that, in our annual review and reconciliation of Riders NDU and PUR, we will require FirstEnergy to demonstrate that it actively pursues collection of unpaid balances and that its collection mechanisms effectively mitigate the volume of uncollectibles.

7. <u>Renewable Energy Resource Requirements</u>

Section 4928.64, Revised Code, establishes an alternative energy portfolio standard (AEPS) comprised of requirements for both renewable and advanced energy resources. Specifically, Section 4928.64(B)(2), Revised Code, introduces specific annual benchmarks for renewable energy resources and solar energy resources beginning in 2009 (Staff Ex. 1 at 2).

The Companies explain that the base generation prices also include all of the costs associated with the Companies' renewable energy resource requirement during the ESP and/or equivalent cost for renewable credits (Co. Ex. 9a at 11). According to the Companies, the renewable energy resources will be acquired in sufficient amounts to comply with the requirements of SB 221, as set forth in Section 4928.64, Revised Code, without additional charge for the duration of the ESP period.

Staff notes that the Companies failed to detail in the application how they expect to comply with the AEPS statutory requirements during the ESP period (Staff Ex. 1 at 3). Staff points out Section 4928.64(C)(3), Revised Code, includes language that excuses electric distribution utilities and electric service companies from complying with the annual AEPS benchmarks if their respective annual compliance costs exceed a certain level. Staff is concerned that the reduction in the base generation rates through the use of deferrals could impact the implementation of this statute; however, until the Commission issues final rules in Case No. 08-888-EL-ORD (*Alternative and Renewable Energy Rules*) which address AEPS, it is not possible to identify the impacts, if any, that the deferrals may have on the cost cap calculations (Staff Ex. 1 at 5).

The Commission notes that, under the terms of the application filed by FirstEnergy, the costs of compliance for the renewable energy requirements under Section 4928.64(B)(2), Revised Code, are included in the modified base generation rates. Thus, customers will see no increase in rates for compliance with the renewable energy standards for 2009, 2010, and 2011 (Co. Ex. 9a at 11).

8. <u>Green Resource Rider (Rider GRN)</u>

The Companies state that, during the ESP period, the Companies will offer a green resource program through a Renewable Energy Resource Requirements and Green Resource Rider (Rider GRN), similar to the one approved in Case No. 06-1112- EL-UNC (*FirstEnergy Generation Competitive Bid Process Case*). The continuation of this rider will allow residential customers the opportunity to support alternative energy resources through the purchase of renewable energy certificates (RECs) (Co. Ex. 9a at 11; Co. Ex. 4 at 8; Co. Ex. 5 at 7).

Staff supports the Companies' proposal to continue the voluntary green product offering through Rider GRN during the ESP. Staff notes that the current Rider GRN approved in the *FirstEnergy Generation Competitive Bid Process Case* ends December 31, 2008. Staff points out that the current rider amount was determined by two independent requests for proposals which used two different definitions for RECs, one used the "green-e" renewable definition and the other used the alternative energy definition set forth in the May 27, 2007, stipulation in the *FirstEnergy Generation Competitive Bid Process Case*. Staff recommends that only the "green-e" renewable definition be used for purposes of the Rider GRN to be implemented during the ESP (Staff Ex. 8 at 11-13).

The Commission agrees with Staff witness Turkenton that only the RECs which meet the "green-e" definition should be used for purposes of Rider GRN (Staff Ex. 8 at 11-12). Therefore, the Commission finds that the ESP should be modified to clarify that only RECs which meet the "green-e" definition will be used for purposes of Rider GRN. Accordingly, Rider GRN should be approved as modified herein.

G. Distribution

1. Resolution of *FirstEnergy Distribution Rate Case* - Case No. 07-551-EL-AIR

FirstEnergy conditioned its ESP application upon a resolution of the *FirstEnergy Distribution Rate Case*, in which FirstEnergy proposes that a distribution rate increase is granted in the amount of $75 million for OE, $34.5 million for CEI, and $40.5 million for TE (Co. Ex. 9a at 19). According to FirstEnergy, the aggregate revenues from the distribution rate case expected by the Companies is $150 million per year (Co. Ex. 1 at 18). In addition, approval of the ESP would include: (1) an allowed rate of return on equity (ROE), in the distribution rate case, of 10.5 percent (2) approval of the revenue distribution and rate design stipulation submitted in the distribution rate case; and (3) approval of the Companies' proposed distribution tariffs (Co. Ex. 9a at 20).

The Commercial Group argues that the Companies' proposal in the ESP for a modified version of the distribution rate increase has not been shown to be reasonable and should not be permitted. Furthermore, the Commercial Group states that the proposed 10.5 percent ROE is excessive and has not been shown to be appropriate in light of the significant risk reduction aspect of SB 221 and FirstEnergy's use of automatic rate adjustment riders in the ESP. The Commercial Group believes that an ROE of around ten percent would be more appropriate, with a common equity ratio of total capital structure used to develop rates of no higher than 50 percent if the ESP riders and deferred cost recovery proposal are permitted (Com. Gr. Ex. 1 at 15).

As stated previously, the Commission declines to resolve in this case the substantive issues of the *FirstEnergy Distribution Rate Case*. The *FirstEnergy Distribution Rate Case* will be decided solely based upon the evidence in the record of that proceeding, and it is our intention to resolve those matters in the near future. At this time, however, theESP, as modified by this order, does not include matters more appropriately reserved for the *FirstEnergy Distribution Rate Case* and our approval of FirstEnergy's application for an ESP should not be construed as our acceptance of the proposed resolution of any of the issues in the *FirstEnergy Distribution Rate Case*.

2. Distribution Rate Freeze

The ESP provides that the new distribution base rates pending in the *FirstEnergy Distribution Rate Case* would be effective for OE and TE on January 1, 2009, and effective for CEI on May 1, 2009 (Co. Ex. 9a at 19). There is a commitment in the ESP to keep these rates in place through 2013, absent limited unforeseeable circumstances (Co. Ex. 9a at 5).

Considering the proposed rate freeze, in conjunction with other provisions of the ESP, Staff recommends against the five-year rate freeze. Staff believes that the provisions of the ESP which give the Companies the ability to defer distribution costs to be included in future rate cases and to adjust rates for certain line items should be considered in a comprehensive rate proceeding where the components of the distribution revenue requirement can be reviewed (Staff Ex. 5 at 6). Kroger and the Consumer Advocates agree that the distribution rate freeze and the distribution deferrals should not be approved and, if the Companies find it necessary to file a rate case, they should do so (Kroger Ex. 1 at 14; Con. Adv. Br. at 40-41).

The Commission finds that FirstEnergy's application should be modified to eliminate the proposed distribution rate freeze. As noted by Staff witness Fortney, FirstEnergy has proposed a number of new distribution deferrals which are linked to the proposed distribution rate freeze (Staff Ex. 5 at 5-8). As we discuss below, the Commission does not believe that additional distribution deferrals are necessary or appropriate at this time. We believe that it would be unfair to FirstEnergy to accept the proposed distribution rate freeze while rejecting the request for deferral authority. Accordingly, FirstEnergy's ESP should be modified to eliminate the proposed distribution rate freeze.

3. <u>CEI and Distribution Service Rider</u>

The Distribution Service Rider proposed in the ESP is only applicable to CEI customers from January 1, 2009, through April 30, 2009. FirstEnergy explains that this rider is necessary because the proposed non-distribution tariffs will be effective January 1, 2009, under the new rate schedule classifications proposed in the *FirstEnergy Distribution Rate Case*, but the proposed distribution tariff changes are not effective until May 1, 2009. Therefore, the Companies state that this rider provides a means of integrating the new rate classifications with the current rate schedule distribution related charges. The Distribution Service Rider will not be effective after April 30, 2009, when the distribution charges will be calculated based on the new proposed rate classifications (Co. Ex. 4 at 7). The Commission finds that, because we have retained the existing rate design and tariff structure for generation rates, there is no mismatch of rate design to address. Therefore, the proposed Distribution Service Rider for CEI is unnecessary and the ESP should be modified to eliminate this rider.

4. <u>Additional Deferred Distribution Costs - Storm Damage and Distribution Enhancement Rider</u>

The ESP provides that, during the period January 1, 2009, through December 31, 2013, the Companies, in the aggregate, may defer certain distribution costs and expenses. Pursuant to the ESP, the Storm Damage and Distribution Enhancement Rider would be an unavoidable rider that would recover deferrals for: (1) storm damage expenses in excess of $13.9 million annually; (2) additional costs, including post-in-service carrying charges, resulting from any changes in the recovery of line extension costs, as a result of rules or policies implemented pursuant to Section 4928.151, Revised Code, compared to the

Companies' proposal in the *FirstEnergy Distribution Rate Case*; and (3) depreciation, property tax obligations, and post-in-service carrying charges on gross plant distribution capital investments placed in service after December 31, 2008, and made to improve reliability and/or enhance the efficiency of the distribution system. The Companies request that the interest on these items be deferred monthly during the period of January 1, 2009, through December 31, 2013, at a rate of 0.7083 percent. This rider would commence on January 1, 2014, and continue for a ten-year period (Co. Ex. 9a at 22; Co. Ex. 2 at 4).

OCC believes that continued use of deferrals regarding line extensions should end (OCC Ex. 1 at 37). The Commercial Group submits that the Companies' proposed rate moratorium coupled with deferrals of the revenue requirements associated with new line extensions and new plant investments will result in the over-recovery of distribution investment costs (Com. Gr. Ex. 1 at 17). Staff recommends that the Companies be permitted to apply to the Commission for recovery of incremental storm damage expenses (Staff Br. at 12).

The Commission agrees with Staff witness Fortney that the expenses which the Companies seek to recover through this rider are best reviewed in a distribution rate case where all components of distribution rates are subject to review (Staff Ex. 5 at 7-8). Further, as discussed above, we have modified FirstEnergy's ESP to eliminate the proposed distribution rate freeze. Therefore, we find that the additional distribution deferrals are neither necessary nor appropriate at this time. Accordingly, the Companies' ESP should be modified to eliminate the distribution deferrals.

5. System Average Interruption Duration Index (SAIDI) Reliability Performance

The Companies are proposing in the ESP that appropriate system average interruption duration index (SAIDI) performance targets be established and that they be designed with performance incentives for the Companies which are skewed to benefit customers (Co. Ex. 9a at 6). Currently, the SAIDI target for TE and OE is 120 minutes and the target for CEI is 95 minutes (Co. Ex. 9a at 21; Co. Ex. 3 at 5). The Companies are proposing that the SAIDI target for CEI be revised to 120 minutes (Co. Ex. 9a at 21; Co. Ex. 3 at 6). In support of the modified SAIDI for CEI, the Companies state that CEI has the most aged distribution system of the three electric utilities and CEI's system design and service area geography make it more difficult that the other two companies to maintain a low SAIDI (Co. Ex. 3 at 6).

According to the ESP, the proposed 120 minute SAIDI targets would be coupled with a reliability performance band between 90 minutes and 135 minutes from January 1, 2009, through December 31, 2013 (Co. Ex. 9a, Att. B). FirstEnergy believes that a performance band is necessary because it recognizes that, with changing weather conditions and other factors outside of the Companies' control, using an absolute number as a performance criterion is not practical. The Companies argue that the proposed performance band is asymmetrically skewed to benefit customers. Furthermore, they contend that, regardless of whether the Companies perform at the high end or the low end of the proposed band, they would remain in the first or second quartile of industry performance (Co. Ex. 3 at 8).

In order to ensure that reliability is measured on an apples-to-apples basis between the three electric utilities, the Companies propose a rear lot reduction factor for CEI, which is a mechanism that establishes an outage duration time which takes into consideration the challenges of rear lot construction in CEI's service area. This mechanism would only apply to CEI and it would multiply CEI's customer outage minutes by a factor of .5 on such circuits where 50 percent or more of the premises are served by rear lot facilities (Co. Ex. 9a, Att. E; Co. Ex. 3 at 6-7). According to the Companies, CEI has 439 circuits where over 50 percent of the customers on those circuits are served from rear lot facilities (Co. Ex. 9a at 9; Co. Ex. 3 at 7; Tr. III at 254). These 439 circuits represent slightly less than 50 percent of CEI's total number of circuits of 1,086 (Co. Ex. 9a at 9; Co. Ex. 3 at 7; OCC Ex. 2 at 28).

The Companies propose that, for purposes of the ESP and all reporting requirements pursuant to Rule 4901:1-10, Ohio Administrative Code (O.A.C.), each of the Companies' SAIDI targets be calculated using the methodology that has been accepted by the Staff, including that major storm exclusions are generally defined as events affecting six percent of the customers in a 12-hour period (Co. Ex. 9a, Att. E).

In response to the Companies' proposal, Staff states that it does not believe that SAIDI should be the only performance measurement to determine the level of electric service that an electric utility should provide its customers (Staff Ex. 3 at 6). In addition, Staff does not support the Companies' proposal to apply a performance band to the SAIDI performance targets. Staff has always considered performance targets to be minimum performance levels and, when a minimum level is not met, then the electric utility must provide an action plan. Under the Companies' proposal, if a minimum level is not met, the Companies are not required to provide an action plan to improve service. Further, as far as performing better than the minimum, Staff believes that all electric utilities should strive to perform better than their minimum targets (Staff Ex. 3 at 9).

In addition, both Staff and OCC oppose the rear lot reduction proposal for CEI's performance index (Staff Ex. 3 at 6; OCC Ex. 2 at 26). OCC believes that the proposed increase in the SAIDI target for CEI to 120 minutes will mitigate any potential impact due to rear lot construction (OCC Ex. 2 at 30).

The Commission notes that there is substantial evidence in the record that the proposed SAIDI adjustment should be considered. According to the record in this case, CEI's SAIDI target is 95 minutes (Co. Ex. 3 at 5). FirstEnergy witness Schneider testified that a recent study by the Institute of Electrical and Electronics Engineers indicated that a SAIDI performance of 89 would be in the top decile of performance of 100 electric distribution companies while a SAIDI performance of 135 would be in the middle of the second quartile. (Co. Ex. 3 at 9). Staff witness Roberts agreed that this study is entitled to be given weight by the Commission (Tr. VII at 318-319). Therefore, based upon the evidence in the record, in order to meet its SAIDI target of 95, CEI's SAIDI would need to be nearly in the top decile of electric distribution companies in this country and well above the middle of the second quartile. Further, Staff witness Roberts testified that CEI could meet this target only under "perfect" or "near perfect" conditions (Tr. VII at 308-309).

Further, the Commission points out that Chapter 4901:1-10, O.A.C., contains rules for amending electric service reliability targets and, in Case No. 06-653-EL-ORD (*Electric Service and Safety Standards*), we recently adopted new rules in this chapter for amending electric service reliability standards. Although the evidence in the record indicates that the change in the SAIDI target may be reasonable, the Commission believes that the established process, set forth in Chapter 4901:1-10, O.A.C., for amending electric service reliability targets with the agreement of the Staff should be followed. Further, if an electric utility and Staff cannot agree upon a revision to a reliability target, the rules provide that they may seek a hearing before the Commission to resolve the dispute. Therefore, FirstEnergy should follow this established process for setting distribution reliability targets if it believes that conditions warrant a downward revision of its SAIDI target. Likewise, with regard to FirstEnergy's request for a rear lot reduction factor for CEI, FirstEnergy should present its arguments for this factor in conjunction with its proposal for a revision to CEI's SAIDI target. Accordingly, we will decline to amend CEI's SAIDI target, and we will modify FirstEnergy's ESP to eliminate the proposed change to the SAIDI target, as well as the implementation of a rear lot reduction factor.

6. <u>Distribution Service Improvement Rider (Rider DSI)</u>

The Companies explain that, consistent with Section 4928.143(B)(2)(h), Revised Code, they are proposing a Distribution Service Improvement Rider (Rider DSI) (Co. Ex. 9a, Att. E). Rider DSI would be an unavoidable rider that would ensure that the expectations of the Companies and the customers pertaining to distribution reliability are aligned. According to the Companies, Rider DSI would help them manage the increasing costs of providing electric distribution service, the need to extend capital for equipment earlier than before, the need to train new employees to replace retirees, the need to replace components of an aging distribution system, the importance of reliability, and the emergence of new technology, such as Smart Grid technology (Co. Ex. 9a at 21; Co. Ex. 3 at 3-4). Rider DSI would be effective from January 1, 2009, through December 31, 2011 (Co. Ex. 9a at 21; Co. Ex. 3 at 4). This rider would be adjusted up or down by up to 15 percent annually, based upon the Companies meeting certain goals related to distribution reliability, as reflected in the SAIDI performance adjustments (Co. Ex. 9a at 6, 21, Att. E; Co. Ex. 3 at 5). The Companies explain that, if an individual company's SAIDI performance for the previous reporting period is higher than 135 minutes, then Rider DSI would be adjusted downward; however, if a company's SAIDI performance is less than 90 minutes, then Rider DSI will be adjusted upward. Prior to this adjustment, the Companies state that the rider would, on average, be 0.2 cents per kWh in 2009 through 2011. For 2012 through 2013, Rider DSI would be set at 0.0 cents per kWh, but remain in place to effectuate any SAIDI performance adjustments (Co. Ex. 9a at 21, Att. E; Co. Ex. 3 at 5). The ESP provides that Rider DSI would not be considered a contribution in aid of construction or be used in any determination of excessive earnings (Co. Ex. 9a at 22; Co. Ex. 3 at 5).

Staff, OCC, OPAE, and Kroger oppose the Companies' proposal for Rider DSI, stating that it has no connection with recovery of actual costs (Staff Ex. 3 at 3; OCC Ex. 2 at 35; OPAE Ex. 1 at 28; Kroger Ex. 1 at 5). Staff states, and OPAE and OCC similarly agree, that the proposal does not contain defined programs with associated costs and benefits, nor does it quantify how much of the cost is incremental to current spending (Staff Ex. 3 at 3; OPAE Ex. 1 at 28; OCC Ex. 3 at 35). Staff believes that the items which the Companies are seeking recovery for in this rider are part of the day-to-day operations of any electric utility company and should not require special funding (Staff Ex. 3 at 3). Further, the Consumer Advocates note that Rider DSI is not properly structured as an incentive plan as required in Section 4928.143(B)(2)(h), Revised Code (Con. Adv. Br. at 31).

OCC, OPAE, and the Commercial Group believe that it is inappropriate to provide price enhancements to the Companies as part of Rider DSI for simply accomplishing what they are expected to provide (OCC Ex. 1 at 35; OPAE Ex. 1 at 31; Com. Gr. Ex. 1 at 17). However, OCC states that, if the Commission were to allow Rider DSI, it would not be opposed to the use of only SAIDI for adjustment of the proposed rider. OCC's research shows that from 2000 through 2007 the Companies had gone over the proposed 135 upper limit of the SAIDI band five times for CEI, twice for TE, and once for OE; for that same period TE went under the proposed 90 lower limit of the SAIDI band four times (OCC Ex. 2 at 22-24).

In response to the intervenors' comments, FirstEnergy emphasizes that this is not a cost-based proceeding. FirstEnergy states that Rider DSI is not based on historically incurred costs, rather, it takes advantage of the provisions in Section 4928.143, Revised Code, that permits the Companies to implement an incentive-based distribution charge. According to the Companies, Rider DSI provides an important incentive to them to achieve a level of service reliability (Co. Br. at 56-57).

The Commission finds that FirstEnergy demonstrated in the record that it faces increased costs due to the need for workforce replacements and for replacing infrastructure (Co. Ex. 3 at 3-4). However, the Commission does not believe that a distribution rider should be approved, unless it is based on a reasonable, forward-looking modernization program and prudently incurred costs. At the hearing, Staff indicated that it could only support mechanisms such as Rider DSI if such mechanism is cost-based (Tr. VII at 302). The Commission believes that this is a sound policy. Although Section 4928.143(B)(2)(h), Revised Code, does provide for distribution modernization riders as part of an ESP, following the sound policy goals of Section 4928.02, Revised Code, the Commission believes that such riders should be based upon prudently incurred costs, including a reasonable return on investment for the electric utility. However, the Companies have not demonstrated that the proposed Rider DSI is based on a reasonable, forward-looking distribution modernization program. Moreover, the testimony in this case clearly represented that the proposed Rider DSI is not cost-based. The Commission does not believe that a distribution rider should be approved, unless the program is shown to comply with both the intent and the scope of the statute and that it is based upon prudently incurred costs. Accordingly, the Commission finds that Rider DSI, as proposed in the ESP, should be modified.

Our approval of Rider DSI is conditioned upon the Companies developing a distribution infrastructure improvement program that reflects the intent and scope of the statute that is inclusive of all infrastructure considerations including, but not limited to, improved workforce and assest utilization, workforce replacement, infrastructure replacement, present and future needs for service reliability and power quality, cyber-security, facilitation of demand response, integration of distributed generation and storage (including electric vehicles), use of Smart Grid technologies, and AMI deployment. To that end, FirstEnergy should work with the Staff to develop a program which comports with this requirement.

Furthermore, while we will set Rider DSI initially at $0.002 per kWh, we believe that this rider should be based on FirstEnergy's actual, prudently incurred costs, including a return on FirstEnergy's investment equal to the rate of return authorized in the *FirstEnergy Distribution Rate Case*. To that end, Rider DSI will be subject to Commission review and reconciliation on an annual basis. Accordingly, Rider DSI should be approved, as modified herein.

7. <u>Capital Improvement Commitment to Distribution System</u>

As part of the ESP, the Companies will commit to invest in the aggregate at least $1 billion in capital improvements in their energy delivery systems through 2013 (Co. Ex. 9a at 6, 22; Co. Ex. 3 at 10). Staff supports this commitment by the Companies because it represents a continuation of the Companies' capital spending over the past five years (Staff Ex. 3 at 4).

The Consumer Advocates state that FirstEnergy's ESP, including the $1 billion commitment in capital improvements, should not be approved. According to the Consumer Advocates, FirstEnergy has not forecasted any improvements in distribution reliability as a result of the commitment and no assurances have been given by FirstEnergy that its commitment to capital spending will have any beneficial effect on customers (Con. Adv. Br. at 50-51).

To ensure that consumers benefit from this commitment, the Commission finds that the Companies should work with staff to develop a capital improvement program that advances state policy and is consistent the distribution infrastructure modernization program described in our findings on Rider DSI. Accordingly, the Commission finds that FirstEnergy's capital improvement commitment, as proposed in the ESP, should be approved.

H. Regulatory Transition Charge and Residential Transition Rate Credit

The Companies propose to waive, on a services rendered basis, on or after January 1, 2009, further regulatory transition charges (RTCs) and extended RTCs for CEI customers, which would otherwise continue through 2010 (Co. Ex. 9a at 9; Co. Ex. 2 at 8). In addition, in accordance with the ESP, as of January 1, 2009, residential customers will not receive transition rate credits. The transition rate credits equate to $5.00 per month for residential customers of CEI and TE, and $1.50 per month for OE residential customers. Furthermore, the credits include a reduction of the RTC by 23.3 percent, 12.8 percent, and 11.4 percent for OE, CEI, and TE residential customers, respectively. These credits were approved in Case No. 99-1212-EL-ETP (*FirstEnergy Electric Transition Plan [ETP] Case*). FirstEnergy states that the value to customers over the period of the ESP of the waiver of the RTCs and extended RTCs, not the residential credits, is $591 million (Co. Ex. 9a at 9; Co. Ex. 1 at 17).

The Commission finds that the Companies' proposal to waive the RTCs and extended RTCs for CEI customers and eliminate the transition rate credits effective January 1, 2009, is reasonable and should be approved.

I. AMI, Smart Grid, Energy Efficiency, Demand Response, Economic Development, and Job Retention

1. Energy Efficiency and Demand Response

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

As part of the ESP, the Companies commit up to $25 million to support energy efficiency and demand response programs (Co. Ex. 9a at 7). According to the Companies, they commit to provide up to $5 million of investment each year from January 1, 2009, through December 31, 2013, for these programs and will not request recovery for these costs (Co. Ex. 9a at 25).

Staff supports the Companies' commitment to contribute shareholder money toward energy efficiency and demand reduction programs, but states that it is unlikely that such a funding level itself will meet the required statutory benchmarks (Staff Ex. 2 at 14). OCC and OEC agree that the funding level is not sufficient to meet the statutory requirements (OCC Ex. 1 at 7; OEC Ex. 1 at 4). OEC states that FirstEnergy would need to increase its annual spending to approximately $28 million to reach the statutory energy saving requirement (OEC Ex. 1 at 10). OCC recommends that, in addition to the $5 million per year of shareholder money, the ratepayers contribute approximately $44 million per year, which equates to about $24.25 per customer, for a total of $49 million per year in order to meet the requirements. Further, OCC recommends that the remainder of the funding for DSM programs approved in Case No. 05-1125-EL-ATA et al. (*FirstEnergy Rate Certainty Plan [RCP] Case*) be used as part of the $44 million ratepayer contribution for the first year of the ESP (OCC Ex. 1 at 7-8).

OCC, NRDC, OPAE, and OEC submit that the Companies' DSM proposal in the ESP is seriously lacking detail and insufficient (OCC Ex. 1 at 5; NRDC Ex. 1 at 3-4; OPAE Ex. 1 at 21; OEC Ex. 1 at 11;). OCC submits that, for FirstEnergy to fail to provide a more substantial DSM filing knowing that SB 221 requires a significant DSM portfolio is objectionable (OCC Ex. 1 at 5-6). OCC recommends that the Companies continue to fund their existing DSM programs and add DSM programs such as: programs for appliances, air-conditioning, and new construction for residential customers; programs for business and state office buildings; and programs for commercial and industrial customers. OCC recommends that the total resource cost test be used to evaluate the cost-effectiveness of the Companies' energy efficiency programs (OCC Ex. 1 at 10-11). COSE agrees that the Companies should specifically include small business and commercial class customers in the ESP energy efficiency education and demand management activities. Further, COSE believes that a specific minimum allocation of resources to commercial class customers should be included in the ESP (COSE Ex. 1 at 2-4).

OPAE notes that the plan fails to provide any significant energy efficiency program targeted to at-risk populations. OPAE states that FirstEnergy should fund a substantial expansion of current programs aimed at low-income, elderly, and at-risk residential customers as part of the overall efficiency and DSM portfolio of programs. In addition, OPAE requests that the Companies be ordered to continue to fund the existing low-income programs until a collaborative can develop a comprehensive portfolio of programs (OPAE Ex. 1 at 23; OPAE Br. at 8-9).

IEU-Ohio submits that customer-sited capabilities are a means that an electric utility may use to comply with the portfolio requirements of SB 221. However, IEU-Ohio points out that the ESP fails to set forth the details regarding how customer-sited capabilities will be relied on to meet this requirement; therefore, IEU-Ohio proposes that FirstEnergy be ordered to supplement the application and provide additional specificity on how the customer-sited capabilities will be accommodated under the ESP (IEU-Ohio Ex. 1 at 5; IEU-Ohio Br. at 18). OHA agrees that FirstEnergy should be required to create a plan that encourages the use of customer-sited generation in order to satisfy the portfolio requirements under the statute (OHA Br. at 20-21). The Commercial Group recommends that the programs be expanded to provide an option for customers to participate in wholesale demand response programs or other such programs at the wholesale level (Com. Gr. Ex. 1 at 9).

Staff, NRDC, OPAE, Citizens' Coalition, and OCC recommend that a collaborative process be formed with respect to the selection and development of energy efficiency and peak demand programs (Staff Ex. 2 at 14; NRDC Ex. 1 at 8; OPAE Ex. 1 at 22; Cit. Coal. Br. at 4; OCC Ex. 1 at 8). In addition, Staff recommends that the Companies contract with an independent third-party to measure and verify the energy and peak reduction savings for the programs (Staff Ex. 2 at 14). OCC also suggests that another option might be for the Companies to develop a standard DSM offer, with collaborative input, and pay a third-party provider of the energy efficiency a fixed kWh charge (OCC Ex. 1 at 9). OPAE agrees that the collaborative should hire a third-party administrator (OPAE Ex. 1 at 23). NRDC submits that, in this case, a third-party administrator should be selected through a competitive bid process because, according to NRDC, the Companies have limited experience with energy efficiency and have shown little desire to develop a comprehensive range of programs. NRDC believes that the third-party administrator should be paid for out of ratepayer funds (NRDC Ex. 1 at 5, 8-9).

In determining the appropriate benchmarks for meeting the statutory requirements, Staff recommends that the Companies use a 30-year rolling average of weather data with a 65-degree day as part of their forecasting method to determine weather normalized sales and peak load (Staff Ex. 2 at 9). In addition, Staff recommends that the Companies evaluate their current programs and consider and undertake a market potential study that will include an analysis of the appropriate program designs that will result in the Companies achieving the required statutory benchmarks. With regard to the inclusion of the energy savings and peak demand reductions from mercantile customers to be committed to the Companies for integration, if the Companies would like to count such efforts toward their benchmarks, Staff states that they would need to submit such requests to the Commission for consideration on a case-by-case basis. As for interruptible programs counting toward annual benchmarks, Staff believes that such reductions would have to actually occur to be credited (Staff Ex. 2 at 12-13).

In response to the criticisms of the energy efficiency and demand response proposal in the ESP, FirstEnergy states that its commitment to spend up to $25 million of shareholder funds on the programs should not be taken to mean that this is the upper limit of what it will spend to meet the benchmarks in Section 4928.66, Revised Code. FirstEnergy believes that the concerns raised by the intervenors are premature and that they would best be addressed in a future proceeding dedicated to reviewing the Companies' benchmark report that will be filed in conformance with the Commission's rules and the statute (Co. Br. at 36).

The Commission notes that Section 4928.66, Revised Code, requires electric utilities to meet certain energy efficiency and demand response requirements and to advance state goals. Like some of the intervenors, we believe that FirstEnergy has yet to develop energy efficiency and demand response programs sufficient to comply with those obligations. To assist with that endeavor, the Commission agrees with the recommendation of numerous intervenors that a collaborative process should be formed with respect to the selection and development of energy efficiency and peak demand programs. Therefore, FirstEnergy should initiate a collaborative in order to assist the Companies in meeting their obligations.

Turning now to the commitment of funds set forth in the proposed ESP, the Commission notes that, regardless of the commitment attested to in the plan, it is the Companies' duty to meet the energy efficiency and demand response requirements set forth in the statute and to comply with any rules adopted thereunder. The provisions of Section 4928.66(C), Revised Code, have been determined by the General Assembly to be a sufficient enforcement mechanism to ensure electric utilities' compliance with the energy efficiency and demand response requirements, and the Companies will be expected to make the expenditures necessary to meet those requirements. With an, as yet undefined program, the Commission believes that it is meaningless for the Companies to set forth any dollar figure in the plan because, regardless of the dollar amount set forth in the plan, the Companies are bound by the statute to comply with the energy efficiency and demand response requirements. Accordingly, the Commission finds that Companies' application should be modified to eliminate the proposed commitment of funds.

2. <u>Demand Side Management and Energy Efficiency (Rider DSE)</u>

Pursuant to the ESP, Rider DSE would recover costs incurred by the Companies associated with energy efficiency, peak load reduction, and DSM programs, including recovery of lost distribution revenues resulting from implementation of such programs and any unrecovered DSM program costs from the *FirstEnergy RCP Case* (Co. Ex. 9a at 27). Rider DSE includes two components which are updated semi-annually: DSE1, which is a \$0.0193 per kWh charge; and DSE2, which reimburses the Companies for past and future costs incurred in complying with energy efficiency and peak demand reduction requirements, including costs for programs approved in the *FirstEnergy RCP Case* (Co. Sch. 5o at 16-17; Co. Br. at 39). The Companies explain that, as permitted by Section 4928.143(B)(2)(i), since the Companies are part of the same holding company, this rider will be determined and allocated across all classes of customers of all the Companies (Co. Ex. 9a at 28). As explained by FirstEnergy, customers may avoid Rider DSE2 by implementing customer-sited programs that help the Companies secure compliance with Section 4928.66, Revised Code (Co. Ex. 4 at 11).

IEU-Ohio notes that customers are not eligible to avoid DSE2 charges if they are taking service under either a unique arrangement or the Reasonable Arrangements Rider (Rider RAR). IEU-Ohio believes that this limitation is contrary to Section 4928.66(A)(2)(c), Revised Code (Co. Ex. 9c at 62; IEU-Ohio Br. at 19). Furthermore, IEU-Ohio points out that Rider DSE2 is initially set a \$0 in the ESP and the earliest date this charge could increase for non-residential customers would be January 1, 2010. Therefore, IEU-Ohio states that, at least initially, the avoidability of the rider will not provide any economic incentives to implement customer-sited capabilities (IEU-Ohio Ex. 1 at 5). Contrary to IEU-Ohio's understanding, the Companies clarify that costs to be recovered as part of the DSE2 charge for non-residential customers will be included in the rider as early as mid-2009. The Companies believe that, if the estimates by certain parties are accurate, the costs to implement programs in 2009 will result in a material incentive to avoid DSE2 charge (Co. Br. at 39).

The Commercial Group believes that an energy allocation of the costs in Rider DSE is inappropriate because none of the costs proposed to be recovered varies with the customers' usage and such allocation will improperly allocate costs to the high-load factor customers (Com. Gr. Ex. 1 at 3). In addition, the Commercial Group insists that the proposal to recover lost distribution revenues in the rider be rejected. Furthermore, the Commercial Group states that the opt-out provisions of the rider should include customers that have already made investments in DSM and energy efficiency programs (Com. Gr. Ex. 1 at 9).

OEC recommends that FirstEnergy's eligibility standards for relief from the rider should include: a threshold for the amount of energy savings a mercantile customer must demonstrate to be eligible for exemption; a high standard for documentation and independent review of the documentation; requirements that only projects with an avoided contribution in excess of \$10,000 would qualify for the exemption; and a requirement that the customer will not qualify for the exemption if its percentage of claimed savings is below the applicable benchmark the Companies are subject to (OEC Ex.

1 at 21-23). IEU-Ohio points out that Section 4928.66(A)(2)(c), Revised Code requires all mercantile demand-response programs, peak demand reduction programs, and all mercantile customer-sited energy efficiency programs to be included in the measurement of compliance with the statutory benchmark. Therefore, IEU-Ohio argues that OEC's recommendation to limit a mercantile customer's opportunity to commit it efficiency and peak demand reduction capabilities towards the Companies' portfolio obligations is contrary to Ohio law and the Commission's rules (IEU-Ohio Br. at 20-21).

Upon consideration of the issues raised by the various parties, the Commission believes that the Companies' proposed Rider DSE is reasonable as proposed. Accordingly, Rider DSE should be approved.

3. AMI Pilot Program and Dynamic Peak Pricing Program

The Companies state that, as part of the ESP, they will provide $1 million toward a residential AMI pilot program and a dynamic peak pricing program to determine the potential for deployment of advanced technologies to support time-of-day pricing and other demand response and energy efficiency programs (Co. Ex. 9a at 7; Co. Ex. 4 at 16). According to the Companies, any costs incurred above $1 million will be recovered through Rider DSE. The Companies explain that the AMI pilot will be conducted with 500 customers, at a cost of between $500 and $1,000 per customer for the meters and installation. The Companies intend to solicit customer participation through a direct mailing. AMI pilot participants will be subject to the dynamic peak pricing program wherein, during the summer months, the generation rates will vary based upon time-of-use periods. Participants will be encouraged to shift or decrease energy usage during peak times on non-critical days. In addition, the Companies will provide notification to the participants via e-mail, telephone, or text message the day before a critical peak day event encouraging the participants to decrease usage (Co. Ex. 9a at 23-24, Att. F).

The Companies also propose to implement a collaborative process, within 60 days after the final order in this case, in which interested stakeholders can provide input on the AMI process and the pilot program. The Companies propose a six-month process for the collaborative, after which they would evaluate the findings and they may file an AMI plan with the Commission which would include a cost recovery mechanism (Co. Ex. 9a at 23-24, Att. F).

OCC is supportive of the proposed AMI pilot program, but believes that the size of the program, 500 participants, is meager (OCC Ex. 1 at 15). Staff believes that the Companies could deploy AMI meters for a lower cost than the Companies estimated, which would allow them to deploy more than 500 meters before they reached the $1 million threshold. Staff recommends that the Companies select the participants based on some form of stratification of the class so that the pilot sample more fully reflects the diversified makeup of the class. In addition, Staff advocates, and the Consumer Groups agree, that any costs above the $1 million threshold should be recovered through an AMI rider, rather than Rider DSE (Staff Ex. 2 at 3, 6; Cons. Gr. Reply Br.[3] at 34).

According to Staff, the Companies are proposing that pilot participants be placed on the dynamic peak pricing rider, which provides customers prices that are more reflective of market prices. However, Staff recommends some form of critical peak pricing rebate for residential customers so that the customers would know in advance that they would pay a fixed amount for a portion of their consumption. Staff also recommends that a similar pilot be made available to commercial customers (Staff Ex. 2 at 6-7). Staff and OCC recommend that technology, such as a programmable thermostat, be offered to the participants (Staff Ex. 2 at 7; OCC Ex. 1 at 18).

OCC recommends that the Companies be required to provide tariffs that make various rate options available for the customers and that they be required to provide cost information on the billing system changes needed to accommodate wide-scale deployment of dynamic pricing. Specifically, with regard to the dynamic peak pricing program, OCC notes that the Companies are proposing only two time-of-use periods, on-peak and off-peak, along with a critical peak period. OCC recommends that the Companies add another shoulder pricing period to the program which it believes will make the program more appealing to customers and allow customers more flexibility to manage their usage (OCC Ex. 1 at 16-18).

NRDC maintains that the question posed for the AMI pilot has already been answered in other studies that have proven that summer time-of-day rates can change customer energy use behavior. Therefore, NRDC advocates that the money for the AMI pilot would be better spent after the Smart Grid study is completed if it is used to validate the savings and benefits from the deployment of Smart Grid technologies (NRDC Ex. 1 at 13).

OPAE believes that, rather than starting from the premise that smart or advanced metering systems are required to achieve customer benefits through price changes, the Companies should evaluate how to achieve peak load reduction from residential customers in the cheapest way possible. OPAE states that the cost of the proposed AMI pilot is very high and there is no basis in the ESP to justify the cost estimates for this program (OPAE Ex. 1 at 25, 27).

The Commission believes it is important that steps be taken by the electric utilities to explore and implement technologies, such as AMI, that will potentially provide benefits

3 OCC, Cleveland, NRDC, Sierra Club, NOAC, Citizen Power, and Citizens Coalition filed a joint reply brief; therefore, when referring to the arguments in this document these parties will be referred to as the Consumer Groups.

to customers in the long-run. We do not agree with NRDC that the AMI pilot program should be delayed until after the Smart Grid study is completed. Rather, we support time-differentiated and dynamic pricing based on the policies of SB 221 and as an essential component in an efficient market. We believe that a well designed AMI pilot program can represent an additional step in the right direction and should be pursued. The Staff testified that it believes that the Companies may be able to deploy AMI meters for a lower cost than they have estimated in the ESP. If this is the case, then the Commission would encourage the Companies to expand the pilot program to include additional customers. Taking note of a significant number of pilot programs showing that residential consumers will respond to time-differentiated pricing and generally find such pricing beneficial, the Companies should focus in the pilot on investigating detailed questions relating to AMI performance and how to use enabling technologies, pricing, and information to enhance the demand-response benefits from large-scale deployment of AMI. While there were other interesting proposals made by various parties regarding the AMI pilot program and the dynamic peak pricing program proposed by the Companies, the Commission suggests that these topics would best be explored as part of the collaborative process proposed by the Companies. We also encourage the Companies to fund an independent evaluation of the pilot program. Accordingly, consistent with these findings, we conclude that the Companies' AMI pilot program and the dynamic peak pricing program should be approved.

4. Economic Development and Job Retention Programs

The Companies propose to commit up to $25 million for economic development and job retention programs (Co. Ex. 9a at 7). According to the Companies, they will provide up to $5 million of investment each year from January 1, 2009, through December 31, 2013, for these programs and will not request recovery for these investments (Co. Ex. 9a at 26).

As discussed above, the Commission has reduced the base generation rates proposed by the Companies in order to promote the economic recovery in Ohio and has denied the proposed generation deferrals. The Commission believes that, in light of these steps and the modifications, FirstEnergy's commitment of $25 million should be used as the first $25 million of delta revenue contributed by the Companies under Rider DRR. With this understanding, the Commission finds that the proposed commitment of additional funds for economic development should be approved.

5. Economic Development (Rider EDR)

Pursuant to the ESP, Rider EDR would be an unavoidable rider that would promote gradualism, recognize the efficient use of electricity, and mitigate the overall bill impacts to customers through a series of credits and charges. The sum of all credits and charges in Rider EDR would be revenue neutral for the Companies and any differences would be reconciled on an annual basis (Co. Ex. 9a at 26). According to the Companies, Rider EDR is designed for interruptible customers who are taking service as of July 31, 2008 (Co. Ex. 5 at 23). In support of the proposal that this rider be unavoidable, FirstEnergy submits that this is a social charge and, if these charges were avoidable, it would be difficult, if not impossible, for the Companies to promote and sustain this effort (Co. Ex. 4 at 9). The Companies explain that, as permitted by Section 4928.143(B)(2)(i), Revised Code, since the Companies are part of the same holding company, this rider would be determined and allocated across all classes of customers of all the Companies (Co. Ex. 9a at 28).

OmniSource argues that FirstEnergy has provided no justification as to why the proposed interruptible credit in Rider EDR should be limited to those loads contractually obligated to interruptible service as of July 31, 2008. According to OmniSource, the limited applicability of the credit to existing interruptible load is contrary to the concepts of gradualism and the desire to mitigate the overall bill impacts expressed by the Companies. OmniSource notes that, without the credit under Rider EDR, it will experience a disproportionately large rate increase. Therefore, OmniSource advocates that the interruptible credit be made available for new transmission voltage, interruptible load customers (OmniSource Br. at 2-4).

As discussed previously, OEG recommends that its proposed rate mitigation plan be accomplished via Rider EDR. OEG agrees that Rider EDR should be an unavoidable rider (OEG Ex. 1 at 23).

The Commercial Group believes that an energy allocation of the costs in Rider EDR is inappropriate because none of the costs proposed to be recovered varies with the customers' usage and such allocation will improperly allocate costs to the high-load factor customers (Com. Gr. Ex. 1 at 3). The Competitive Suppliers advocate that, if all customers pay for the incentives, then Rider EDR should be modified so that customers taking service from either FirstEnergy or a competitive supplier should be eligible to receive a discount in exchange for job retention, economic development, or other programs (Comp. Supp. Br. at 20).

In light of the fact that the Commission has directed the Companies to continue their existing generation rate design and tariff structure until a new revised rate design is filed with and approved by the Commission, the Commission finds that Rider EDR is unnecessary. Accordingly, the ESP should be modified to eliminate Rider EDR.

6. Energy for Education

FirstEnergy has not proposed either in the *FirstEnergy Distribution Rate Case* or in this case to renew its existing Energy for Education II electricity program, which gives public schools a discount in exchange for the prepayment of their bills, using the schools' bonding authority.

According to OSC, by adopting the rate design advocated by the Companies in the *FirstEnergy Distribution Rate Case*, the ESP completely ignores the rate impacts on the schools as a unique customer class (OSC Br. at 6). OSC argues that the elimination of school rates and the forced inclusion of the schools in the general service classes, without a proper rate adjustment to reflect the schools' actual and lower cost of service, constitute an unreasonable, undue, and unlawful prejudice and disadvantage to this customer class contrary to Ohio law (OSC Br. at 10).

OSC represents 249 public school districts that currently participate in FirstEnergy's Energy of Education II program; these school districts represent 41 percent of all public school districts in the state of Ohio. According to OSC, the Energy for Education II program provided an average of 13.4 percent discount in the schools' electric rates and saved the 249 participating school districts $11.7 million in 2008 (OSC Ex. 1 at 2-4; OSC Ex. 2). OSC indicates that the Companies' proposal to eliminate the currently available school rates effective December 31, 2008, the proposed generation and distribution rate increases, and the proposed riders will result in severe increases in electric costs for public school customers in a manner incongruous with the schools' usage characteristics. OSC states that continuation of the Energy of Education program is critical to the education of Ohio's children and the promotion of economic development in the state. OSC points out that there is a complete record in the *FirstEnergy Distribution Rate Case* upon which the Commission can make its determination concerning the continuation of this program (OSC Ex. 1 at 6, 9). OSC recommends that approval of FirstEnergy's ESP should be conditioned upon the Companies offering the public school districts within their territory an Energy of Education III program or a school rider. According to OSC, either of these alternatives is appropriate in order to mitigate the rate increases proposed for schools and to apply the principle of gradualism (OSC Ex. 1 at 12; OSC Br. at 22-23).

As stated previously, the Commission is concerned about the elimination of the discount provided to public schools in FirstEnergy's territory. Although this has been partially addressed by the continuation of FirstEnergy's existing rate design and tariff structure, the Commission agrees that FirstEnergy should implement a new Energy for Education program which is consistent with the existing Energy for Education II program (OSC Ex. 1 at 2-4; OSC Ex. 2). Accordingly, the ESP should be modified consistent with this determination.

7. <u>Economic Load Response Program (Rider ELR) and Optional Load Response Program (Rider OLR)</u>

According to FirstEnergy, Rider ELR is available for customers that are currently on the Companies' existing interruptible tariffs or a special contract containing interruptible provisions which was approved before July 31, 2008. FirstEnergy explains that the terms and conditions of Rider ELR are modeled after OE's current interruptible tariffs. Rider

ELR obligates these customers to designate a contract firm load, and then be subject to interruption or required to buy power at market prices during a buy-through period. In exchange for being subject to these terms, an interruptible program credit of $1.95 per kW/month is applied to the customer's realizable curtailable load (RCL), which is calculated by subtracting the customer's contract firm load from its average hourly demand. FirstEnergy states that the value of the interruptible program credit is based on the market value of MISO designated network resources (Co. Ex. 5 at 22).

FirstEnergy states that Rider ELR is designed to be utilized with the interruptible credit provision of Rider EDR. According to the Companies, Rider EDR is designed for interruptible customers who are taking service as of July 31, 2008. The Companies explain that these customers are currently subject to economic buy-through option events and that this concept is incorporated into Rider ELR. Conversely, Rider OLR is designed for use with new interruptible customers/load as an interruptible credit that recognizes that the customers are only subject to interruption in an emergency, and are not subject to economic buy-through option events or the interruptible credit provision of Rider EDR (Co. Ex. 5 at 23).

IEU-Ohio argues that FirstEnergy has provided no support for limiting Riders ELR to customers served under interruptible service arrangements as of July 31, 2008. Further, IEU-Ohio submits that customers served under Riders ELR and OLR should not be foreclosed from participating in any other load curtailment programs, including demand-response options available through MISO (IEU-Ohio Ex. 1 at 11).

OEG supports Rider ELR, however, OEG believes that the terms of the rider are not reasonable. Therefore, OEG recommends that Rider ELR be modified, similar to the Companies' proposal in Case No. 07-796-El-ATA, et al. (*FirstEnergy Competitive Bid Process for SSO Case*), to provide that: economic interruptions will be invoked when the day-ahead locational marginal price (LMP) exceeds 125 percent of the ESP generation rate for three consecutive hours; and economic interruptions would be limited to 1,000 hours annually. (In its brief, OEG recommended that the interruptions be limited to 250 hours annually) (OEG Ex. 1 at 28-30; OEG Br. at 22). Nucor recommends that economic interruptions be limited to 250 hours annually (Nucor Ex. 3 at 27). FirstEnergy disagrees with the suggestions to place an hour limitation on the Companies' ability to invoke the economic interruption clauses of Rider ELR. Such a limitation, according to FirstEnergy, would reduce the value of the economic interruption and would put the Companies at risk of running out of their rights to invoke the economic interruption provision at a time of high prices (Co. Ex. 19 at 7-8).

By OEG's calculations, the Rider ELR credit should be $2.50 per kW/month, rather than $1.95 per kW/month set forth in the ESP. Therefore, OEG submits that the

Companies should provide justification for the interruptible credit set forth in the ESP (OEG Ex. 1 at 30-31).

Nucor advocates that these riders be stand-alone interruptible rate options that are available for current, as well as new interruptible customers. Nucor proposes that Riders ELR and OLR be modified to include stand-alone emergency (mandatory) and economic (voluntary) interruption options. Nucor states that the emergency interruptible credit in Riders ELR and OLR should be $7.50 per kW/month, and the economic interruptible credit in Riders ELR and OLR should be $2.60 per kW/month (Nucor Ex. 3 at 19-20). OmniSource supports Nucor's proposal (OmniSource Br. at 6).

With regard to the RCL, OEG contends that the customer should receive credit for the full amount of its load that is subject to curtailment; therefore, the RCL should be computed based on the difference between a customer's on-peak load, rather than the average on-peak load as proposed by the Companies, and its firm load (OEG Ex. 1 at 30-31). Nucor recommends that the RCL be defined to reflect a customer's monthly peak demand used to calculate billing demand, instead of the customer's historical average demand during selected summer hours, as the Companies propose (Nucor Ex. 3 at 20). Further, Nucor points out that all demand charges proposed in the ESP are measured on the customer's peak, not average, demand; therefore, to be consistent with these other provisions of the ESP, the RCL should likewise be measured on the customer's peak demand (Nucor Br. at 30). However, Nucor submits that there is no record support for FirstEnergy's assertion that emergency interruptions occur at the time of peak demand; also, there is no record support, and FirstEnergy does not claim, that economic interruptions occur during the peak summer hours that FirstEnergy proposes to use to calculate the RCL. Nucor believes that FirstEnergy's proposed RCL approach will undercompensate interruptible customers (Nucor Br. at 32, 35, 37).

FirstEnergy disagrees with the proposals of OEG and Nucor, stating that the credit value developed and proposed in the ESP is based on the cost of capacity and the RCL value proposed by OEG and Nucor overstates the kW likely to be interrupted. FirstEnergy explains that a customer's peak demand is not likely to coincide with the time of an emergency interruption. Therefore, according to FirstEnergy, if the customer's peak demand, as proposed by OEG and Nucor, rather than the average hourly demand proposed in the ESP, is used to calculate the credit for Riders ELR and OLR, the Companies would be overcompensating the customer for the value of the interruption (Co. Ex. 19 at 3-6).

FirstEnergy believes that the criticisms of Riders ELR and OLR by the intervenors largely amount to requests for bigger credits. In response to these criticisms, FirstEnergy points out that, if such objectives are warranted and desirable under given circumstances, they can be pursued through the special arrangements mechanism and do not require a change to the ESP (Co. Br. at 42).

In light of the fact that the Commission has directed the Companies to continue their existing rate design and tariff structure until a revised new rate design is filed with and approved by the Commission, we find that Riders ELR and OLR are unnecessary, at this time. Accordingly, FirstEnergy's ESP should be modified consistent with this determination.

8. Reasonable Arrangements (Rider RAR)

Pursuant to the ESP, Rider RAR would provide the mechanism to administer certain tariff discounts pursuant to Sections 4905.31 and 4905.34, Revised Code, as well as the Commission's recently adopted rules for reasonable arrangements in Chapter 4901:1-38, O.A.C. (Co. Ex. 9a at 27). FirstEnergy asserts that mechanisms, such as Rider RAR, foster job retention and promote economic development (Co. Ex. 4 at 10). To receive the benefits associated with this rider, the Companies explain that a customer would have to commit to certain energy efficiency improvements and the discounts would be forfeited if the customer switches to an alternative supplier (Co. Ex. 9a at 27).

The Competitive Suppliers advocate that, if all customers pay for the incentives, then Rider RAR should be modified so that customers taking service from either FirstEnergy or a competitive supplier should be eligible to receive a discount in exchange for job retention, economic development, or other programs (Comp. Supp. Br. at 20).

IEU-Ohio notes that Rider RAR is limited in that, if a customer is taking service under a unique arrangement or avoiding charges under Riders DSE1 or DSE2, the customer is not eligible for Rider RAR. IEU-Ohio believes that this limitation is contrary to Section 4928.66(A)(2)(c), Revised Code (Co. Ex. 9c at 75; IEU-Ohio Br. at 19).

The Commission notes that reasonable arrangements will be considered by the Commission in accordance with Chapter 4901:1-38, O.A.C. Therefore, while we acknowledge the issues raised by several parties regarding Rider RAR, we believe that our adopted rules governing reasonable arrangements take these concerns into account. Therefore, we find that Rider RAR should not be approved as proposed by the Companies and the ESP should be modified accordingly.

9. Delta Revenue Recovery (Rider DRR)

Pursuant to the ESP, Delta Revenue Recovery Rider (Rider DRR) is an unavoidable rider that would recover the difference in revenue from the application of rates in the otherwise applicable rate schedule and the result of any reasonable arrangement, governmental special contract, or unique arrangement approved by the Commission.

FirstEnergy contends that Section 4905.31, Revised Code, as amended by SB 221, permits the electric utilities to recover the revenue forgone as a result of discounts in special arrangements. FirstEnergy submits that approval of a special arrangement must also include approval of complete revenue recovery resulting from the arrangement; to do otherwise would jeopardize the financial viability of the Companies because, as stand-alone electric utilities, they have limited resources and a limited ability to absorb such lost revenue. FirstEnergy states that Rider DRR's initial charges represent the recovery of CEI's contracts that are presently in place and continue past December 31, 2008, which will only be recovered from CEI customers. With regard to new contracts, the Companies explain that, as permitted by Section 4928.143(B)(2)(i), Revised Code, since the Companies are part of the same holding company this rider will be determined and allocated across all classes of customers of all the Companies (Co. Ex. 9a at 27-28; Co. Ex. 4 at 11-12).

According to the Consumer Advocates, FirstEnergy did not undertake any studies or analysis to evaluate what loss of delta revenues it would take to significantly impact the energy delivery system (Con. Adv. Br. at 67). OCC points out that, prior to the ESP filing, FirstEnergy's shareholders contributed to the recovery of delta revenues. OCC recommends that the Companies be permitted to recover no more than 50 percent of the delta revenues from customers that do not have special contracts (OCC Ex. 1 at 26). Cleveland agrees that the amount of delta revenue to be recovered through this rider should be limited so as not to impose a hardship on retail customers who do not receive a discount through a special contract (Cleve. Ex. 1 at 7-8).

In the past, the Commission generally has allowed recovery of only 50 percent of the delta revenue for special contracts. Although an increase in the percentage of revenue which electric utilities recover may be warranted following the restructuring of the industry by SB 3 and SB 221, we do not believe that 100 percent recovery of the delta revenue will always be appropriate. Therefore, we find it necessary to clarify that the proportion of delta revenue to be recovered by the Companies will be determined by the Commission on a case-by-case basis when approving each individual arrangement. Therefore, we find that Rider DRR should be approved, subject to this clarification.

10. Smart Grid

The ESP provides that the Companies commit to undertake a comprehensive study of energy delivery system enhancement, including Smart Grid technologies, on or before December 31, 2009 (Co. Ex. 9a at 7, Att. E). The Companies state that they will bear the expense of this study (Co. Ex. 9a, Att. E). Upon completion of the study, the Companies will share the results with the Staff and OCC (Co. Ex. 3 at 11).

The Consumer Advocates state that FirstEnergy's proposed Smart Grid study lacks substance and a clear timeline for moving forward. The Consumer Advocates recommend that a collaborative be established to define the appropriate goals and timelines for the study (Con. Adv. Br. at 57).

The Commission's perspective is that a Smart Grid involves the integration of the power system with an open architecture, advanced communications infrastructure. This infrastructure may provide the platform for a potentially broad range of sensing, measurement, transactional, control, and other applications that might include advanced distribution automation, equipment monitoring, dynamic retail pricing, AMI, automated demand response, distributed resource management, and electric vehicle charging systems. A Smart Grid should support new applications and enable them to interact with one another and with established power system functions.

Consistent with our conclusion on Rider DSI, the Commission believes the Companies should complete a comprehensive study of energy delivery system enhancements, including Smart Grid technologies, on an accelerated basis. The study should include planning for: Smart Grid and infrastructure enhancements, Smart Grid system architecture and interoperability requirements, and a large-scale AMI deployment.

Therefore, the Commission finds that no later than December 31, 2009, as proposed by FirstEnergy, and earlier if possible, for completion of the Smart Grid study is appropriate for such a critical issue. Furthermore, the Commission finds that FirstEnergy should work with Staff to develop a proposal to hire an independent consultant to conduct the Smart Grid study. This study should be filed with the Commission in a separate docket and a public version of this study should be made available for interested parties for review and comment. Therefore, we find that the Smart Grid proposal set forth in the ESP should be modified consistent with our decision herein.

J. Transmission

1. Transmission Rates

FirstEnergy states that the transmission rate design is now consistent with the voltage-based rate schedules set forth in the distribution rate case filing in the *FirstEnergy Distribution Rate Case*. FirstEnergy explains that the transmission rider will account for the same expenses as it did in the previous two years as set forth in Case No. 07-128-EL-ATA (*FirstEnergy 2007 Regional Transmission Organization Cost Rider Case*); with the exception that it will no longer include the amortization of the 2005 transmission expense deferral that will be recovered through the Deferred Transmission Costs Recovery Rider (Rider DTC). The Companies will continue to file in mid-October for transmission rates to be effective for January 1 through December 31 of the flowing year (Co. Ex. 5 at 25).

As the Commission stated previously, because we have retained the existing rate design and tariff structure, there is no need to change the transmission rate design.

2. Transmission and Ancillary Services (Rider TAS)

Pursuant to the ESP, the Transmission and Ancillary Services Rider (Rider TAS) would be an avoidable rider that would recover transmission and transmission-related costs, including ancillary and congestion costs and new charges imposed by FERC, a regional transmission organization (RTO), or an independent transmission systems operator (ISO) (Co. Ex. 9a at 28). This rider would be adjusted annually to reflect the costs actually incurred by the Companies' to serve the customers (Co. Ex. 9a at 6; Co. Ex. 5 at 23-24).

Staff believes that the Companies' approach is reasonable and recommends that Rider TAS be approved (Staff Br. at 17). IEU-Ohio suggests that the Staff continue to review the RTO-incurred costs to determine if the Companies are managing controllable costs so that they are prudently incurred and, to the extent an automatic recovery mechanism is allowed, FirstEnergy should be required to proactively minimize costs (IEU-Ohio Ex. 1 at 8).

The Commission finds that Rider TAS is reasonable, as proposed by the Companies, and should be approved, subject to our decision above regarding the transmission rate design. While we are approving Rider TAS, the Commission notes that, in accordance with our entry issued today in Case No. 08-1172-EL-ATA (*FirstEnergy Transmission Cost Recovery Rider Case*), the current transmission and ancillary services rider should be extended and continued until the rate design and tariff structure in the *FirstEnergy Distribution Rate Case* is approved and made effective by the Commission. The current transmission and ancillary services rider should be incorporated into the new Rider TAS, effective January 1, 2009.

K. Legacy Issues

The Companies note that the ESP provides for the recovery of certain costs from prior periods which, with the Commission's approval, were deferred for future recovery (Co. Ex. 9a at 29).

1. Deferred Distribution Cost Recovery Rider (Rider DDCRR)

Pursuant to the ESP, the Deferred Distribution Cost Recovery Rider (Rider DDCRR) would be an unavoidable rider that would recover: (1) the post May 31, 2007, unrecovered balances of distribution costs deferred in the *FirstEnergy RCP Case*; (2) the deferred distribution-related costs incurred by CEI from January 1, 2009, through April 30, 2009, equating to $25 million; (3) the post-May 31, 2007, unrecovered balances of deferred transition taxes under the *FirstEnergy ETP Case*; and (3) the post-May 31, 2007, unrecovered balances of line extension deferrals pursuant to Case No. 01-2708-EL-COI

(*Commission Investigation of Line Extension Tariffs Case*). The Companies also propose to defer the interest on the accumulated balances, including the accumulated deferred interest, from January 1, 2009, through December 31, 2010, at .0783 percent per month (8.5 percent annually) without reduction for deferred income taxes. The Companies propose that the rider be effective on January 1, 2011 (Co. Ex. 9a at 19, 29-30, Att. G; Co. Ex. 2 at 5).

While Staff supports recovery of the types of costs contained in this rider, it believes that recovery of distribution items should be handled in distribution cases, although Staff acknowledges that the recovery requested by the Companies is permissible under SB 221. However, Staff states that, should the Commission approve this rider, the rider should be adjusted to reflect the effect of taxes and the deferred interest on accumulated balance should be net of deferred income taxes (Staff Ex. 7 at 3).

The Consumer Advocates oppose approval of these deferrals and question the breadth of the proposed deferrals. Furthermore, the Consumer Advocates note that the RCP distribution deferrals and the transition tax deferral issues are pending in the *FirstEnergy Distribution Rate Case* and, if the additional distribution charges are not approved in the *FirstEnergy Distribution Rate Case,* then the additional charges resulting from the same conceptual arguments should not be approved in the ESP (OCC Ex. 1 at 34-35; Con. Adv. Br. at 69-70).

The Commission finds that the carrying charges for the deferral balances should be adjusted for tax effects as recommended by OCC and the Staff. We agree with Staff that the calculation of the carrying charges on a net of tax basis is in accordance with sound ratemaking theory, as well as Commission precedent (Staff Ex. 7 at 3-4; *FirstEnergy Distribution Rate Case* Staff Ex. 16 at 8, 12). *See also In re Cleveland Electric Illuminating Co.,* Case No. 88-205-EL-AAM, Entry (February 17, 1988); *In re Cleveland Electric Illuminating Co.,* Case No. 92-713-EL-AAM, Entry (December 17, 1992). The stipulation in the *FirstEnergy RCP Case* did not explicitly call for the carrying charges to be calculated on a gross tax basis, and, in the absence of such explicit statement of the parties to the stipulation in the *FirstEnergy RCP Case,* our intent was for the carrying charges to be calculated on a net of tax basis in accordance with Commission precedent. Thus, Rider DDCRR should be approved as modified herein.

2. Deferred Transmission Costs Recovery (Rider DTC)

The ESP provides that Rider DTC would be an unavoidable rider that would recover certain 2005 deferred incremental transmission and related interest costs, as well as deferred ancillary service-related charges in accordance with Case Nos. 04-1931-EL-AAM and 04-1932-EL-ATA (*FirstEnergy 2004 Regional Transmission Organization Cost Rider Cases*). Rider DTC would commence January 1, 2009, and end December 31, 2010, pursuant to the ESP (Co. Ex. 9a at 30, Att. G; Co. Ex. 2 at 6; Co. Ex. 5 at 28).

The Competitive Suppliers state, and Dominion agrees, that Rider DTC should be avoidable because it is inappropriate to require customers who take generation supply service from a competitive provider to be forced to pay for cost properly attributable to the generation portion of FirstEnergy's SSO rates (Comp. Supp. Ex. 1 at 9 and Ex. 3 at 8; Dom. Br. at 6).

While we acknowledge the issue raised by the intervenors, the Commission finds that the proposal set forth by FirstEnergy is reasonable. Therefore, we find that Rider DTC should be approved, as proposed by FirstEnergy. While we are approving Rider DTC, the Commission notes that, in accordance with our entry issued today in the FirstEnergy Transmission Cost Recovery Rider Case, Rider DTC will not go into effect until either January 1, 2009, or the date on which the new tariffs are in effect in the FirstEnergy Distribution Rate Design Case, whichever date is later.

3. Deferred Fuel Cost Recovery (Rider DFC)

According to the Companies, they were authorized to defer and recover certain fuel costs and related interest above an established baseline, pursuant to the rate stabilization plan (RSP) in Case No. 03-2144-EL-ATA (*FirstEnergy RSP Case*), as modified by the RCP. The Companies state that Case No. 08-124-EL-ATA, et al. (*FirstEnergy Deferred Fuel Costs Case*), which is currently pending before the Commission, has been continued in order to permit the resolution of the recovery mechanism for these deferred fuel costs for 2006 and 2007 to occur in this proceeding. The Companies point out that, prior to the enactment of SB 221, the Commission allowed the current recovery of 2008 fuel expense that would have otherwise been deferred. Pursuant to the ESP, the Deferred Fuel Cost Recovery Rider (Rider DFC) would be an unavoidable rider that would recover the accumulated deferred balance of these fuel costs as of December 31, 2008, and would become effective on January 1, 2009. The aggregate estimated balance to be recovered is $235,014,038 for 2006 and 2007, which includes $28,202,182 of deferred interest. Based on a 25-year recovery period, the Companies state that the recovery factor would be 0.0375 cent per kWh for OE, 0.0339 cents per kWh for CEI, and 0.0260 cents per kWh for TE, which would be reconciled on an annual basis (Co. Ex. 9a at 30-31; Co. Ex. 2 at 9; Co. Ex. 5 at 18-19).

Staff proposes that the Commission adopt its recommendations set forth in its report of investigation filed in the *FirstEnergy Deferred Fuel Costs Case* (Staff Br. at 26). Consistent with its recommendation in the *FirstEnergy Deferred Fuel Costs Case*, Staff recommends that the fuel deferral contained in Rider DFC be reduced and the Companies be allowed to recover $197,488,075 of deferred fuel for 2006-2007 (Staff Ex. 8 at 15; Staff Br. at 23-28). The Consumer Advocates support Staff's proposal to disallow recovery of certain costs (Con. Adv. Br. at 93). FirstEnergy disagrees stating that, contrary to Staff's position, the deferral of fuel costs should recognize the cost to FES to achieve the savings recognized from the purchase of the fuel and the Companies should be permitted to recover this deferral through Rider DFC. In addition, FirstEnergy argues that it should be permitted to recover the deferrals associated with emission allowance through Rider DFC (Co. Ex. 19 at 11-14). In response to FirstEnergy's position, Staff states that FirstEnergy misunderstands the facts presented in the Staff report in the *FirstEnergy Deferred Fuel Costs Case* and, therefore, FirstEnergy's position should be rejected and Staff's proposals should be adopted (Staff Br. at 28-31).

The Competitive Suppliers state, and Dominion agrees, that Rider DFC should be avoidable because it is inappropriate to require customers who take generation supply service from a competitive provider to be forced to pay for costs properly attributable to the generation portion of FirstEnergy's SSO rates (Comp. Supp. Ex. 1 at 9 and Ex. 3 at 8; Dom. Br. at 6).

The Commission finds that FirstEnergy's request for recovery of the deferred fuel costs should be reduced by $9,135,561, consistent with the recommendation of Staff (Staff Ex. 8 at 15). With this modification, the Commission finds that Rider DFC should be approved.

L. Corporate Separations Plan and Operational Support Plan

FirstEnergy submits that the Companies' corporate separation plans are in compliance with Section 4928.17, Revised Code, and Chapter 4901:1-37, O.A.C. Furthermore, the Companies offer that their operational support plan has been filed and implemented pursuant to Section 4928.31(A)(2), Revised Code (Co. Ex. 1 at 26-28).

Staff states that the Companies' generating assets have been structurally separated from the operating companies. Staff submits that, in accordance with the recently adopted corporate separation rules issued by the Commission in the *SSO Rules Case*, the Companies should file for approval of its corporate separations plan within 60 days after the rules become effective. Furthermore, Staff proposes that the Companies' corporate separations plan should be audited by an independent auditor within the first year of approval of the ESP, the audit should be funded by the Companies, but managed by Staff, and the audit should cover compliance with the Commission's rules on corporate separations (Staff Ex. 4 at 2-4).

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

M. Significantly Excessive Earnings Test

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

> ...resulted in excessive earnings as measured by whether the earned return on common equity of the electric distribution utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate.

FirstEnergy proposes a test for significantly excessive earnings that it believes mitigates the potential to impose asymmetric risk on the electric utilities by guarding against incorrectly determining that significantly excessive earnings have occurred. According to FirstEnergy, if asymmetric risk is imposed on the electric utilities, the electric utilities' allowed returns would have to be increased so that they could expect to earn their cost of capital on average (Co. Ex. 8 at 2, 17-18). Furthermore, FirstEnergy states that the purpose of the test is to identify significantly excessive, windfall profits (Co. Ex. 8 at 9).

In accordance with the ESP, the significantly excessive earnings test will be comprised of two parts. First, recognizing an adjustment for differences in capital structure, if the ROE for each electric utility for a year of the ESP is greater than the average ROE, plus 1.28 standard deviations above the average for a group of capital intensive industries, then significantly excessive earnings may exist for the particular electric utility, subject to the consideration of the capital requirements of future committed investments in Ohio. The group of capital intensive industries referred to by the ESP is comprised of electric utilities, natural gas utilities, oil and gas distribution companies, water utilities, environmental companies, railroads, and telecommunications service companies that have an investment-grade credit rating (Co. Ex. 9a, Att. H; Co. Ex. 8 at 10-14). Based on its analysis, FirstEnergy believes that a reasonable threshold ROE for measuring significantly excessive earning would be 19.82 percent (Co. Ex. 8 at 21).

Second, the ESP provides that the earnings in the test would be adjusted to exclude Rider DSI, subsidiary equity earnings, and any RTC or impairment write-offs that may occur subsequent to December 31, 2007. In addition, the ESP states that the equity base, for purposes of the test, would be increased by any RTC write-off or impairment write-offs that have accumulated subsequent to December 31, 2007 (Co. Ex. 9a, Att. H; Co. Ex. 2 at 7-8; Co. Ex. 1 at 23-24).

OEG submits that there are two components to determine the appropriate methodology for the significantly excessive earnings test: the significantly excessive earnings threshold and the actual earned return on common equity (OEG Ex. 2 at 23). OEG proposes that the actual earned return on common equity be computed using the per books actual earnings on common equity and the Companies' year-end actual common equity balance, with limited ratemaking adjustments. OEG believes that, for the significantly excessive earnings test, the actual return on common equity should include: Rider DSI, off-systems sales, and prudent purchased power expenses. On the other hand, OEG believes that the following should be excluded from the actual return on common equity calculation: refunds from the previous year, the effects of fines and penalties, one-time write-offs, costs and acquisition premiums, and an accounting for derivative gains and losses. As for the Companies' proposal to exclude the after tax earnings effect on CEI's proposed write-off of RTC and extended RTC, OEG proposes that they be allowed an adjustment on a declining basis reflecting a three-year amortization of the write-off (OEG Ex. 2 at 25-28).

To identify a group of utilities and other companies that bear the same business and financial risk as the Companies, OEG identified two comparison groups, one of utilities and the other of non-utilities; adjusted the earned returns of each group to match the risks faced by the Companies (for the non-utility group the beta measure generated by Value Line was used to make the adjustment to reflect the lower risk for utility distribution service); averaged the returns to derive a base line earned level of return; and applied an adder, equivalent to FERC's 200 basis points for RTO participation and incentive investments, that describes the margin over the base line ROE that should be allowed before the earnings are considered significantly excessive (OEG Ex. 3 at 4, 7, 9). To illustrate the outcome of its methodology for computing significantly excessive earnings, OEG applied 2007 data to its methodology and derived ROEs of 12.27 percent, 13.78 percent, and 12.57 percent for TE, CEI, and OE, respectively (OEG Ex. 3 at 9). According to OEG, in 2007, the earned return of common equity for TE, CEI, and OE was 18.8 percent, 18.55 percent, and 12.51 percent, respectively. Therefore, using the threshold computed by OEG, both TE and CEI would be over the significantly excessive earnings threshold for 2007 (OEG Ex. 2 at 34).

OCC believes that FirstEnergy's comparable company methodology is arbitrary and includes no risk measures, and OCC does not believe that the reported ROE of the comparable companies should be adjusted for special or extraordinary items that affect reported earnings. According to OCC, defining significantly excessive earnings in terms of statistical significance using a 90 percent significance level, as the Companies have done, would mean that very few electric utilities would ever have significantly excessive earnings. Furthermore, OCC avers that, by applying a 1.28 standard deviation adjustment to the return on total capital, as proposed by the Companies, the threshold ROE is unnecessarily inflated. OCC proposes a seven-step procedure for the significantly excessive earnings test: (1) identify a proxy group of electric companies; (2) identify a list of business and financial risk measures; (3) establish the ranges for the proxy group for the risk factors; (4) identify a group of companies whose risk indicators fall within the ranges of the proxy group; (5) compute the benchmark ROE for comparable companies; (6) adjust the benchmark ROE for the capital structures of the Ohio electric utilities; and (7) add an ROE premium equivalent to FERC's 150 basis points ROE rider to establish the threshold

(OCC Ex. 4 at 5). Based on its analysis, OCC recommends that the threshold ROE for TE, CEI, and OE be 12.35 percent, 13.44 percent, and 12.51 percent, respectively (OCC Ex. 4 at 13-16).

Staff likewise disagrees with what it believes is a statistical methodology used by the Companies for determining what constitutes "significantly excessive" in the statute (Staff Ex. 6 at 8). Staff alleges that the Companies' approach is problematic in several respects. First, Staff believes that, under the Companies' proposal, the level of "significance" to demonstrate significantly excessive is itself excessive. Second, Staff notes that the Companies' test to determine significant has been constructed in a way counter to that required by SB 221, such that it puts the burden of proving that significantly excessive earnings have occurred on anyone claiming that the Companies have an excessive ROE, rather than the Companies as required by the statute. Staff believes that the significance test is not to show that earnings are excessive, but rather to show that they are not excessive. Thus, since the Companies own the information necessary to determine this issue, only the Companies are in a position to support a burden of proof. Third, Staff avers that the statistical definition of "significant" does not provide a useful interpretation of the legislative language. Given that the term "significantly excessive" is used several times in the statute, Staff submits that the application of the statistical definition for the word "significant" as the criterion for applying the annual test, causes the statute to have internal inconsistencies (Staff Ex. 6 at 9, 16-20; Staff Br. at 37-38).

Staff believes that the concept of "significantly excessive" is a fairness issue, rather than a statistical issue as set forth by the Companies (Staff Ex. 6 at 22). Staff maintains that, by using the wrong analytical framework, the Companies are advocating a range of values that are irrationally high (Staff Br. at 41). In order to frame a zone of reasonableness in which to apply Staff's fairness approach, Staff finds the testimony of OEG and OCC in which they refer to ROE adders such as those offered by FERC to encourage risky investment to be useful (Staff Ex. 6 at 22; OEG Ex. 3 at 9; OCC Ex. 4 at 14). With these types of considerations in mind, Staff recommends that the issue of what constitutes "significantly excessive returns on equity" in the annual earnings test be decided by implementing an adder over the average of the comparable group of between 200 and 400 basis points. According to the Staff, this method may be superior to the 1.28 standard deviation method proposed by the Companies (Staff Ex. 6 at 2, 22-24). In choosing an amount in this range, the Staff recommends that the Commission consider features, including those that serve to reduce risk or volatility, such as riders that track costs, deferrals that stabilize earnings, unavoidable charges (POLR charges), as well as the possible asymmetric risk faced by the Companies (Staff Ex. 6 at 24-25).

The Commercial Group states that the Companies' proposed earnings test is unreasonable. The Commercial Group recommends that the significantly excessive earnings test be based on whether the electric utilities are earning the approved return on common equity. According to the Commercial Group, if the Companies' ROE is equal to or more than the Commission's approved ROE, an increase in rates and the proposed riders are not necessary and should not be permitted (Com. Gr. Ex. 1 at 18).

FirstEnergy states that the utilization by OCC, OEG, and Staff of FERC's incentive ROE adder as a measure of the cutoff over the mean of the comparable sample is completely arbitrary and attempts to use FERC's ROE adder for a purpose which it was never intended (Co. Ex. 18 at 2).

Staff recommends that the methodology for determining what comprises a comparable group for purposes of the excessive earnings test in the statute should be examined by stakeholders at a workshop or technical conference and then reported back to the Commission (Staff Ex. 6 at 2, 6). Staff states that the Companies' proposal for selecting the comparable group and calculating the ROE to be used has some good properties. However, Staff believes, and the Consumer Advocates agree, that a common methodology for the excessive earnings test should be adopted for all of the ESP cases filed at the Commission (Staff Ex. 6 at 6; Con. Adv. Br. at 95).

FirstEnergy opposes Staff's suggestion that the determination of the comparable companies and the associated ROE be postponed to a technical conference. FirstEnergy submits that the significantly excessive earnings proposal in the ESP is expressly part of the ESP and must be decided and approved herein (Co. Br. at 66-67).

The Commission believes that the determination of the appropriate methodology for the significantly excessive earnings test is extremely important. As evidenced by the extensive testimony in this case concerning the test, there are many different views concerning what is intended by the statute and what methodology should be utilized in this case. However, as pointed out by several parties, whatever the ultimate determination of what the methodology should be for the test, the test itself will not be actually applied until 2010. Therefore, the Commission agrees with Staff that it would be wise to examine the methodology for the excessive earnings test set forth in the statute within the framework of a workshop. The goal of the workshop would be for the Staff to develop a common methodology for the excessive earnings test that should be adopted for all of the electric utilities and then report back to the Commission on its findings. According, the Commission finds that Staff should convene a workshop consistent with this determination.

N. <u>MRO v. ESP</u>

As stated previously, contemporaneous with the filing of the ESP, the Companies also filed an application for an MRO (Co. Ex. 9a at 8). Section 4928.143(C)(1), Revised Code, provides that, if an application for an MRO is filed, then the Commission is required to approve, or modify and approve, the ESP if the ESP, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under the MRO.

The Companies note that the matter of generation supply beginning January 1, 2009, must be addressed in some manner because the Companies do not own generation nor do their employees currently have experience in wholesale purchases; this expertise now resides in the Companies' competitive affiliate (Co. Ex. 9a at 8). While the Companies believe that the ESP is more favorable than an MRO, they believe that, if an acceptable solution cannot be reached through an ESP mechanism, under the statute, an MRO is the alternative (Co. Ex. 9a at 8).

FirstEnergy concludes that, under the MRO proposal for full requirements service, retail customers would pay $90.47 per MWh in 2009, $97.56 per MWh in 2010, and $105.49 per MWh in 2011. These prices were calculated by FirstEnergy using market data as of July 15, 2008 (Co. Ex. 6 at 2). Furthermore, FirstEnergy conducted an analysis to establish a market price benchmark for the expected cost of electricity supply for retail electric generation SSO customers in the Companies' service territory for the next three years (Co. Ex. 7 at 4). The Companies' analysis results in a market reference point for the ESP of around $90 to $92 per MWh over the next three years (Co. Ex. 7 at 17).

Upon review of the expected generation rates under the MRO, FirstEnergy submits that the market rate averages, net transmission costs, would be $82.57, $84.88, and $88.19 per MWh for 2009, 2010, and 2011, respectively (Co. Ex. 1 at 18, Att. 1 at 1). FirstEnergy provides that the ESP generation rates, net transmission costs, would be $67.50, $71.50, and $75.50 per MWh for 2009, 2010, and 2011, respectively (Co. Ex. 1, Att. 1 at 1). According to FirstEnergy, on a net present value basis, the cost of the ESP is $1,577.1 billion and the cost of the MRO is $2,880.5 billion. Therefore, FirstEnergy states that the ESP for the Companies in the aggregate and for each individual company is clearly more favorable for customers, and would result in a net benefit to the customers under the ESP as compared to the MRO of $1,303.4 billion (Co. Ex. 1 at 19; Co. Ex. 1, Att. 1 at 1).

FirstEnergy maintains that Section 4928.143, Revised Code, requires that the ESP be approved if it is more favorable in the aggregate than the expected results of an MRO. According to FirstEnergy, contrary to arguments raised by various intervenors, the legal standard to approve the ESP is not: whether the rates are just and reasonable; whether the costs are prudently incurred; whether the plan provisions are cost-based; or whether each provision of the plan is more favorable than an MRO (Co. Reply Br. at 8-12).

The Companies state that, in considering the aspects of the ESP pertaining to the provision of generation service, the ESP is more favorable to customers than the MRO would be (Co. Ex. 9a at 6, 32; Co. Ex. 1 at 5). The Companies submit that, in addition to the generation component, the ESP has other elements than, when taken in the aggregate, make the ESP considerably more favorable to customers that the MRO alternative (Co. Ex. 9a at 6). FirstEnergy points out the benefits in the ESP that are not available in the MRO, which include: price stability for both generation and distribution service; a five-year stay-out period for increasing base distribution rates; a comprehensive arrangement that settles pricing and service arrangements for the totality of electric service, not just generation; the waiver of $591 million in RTC charges for CEI customers; a commitment to funding up to $96 million in program costs for energy efficiency, economic development, AMI, and environmental remediation programs; substantial flexibility for the Commission to manage overall price trends; and the introduction of a performance-based rider mechanism (Co. Ex. 1 at 6, 13-15; Co. Br. at 7, 21). According to FirstEnergy, the net present value to the Companies' customers of $1.3 billion over the plan period represents a savings averaging over $600 per customer for the plan period (Co. Ex. 1 at 5-6, 15-18).

Staff states that, if the Commission adopts the recommendations of Staff and considers the benefits of the ESP, the Commission would find that the ESP, in the aggregate, is a better plan for customers than the MRO (Staff Ex. 5 at 10). Similarly, IEU-Ohio states that, given the uncertainty in the markets and the increase in the risk and cost of doing business for both the customers and the Companies, the ESP is the best means of satisfying the objectives of Section 4928.02, Revised Code (IEU-Ohio Br. at 11).

OEG maintains that there is an error in the Companies' analysis which compares the ESP to the MRO. OEG believes that, if this error is corrected and more current wholesale prices are used, and the market risk is addressed consistently, the ESP would be more expensive than an MRO by $1,692.6 billion. Therefore, OEG submits that, as proposed by the Companies, the ESP is not more favorable in the aggregate than the MRO (OEG Ex. 2 at 13). However, OEG maintains that the ESP should be modified to include a least-cost portfolio of generation products, require that the POLR risk be retained by the Companies, and provide that the Companies be compensated for their prudently incurred costs. According to OEG, this modification coupled with the qualitative benefits of an ESP, such as the encouragement of new base load generation, job retention, and economic development, would, on balance, make the ESP more favorable in the aggregate than the MRO (OEG Ex. 2 at 3-4, 16). According to OEG, the effect of using the more recent September 2008 forward prices versus the July 2008 forward prices used by the Companies in their calculation is that the ESP benefit computed by the Companies has been reduced. Therefore, OEG notes that, based on September 19, 2008, forward prices, the wholesale market price to serve the Companies' load would be $63.45, $65.23, and $66.15 per MWh, for 2009, 2010, and 2011, respectively; compared to FES's offer price proposed in the ESP of $75, $80, and $85 per MWh, respectively, for the same years (OEG Ex. 2 at 4, 11). Furthermore, OEG points out that FirstEnergy includes all wholesale generation prices and all retail risk premiums in computing the MRO wholesale supplier market prices that it uses to compare the MRO to the ESP; however, FirstEnergy's ESP computation only includes the wholesale generation prices. In addition, OEG indicates that FirstEnergy's comparison computation does not include additional items in the ESP cost, such as fuel transportation surcharges, costs for alternative energy/renewable requirements, cost for new taxes or environmental requirements, increased fuel expenses in 2011 and capacity purchases, and the proposed Rider MDS (OEG Ex. 2 at 12).

Based on data from July 15, 2008, and taking in consideration adjustments for load shaping and distribution losses, OCC calculates that the more realistic forward market prices would be $55.65, $54.78, and $53.87 per MWh for 2009, 2010, and 2011, respectively (OCC Ex. 3 at 12; Con. Adv. Br. at 12). The Consumer Advocates argue that FirstEnergy's proposed ESP is less favorable than the alternative. According to the Consumer Advocates, the ESP would need to be significantly modified before it could be considered more favorable than the alternative (Con. Adv. Br. at 96, 99). OMA, OEC, Material Sciences, and the Commercial Group agree that FirstEnergy has failed to meet its burden of proof under the statute that the proposed ESP, in the aggregate, is more favorable than an MRO (OMA Br. at 6; OEC Br. at 4; Mat. Sci. Br. at 5; Com. Gr. Br. at 3). Similarly, OHA contends that the proposed ESP fails to mitigate the harmful effects of the new regulatory assets, the proposed deferrals, and the effects the rate increases will have on hospitals and, therefore, the ESP does not provide benefits that make it more favorable than a simple MRO (OHA Br. at 7).

The Competitive Suppliers submit that the ESP is not more favorable, in the aggregate, than the MRO. The Competitive Suppliers cite five reasons supporting their view that FirstEnergy has not demonstrated that the ESP is more favorable than the MRO. First, they point out that the July 2008 forward electricity prices used by the Companies in support of the ESP are out of date and the current forward prices are now lower. Second, the Competitive Suppliers believe that the Companies' quantitative comparison of between the MRO and ESP is materially flawed in that it was not done on an apples-to-apples basis and it uses an incorrect risk premium basis. Third, the suppliers opine that, when the Companies' analysis is adjusted to take into consideration the first and second errors stated above, the claimed benefit of the ESP in the aggregate is eliminated and the ESP is actually $200 to $840 million more expensive that the MRO. Fourth, the suppliers contend that the ESP structure would be highly adverse to retail competition, pointing out that the net result of Riders DGC, MDS, SBC, and NDU is that the shopping credit is reduced and customers will have an economic disincentive to switch to a competitive provider. Finally, the Competitive Suppliers state that there are fundamental differences between the MRO and ESP regarding the risk that will be borne by the Companies, the suppliers, and the customers and, because of these differences, on the basis of the MRO and ESP commodity price comparisons, it can not be concluded that the contract in the ESP between the Companies and FES is fairly priced (Comp. Supp. Ex. 1 at 5, 8 and Ex. 2 at 3-4, 6). Dominion agrees with the analysis of the Competitive Suppliers, stating that the proposed ESP would be more expensive for customers than a properly structured MRO (Dom. Br. at 4).

Contrary to the position taken by OEG, FirstEnergy contends that the market price analysis supplied in support of the ESP does not need to be updated in order for the Commission to determine whether the ESP is more favorable that the expected result of the MRO. Furthermore, FirstEnergy states that the use of more recent market forwards cannot be done in a vacuum and must be considered along with credit market conditions, regulatory rulings, and increased risk premiums, all of which will have the effect of increasing expected MRO prices (Co. Br. at 20).

Staff offers that, if the current market rates are indicative of the prices that would occur during the term of the ESP, then it may be appropriate to lower the generation rates. However, Staff believes that the current low prices may not last. Therefore, Staff recommends that, if the rate is lowered from the proposal set forth by FirstEnergy, perhaps an annual or semi-annual true-up mechanism might be the best choice to correct the price charged so that it reflects the actual cost of power acquisition. Staff proposes that this adjustment be in lieu of the deferrals suggested by the Companies and that the rates could be adjusted either up or down, but no higher than the generation rates proposed by the Companies (Staff Br. at 8-9).

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

III. CONCLUSION

Upon review of FirstEnergy's ESP application, taking in consideration the requirements established by SB 221, the Commission finds that the proposed ESP should be approved with the modifications set forth in this order.

Furthermore, the Commission finds that the Companies' should file revised tariffs consistent with this order by December 29, 2008. In light of the short timeframe remaining before these tariffs by necessity must go into effect, the Commission finds that the revised tariffs shall be approved effective January 1, 2009, contingent upon final review and approval by the Commission.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

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

(2) On July 31, 2008, FirstEnergy filed an application for an SSO in accordance with Section 4928.141, Revised Code.

(3) On August 18, 2008, a technical conference was held regarding FirstEnergy's application and on August 25, 2008, a prehearing conference was held in this matter.

(4) On September 15, 2008, and December 16, 2008, intervention was granted to: OEG; OCC; Kroger; OEC; IEU-Ohio; OPAE; Nucor; NOAC; Constellation; Dominion; OHA; Citizens' Coalition; NRDC; Sierra Club; NEMA; Integrys; Direct Energy; city of Akron; OMA; FPL; Cleveland; NOPEC; OFBF; American Wind Association, Wind on Wires, and Ohio Advance Energy; Citizens; OmniSource; Material Sciences; OSC; COSE; Morgan Stanley Capital Group; Commercial Group; and OASBO/OSBA/BASA.

(5) The hearing in this proceeding commenced on October 16, 2008, and concluded on October 31, 2008. Eight witnesses testified on behalf of FirstEnergy, 21 witnesses testified on behalf of various intervenors, and nine witnesses testified on behalf of the Staff.

(6) Nine local hearings were held in this matter at which 106 witnesses testified.

(7) Briefs and reply briefs were filed on November 21, 2008, and December 12, 2008, respectively.

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

(9) The average base generation rates for the ESP, as modified and approved by the Commission are $0.0675 per kWh for 2009, $0.0695 per kWh for 2010, and $0.071 per kWh for 2011.

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

ORDER:

It is, therefore,

ORDERED, That the application of FirstEnergy for approval of an ESP, pursuant to Sections 4928.141 and 4928.143, Revised Code, be modified and approved, to the extent set forth herein. It is, further,

ORDERED, That the Companies' shall file revised tariffs consistent with this order by December 29, 2008, and that the revised tariffs shall be approved effective January 1, 2009, contingent upon final review and approval by the Commission. It is, further,

ORDERED, That the Companies shall notify their customers of the changes to the tariff via bill message or bill insert within 30 days of the effective date of the tariff. A copy of this customer notice shall be submitted to the Commission's Service Monitoring and Enforcement Department, Reliability and Service Analysis Division at least 10 days prior to its distribution to customers. It is, further, ORDERED, That a copy of this opinion and order be served on all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Paul A. Centolella

Ronda Hartman Fergus

Valerie A. Lemmie

Cheryl L. Roberto

CMTP/GAP/vrm

Entered in the Journal

DEC 1 9 2008

Reneé J. Jenkins
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications Associated with Reconciliation Mechanism, and Tariffs for Generation Service.	Case No. 08-936-EL-SSO

OPINION AND ORDER

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

APPEARANCES:

James W. Burk, Mark A. Hayden, Ebony Miller, FirstEnergy Service Company, 76 South Main Street, Akron, Ohio 44308, and Jones Day, by David A. Kutik, North Point, 901 Lakeside Avenue, Cleveland, Ohio 44114-1190, Mark A. Whitt, 325 John H. McConnell Boulevard, Suite 600, Columbus, Ohio 43215-2673, on behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company.

Sheryl Creed Maxfield, First Assistant Attorney General of the State of Ohio, by Duane W. Luckey, Section Chief, by William L. Wright and John H. Jones, Assistant Attorneys General, 180 East Broad Street, Columbus, Ohio 43215, on behalf of the Staff of the Public Utilities Commission of Ohio.

Janine L. Migden-Ostrander, Ohio Consumers' Counsel, by Jeffrey L. Small, Jacqueline Lake Roberts, Richard C. Reese, and Gregory J. Poulos, Assistant Consumers' Counsel, 10 West Broad Street, Columbus, Ohio 43215-3485, on behalf of the residential utility consumers of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company.

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

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

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

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

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

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

Robert J. Triozzi, Director of Law, and Steven Beeler, Assistant Director of Law, City of Cleveland, and Schottenstein, Zox & Dunn Co., LPA, by Gregory H. Dunn, Christopher L. Miller, and Andre T. Porter, 250 West Street, Columbus, Ohio 43215, on behalf of the city of Cleveland.

Brickfield, Burchette, Ritts & Stone, P.C., by Damon E. Xenopoulos, 1025 Thomas Jefferson Street, N.W., 8th Floor, West Tower, Washington, D.C. 20007, on behalf of OmniSource Corporation.

Bell & Royer Co., LPA, by Barth E. Royer, 33 South Grant Avenue, Columbus, Ohio 43215-3927, and Nolan Moser and Trent A. Dougherty, Ohio Environmental Council, 1207 Grandview Avenue, Suite 201, Columbus, Ohio 43212-3449, on behalf of Ohio Environmental Council.

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

The Legal Aid Society of Cleveland, by Joseph P. Meissner, 1223 West 6th Street, Cleveland, Ohio 44113, on behalf of The Neighborhood Environmental Coalition, The Empowerment Center of Greater Cleveland, United Clevelanders Against Poverty, Cleveland Housing Network, and The Consumers for Fair Utility Rates.

Leslie A. Kovacik, city of Toledo, 420 Madison Avenue, Suite 100, Toledo Ohio 43604-1219; Lance M. Keiffer, Lucas County, 711 Adams Street, 2nd Floor, Toledo, Ohio 43624-1680; Marsh & McAdams, by Sheilah H. McAdams, city of Maumee, 204 West Wayne Street, Maumee, Ohio 43537; Ballenger & Moore, by Brian J. Ballenger, city of Northwood, 3401 Woodville Road, Suite C, Toledo, Ohio 43619; Paul S. Goldberg and Phillip D. Wurster, city of Oregon, 5330 Seaman Road, Oregon, Ohio 43616; James E. Moan, city of Sylvania, 4930 Holland-Sylvania Road, Sylvania, Ohio 43560; Leatherman, Witzler, by Paul Skaff, city of Holland, 353 Elm Street, Perrysburg, Ohio 43551; and Thomas R. Hayes, Lake Township, 3315 Centennial Road, Suite A-2, Sylvania, Ohio 43560, on behalf of Northwest Ohio Aggregation Group.

Henry W. Eckhart, 50 West Broad Street, Suite 2117, Columbus, Ohio 43215, on behalf of the Natural Resources Defense Council.

Craig G. Goodman, 3333 K. Street, N.W., Suite 110, Washington, D.C. 20007, on behalf of National Energy Marketers Association.

Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff and Stephen M. Howard, 52 East Gay Street, Columbus, Ohio 43216-1008, and Bobby Singh, 300 West Wilson Bridge Road, Suite 350, Worthington, Ohio 43085, on behalf of Integrys Energy Services, Inc.

Sean W. Vollman and David A Muntean, 161 South High Street, Suite 202, Akron, Ohio 44308, on behalf of the city of Akron.

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

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

F. Mitchell Dutton, FPL Energy Power Marketing, Inc., 700 Universe Boulevard, Juno Beach, Florida 33408, on behalf of FPL Energy Power Marketing, Inc., and Gexa Energy Holdings, LLC.

Henry W. Eckhart, 50 West Broad Street, Suite 2117, Columbus, Ohio 43215, on behalf of the Sierra Club, Ohio Chapter.

Bricker & Eckler, LLP, by Glenn S. Krassen, 1375 East Ninth Street, Suite 1500, Cleveland, Ohio 44114, and E. Brett Breitschwerdt, 100 South Third Street, Columbus, Ohio 43215, on behalf of Northeast Ohio Public Energy Council.

Larry Gearhardt, 280 North High Street, P.O. Box 182383, Columbus, Ohio 43218-2383, on behalf of Ohio Farm Bureau Federation.

Bricker & Eckler, LLP, by Sally W. Bloomfield and Terrence O'Donnell, 100 South Third Street, Columbus, Ohio 43215, on behalf of American Wind Energy Association, Wind on the Wires, and Ohio Advanced Energy.

Theodore S. Robinson, 2121 Murray Avenue, Pittsburgh, Pennsylvania 15217, on behalf of Citizens Power, Inc.

McDermott, Will & Emery, LLP, by Douglas M. Mancino, 2049 Century Park East, Suite 3800, Los Angeles, California, 90067-3218, and Grace C. Wung, 600 Thirteenth Street, N.W., Washington D.C., 20005, on behalf of Wal-Mart Stores East, LP, and Sam's East, Inc., LP, Macy's, Inc., and BJ's Wholesale Club, Inc.

Craig I. Smith, 2824 Coventry Road, Cleveland, Ohio 44120, on behalf of Material Sciences Corporation.

Bricker & Eckler, LLP, by Glenn S. Krassen, 1375 East Ninth Street, Suite 1500, Cleveland, Ohio 44114, and E. Brett Breitschwerdt, 100 South Third Street, Columbus, Ohio 43215, on behalf of Ohio Schools Council.

McDermott, Will & Emery, LLP, by Douglas M. Mancino, 2049 Century Park East, Suite 3800, Los Angeles, California, 90067-3218, and Gregory K. Lawrence, 28 State Street, Boston, Massachusetts 02109, on behalf of Morgan Stanley Capital Group, Inc.

Tucker, Ellis & West, LLP, by Nicholas C. York and Eric D. Weldele, 1225 Huntington Center, 41 South High Street, Columbus, Ohio 43215-6197, and Steve Millard, 100 Public Square, Suite 201, Cleveland, Ohio 44113, on behalf of Council of Smaller Enterprises.

OPINION:

I. HISTORY OF THE PROCEEDING

On July 31, 2008, Ohio Edison Company, The Cleveland Electric Illuminating Company (CEI), and the Toledo Edison Company (FirstEnergy or the Companies) filed an application for a standard service offer (SSO) pursuant to Section 4928.141, Revised Code. This application is for a market rate offer (MRO) in accordance with Section 4928.142, Revised Code. Contemporaneously, in Case No. 08-935-EL-SSO, FirstEnergy filed a separate application for an electric security plan (ESP) in accordance with Section 4928.143, Revised Code (ESP case).

On August 18, 2008, a technical conference was held regarding FirstEnergy's applications. Moreover, on August 25, 2008, a prehearing conference was held in order to discuss procedural issues in the above-captioned case. Subsequently, by entry dated August 28, 2008, the attorney examiner set this matter for hearing on September 16, 2008.

On August 29, 2008, the Ohio Consumers' Counsel (OCC) filed a motion for bifurcated hearings in Case No. 08-936-EL-SSO, and a motion to consolidate Case No. 08-936-EL-SSO with Case No. 08-935-EL-SSO. On September 8, 2008, FirstEnergy filed a memorandum contra OCC's motions. The city of Cleveland (Cleveland) filed a motion for bifurcated hearings and a memorandum in support of OCC's motion on September 9, 2008. OCC filed a reply to FirstEnergy's memorandum contra on September 11, 2008. The motions to bifurcate the hearings and OCC's motion to consolidate the cases were denied by the attorney examiner on September 12, 2008.

The following parties were granted intervention by entry dated September 15, 2008: Ohio Energy Group (OEG); OCC; Kroger Company (Kroger); Ohio Environmental Council (OEC); Industrial Energy Users-Ohio (IEU-Ohio); Ohio Partners for Affordable Energy (OPAE); Nucor Steel Marion, Inc. (Nucor); Northwest Ohio Aggregation Coalition (NOAC); Constellation NewEnergy and Constellation Energy Commodities Group, Inc. (Constellation); Dominion Retail, Inc. (Dominion); Ohio Hospital Association (OHA); Neighborhood Environmental Coalition, The Empowerment Center of Greater Cleveland, United Clevelanders Against Poverty, Cleveland Housing Network, and The Consumers for Fair Utility Rates (Citizens' Coalition); Natural Resources Defense Council (NRDC); Sierra Club; National Energy Marketers Association (NEMA); Integrys Energy Service, Inc. (Integrys); Direct Energy Services, LLC (Direct Energy); city of Akron; Ohio Manufacturers' Association (OMA); FPL Energy Power Marketing, Inc and Gexa Energy Holdings, LLC (FPL); Cleveland; Northeast Ohio Public Energy Council (NOPEC); Ohio Farm Bureau Federation (OFBF); American Wind Association, Wind on Wires, and Ohio Advance Energy; Citizens Power, Inc. (Citizens); Omnisource Corporation (OmniSource); Material Sciences Corporation (Material Sciences); Ohio Schools Council (OSC); Council of

Smaller Enterprises (COSE); Morgan Stanley Capital Group; and Wal-Mart Stores East, LP and Sam's East, Inc., Macy's, Inc., and BJ's Wholesale Club, Inc. (Commercial Group).

The hearing in this proceeding commenced on September 16, 2008, and concluded on September 22, 2008. Four witnesses testified on behalf of FirstEnergy, eight witnesses testified on behalf of various intervenors, and three witnesses testified on behalf of the Staff. Briefs and reply briefs were filed on October 6, 2008, and October 14, 2008, respectively.

II. APPLICABLE LAW

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

Chapter 4928 of the Revised Code provides a roadmap of regulation in which specific provisions were put forth to advance state policies of ensuring access to adequate, reliable, and reasonably priced electric service in the context of significant economic and environmental challenges. In reviewing the Companies' application for an MRO, the Commission is aware of the challenges facing Ohioans and the electric power industry and will be guided by the policies of the state as established by the General Assembly in Section 4928.02, Revised Code, as amended by Amended Substitute Senate Bill No. 221 (SB 221), effective July 31, 2008.

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

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

(2) ensure the availability of unbundled and comparable retail electric service;

(3) ensure diversity of electric supplies and suppliers;

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

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

(6) ensure effective retail competition by avoiding anticompetitive subsidies;

(7) ensure retail consumers protection against unreasonable sales practices, market deficiencies, and market power;

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

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

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

Among the provisions of SB 221 were changes to Section 4928.14, Revised Code, requiring electric utilities to provide consumers with an SSO, consisting of either an MRO or an ESP. The SSO is to serve as the electric utility's default SSO. The law provides that utilities may apply simultaneously for both an MRO and an ESP; however, at a minimum, the first SSO application must include an application for an ESP.

Section 4928.142, Revised Code, authorizes electric utilities to file an MRO as their SSO, whereby retail electric generation pricing will be based, in part, upon the results of a competitive bid process (CBP). Paragraphs (A) and (B) of Section 4928.142, Revised Code, set forth the specific requirements that an electric utility must meet in order to demonstrate that the competitive bidding process and the MRO proposal comply with the statute. In determining whether an MRO meets the requirements of Section 4928.142(A) and (B), Revised Code, the Commission must read those provisions together with the policies of this state as set forth in Section 4928.02, Revised Code. Accordingly, the policy provisions of Section 4928.02, Revised Code, will guide the Commission in its implementation of the statutory requirements of Section 4928.142(A) and (B), Revised Code.

By finding and order issued September 17, 2008, in Case No. 08-777-EL-ORD, the Commission adopted new rules concerning SSO, corporate separation, and reasonable arrangements for electric utilities pursuant to Sections 4928.14, 4928.17, and 4905.31, Revised Code.[1] Section 4928.142(B), Revised Code, provides that a utility may file its

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1 *See In the Matter of the Adoption of Rules for Standard Service Offer, Corporate Separation, Reasonable Arrangements, and Transmission Riders for Electric Utilities Pursuant to Sections 4928.14, 4928.17, and 4905.31, Revised Code, as amended by Amended Substitute Senate Bill No. 221, Case No. 08-177-EL-ORD, Finding and Order (September 17, 2008).*

application for an MRO prior to the effective date of the Commission rules required under the statute; however, as the Commission determines necessary, the utility shall immediately conform its filing to the rules upon the rules taking effect.

III. DISCUSSION

A. Background and Summary of Application

The Companies are currently providing service to their customers in accordance with their rate stabilization plan and rate certainty plan (RCP) approved by the Commission (Co. Ex. 4 at 2).[2] The Companies procure their full requirements power to supply generation service to their retail generation customers (SSO customers) through a wholesale power purchase agreement which is scheduled to terminate on December 31, 2008 (Co. Ex. 4 at 8).

In their application, the Companies set forth a proposed MRO whereby they will conduct a CBP designed to procure supply for the provision of SSO electric generation service beginning January 1, 2009, to the Companies' retail electric customers who do not purchase electric generation service from a competitive retail electric supplier (Co. Ex. 4 at 1). The retail customers who will be served under the MRO include all retail customers served under special contracts approved under Section 4905.31, Revised Code, as well as existing and future contracts entered into under Section 4905.34, Revised Code (Co. Ex. 4 at 8-9).

The Companies are requesting that the Commission determine that their proposed MRO meets the requirements found in Section 4928.142(A) and (B), Revised Code. If this application is found to meet the statutory criteria, the earliest date the bid could be conducted would be December 29, 2008. Thus, the Companies have proposed a very aggressive CBP timeline because the retail rates based upon the results of the CBP must go into effect on January 1, 2009, because, according to the Companies, they have no wholesale power arrangements beyond 2008. The Companies note that, as part of their ESP case, which was filed contemporaneously with this case, they have proposed a short-term ESP that contains an SSO pricing proposal for January 1, 2009, through April 30, 2009. According to the applicants, approval of the short-term ESP would allow extra time for the Commission to issue a final decision on the long-term ESP and, in the event the long-term

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2 *See In the Matter of the Applications of FirstEnergy for Authority to Continue and Modify Certain Regulatory Accounting Practices and Procedures, for Tariff Approvals and to Establish Rates and Other Charges Including Regulatory Transition Charges Following the Market Development Period*, Case No. 03-2144-EL-ATA, Opinion and Order (June 9, 2004); and *In the Matter of the Application of FirstEnergy for Authority to Modify Certain Accounting Practices and for Tariff Approvals*, Case No. 05-1125-EL-ATA et. al., Opinion and Order (January 4, 2006).

ESP is not implemented, it would allow time for the CBP that is part of the MRO process to be completed in a more measured fashion (Co. Ex. 4 at 2-3).

B. Competitive Bid Process - Section 4928.142(A)(1), Revised Code

Section 4928.142(A)(1), Revised Code, requires that an MRO be determined through a CBP that provides for all of the following: an open, fair, and transparent competitive solicitation; a clear product definition; standardized bid evaluation criteria; oversight by an independent third party; and evaluation of submitted bids prior to selection of the least-cost bid winner or winners.

1. Open, fair, and transparent competitive solicitation – Section 4928.142(A)(1)(a), Revised Code

The Companies state that the CBP will consist of, among other things: pre-solicitation activities to promote bidder interest and participation; bidder education and communication; and competitive safeguards to guard against anti-competitive behavior during bidding (Co. Ex. 1 at 11). As part of the application, the Companies have presented proposed CBP rules which establish the process under which the CBP manager will conduct the CBP. The CBP rules address: the information provided to bidders; the application process; the qualification and credit processes; the bidding rules and process; conclusion of the bidding; and confidentiality requirements (Co. Ex. 3 at 8; Co. Ex. 4, Ex. A). As part of the application, the Companies have also included a document containing proposed communication protocols, which describes the information made available during the CBP and the treatment of confidential information (Co. Ex. 4, Ex. G). In addition, the Companies state that they will make available a CBP website in order to keep the interested parties informed of developments and notices related to the CBP. The Companies believe that, consistent with Section 4928.142(A), Revised Code, affiliates of the Companies may participate as bidders in the CBP solicitations and win the right to provide SSO supply (Co. Ex. 4 at 17).

The Companies explain that the bidders in the CBP would provide SSO supply for tranches comprised of all SSO customer voltage classes for all three companies (Co. Ex. 4 at 18). The Companies peak load is approximately 11,500 megawatts (MW). In the initial solicitation, the nominal size per tranche will be 100 MW, which equates to 115 tranches and each tranche represents 0.87 percent of peak load (Co. Ex. 1 at 11). As proposed by the Companies, the initial MRO competitive solicitation would procure one-third of the total SSO load for all three companies for the period from January 1, 2009, through May 31, 2010; one-third of the total SSO load for all three companies for the period January 1, 2009, through May 31, 2011; and one-third of the total SSO load for all three companies for the period from January 1, 2009, through May 31, 2012 (Co. Ex. 1 at 7; Co. Ex. 4 at 4). After the initial solicitation, beginning in 2009 and during each calendar year thereafter, the

Companies will hold two competitive solicitations, one in October and one in the subsequent January. During these solicitations, one-third of the power requirements of all three Companies' provider of last resort (POLR) load for a three-year period will be bid out as part of each of the two competitive solicitations. The results of these solicitations will be blended to formulate the generation price paid by the Companies' retail electric customers (Co. Ex. 4 at 4). The Companies submit that this approach will help balance out wholesale market price fluctuations and provide retail electric customers with a more stable price for a specified period of time (Co. Ex. 4 at 9).

The Companies explain that this MRO proposal utilizes a slice-of-system approach (Co. Ex. 4 at 5). The total amount of SSO supply to be procured will be divided into equal tranches, with each tranche representing a fixed percentage of the Companies' SSO hourly load. Bidders will bid through a descending clock (reverse auction) format to provide SSO supply (Co. Ex. 4 at 12). The winning bid price will reflect a blending of the pricing from the applicable solicitations. Once a winning bid price is known, a rate conversion process will be used to convert the blended competitive bid price to a retail rate. The rate-specific generation prices will be derived through the application of distribution line loss factors and seasonality factors, and grossing up for applicable taxes (Co. Ex. 2 at 4; Co. Ex. 4 at 5 and Ex. C at 1). Furthermore, the proposal includes a reconciliation mechanism to ensure a neutral financial outcome with regard to the Companies' provision of SSO generation service (Co. Ex. 4 at 5).

The Companies' posit that the descending clock format promotes a competitive bid format that is open, fair, and transparent. The Companies explain that, through this format, bidders can clearly understand how the final solicitation prices are determined and how to compete for a winning position. In addition, the Companies submit that the informational session and the additional training before the solicitation ensure that the bidders are fully aware of the mechanics of the bidding process (Co. Ex. 3 at 11). Constellation supports the basic form and substance of FirstEnergy's MRO and the MRO procurement process, including the provision of data and information, and the communication protocols, and believes that it meets the criteria set forth in the statute (Const. Ex. 1 at 4 and 17)

OEG argues that FirstEnergy's proposed reverse auction is not an "open, fair and transparent competitive solicitation," and would not result in the least-cost rate for consumers (OEG Ex. 1 at 3). According to OEG, outsourcing to third-party bidders of POLR risk through a reverse auction results in an unreasonable retail risk premium of between 17 and 40 percent above the Federal Energy Regulatory Commission (FERC) regulated wholesale market generation rates (OEG Ex. 1 at 3 and 14).

Cleveland submits that the rate conversion process proposed by the Companies to derive the retail rate is not an appropriate method to use because it fails to give proper recognition to the load characteristics of the individual rate classes (Cleve. Ex. A at 4). Cleveland maintains that the Companies have the ability to account for the differences between each rate class. According to Cleveland, if the load characteristics are recognized with specificity, customers will be charged rates appropriate to the way they use electricity, thereby resulting in appropriate pricing and cost savings (Cleve. Br. at 4). Similarly, Nucor states that the result of utilizing a slice-of-system approach and a uniform blended cost to service all loads will be a set of MRO rates that indirectly create interclass subsidies, effectively ignoring the market realities and the fact that it takes lower average cost to serve higher load factor classes (Nucor Ex. 1 at 17).

Included with the application is a form of the Master SSO Supply Agreement for the CBP (Co. Ex. 4, Ex. F). The Consumer Advocates[3] point out that the provision of the Master SSO Supply Agreement that makes the SSO supplier solely responsible for payment of all MISO charges discourages bidder involvement by not protecting them against new MISO and other regulatory charges (Co Ex. 4, Ex. F at 18; Con. Adv. Br. at 10). Therefore, the Consumer Advocates recommend that the Commission require that "net" changes in MISO and regulatory charges be allowed outside of the bidding. Furthermore, the Consumer Advocates state that the agreement is not fair to all potential bidders and will not encourage vigorous participation by a wide range of bidders because the agreement and the bidding process place all risk of forecasting and supply on suppliers who are not the Companies' affiliate supplier (Con. Adv. Br. at 10).

The Consumer Advocates and OPAE agree that the Companies' affiliate, FirstEnergy Solutions (FES), has an unfair advantage in the bidding process (Con. Adv. Br. at 11; OPAE Ex. 1 at 10). Consumer Advocates claim that the Master SSO Supply Agreement should not be approved until all bidders have the same information that FES has gained through supplying generation service to the Companies' territory (Con. Adv. Br. at 11). OEG agrees that the Companies have ignored the fact that FES may be able to influence the market clearing price by virtue of its concentration of generation ownership. OEG contends that, if FES has market power and the ability to control pricing, the result would not be a fair price that reflects effective competition. OEG notes that the application fails to address market power or transmission constraints that may result in market power. Absent convincing evidence that FES does not have market dominance, OEG contends that the Commission should not approve a reverse auction (OEG Ex. 1 at 7-11).

OEG recommends that, if the reverse auction proposed by FirstEnergy is rejected by the Commission, FirstEnergy's market rate offer should be procured by a third-party portfolio manager through a sealed competitive bid or request for proposal process to achieve the lowest and best price for consumers. OEG claims that a procurement process

3 OCC, Citizen Power, Lucas County, city of Toledo, and NOAC filed joint initial and reply briefs; therefore, when referring to the arguments in these documents these parties will be referred to as the Consumer Advocates.

where the Companies obtain blocks of wholesale power, rather than full requirements service, places the risk of POLR supply on FirstEnergy. As a result, the cost of wholesale generation should be significantly reduced. However, OEG believes that FirstEnergy should be fully compensated for this risk through distribution rates, including an appropriate rate of return, set by the Commission (OEG Ex. 1 at 13-14; OEG Br. at 11).

The Consumer Advocates disagree with the slice-of-system approach proposed by the Companies. Rather, the Consumer Advocates believe that bidding by class is preferable to the slice-of-system approach, because bidding by classes offers the potential to tailor bidding according to the characteristics of the customer. The Consumer Advocates point out the large customers are served using meters that register demand; therefore, they state that these demand-metered customers should be combined and bid out together (Con. Adv. Br. at 8).

OPAE states that the Companies' proposed procurement plan, which calls for the acquisition of 100 percent of the SSO load for all customer classes at one point in time by means of one type of wholesale market contract, carries the risk of higher prices and more volatility compared to other options that were not identified or considered (OPAE Ex. 1 at 11). OPAE recommends that the Commission require FirstEnergy to explore a more actively managed portfolio of wholesale market products to assure the most reasonable and lowest prices possible for the SSO, taking into account the need for price stability. As explained by OPAE, a more managed portfolio and procurement planning process would require the evaluation of a variety of contract terms and types over a longer term planning period, of between five to fifteen years, thus allowing the SSO provider to integrate energy efficiency, renewable, and traditional generation supply options to achieve the long-term lowest cost for customers. OPAE also recommends that the portfolio use a minimum of spot market and short-term transactions, because OPAE believes that such an approach will make it impossible to offer budget payment plans due to the significant changes in SSO prices and the need to levelize the payment amount during the budget year. In addition, OPAE believes that the Commission should require FirstEnergy to identify its SSO loads by class and use the power of the aggregated residential class to get a better price on its behalf (OPAE Ex. 1 at 11-14 and 19-20). OPAE believes that SSO procurement planning and prices should reflect products and prices separately for residential and small commercial customers (OPAE Ex. 1 at 33).

The Companies disagree with the active portfolio approach proposed by OEG and OPAE. According to the Companies, since they do not own or operate generation facilities, they are not in a position to assess generation portfolios and associated risks; they believe the suppliers are in the best position to manage such risks (Co. Reply Br. at 9).

Furthermore, Staff submits that the MRO application may fail to meet the requirements of some of the Commission's rules issued in Case No. 08-777-EL-ORD.

Specifically, Staff points to the requirements pertaining to the CBP, corporate separation plans, and those rules requiring the provision for certain detailed customer load information. Therefore, the Staff submits that the Companies will need to bring their proposal into compliance with the Commission rules (Staff Exs. 1A at 3 and Ex. 2 at 2-3).

OPAE further argues that the Companies have failed to meet the threshold requirement that the MRO must demonstrate compliance with Section 4928.02, Revised Code. According to OPAE, among these critical policies are the requirements to: ensure the availability of reasonably priced retail electric service; ensure diversity of suppliers and encourage development of distributed and small generation facilities; encourage market access for cost-effective supply and DSM resources; protect customers against unreasonable sales practices, market deficiencies, and market power; provide incentives to technologies that can adapt to potential environmental mandates; and protect at-risk populations (OPAE Br. at 4).

In response to OPAE, FirstEnergy argues that the provisions of a policy statute do not prevail over specific statutory mandates. FirstEnergy claims that Section 4928.02, Revised Code, does not impose any obligations or duties upon the Companies but simply reflects the policy goals and objectives of the state, as carried out by the Commission. FirstEnergy believes that, once the Commission finds that the requirements of Section 4928.142, Revised Code, have been met, any further analysis is redundant (Co. Reply Br. at 13-14).

The Commission does not agree with FirstEnergy. As a preliminary matter, we do not find that there is a conflict between the policy provisions of Section 4928.02, Revised Code, and the requirements for a CBP contained in Section 4928.142, Revised Code, such that one statute must prevail over the other. On the contrary, as we stated previously, the policy provisions of Section 4928.02, Revised Code, will guide the Commission in its implementation of the statutory requirements of Section 4928.142(A), Revised Code.

The Commission notes that Section 4928.06, Revised Code, makes the policy specified in Section 4928.02, Revised Code, more than a statement of general policy objectives. Section 4928.06(A), Revised Code, imposes on the Commission a specific duty to "ensure the policy specified in section 4928.02 of the Revised Code is effectuated." We have done so in rules governing MRO applications[4] and will do so through our implementation of Section 4928.142, Revised Code, in this case.

Moreover, we disagree with FirstEnergy's claim that Section 4928.02, Revised Code, does not impose any obligations or duties upon the Companies. The Ohio Supreme Court recently held that the Commission may not approve a rate plan which violates the policy

[4] *See* Case No. 08-777-EL-ORD.

provisions of Section 4928.02, Revised Code. *See Elyria Foundry v. Pub. Util. Comm.* (2007), 114 Ohio St. 3d 305. Accordingly, an electric utility should be deemed to have met the statutory requirements of Section 4928.142(A), Revised Code, only to the extent that the electric utility's proposed MRO is consistent with the policies set forth in Section 4928.02, Revised Code.

The Commission finds that the competitive solicitation proposed by FirstEnergy should not be approved as proposed. The Commission believes, in considering the record in this case, that FirstEnergy has not demonstrated that its proposal will result in an open, fair, and transparent competitive solicitation.

First, the Companies have not demonstrated that the reverse auction format that they have proposed is, in the universe of competitive bids, the superior format to result in the lowest and best possible prices for consumers (OEG Ex. 1 at 11-12). The record in this proceeding demonstrates that, at the time of the auction, there will be a significant concentration of generation available for bidding under the control of a single party, the Companies' affiliate, FES, and that the reverse auction format may allow a bidder holding a significant concentration of the generation to strategically withhold some of its generation to ensure a higher price (OEG Ex. 1 at 7-8, 9-11). Further, testimony in the record indicates that FES may have an undue advantage in the bidding process proposed by FirstEnergy (OPAE Ex. 1 at 10). Based upon the evidence in the record, the Commission is not persuaded that the reverse auction format, as proposed by the Companies, will protect customers from the potential of FES to exercise market power.

Moreover, as Staff points out, FirstEnergy has not adequately addressed questions regarding corporate separation in this application (Staff Ex. 1a at 3). FirstEnergy must demonstrate that it has a separation plan and policies in place that, within the context of its proposed MRO, would meet the requirements of Section 4928.17, Revised Code, and the Commission's newly adopted rules. Given the potential for FES to exercise market power, it is necessary for FirstEnergy to clearly demonstrate in the record that the functional separation between the Companies and their affiliate has effectively prevented FES and persons with a financial interest in FES' performance from improperly influencing the decision to use the reverse auction format or specific bidding requirements. Therefore, the Commission finds that the evidence in the record does not demonstrate how the auction process proposed by FirstEnergy would protect customers against market deficiencies and market power and would provide for an open, fair, and transparent competitive solicitation pursuant to Section 4928.142(A)(1), Revised Code.

In addition, SB 221 amended Section 4928.02, Revised Code, to specifically include the promotion of DSM, time-differentiated pricing, and implementation of AMI as policies of this state. As the Staff points out, the application does not address time-differentiated and dynamic retail pricing (Staff Ex. 2 at 3). Time-differentiated and dynamic retail pricing make the economic costs to the Companies of providing retail generation service transparent to consumers. However, FirstEnergy has not demonstrated how its application promotes any of these policies. In particular, the Commission believes that AMI and time-differentiated pricing have the potential to promote an open, fair, and transparent competitive solicitation by giving customers the information needed to control their electricity bills and make appropriate decisions regarding the purchase of power, and by providing a potential check on the abuse of market power. FirstEnergy has not adequately explained how its application advances the policies of the state and achieves an open, fair, and competitive solicitation in the absence of such provisions.

Additionally, there is no evidence in the record establishing how FirstEnergy's proposal is open to and encourages participation by distributed and small generation facilities, and cost-effective and DSM resources.

2. Clear product definition - Section 4928.142(A)(1)(b), Revised Code

According to the application, the product is designed to be a full requirements SSO supply which will be provided for a specified term by the winning bidders. Thus, the product includes all energy and capacity, resource adequacy requirements, i.e., capacity associated with planning reserve requirement, transmission service, and ancillary services (Co. Ex. 1 at 10; Co. Ex. 4 at 12).

IEU-Ohio believes that, as presently designed, the slice-of-system tranches do not provide a clear product definition. According to IEU-Ohio, the design proposed by the Companies requires the bidders to bid on a product and to assume the obligation to do whatever it takes to supply FirstEnergy's retail load. IEU-Ohio believes that this approach places all of the risk of the lack of product specificity on the bidder and will work to increase prices. IEU-Ohio points out that the Master SSO Supply Agreement that bidders are required to execute identifies the products that suppliers are expected to provide and requires the suppliers to adhere to rules established by MISO, which might be amended from time to time. According to IEU-Ohio, considering how MISO markets are in a significant state of flux, if prospective bidders are requested to bid on a full requirements tranche, subject to whatever requirements MISO might put in place, then the product can not be considered clearly defined. Another example of how the proposal does not reflect a clear product definition, according to IEU-Ohio, is the fact that potential bidders will be asked to bid on tranches defined as load-following, but the quantities of electricity they will be required to provide are largely undefined and unpredictable. While each tranche is nominally 100 MW, the actual amount of electricity a successful bidder will be required to provide will vary hour by hour (IEU Ex. 1 at 10-13).

The Commission finds that FirstEnergy has not demonstrated that the application filed in this case provides a clear product definition in accordance with the requirements of Section 4928.142(A)(1)(b), Revised Code. The Commission believes that the evidence in the record of this proceeding does not establish that the slice-of-system, load-following product proposed by the Companies, which includes all energy and capacity, resource adequacy requirements, transmission, and ancillary services, provides a clear product definition which will enable potential bidders to properly assess the risks of bidding. The Commission notes that the load-following product in the CBP will commit the winning bidders to a load which will vary over time (creating a "quantity" risk or "supply" risk) and that FirstEnergy will not be supplying forecasting data to the winning suppliers (Tr. I. at 87-88; IEU Ex. 1 at 10-13). Moreover, the Commission notes that FirstEnergy has not addressed in the record in this case the potential for future changes with respect to resource adequacy in the MISO planning reserve sharing group and how such changes would impact FirstEnergy's product definition (Tr. I at 84-85).

Testimony at the hearing indicates that a procurement process where the Companies obtain blocks of wholesale power, rather than full requirements service, may result in a significantly reduced cost of wholesale generation, including consideration of the fact that the Companies would need to be compensated for absorbing the quantity risk (OEG Ex. 1 at 13-14). The Companies have not demonstrated that their proposal is superior to making forward purchases of a clearly defined quantity and flowing through, via a reconciliation adjustment, the net result of any short-term power purchases and sales needed to match load. Thus, FirstEnergy has not demonstrated that it has proposed a sufficiently clear product definition to advance the state policy goal of ensuring the availability of adequate, safe, efficient, nondiscriminatory, and reasonably priced retail electric service, such that it satisfies the requirements of Section 4928.142(A)(1)(b), Revised Code.

3. Standardized bid evaluation criteria - Section 4928.142(A)(1)(c), Revised Code

The Companies explain that the CBP manager will establish the starting price for the solicitation in a manner to foster bidder participation in the bidding process. The bidding concludes when the number of bids for the tranches equals the total number of tranches that are offered. The price at which the tranches are offered during the final round in the CBP will be the price paid to the winning bidders for the SSO supply (Co. Ex. 4 at 12).

The Companies explain that each winning bidder will be required to execute the Master SSO Supply Agreement. Pursuant to the Master SSO Supply Agreement, every SSO supplier must be a MISO load-serving entity. In addition the agreement obligates every SSO supplier to join the MISO planning reserve sharing group and to abide by the resource adequacy requirements of that group. This provision, according to the Companies, will ensure that there is sufficient generating capacity to reliably serve future load and comply with applicable capacity requirements and reliability standards (Co. Ex. 4 at 24).

The Companies explain that the rules of the descending clock format are pre-specified in a way that can be thoroughly replicated and verified. In addition, because bidders are prequalified, the Companies state that the evaluation of the submitted bids is on a price-only basis (Co. Ex. 3 at 11).

The Commission finds that there is not sufficient evidence in the record of this proceeding establishing that potential suppliers would be satisfactorily evaluated on their ability to provide adequate and reliable retail electric service as required by Section 4928.02(A), Revised Code. In fact, according to the testimony in the record, the bids would be evaluated only on price, and there would be no evaluation on such other factors (Co. Ex. 3 at 18).

4. Oversight by an independent third party - Section 4928.142(A)(1)(d), Revised Code

An independent third party will be retained for each solicitation as the CBP manager, in accordance with the application (Co. Ex. 4 at 13). The Companies indicate that the CBP manager will be responsible for ensuring that the CBP is designed to be an open, fair, and transparent competitive solicitation; the product definition is clear, and there is a standardized bid criteria, consistent with Section 4928.142, Revised Code (Co. Ex. 1 at 5-6; Co. Ex. 4 at 13).

OEG argues that the MRO must be overseen by an independent third party that should be chosen by the Commission and not FirstEnergy (OEG Ex. 1 at 19). Kroger emphasizes that the Companies' proposal should be modified to make it clear that the CBP manager is accountable to the Commission, as required by statute (Kroger Ex. 1 at 4).

The Companies have retained the Brattle Group as the CBP manager (Co. Ex. 1 at 5). IEU-Ohio states that, contrary to FirstEnergy's assertions in the application, it is evident that the Brattle Group had no involvement in designing what prospective bidders would bid on. In fact, IEU-Ohio believes that FirstEnergy exclusively designed what suppliers would bid on and then turned the reigns over to the Brattle Group to administer the bidding process. IEU-Ohio opines that, had the CBP been designed by an independent third party, other structures for the bidding process, such as a mix of fixed block and load-following requirements, would have been considered (IEU Ex. 1 at 8-9).

With regard to FirstEnergy's selection of the Brattle Group as the independent third party that will design the solicitation and administer the bidding of the MRO, OEG notes that FirstEnergy currently employs two principals of the Brattle Group as expert witnesses in its ESP proceeding. Moreover, the Brattle Group has presented testimony on behalf of the Companies in four prior cases before the Commission and in five separate proceedings before the Pennsylvania Public Utilities Commission on behalf of FirstEnergy affiliates. OEG claims that a consulting group whose principals have been and are currently employed by FirstEnergy cannot be considered an "independent third party," because there is an inherent conflict of interest when a consultant is asked to act on behalf of his employer in one proceeding and act independently from his employer in a related, contemporaneous proceeding (OEG Ex. 1 at 17).

The Commission finds that the application submitted by FirstEnergy does not meet the statutory requirement for oversight by an independent third party. FirstEnergy's application provides for a critical and central role to be played by the CBP manager. The CBP manager will be responsible for ensuring that the CBP is designed to be open, fair, and transparent, that the product definition is clear, and that there are standardized bid evaluation criteria (Co. Ex. 1 at 5-6; Co. Ex. 4 at 13). Further, the CBP manager is responsible for all communications with potential bidders and for overseeing the website which will contain essential information for the bidding process (Co. Ex. 3 at 5, 7-9). Accordingly, the CBP manager must be clearly seen as independent by any and all potential bidders.

The Commission notes that Section 4928.142(A)(1)(d), Revised Code, requires that the CBP manager be an "independent third party." It is not sufficient that the CBP manager simply be a third party as FirstEnergy claims; the CBP manager must be "independent" as well. Although the Commission does not intend to impugn the integrity or reputation of the CBP manager retained by FirstEnergy, the Commission finds that the CBP manager retained by FirstEnergy has an appearance of a conflict of interest in this case.

The record demonstrates that the CBP manager was not selected through a transparent process or in consultation with Staff or any other interested parties. Instead, the CBP manager was selected at the sole discretion of the Companies through a closed selection process (Tr. I at 119-120, 137). Moreover, principals of the CBP manager have testified for the Companies or its affiliates on several occasions in the past, including the FirstEnergy distribution rate case presently pending before the Commission. More importantly, principals for the CBP manager testified for the statutory alternative to the MRO in FirstEnergy's ESP proceeding (Tr. I at 60-61). The Commission believes that such testimony, in support of the statutory alternative to the CBP in which the CBP manager is intended to play the central role, creates an appearance of a conflict of interest, particularly in light of the fact that the CBP manager was not selected through an open, transparent process, or in collaboration with other interested parties.

5. Evaluation of submitted bids - Section 4928.142(A)(1)(e), Revised Code

In the application, the Companies explain that, at the conclusion of each solicitation, the CBP manager will submit a report to the Commission which will include the information and data necessary for the Commission to determine whether the statutory criteria has been met, along with recommendations regarding the least-cost winning bidders (Co. Ex. 4 at 15). The Companies offer that the report will answer the question posed in Section 4928.142(C), Revised Code, regarding whether there were at least four bidders, whether each product in the solicitation was oversubscribed, and whether at least 25 percent of the volume was bid on by entities other than the utility (Co. Ex. 3 at 14). Constellation agrees that the CBP proposed by the Companies provides appropriate Commission evaluation, preapproval, and oversight prior to the CBP prices becoming retail rates (Const. Ex. 1 at 19).

The Consumer Advocates do not believe that the Companies' proposal that the final prices achieved by the CBP will be filed with the Commission, immediately after close of the initial CBP and within 30 days for subsequent CBPs, provides sufficient time for public review and comment (OCC Ex. 1 at 7-8). Furthermore, the Consumer Advocates note that the Companies' proposal provides for little or no Commission oversight, which constitutes a serious flaw in the MRO that must be corrected (Con. Adv. Br. at 6). In addition, the Consumer Advocates recommend that the Commission establish an appropriate review period that includes the opportunity for stakeholders to comment on the CBP and propose improvements to the Companies' procurement and pricing procedures (OCC Ex. 1 at 8; Con. Adv. Br. at 6)

The Commission finds that the application filed by FirstEnergy meets the statutory criterion regarding evaluation of proposed bids. The Consumer Advocates believe that the proposal does not provide an adequate opportunity for public review and comment. However, Section 4928.142(C), Revised Code, plainly does not provide for such an opportunity, as it provides the Commission with only three days to reject the results of a CBP.

The Consumer Advocates also recommend that the Commission establish a review period which includes an opportunity to comment on the CBP after the fact, including comments regarding the manner in which future CBPs should be conducted. The Commission notes that Section 4928.02(I), Revised Code, provides, *inter alia*, that it is the policy of this state to ensure that retail customers are protected against market deficiencies and market power. We believe that the proposed opportunity for review and comment by stakeholders would advance this state policy.

B. Criteria for eligibility for market rate offer plan - Section 4928.142(B), Revised Code

Section 4928.142(B) requires that an MRO application detail the electric utilities' proposed compliance with the CBP requirements and the Commission's rules. In addition, this provision requires that the utility demonstrate all of the following: membership in a regional transmission organization (RTO); the RTO has a market-monitor function; and there is a published source of information that identifies pricing.

1. Membership in regional transmission organization – Section 4928.142(B)(1), Revised Code

Section 4928.142(B)(1), Revised Code, requires that an applicant filing an MRO application must demonstrate that the electric utility or its transmission service affiliate belongs to at least one RTO approved by FERC. According to the Companies, their transmission affiliate, American Transmission System, Inc. (ATSI), is a member of the Midwest Independent Transmission System, Operator (MISO), which is an RTO that has been approved by FERC. On September 1, 2003, ATSI transferred functional control of its transmission facilities to MISO (Co. Ex. 1 at 2-3; Co. Ex. 4 at 7).

No party disputed the fact that FirstEnergy and its transmission affiliate belong to MISO or that MISO is an RTO approved by FERC. Therefore, the Commission finds that the Companies have fulfilled the requirements of Section 4928.143(B)(1), Revised Code.

2. Market-monitor function - Section 4928.142(B)(2), Revised Code

Section 4928.142(B)(2), Revised Code, requires that the RTO has a market-monitor function and the ability to take actions to identify and mitigate market power or the electric utility's conduct. The Companies submit, and Constellation agrees, that MISO has an independent market-monitor function and the requisite abilities required by this section of the code (Co. Ex. 1 at 3; Co. Ex. 4 at 7; Const. Ex. 1 at 11).

Staff believes that the MRO does not meet the requirements pertaining to market monitoring and that the application is vague and ambiguous in delineating which entity, the market-monitor unit or MISO, is responsible for mitigating market power. Staff submits that Section 4928.142(B), Revised Code, contemplates that the market-monitor function will encompass both the authority to identify and act to mitigate market power; therefore, Staff maintains that the market-monitor function must be performed by a market-monitor unit, rather than MISO, which may be reluctant to police its own members (Staff Br. at 10-11).

OPAE believes that there are serious questions regarding MISO's ability to mitigate market power or the Companies' market conduct. OPAE points out that the Companies' witness Warvell could cite no instances where MISO has acted to mitigate market power, nor could he point to any evidence that such authority had been used with respect to ATSI (OPAE Br. at 3). IEU-Ohio states that, despite FERC's acceptance of MISO's market monitoring and mitigation measures, the structure of MISO's mitigation measures do not attempt to detect and mitigate marker power, at least in the traditional sense. Rather, IEU-Ohio believes that MISO's mitigation measures are structured to create safe harbors of behavior that might otherwise be viewed as an exercise of market power (IEU Ex. 1 at 18 and 21).

The Commission notes that, after the deadline for briefs in this proceeding, FERC issued a decision regarding the function of the market monitor.[5] There is no testimony in the record of this proceeding regarding the impact of this recent FERC decision on the ability of the market monitor to take actions to identify and mitigate market power or the electric utility's conduct. Because the record in this proceeding demonstrates that the precise duties of the market monitor are in flux, we find that FirstEnergy has not demonstrated that the RTO market monitor has the ability to take actions to identify and mitigate market power or the Companies' conduct.

3. Published source of pricing information - Section 4928.142(B)(3), Revised Code

Section 4928.142(B)(3), Revised Code, requires that an MRO application demonstrate that a published source of information is available publicly or through subscription that identifies pricing information for traded electricity. According to the Companies, published information is available through a combination of such sources at the Intercontinental Exchange (ICE), New York Mercantile Exchange (NYMEX), ICAP, and Platts (Co. Ex. 1 at 4; Co. Ex. 4 at 8). Constellation agrees that these publications satisfy the statutory requirement (Const. Ex. 1 at 12).

OPAE submits that the Companies failed to show that the publications they cited represent pricing for the volume of capacity and energy necessary to meet the load of the Companies. Therefore, OPAE asserts that the publications cited are not adequate to meet the need to establish a transparent price to provide SSO service going forward, as required by statute (OPAE Br. at 4). IEU-Ohio agrees that the sources cited by the Companies are not adequate to meet the statutory requirement and that actual transactional forward pricing data, as opposed to broker quotes, must be available (IEU Ex. 1 at 15).

5 This decision was the subject of a motion filed by Constellation to supplement its reply brief. We find that it would be prejudicial to the other parties in this proceeding to grant Constellation's motion, as the other parties have had no opportunity to rebut Constellation's interpretation of the decision, given the accelerated schedule of this proceeding. Therefore, the motion will be denied.

The Commission finds that the record in this proceeding does not demonstrate that published sources of information are publically available or available through subscription that identify pricing information for traded electricity, in accordance with the requirements of Section 4928.142(B)(3), Revised Code. The testimony in the record does not support a finding that pricing information is available from a single source which represents actual transactions for both peak and off-peak power and that such pricing information includes specific information regarding the quantities of electricity traded in such transactions for the period specified in the statute (Tr. I at 88-89; IEU Ex. 1a at 15). Based upon the record in this proceeding, we cannot find that the requisite pricing information is consistently and reliably available.

C. Rate design

With regard to the generation rate design proposed in the MRO application, the Companies have proposed tariffs that are based solely on per kilowatt hour (kWh) charges, as opposed to the existing tariffs which include demand charges and a declining block structure. The Companies state that this change in rate design will remove disincentives for energy efficiency measures because the declining block rates will be eliminated. Furthermore, the applicants propose that seasonal pricing, which will be fixed and based on the seasonality characteristics observable in historical locational marginal prices, be applicable to all SSO generation charges. The Companies believe that seasonal pricing, which will apply to all residential and general service tariffs, will send more appropriate price signals to customers, thereby encouraging customers to reduce usage during higher priced summer periods (Co. Ex. 4 at 5-6 and 19).

Nucor states that the elimination of FirstEnergy's current rate design will result in significant rate increases for customers. Despite these increases, Nucor states that the Companies have done nothing to mitigate the rate shock to customers (Nucor Ex. 1 at 7-9). OmniSource agrees with Nucor that customers' options, such as time-of-day pricing, interruptible and economic development rates, and incentives for customers related to energy use and efficiency, must be required as part of the MRO (OmniSource Br. at 2; Nucor Ex. 1 at 7). Likewise, Kroger comments that the Companies' proposed rate design fails to account for time-of-use differences between customer classes in allocating generation costs. According to Kroger, this deficiency will result in cross-subsidization because there will be no recognition in the rates of the fact that some customer classes have a higher portion of usage in lower-cost, off-peak periods that other customer classes (Kroger Ex. 1 at 5).

The Consumer Advocates maintain that the MRO should be modified regarding interruptible service in order to reduce the procurement costs for customers served by the Companies. According to the Consumer Advocates, a well-designed load response program could provide benefits as part of the MRO process by reducing the demand that bidders would have to meet. Under the Consumer Advocates' proposal, credits for interruptible customers, once an effective interruptible program is developed, should be paid by all customers who are combined with the interruptible customers for bidding purposes (Con. Adv. Br. at 5).

OCC disagrees with the Companies' proposal to eliminate demand components in non-residential retail generation rates. OCC believes that the elimination of historic demand charges from all non-residential generation tariffs will encourage an inefficient demand for, and use of, generation resources. According to OCC, this weakness in the rate design of the retail generation rates will be recognized by bidders in the CBP and will result in higher bids. OCC does not believe that the seasonality factor proposed by the Companies provides enough control over the growth in demand; thus, OCC recommends that the demand components be reintroduced before any bidding takes place. OCC recommends that, in future auctions, mandatory real-time pricing for large customers, rather than demand charges, should be considered as a preferred pricing mechanism (OCC Ex. 1 at 5-7). The Consumer Advocates believe that the Commission should encourage advanced metering infrastructure to attain this goal (Con. Adv. Br. at 5).

The Companies disagree with OCC's proposal to maintain demand components for non-residential customers, stating that introducing demand charges means that higher-than-average load factor customer could pay lower-than-average SSO generation charges, and conversely lower-than-average load factor customers could pay higher-than-average charges. The result, according to the Companies, is that the lower-than-average customers would have an incentive to shop in comparison to the higher-than-average customers. Therefore, the Companies argue that the level of shopping would be influenced by rate design, rather than cost. The Companies also believe this would lead to under-recovery of costs by the Companies and higher reconciliation costs for customers (Co. Ex. 9 at 5).

In response to the intervenors' overall criticisms of the rate design, the Companies maintain that inclusion in the retail rates of cost components, e.g., demand, time-of-day, or interruptible components, other than seasonal and voltage-based cost difference, would be arbitrary and could not be designed to match the costs incurred by the Companies. FirstEnergy maintains that there is no reasonable way to quantify demand, time-of-day, or interruptible components for all winning bidders in the aggregate and no way to know whether suppliers have included such components in their bids. In addition, the Companies note that, if the retail rate for a certain class of customers is reduced as a result of the suggested modifications by the intervenors, such a reduction would have to be made up by increasing the retail rate for other classes of customers (Co. Ex. 9 at 4-5). Finally, the Companies point out that the arguments raised by the intervenors regarding the rate design are more of an attack on SB 221 and not the Companies' proposal. The Companies emphasize that their proposal is for an SSO and, if customers believe that they can get a better rate based on their particular circumstances, they are free to obtain those rates in the competitive market (Co. Br. at 4-5).

FirstEnergy argues that there is nothing in Section 4928.142, Revised Code, which requires the use of time-of-day rates or interruptible rates in market rate offers. However, there also is nothing in Section 4928.142, Revised Code, which diminishes the Commission's existing authority over rate design or duty to ensure the availability of reasonably priced electric service. Section 4928.142, Revised Code, simply provides a new mechanism for the determination of the amount of generation rates and expressly authorizes the Commission to prescribe retail rates; it does not speak to how such rates are designed or allocated among customers.

The Commission notes that the policy of the state, as codified in Section 4928.02, Revised Code, requires the Commission to ensure the availability of unbundled and comparable retail electric service that provides customers with the supplier, term, price, conditions, and quality options they elect to meet their respective needs. Further, SB 221 amended Section 4928.02, Revised Code, to specifically include the promotion of time-differentiated pricing as a policy goal of this state. FirstEnergy has not demonstrated how its proposed rate design advances these policy goals. In fact, the record clearly indicates that FirstEnergy could have proposed a rate design which would advance these goals. The Commission agrees with Kroger that time-of-day rates would recognize that some customers have a higher proportion of usage in lower-cost, off-peak periods (Kroger Ex. 1 at 5). Likewise, the record demonstrates that interruptible rates can be used to reduce generation and transmission capacity needs (Nucor Ex. 1 at 11). Moreover, the Commission notes that FirstEnergy has not demonstrated that time-of-day rates or interruptible rates are impractical or cannot be implemented as part of a competitive bidding process (Tr. I at 159; Tr. V at 21). In fact, the record in this proceeding demonstrates that FirstEnergy included both time-of-day rates and interruptible rates in its prior request, in Case No. 07-796-EL-ATA, for a competitive bidding process (Nucor Ex. 1 at 5, 10). Therefore, because the Commission finds that FirstEnergy has not demonstrated that its proposed rate design advances the state policies enumerated in Section 4928.02, Revised Code, the proposed rate design should not be adopted and approved by the Commission.

D. Riders

The Companies propose a non-bypassable cost recovery true-up reconciliation mechanism (Rider CRT) which will be applied quarterly to the retail price in order to account for the differences between the SSO generation service revenues and the SSO supply costs during the prior quarter (Co. Ex. 4 at 19-20; Co. Ex. 2 at 5-6). In addition, the Companies propose that Rider CRT be used to recover certain incremental expenses associated with the implementation of the CBP. As explained in the application, these incremental charges include: the CBP expenses permitted by Section 4928.142(C), Revised Code, that are not recovered through the tranche fees paid by the SSO suppliers (including fees and expenses associated with the independent third party and any consultant hired by the Commission); actual uncollectible expense amounts related to the provision of SSO generation service; and the delta revenues for special contracts both those remaining after December 31, 2008, and those approved by the Commission after January 1, 2009, i.e., for economic development and energy efficiency schedules, governmental special contracts, or unique arrangements (Co. Ex. 4 at 19-21, Ex. 3 at 4). Specifically, full recovery of the total SSO revenue requirements will be ensured through the application of two separate Rider CRT charges (Rider CRT1 and Rider CRT2). Rider CRT1, which will be recovered from all customers of the Companies, will reconcile aggregate SSO revenue requirements for the Companies with the associated SSO generation revenues. Rider CRT2, which will be recovered only from CEI customers, will include the revenue variance associated with CEI's special contract customers remaining after December 31, 2008 (Co. Ex. 4, Ex. C at 3). The Companies propose that the avoidable generation charges will be equal to the customer's SSO generation charge (Co. Ex. 2 at 9).

OPAE believes that Rider CRT is not justified and that the "costs" it contains are not costs incurred by the Companies; therefore, OPAE urges that Rider CRT be rejected (OPAE Br. at 9-10). Staff, Constellation, and Dominion argue that all of the generation-related charges should be avoidable by shopping customers (Staff Ex. 3 at 3; Const. Ex. 1 at 23; Dom. Br. at 5). Furthermore, Dominion points out that the CBP pertains to wholesale competition, not retail competition; thus, Dominion argues that these costs should be recovered through the price paid by the SSO generation supply customers and not shopping customers (Dom. Br. at 5-6). OEG argues that, if the Companies' MRO is approved and they are allowed to outsource all POLR responsibility and risk to third parties for supplying the non-shopping load, then the Companies will not incur any POLR costs because all POLR costs will be reflected in the retail mark-up or the FERC-regulated market generation rates. Therefore, OEG insists that consumers who elect to shop should not have to pay the Companies any POLR charges (OEG Ex. 1 at 20).

As pointed out by the Consumer Advocates, the Companies must allow net-meterers on their systems and must credit net-meterers with the excess generation they contribute to the systems; therefore, any bundling of non-generation charges with generation charges must be addressed in crediting net-meterers for their contribution to the system. The Consumer Advocates submit that, either the Companies must create a means to take the transmission charges out of the bids or they must credit net-meterers with the full service bundle. Accordingly, the Consumer Advocates recommend that the Companies apply a reconciliation adjustment to the credits given net-meterers for their contributions to the distribution system. (Con. Adv. Br. at 13).

OEG agrees that, with the exception of the delta revenues, the generation-related charges contained in the CRT should be avoidable. Specifically, with regard to the delta revenues, OEG believes that these revenues can be non-bypassable; however, OEG believes that it is critical that the Commission formally approve in a separate docket each transaction that results in delta revenues in order to avoid the possibility of undue discrimination (OEG Ex. 1 at 21). Staff advocates that the delta revenues should be removed from Rider CRT and that recovery for delta revenues should be placed in a separate rider. In addition, Staff states that the Companies should be required to apply to recover any delta revenues in accordance with the Commission rules (Staff Ex. 3 at 3).

OCC and Cleveland disagree with the Companies' proposal pertaining to the handling of lost revenues resulting from special contracts through Rider CTR (OCC Ex. 1 at 9; Cleve. Ex. A at 7). Cleveland states that, as proposed by the Companies, Rider CRT allows them to recover 100 percent of non-quantified, unidentified, and uncontrolled delta revenues and costs related to alternative energy resources without any review by the Commission or interested parties (Cleve. Ex. A at 7). The Consumer Advocates maintain that the Companies have failed to establish a market-based SSO for CEI's special contracts customers. The Consumer Advocates state that FirstEnergy and not the customers should be responsible for the delta revenues (Con. Adv. Br. at 8-9). OCC points out that, prior to this filing, FirstEnergy's shareholders contributed to the recovery of delta revenues. Therefore, OCC advocates that the Commission should not allow any more that 50 percent of the delta revenues to be recovered from customers who do not have special contracts (OCC Ex. 1 at 10). Similarly, Kroger's witness Higgins believes that the recovery of delta revenues is inconsistent with the adoption of an MRO and that any costs of special deals made by the Companies should be absorbed by FirstEnergy and not subsidized by the customers (Kroger Ex. 1 at 6).

The Companies insist that Rider CRT is consistent with the statute which allows the Companies to recover generation-related costs through a reconciliation mechanism, Rider CRT. The Companies point out that most of the parties do not appear to dispute that certain items included in Rider CRT, i.e., the cost of recovering revenue variance, conducting the CBP, uncollectible expense, and delta revenues, should be recoverable; the dispute is whether shopping customers should also pay these charges (Co. Br. at 4-5). The Companies disagree with the proposal that all of the generation-related charges in Rider CRT should be avoidable. Specifically, with regard to Staff's proposals that the difference between purchase power expenses and retail generation revenue, as well as the fines and damages related to the auction, should be bypassable. The Companies argue that, if customers are allowed to shop and avoid such charges, there would be a shrinking pool of customers from which to recover such cost. Thus, the Companies state that they would bear the risk of not recovering all of the costs of procuring generation. In response to the proposal that uncollectible costs in Rider CRT should be avoidable, the Companies state that, if the proposal is adopted, customers taking service from third-party suppliers would avoid sharing in the cost of the state policy provision which protects at-risk population (Co. Ex. 9 at 9-11).

FirstEnergy states that Rider CRT keeps the Companies revenue neutral. On rebuttal, the Companies state that they are entitled to recover their full costs of power supply procured in the MRO process and, if they do not recover such costs for the customer that has an approved reasonable arrangement, then such delta revenue should be recoverable from all customers. The Companies submit that, if they are not allowed to recover the delta revenues, they would be denied the opportunity to earn a reasonable rate of return (Co. Ex. 9 at 6-8).

The Commission finds that Rider CRT should not include recovery of delta revenue for the CEI special contracts which were extended beyond December 31, 2008, in the RCP case, Case No. 05-1125-EL-ATA. There is no evidence in the record that this provision was including recovery of delta revenue after December 31, 2008 (Tr. V at 35-42). In fact, FirstEnergy's witness Ridmann testified that there was no provision in the stipulation approved by the Commission in the RCP case for recovery of delta revenues after December 31, 2008 (Tr. V at 39). Further, there is no provision in Section 4928.142, Revised Code, which permits the recovery of delta revenue for contracts entered into prior to the implementation of the MRO.

Moreover, the Commission agrees with Staff witness Fortney that the delta revenue recovery for future special or unique arrangements should be made by a separate rider. Further, once delta revenue recovery is removed from Rider CRT, all remaining aspects of Rider CRT relate to generation (Staff Ex. 3 at 3). Thus, the Commission finds that Rider CRT should be avoidable for customers who shop.

The Companies propose four other riders. Two of the proposed riders only apply to CEI customers. The regulatory transition charge rider (Rider RTC) will apply to CEI customers only through December 31, 2010, in accordance with the Companies' RCP (Co. Ex. 4 at 21). The Companies submit that SB 221 allows for the continuation of this transition cost recovery as provided for in the current RCP. Rider RTC will begin January 1, 2009, and will be updated around May 1, 2009, to account for the reductions called for in the RCP. The second rider applicable to CEI customers from January 1, 2009, through April 30, 2009, is the distribution service rider (Rider DSI). As explained by the Companies, Rider DSI is necessary to provide for application of distribution charges to CEI for the designated period, since the distribution rates for CEI customers do change under the Companies' proposal in *In the Matter of the Application of FirstEnergy for Authority to Increase Rates for Distribution Service*, Case No. 07-551-EL-AIR, until May 1, 2009 (Co. Ex. 2 at 7-8; Co. Ex. 4 at 22).

The proposed grandfathered contracts rider (Rider GRC) is applicable only to certain customer facilities under a special contract entered into pursuant to Section 4905.31, Revised Code, and entered into prior to January 1, 2001. Finally, the Companies propose a deferred transmission cost recovery rider (Rider DTC). According to the Companies, Rider DTC is necessary to recover certain deferred incremental transmission and ancillary service-related costs, as well as the recovery of such deferrals, in accordance with the Commission's decision in Case Nos. 04-1931-EL-AAM and 04-1932-EL-ATA. The Companies explain that recovery of these deferrals began January 1, 2006, and, under Rider DTC, will continue from January 1, 2009, through December 31, 2010 (Co. Ex. 2 at 7-8; Co. Ex. 4 at 22).

The Commission notes that no party opposed FirstEnergy's proposals concerning Rider RTC, Rider DSI, Rider GRC, and DTC. However, it is unnecessary for the Commission to reach a decision on these riders in light of the fact that the Commission is not approving FirstEnergy's application at this time.

E. Renewable energy, energy efficiency, and peak demand reduction requirements

Sections 4928.64 and 4928.66, Revised Code, set forth requirements that electric utilities must comply with regarding alternative energy portfolios, energy efficiency, and peak demand reduction. In their application, the Companies propose that any requirements for meeting renewable energy requirements will be achieved through a separate request for proposal during 2009 so that all such requirements will be met by the end of 2009. According to the instant application, the renewable energy resources will be in the form of renewable energy credits and the cost will be passed on to customers. The Companies intend on pursuing their plans for meeting the targets pertaining to load reductions and energy efficiency through programs that are separate from this application. According to the Companies, no specific requirements related to advanced energy or advanced energy technologies are applicable during the time period contemplated by the initial CBP under this application (Co. Ex. 4 at 29).

It is the understanding of IEU-Ohio that customer-sited capabilities must be set forth by the Companies in their MRO proposal in order to meet the alternative energy resource, energy efficiency, and peak demand reduction portfolio requirements in SB 221. IEU-Ohio points out that FirstEnergy did include provisions dealing with customer-sited capabilities in its ESP case, which was filed contemporaneously with this case (IEU Ex. 1 at 6-7). OPAE agrees and recommends that FirstEnergy consider an integrated procurement plan whereby the impact of various cost-effective demand side management programs are considered as substitutes for some portion of the traditional generation supply contracts (OPAE Ex. 1 at 34-35). In addition, Nucor notes that interruptible rates, which are not proposed in the MRO application, are critical to meet the broad demand response policy objectives of SB 221, as well as the peak demand reduction targets in the statute; therefore, Nucor avers that the Commission should require that customers be allowed to take service under interruptible rate options (Nucor Ex. 1 at 12).

The record in this case demonstrates that FirstEnergy has not included in its application a proposal for compliance with the renewable energy requirements in Section 4928.64, Revised Code (Tr. I at 81). The Commission finds that the Companies' application for an MRO cannot be approved in the absence of a proposal for compliance with the renewable energy requirements of Section 4928.64, Revised Code. The Commission notes that Section 4928.142, Revised Code, which allows electric utilities to apply for MROs, and Section 4928.64, Revised Code, which provides renewable energy requirements for electric utilities, were enacted together as part of SB 221. Reading these provisions together, it is clear that the General Assembly intended for the Commission to consider the utility's proposal for addressing the renewable energy requirement in the context of considering the utility's application for an MRO.

In addition, the Commission notes that Section 4928.02, Revised Code, states that it is the policy of this state to protect at-risk populations in considering the implementation of new advanced energy or renewable energy resources. By attempting to sever the Commission's consideration of its MRO from the consideration of its proposal for compliance with the statutory renewable energy resource requirements, FirstEnergy's application has the potential to frustrate, rather than advance, this policy goal of the state.

Moreover, by failing to include the proposal to meet the renewable energy requirements as part of its application for an MRO, FirstEnergy precludes the possibility that generation based upon renewable energy could be part of the winning bidder's portfolio in the CBP. Instead, FirstEnergy assumes that the only means of meeting the renewable energy requirement will be through the purchase of renewable energy credits, with the cost of such credits being passed through to consumers.

Likewise, the Commission finds that FirstEnergy's application for an MRO cannot be approved in the absence of a proposal by the Companies for compliance with the energy efficiency and peak demand reduction requirements of Section 4928.66, Revised Code. The Commission further notes that SB 221 amended the policies of the state, codified in Section 4928.02, Revised Code, to specifically enumerate DSM, time-differentiated pricing, and implementation of AMI as policies which should be promoted by the Commission. These provisions were all enacted as part of SB 221, and it is clear that the General Assembly intended for the Commission to consider an electric utility's plan for compliance with the energy efficiency and peak demand reduction requirements in conjunction with the consideration of its application for an MRO.

F. <u>Other issues</u>

The Companies have also developed contingency plans in the event one or more of the winning bidders repudiate the Master SSO Supply Agreement prior to the beginning of the delivery period, or if one or more SSO supplier defaults during the delivery period (Co. Ex. 1 at 14-15; Co. Ex. 4 at 26). Constellation supports the contingency plans proposed in the MRO (Const. Ex. 1 at 4). IEU-Ohio notes that, in the event of these types of defaults, measures should be taken to offset the costs being passed on to retail customers (IEU Ex. 1 at 22). The Consumer Advocates believe that increased oversight by the Commission should be applied to circumstances where a winning bidder fails to provide service and the Companies should not have unfettered discretion to determine how they will acquire replacement tranches (Con. Adv. Br. at 11). Constellation also recommends several changes to the propose SSO Master Supply Agreement (Const. Ex. 1 at 29).

In light of the fact that FirstEnergy's application is not being approved at this time for the reasons discussed above, the Commission finds that it is unnecessary to reach these additional issues. The Commission directs FirstEnergy, in the event it chooses to continue to pursue an MRO, to carefully consider the revisions to the Master SSO Supply Agreement proposed by the parties. In addition, the Commission notes that FirstEnergy has failed to meet the requirements of some of the Commission's rules issued in Case No. 08-777-EL-ORD. Therefore, if FirstEnergy pursues an MRO in the future it will be required to comply with the rules adopted by the Commission in Case No. 08-777-EL-ORD, once such rules become effective.

IV. CONCLUSION

Upon review of FirstEnergy's MRO application, taking in consideration the requirements established by SB 221, the Commission finds that the MRO application can not be approved as filed. In the event FirstEnergy decides to continue to pursue an MRO, FirstEnergy is directed to provide a sufficient demonstration to address the concerns we have noted herein.

FINDINGS OF FACT:

(1) On July 31, 2008, FirstEnergy filed an application for an MRO in accordance with Section 4928.142, Revised Code.

(2) On August 18, 2008, a technical conference was held regarding FirstEnergy's application and on August 25, 2008, a prehearing conference was held in this matter.

(3) On September 15, 2008, intervention was granted to: OEG; OCC; Kroger; OEC; IEU-Ohio; OPAE; Nucor; NOAC; Constellation; Dominion; OHA; Citizens' Coalition; NRDC;

Sierra Club; NEMA; Integrys; Direct Energy; City of Akron; OMA; FPL; Cleveland; NOPEC; OFBF; American Wind Association, Wind on Wires, and Ohio Advance Energy; Citizens; OmniSource; Material Sciences; OSC; COSE; Morgan Stanley Capital Group; and Commercial Group.

(4) The hearing commenced on September 16, 2008, and concluded on September 22, 2008.

(5) Briefs and reply briefs were filed on October 6, 2008, and October 14, 2008, respectively.

CONCLUSIONS OF LAW:

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

(2) The Companies' application was filed pursuant to Section 4928.142, Revised Code, which authorizes the electric utilities to file an MRO as their SSO, whereby retail electric generation pricing will be based upon the results of a CBP.

(3) Paragraphs (A) and (B) of Section 4928.142, Revised Code, set forth the specific requirements that an electric utility must meet in order to demonstrate that the CBP and the MRO proposal comply with the statute.

(4) Section 4928.142(A)(1), Revised Code, requires that an MRO be determined through a CBP that provides for: an open, fair, and transparent competitive solicitation; a clear product definition; standardized bid evaluation criteria; oversight by an independent third party; and evaluation of submitted bids prior to selection of the least-cost bid winner or winners.

(5) Section 4928.142(B) requires that an MRO application detail the electric utilities' proposed compliance with the CBP requirements and the Commission's rules, and demonstrate: membership in an RTO; the RTO has a market-monitor function and the ability to take actions to identify and mitigate market power and the distribution utility market conduct; and that there is a published source of information that identifies pricing for on- and off-peak energy products that are contracts for delivery beginning at least two years in the future.

(6) Section 4928.142(B), Revised Code, provides that a utility may file its application for an MRO prior to the effective date of the Commission rules required under the statute; however, as the Commission determines necessary, the utility shall immediately conform its filing to the rules upon the rules taking effect.

(7) In keeping with Section 4928.142(A)(1)(a), Revised Code, the competitive solicitation proposed by FirstEnergy should not be approved.

(8) The application does not provide a clear product definition in accordance with the requirements of Section 4928.142((A)(1)(b), Revised Code.

(9) The application does not meet the statutory requirement for standardized bid evaluation found in Section 4928.142(A)(1)(c), Revised Code.

(10) The application does not meet the statutory requirement for oversight by an independent third party found in Section 4928.142(A)(1)(d), Revised Code.

(11) The application meets the statutory criterion regarding evaluation of proposed bids found in Section 4928.142(A)(1)(e), Revised Code.

(12) FirstEnergy has fulfilled the requirements of Section 4928.143(B)(1), Revised Code, requiring membership in an RTO.

(13) FirstEnergy has not demonstrated that the application meets the requirements of Section 4928.143(B)(2), Revised Code, pertaining to the market-monitor function.

(14) FirstEnergy has not demonstrated that a source of information is available for pricing of traded electricity, in accordance with the requirements of Section 4928.142(B)(3), Revised Code.

(15) The rate design included in the application cannot be approved because FirstEnergy has not demonstrated that the proposed rate design advances state policies.

(16) Rider CRT should not include recovery of delta revenue for the special contracts and all remaining aspects of Rider CRT relating to generation should be avoidable. The delta revenue recovery for future special or unique arrangements should be made by a separate rider.

(17) The application for an MRO cannot be approved in the absence of a proposal for compliance with the renewable energy requirements of Section 4928.64, Revised Code, and a proposal for compliance with the energy efficiency and peak demand reduction requirements of Section 4928.66, Revised Code.

(18) In the event FirstEnergy chooses to continue to pursue an MRO, it should consider the revisions to the Master SSO Supply Agreement proposed by the parties.

(19) If FirstEnergy continues to pursue an MRO, it will be required to comply with the rules adopted by the Commission in Case No. 08-777-EL-ORD, once such rules become effective.

<u>ORDER</u>:

It is, therefore,

ORDERED, That FirstEnergy's application for approval of its proposed MRO is not approved for the reasons set forth in this opinion and order and, in the event FirstEnergy elects to pursue an MRO, FirstEnergy is directed to provide a sufficient demonstration to address the specific concerns noted herein. It is, further,

ORDERED, That Constellation's motion to supplement its reply brief be denied. It is, further, ORDERED, That a copy of this opinion and order be served on all parties of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Alan R. Schriber, Chairman

Paul A. Centolella

Ronda Hartman Fergus

Valerie A. Lemmie

Cheryl L. Roberto

CMTP/GAP/vrm

Entered in the Journal

NOV 25 2008

Reneé J. Jenkins
Secretary

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of the foregoing *Merit Brief and Appendix by Intervening Appellee the Office of the Ohio Consumers' Counsel* has been served upon the below-named counsel via First Class mail, postage prepaid this 19th day of April 2010.

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