BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of Application of Duke Energy Ohio, Inc. for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for a Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service.	)	Case No. 10-2586-EL-SSO

OPINION AND ORDER

The Public Utilities Commission of Ohio, having considered the record in this matter and being otherwise fully advised, hereby issues its opinion and order.

APPEARANCES:

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

Kravitz, Brown & Dortch, LLC, by Michael D. Dortch, 65 East State Street, Suite 200, Columbus, Ohio 43215, on behalf of Duke Energy Retail Services, LLC.

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

Janine L. Migden-Ostrander, Ohio Consumers' Counsel, by Ann M. Hotz, Jody M. Kyler, and Richard C. Reese, Assistant Consumers' Counsel, 10 West Broad Street, Columbus, Ohio 43215, on behalf of the residential utility consumers of Duke Energy Ohio, Inc.

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

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

McNees, Wallace & Nurick, LLC, by Samuel C. Randazzo and Joseph E. Oliker, 21 East State Street, 17th Floor, Columbus, Ohio 43215, 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, on behalf of Ohio Partners for Affordable Energy.

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

Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff, Stephen M. Howard, and Lija Kaleps-Clark, 52 East Gay Street, Columbus, Ohio 43216, on behalf of Constellation New Energy, Inc., Constellation Energy Commodities Group, Inc., and the Retail Energy Suppliers Association.

Mark A. Hayden, FirstEnergy Service Company, 76 South Main Street, Akron, Ohio 44308, and Jones Day, by David A. Kutik and Grant W. Garber, North Point, 901 Lakeside Avenue, Cleveland, Ohio 44114, on behalf of FirstEnergy Solutions Corp.

William R. Reisinger, Nolan Moser, and Trent A. Dougherty, 1207 Grandview Avenue, Suite 201, Columbus, Ohio 43212, on behalf of Ohio Environmental Council.

Bricker & Eckler, LLP, by Christopher M. Montgomery and Terrence O'Donnell, 100 South Third Street, Columbus, Ohio 43215, on behalf of Ohio Advanced Energy.

Bricker & Eckler, LLP, by Thomas J. O'Brien, 100 South Third Street, Columbus, Ohio 43215, on behalf of the city of Cincinnati.

Bricker & Eckler, LLP, by Matthew W. Warnock, 100 South Third Street, Columbus, Ohio 43215, and Kevin Schmidt, 33 North High Street, Columbus, Ohio 43215, on behalf of Ohio Manufacturers Association.

The Law Office of Douglas E. Hart, by Douglas E. Hart, 441 Vine Street, Suite 4192, Cincinnati, Ohio 45202, on behalf of The Greater Cincinnati Health Council and Eagle Energy, LLC.

Behrens, Taylor, Wheeler & Chamberlain, by Rick D. Chamberlain, 6 Northeast 63rd Street, Suite 400, Santa Fe North Building, Oklahoma City, Oklahoma 73105, and Roetzel & Andress, by Kevin J. Osterkamp, 155 East Broad Street, 12th Floor, Columbus, Ohio 43215, on behalf of Wal-Mart Stores East, LP and Sam's East, Inc.

Anne M. Vogel, 1 Riverside Plaza, 29th Floor, Columbus, Ohio 43215, on behalf of AEP Retail Energy Partners, LLC.

Matthew J. Satterwhite and Erin C. Miller, 1 Riverside Plaza, 29th Floor, Columbus, Ohio 43215, on behalf of Ohio Power Company and Columbus Southern Power Company.

Christensen & Christensen, LLP, by Mary W. Christensen, 8760 Orion Place, Suite 300, Columbus, Ohio 43240, on behalf of People Working Cooperatively, Inc.

OPINION:

I. HISTORY OF THE PROCEEDING

On November 15, 2010, Duke Energy Ohio, Inc. (Duke or company) filed an application for a standard service offer (SSO)[1] pursuant to Section 4928.141, Revised Code. This application is for a market rate offer (MRO) in accordance with Section 4928.142, Revised Code. In support of its application, Duke filed the testimony of 14 witnesses.

By entry issued November 16, 2010, the attorney examiner established the procedural schedule in this case. On November 22, 2010, a technical conference was held regarding Duke's application. On December 7, 2010, Staff filed comments on the application (Staff Ex. 3). Subsequently, on December 13, 2010, a prehearing conference was held in order to discuss procedural issues in the above-captioned case.

The following parties were granted intervention by entry dated December 13, 2010: Industrial Energy Users-Ohio (IEU); The Ohio Energy Group (OEG); Ohio Partners for Affordable Energy (OPAE); The Kroger Company (Kroger); Ohio Environmental Council (OEC); FirstEnergy Solutions Corp. (FES); The Greater Cincinnati Health Council (GCHC); Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc. (Constellation); Ohio Consumers' Counsel (OCC); Duke Energy Retail Sales, LLC (DERS); Dominion Retail, Inc. (Dominion); Wal-Mart Stores East, LP and Sam's East, Inc. (Wal-Mart); Ohio Manufacturers' Association (OMA); Retail Energy Supply Association (RESA); Columbus Southern Power and Ohio Power Company (AEP Ohio); AEP Retail Energy Partners LLC (AEP Retail); city of Cincinnati (Cincinnati); Eagle Energy, LLC (Eagle); People Working Cooperatively, Inc. (PWC); and Ohio Advanced Energy (OAE). By this same entry the motions for admission *pro hac vice* filed on behalf of Robert A. Weishaar, Jr., David C. Rinebolt, Cynthia A. Fonner Brady, and Rick D. Chamberlain were granted.

The hearing commenced on January 4, 2011, and, at the request of Duke, was continued until January 11, 2011. The hearing concluded on January 19, 2011. At the brief hearing held on January 4, 2011, Duke's motion to allow B. Keith Trent to adopt the testimony of James E. Rogers was granted. In addition to the 14 witnesses testifying on behalf of Duke, eight witnesses testified on behalf of various intervenors, and two

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1 See Appendix A for a listing of all acronyms used in this order.

witnesses testified on behalf of Staff. Briefs were filed on January 27, 2011, by Duke, Staff, IEU, OEG, OPAE, Kroger, OEC, FES, GCHC, Constellation, OCC, Dominion, OMA, RESA, Eagle, and OAE. In its brief, Eagle joined in all of the arguments contained in the brief filed by GCHC. On January 31, 2011, Wal-Mart filed its brief, along with a motion requesting that its brief be accepted as timely filed. In support of its motion, Wal-Mart states that it inadvertently electronically filed its initial brief on January 27, 2011, without a signature; therefore, to cure this problem, Wal-Mart filed a hard copy of its brief on January 31, 2011. No one filed a memorandum contra Wal-Mart's motion. The Commission finds that Wal-Mart's request that its brief be accepted as timely filed is reasonable and should be granted. Reply briefs were filed on February 3, 2011, by Duke, Staff, GCHC, OEG, OPAE, OCC, OMA, FES, DERS, IEU, and RESA. On February 3, 2011, Cincinnati filed a statement that it supports the initial brief filed by Staff.

At the hearing held in this matter, the attorney examiner granted Duke's motion for protective treatment of certain information presented on the record in this docket. In accordance with that ruling, the unredacted copies of Volumes II and III of the transcript were filed under seal in this docket on January 13, and 14, 2011, respectively, and the unredacted copies of IEU Exhibits 1 through 10 were filed under seal on January 19, 2011. In addition, IEU filed its brief, and IEU and Duke filed their reply briefs under seal in this docket on January 27, 2011, and February 3, 2011, respectively, consistent with the attorney examiner's directives at the hearing regarding the filing of briefs containing confidential information that has been granted protection. On February 4, 2010, Duke filed a motion for protective order of the briefs and reply briefs filed under seal on January 27, 2011, and February 3, 2011. At this time, the Commission finds that, in accordance with Rule 4901-1-24(D), Ohio Administrative Code (O.A.C.), the unredacted version of IEU's brief, and the reply briefs of IEU and Duke, filed under seal in this docket on January 27, 2011, and February 3, 2011, should be granted protective treatment. Accordingly, confidential treatment shall be afforded to the unredacted versions of: Volumes II and III of the transcript, filed under seal on January 13, and 14, 2011, respectively; IEU Exhibits 1 through 10, filed under seal on January 13, 2011; IEU's brief filed under seal on January 27, 2011; and IEU's and Duke's reply briefs filed under seal on February 3, 2011. Rule 4901-1-24(F), O.A.C., provides that, unless otherwise ordered, protective orders issued pursuant to Rule 4901-1-24(D), O.A.C., automatically expire after 18 months. Therefore, confidential treatment shall be afforded for a period ending 18 months from the date of this order or until August 23, 2012. Until that date, the docketing division should maintain, under seal, the information filed confidentially. Any party wishing to extend the protective order, must file an appropriate motion at least 45 days in advance of the expiration date. If no such motion to extend confidential treatment is filed, the Commission may release this information without prior notice to Duke.

On January 4, 2011, IEU filed a motion to dismiss asserting that Duke's application should be dismissed because it does not meet the statutory criteria contained in Section

4928.142(D), Revised Code. On January 7, 2011, Duke filed a memorandum contra IEU's motion to dismiss. IEU's motion and the arguments set forth by both IEU and Duke will be considered later in this order.

II. APPLICABLE LAW

Duke is a public utility as defined in Section 4905.02, Revised Code, and, as such, is 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, safe, reliable, and reasonably priced electric service in the context of significant economic and environmental challenges. In reviewing Duke's 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, which state, *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, and the development of distributed and small generation facilities;

(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 (TDP), 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 that an electric utility's transmission and distribution systems are available to customer-generator or owner of distributed generation;

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

(8) ensure effective retail competition by avoiding anticompetitive subsidies;

(9) ensure retail consumers protection against unreasonable sales practices, market deficiencies, and market power;

(10) provide a means of giving incentives to technologies that can adapt to potential environmental mandates;

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

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

(13) encourage education of small business owners regarding the use of, and encourage the use of, energy efficiency programs and alternative energy resources (AER); and

(14) facilitate the state's effectiveness in the global economy.

The applicant's SSO must be consistent with these policies. *Elyria Foundry v. Pub. Util. Comm.* (2007), 114 Ohio St. 3d 305.

Section 4928.141, Revised Code, requires electric utilities to provide consumers with an SSO, consisting of either an MRO or an electric security plan (ESP). The SSO is to serve as the electric utility's default SSO.

Section 4928.142, Revised Code, authorizes an electric utility to file an MRO as its 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 requirements an electric utility must meet in order to demonstrate that the CBP and the MRO proposal comply with the statute. Paragraph (B) provides that an application must detail the utility's proposed compliance with the statutory CBP requirements, with the requirements set forth in the Commission's rules, and with the regional transmission organization (RTO) and pricing information requirements. In determining whether an MRO meets the requirements of Sections 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.

Paragraphs (D) and (E) of Section 4928.142, Revised Code, set forth the blended price requirements any electric distribution utility, which, as of July 31, 2008, directly owns operating electric generating facilities that had been used and useful in this state, must abide by.

Chapter 4901:1-35, O.A.C., sets forth requirements each electric utility must comply with when filing an SSO in the form of an MRO, pursuant to Sections 4928.141 and 4928.142, Revised Code.

III. DISCUSSION

A. Background and Summary of Application

Duke provides electric distribution service to approximately 690,000 residential, commercial, industrial, and public authority customers in southwestern Ohio (Duke Ex. 2 at 4). Duke currently provides generation service to its customers through an ESP pursuant to Section 4928.143, Revised Code, and the stipulation approved by the Commission on November 17, 2008, in *In the Matter of the Application of Duke Energy Ohio, Inc. for Approval of an Electric Security Plan*, Case No. 08-920-EL-SSO, et al. *(Duke ESP Case)*. According to Duke witness Janson, the ESP was approved in the *Duke ESP Case* as a three-year price formula for generation service beginning January 1, 2009 through December 31, 2011. Ms. Janson notes that the ESP formula consists of two parts, an avoidable price-to-compare (PTC) component and an unavoidable provider of last resort (POLR) component. (Duke Ex. 3 at 1; Duke Ex. 2 at 7.)

In its application in the instant case, Duke sets forth a proposed MRO whereby it will conduct a CBP designed to procure supply for the provision of SSO electric generation service beginning January 1, 2012, to the company's retail electric customers who do not purchase electric generation service from a competitive retail electric service (CRES) provider (Duke Ex. 3 at 12). Duke requests that the Commission determine that its proposed MRO meets the requirements found in Sections 4928.141 and 4928.142, Revised Code, as well as Chapter 4901:1-35, O.A.C. (Duke Ex. 3 at 1). In addition, Duke submits that its MRO proposal is consistent with the policies of the state of Ohio, as established in Section 4928.02, Revised Code (Duke Ex. 2 at 16-29).

Prior to considering whether the MRO application filed by Duke is in compliance with paragraphs (A) and (B) of Section 4928.142, Revised Code, the state policy, and the Commission's rules, we must first address the parties' disagreement regarding the correct interpretation of paragraphs (D) and (E) of Section 4928.142, Revised Code, pertaining to the required blending price.

B. Sections 4928.142(D) and (E), Revised Code, Duke's Blended Price Proposal

Section 4928.142(D), Revised Code, provides that the first MRO application filed by a utility that, as of July 31, 2008, owns electric generating facilities:

> shall require that a portion of that utility's standard service offer load for the first five years of the market rate offer be competitively bid... as follows: ten per cent of the load in year one, not more than twenty per cent in year two, thirty per cent in year three, forty per cent in year four, and fifty per cent in year five. Consistent with those percentages, the commission shall determine the actual percentages for each year or years one through five.

Section 4928.142(E), Revised Code, provides, *inter alia,* that:

> Beginning in the second year of a blended price under division (D) of this section and notwithstanding any other requirement of this section, the commission may alter prospectively the proportions specified in that division to mitigate any effect of an abrupt or significant change in the electric distribution utility's standard service offer price that would otherwise result in general or with respect to any rate group or rate schedule but for such alteration.

The statute prohibits such an alteration from being made more often than annually and the Commission can not, through such alteration, cause the blending period to exceed 10 years.

If this application complies with the statutory filing requirements for such applications, this will be Duke's first MRO application. In light of the fact that Duke has ownership of electric generating facilities as of July 31, 2008, Duke acknowledges that it must apply the blending requirements set forth in Section 4928.142(D), Revised Code. (Duke Ex. 3 at 12; Duke Ex. 16 at 5.) Thus, Duke must transition from its current structure, where its retail rates were established under an ESP, to a full MRO. (Duke Ex. 3 at 9-10).

In describing the proposed retail rate design, Duke explains that, pursuant to the statute, the SSO price during the MRO blending period (blended SSO price) is the sum of a percentage of the auction price (market price) and a percentage of Duke's current ESP generation service price (ESP price). Duke proposes that the ESP price to be blended with the winning auction price is the SSO price for generation that will exist as of December 2011, adjusted for any over- or under-recovery of eliminated ESP-era riders. (Duke Ex. 3 at 33-34.)

Duke witness Wathen submits that, absent any other factors, Duke would follow the five-year blending schedule set forth in the statute. According to Mr. Wathen, based on Duke's expectations of the market prices, current trends, and current forward prices, for the first two years of the MRO, the blended SSO price is expected to be higher than the market price; however, Duke expects that the blended SSO price will be lower than the current ESP price. Mr. Wathen explains that, at the time the company's ESP was approved in July 2008, market prices for power were at or above the company's expected ESP price; since that time, market prices have been and are expected to remain below the company's current ESP price. Duke expects that the retail market price will remain below the company's blended SSO price until 2014, when Duke expects the ESP price and the market price will converge. (Duke Ex. 16 at 9-10.)

Duke asserts that the intent of the statute is for the blending requirement to function in a way that would simultaneously protect both Duke and its customers during the migration from the company's most recent ESP price to the competitive market price (Duke Ex. 3 at 3; Duke Ex. 2 at 12). Duke avers that blending is intended to lessen the risk of dramatic price changes for customers, while simultaneously ensuring appropriate recovery by Duke of the costs to serve its SSO customers and protecting the utility's financial integrity (Duke Ex. 3 at 11; Duke Br. at 29). Therefore, Duke argues that, when the company's most recent ESP price and the market price converge (which Duke believes with likely occur in the third year of the MRO, 2014), the impact of proportionately combining the ESP price and the market rate, in order to mitigate price volatility while allowing full cost recovery to the company, is rendered nonexistent. (Duke Ex. 3 at 4; Duke Ex. 16 at 10.) According to Ms. Janson, blending during the first two years will allow customers to obtain an increasing fraction of the commodity at market prices, while protecting Duke's economic viability and the CRES providers' ability to compete against the SSO price (Duke Ex. 2 at 13-14).

Because the market price and the ESP price will converge in the third year of the MRO and, because the company is proposing to transfer its legacy generation to an affiliate no later than the beginning of year three, Duke proposes to end the blending period at the beginning of year three and make available to customers an SSO price based exclusively on the market prices derived from an auction. Mr. Wathen further explains that the blending period must end when the generation assets are transferred from Duke, insofar as the electric distribution utility can then only meet its SSO obligation through market purchases. (Duke Ex. 16 at 10-12.)

Duke witness Whitlock explains that Duke is not requesting approval of the transfer of its legacy generation assets in this case, but Duke will be filing a subsequent case requesting such approval (Duke Ex. 11 at 8). Mr. Whitlock believes that the transfer of Duke's generation assets into a separate company advances competition in Ohio and benefits Duke and its customers (Duke Ex. 11 at 3). Duke explains that there are several reasons why it should transfer the legacy assets to an affiliate. First, the nexus between Duke's ownership of generation assets and the dedication of those generation assets to serve its SSO load no longer exists. Second, it allows Duke to effectively plan for reliable service in the wake of competition and assure customers of the lowest market price. Third, the competitive market is fully functioning. Fourth, it will protect Duke's financial stability by removing the uncertainty of future capital deployment and operation expenditures, which are affected by customer switching. (Duke Ex. 2 at 15; Duke Ex. 11 at 9.) In support of his view, Mr. Whitlock notes that the 60 percent of Duke's load served by CRES providers breaks down to 89 percent of the industrial load, 70 percent of the commercial load, and 29 percent of the residential load (Duke Ex. 11 at 19).

OEG witness Baron opposes Duke's plan to transfer its legacy generation assets pointing out that, following the transfer, the blended rate would be comprised of a weighted average of the price of power purchased under a purchased power agreement (PPA) and the market rate. Since the PPA would logically be priced at market, Mr. Baron believes that there would be no need for blending of the ESP price and market prices. Mr. Baron submits that Duke's argument that the transfer of the legacy generation supports Duke's proposed shortened blending period only has merit if the Commission grants Duke's request to transfer the generation assets. However, if the Commission denied the transfer, customers would continue to be protected during the full five years of the blending period, up to 10 years under the statute. (OEG Ex. 1 at 10-11; OEG Br. at 8.) Mr. Baron advocates, and OPAE agrees, that the Commission not authorize a transfer of the legacy generation assets until after the five- to ten-year blending period (OEG Ex. 1 at 16; OEG Br. at 8-9; OPAE Br. at 6). OPAE asserts that the purpose of Section 4928.142(E), Revised Code, is to further protect consumers from the vagaries of the marketplace (OPAE Br. at 2).

Under the MRO, Duke proposes that its SSO supply be acquired through CBP auctions. Duke explains that the auctions will be conducted on at least an annual basis, with the first auction occurring in June 2011. Because Duke plans on joining PJM Interconnection (PJM) before the beginning of the MRO and Duke will be conducting the auction in the PJM market for that share of the load being blended to create the blended SSO price, Duke seeks to align its CBP auction schedule with PJM's auction schedule, which is a 12-month period beginning in June of each year. Therefore, Duke proposes that the first year of its MRO be defined as including 17 months, from January 1, 2012 through May 31, 2013. (Duke Ex. 3 at 12-13; Duke Ex. 16 at 8.) Duke asserts that following the PJM auction cycle will provide participants in the Duke auction with increased certainty around capacity prices on a forward-looking three-year basis, thus enabling them to better manage price risk. According to Duke, this improved risk management should translate into an enhanced bidding process that yields more competitive prices. (Duke Ex. 3 at 12-13; Duke Ex. 8 at 5-6.)

Duke believes that the statutory language, in Section 4928.142(E), Revised Code, that confers upon the Commission the ability to alter the blending period was created in the event the acceleration of the blending period could more quickly realize a fully-competitive market (Duke Ex. 3 at 11). Duke requests that the Commission exercise its discretion, pursuant to Section 4928.142. Revised Code, to revise the blending period, and that the following blended SSO price be implemented for Duke's MRO:

(1) Year One - January 1, 2012 through May 31, 2013 – 10 percent market price and 90 percent ESP price.

(2) Year Two - June 1, 2013 through May 31, 2014 - 20 percent market price and 80 percent ESP price.

(3) Year Three and Beyond – 100 percent market price.

Duke witness Wathen explains that, during the blending period, Duke is permitted to adjust the ESP price component for changes in fuel, purchased power, and environmental costs. However, Duke proposes that, as explained in detail below, contingent on the Commission accepting its proposed blending period, the ESP price component of the blended SSO price be frozen for the two-year blending period. (Duke Ex. 3 at 33-34; Duke Ex. 16 at 13.) Duke offers that its proposed blending period, together with a properly formulated CBP plan, will not result in abrupt or significant rate changes for customers, because Duke is willing to forego any adjustments to its most recent SSO price under the ESP during the blending period. (Duke Ex. 3 at 12.) However, if the blending period is extended and the generation asset transfer does not occur before June 1, 2014, Duke has provided proposed tariffs that would be used to adjust the ESP price component on a quarterly basis to address changes in fuel, purchased power, and environmental costs (Duke Ex. 16 at 14).

C. Positions on Convergence of the ESP Price and the Market Price

Duke witness Rose offers that the formulas that make up portions of the current ESP price do not track short-term perturbations in wholesale or retail market conditions. Mr. Rose notes that Duke is not permitted to adjust its ESP price in response to market conditions. The witness points out that, after the ESP was approved in 2008, due to the economic recession, the wholesale and retail market prices decreased dramatically, e.g., wholesale prices decreased 43 percent by 2009. He explains that current wholesale prices are lower than average because: due to the recent recession there is lower peak electricity demand, which results in excess capacity and lower capacity prices in the market; natural gas prices are low, in part, due to the recession; lower demand lowers the price of electric energy; and environmental regulations have lowered the cost of generating electric energy using coal plants. Mr. Rose states that, as a result, by September 2010, 62 percent of Duke's load demand per megawatt hour (MWh) had switched to CRES providers. Mr. Rose notes that the switching is occurring across all classes, but more so in the commercial and industrial categories. In light of these developments, Mr. Rose states that Duke is proposing an MRO starting in 2012, rather than an ESP (Duke Ex. 4 at 5-6, 13-14; 22-23).

According to Mr. Rose, the convergence of the retail market price and the legacy ESP price is the result of the expectation that wholesale power prices delivered to Duke will increase over time. The witness bases his conclusion principally on the observable forward prices for the delivery of wholesale power to Duke that are available for the Intercontinental Exchange (ICE). Mr. Rose states that the information shows a wholesale power price increase between 2009 and 2014 cumulatively on a nominal basis of 54 percent; thus, bringing the retail prices very close to the avoidable portion of Duke's ESP prices. He believes that the prices may increase due to: the retirement of coal power plants due to environmental regulations; the economic recovery in the United States and PJM; rising electricity demand; and rising gas prices. While the witness notes that there are no forward prices available after 2014, he states that there is potential for higher power prices after June 1, 2014, due to the potential for tighter emission regulations and higher natural gas prices. In addition, Mr. Rose projected the capacity prices for 2012 to 2014, based on the PJM forward capacity price. Mr. Rose projects that the average RTO capacity price for the PJM Reliability Pricing Model (RPM) for 2012 to 2014 will be $8.8 per kilowatt (kW) per year. (Duke Ex. 4 at 7-8, 27-29.)

Furthermore, Mr. Rose testifies that retail power prices generally track wholesale power prices; thus, retail power prices are expected to increase. The witness explains that retail prices are not as observable as wholesale prices because each customer or class of customers has a different cost of service and prices can vary; therefore, to address this problem, he projected retail prices on the assumption that prices will reflect the cost of service. The components of the witness' retail price projection are: the market index of energy prices; the capacity price; the broker's fee or ask-adder; the covariance adjustment to account for the covariance between the customer load variation and the price variation; the energy and demand losses in the transmission and distribution system; a supply management fee; and an operating risk adjustment. Mr. Rose projects that the 2014 retail market price is expected to be 23 percent higher than the 2012 price. (Duke Ex. 4 at 7-8, 31-37.) Mr. Rose calculates that the weighted average energy charge or retail market price, excluding POLR costs, for all customer classes in 2012 will be $.0582 per kW hour (kWh) (Duke Ex. 4 at 42).

According to Mr. Rose, the 2014 retail market price ($.0717 per kWh) is expected to be very close to the projected avoidable legacy ESP price for generation ($.0734 per kWh). Thus, when the blended price is proposed to end in 2014, the prices are expected to be close and, were the market prices and legacy ESP price to continue at these levels, continued blending would have no effect on the price available to customers. In the event the forecast is wrong and the market prices remain at a discount, Mr. Rose states that the proposal has the advantage of maximum access to lower market prices. (Duke Ex. 4 at 9.)

OEG witness Baron notes that, if Mr. Rose's projections are wrong, in year three, the market rates could substantially exceed the otherwise applicable blended SSO price. Mr. Baron points out that Mr. Rose does not offer any projection for market rates beyond 2014. Mr. Baron believes that, since Mr. Rose expects substantial increases in market prices through 2014, which closes the gap with Duke's ESP price, it seems reasonable to believe that market prices could begin accelerating beyond the ESP price in 2015 and 2016. Mr. Baron states, and OPAE agrees, if market prices increase beyond the ESP prices in 2015 and 2016, that is the time that ratepayers will need the protection afford by the statutory minimum five-year blending period. Mr. Baron points out that, if the ESP prices and market prices will be roughly identical by 2014, Duke would receive essentially the same level of SSO revenues under a 29-month transition period and a 60-month period as is called for by the statute. (OEG Ex. 1 at 8-9; OPAE Br. 5.) Mr. Baron argues, and OPAE agrees, that Duke's proposed 29-month transition plan transfers substantial risk to retail customers who no longer have the legacy ESP price options in years three through ten as contemplated by the statute. OPAE also agrees with Mr. Baron's assertion that the blending provisions in the statute establish a schedule to share the risks and rewards of market pricing between Duke's shareholders and its retail customers. Mr. Baron argues that Duke's proposed 29-month transition plan transfers substantial risk to retail customers and eliminates the potential relief the Commission could offer to customers by extending the blending period for up to 10 years. Furthermore, OPAE notes that market rates could substantially exceed the blended SSO price, which would mean that Duke's revenues would be higher as a result of the shortened blending period. (OEG Ex. 1 at 9, 14-15; OEG Br. at 7 and 11; OPAE Br. at 4-5.)

Kroger argues that Duke's contention that, in the third year of the MRO, the projected market price will approximately equal the legacy ESP price is not a sufficient reason to jettison all but two years of the required five- to ten-year blended price, even if it is permissible under the statute. Kroger notes that the 2014 market price set forth by Duke is a forecasted price and forecasted energy prices are often wrong. Furthermore, even if the prices do converge in the third year, that could be temporary and the Commission should be concerned about the price implications for the entire blending period not just what may occur in 2014. In addition, Kroger submits that, even if the prices do converge, customers would not be harmed by blending two similar prices for several years, and the Commission should err on the side of caution. Kroger offers that the blending period is important to ensure that a robust market materializes under an MRO and the full blending period would allow the Commission to monitor the development of the retail market. (Kroger Br. at 8-9.)

D. Section 4928.142(D), Revised Code, Blended Price Percentages

All parties agree that Section 4928.142(D), Revised Code, also provides that the blended SSO price for retail electric generation service under the first MRO application shall be a proportionate blend of the auctioned market price and the legacy ESP price. Furthermore, there is no contest that the statute provides that the ESP price may be adjusted up or down as the Commission determines is reasonable for certain costs which are reflected in the utility's most recent ESP price, i.e., fuel costs, purchased power, supply and portfolio requirements, and environmental compliance.

In addition, the Commission notes that no party disputes the fact that paragraph (D) of Section 4928.142, Revised Code, requires that the blending percentage for year one of the MRO must be 10 percent. Likewise, it is undisputed that the blending percentage in year two must be no more than 20 percent, as determined by the Commission.

However, there is strong disagreement between the parties with regard to the interpretation of the statute and the required blended price percentages for years three, four, and five of the MRO. Therefore, the following discussion regarding paragraph (D) of Section 4928.142, Revised Code, will focus on the parties' arguments pertaining to years three, four, and five.

According to Duke, the statute, "suggests a five-year migration to market, with an initial expectation that the electric distribution utility initiate an auction for its entire load beginning in year six." (Duke Ex. 3 at 9-10). Duke submits that paragraph (D) of Section 4928.142, Revised Code, establishes baseline blending percentages, and then, in paragraph (E) of Section 4928.142, Revised Code, the Commission is granted the flexibility to change the percentages after the second year of the MRO (Duke Br. at 22).

Duke asserts that the words "not more than" in paragraph (D) of Section 4928.142, Revised Code, do not apply to the percentages applicable to years three, four, and five of the blending period years. Therefore, Duke maintains that the Commission's determination does not have to result in percentages that do not exceed 30, 40, and 50 percent market prices in years three, four, and five, respectively. According to Duke, there would have to be an "and" inserted before "not more than" if this limitation were to apply to these subsequent years as well. (Duke Br. 25; Duke Reply Br. at 23.)

GCHC and Eagle believe that, based on the plain language of paragraph (D) of Section 4928.142, Revised Code, and its legislative history, an MRO must use blending percentages of exactly 30 percent in year three, 40 percent in year four, and 50 percent in year five. In support of their view, GCHC and Eagle note that, in previous drafts of the legislation, the language alternated between making the blending percentages minimums and maximums, but the final language settled on fixed percentages for all but year two. GCHC and Eagle assert that Section 4928.142(D), Revised Code, permits the Commission to look forward one year, but no further, and allows that Commission to slow down the blending if it foresees that a 20 percent blending requirement would be inappropriate in year two. Then, in accordance with paragraph (E) of Section 4928.142, Revised Code, beginning in year two, the Commission has the authority to vary from the fixed 30, 40, and 50 percent blending rates for years three, four, and five, and potentially to year ten. GCHC and Eagle point out that, at that point, the Commission would have more current information about the market conditions to make a better decision. (GCHC Br. at 9-10.)

Kroger believes that Duke interprets the first sentence in paragraph (D) of Section 4928.142, Revised Code, to provide that the phrase "not more than" modifies only 20 percent, and not the 30, 40, and 50 percent that follow. Contrary to Duke's belief, Kroger asserts that "not more than" applies not just to 20 percent, but to all items that follow. In addition, Kroger points to the second sentence in Section 4928.142(D), Revised Code, to require that, for the Commission to determine actual percentages that are consistent with the enumerated percentages, some range of percentages would be implicit in the enumerated percentages. Kroger believes that Duke's interpretation of the second sentence is that a range of percentages is indicated only for the second year of the MRO. Kroger disagrees with Duke's allegation that the proportionate weight given to the bid price of 100 percent could be assigned in years three, four, and five of the MRO; rather, Kroger submits that the only rational interpretation is that the weight given for years three, four, and five can be "no more than" 30 percent, 40 percent, and 50 percent, respectively. Thus, the Commission could adjust the bid price proportion in an amount up to the percentages, but not beyond. Therefore, Kroger asserts that Duke's application does not comply with Section 4928.142(D), Revised Code, and should be rejected as deficient. (Kroger Br. at 7-8.)

The Commission finds that the words, "not more than" in paragraph (D) of Section 4928.142, Revised Code, apply to years two, three, four, and five of the blending period and not just to year two, as argued by Duke. In accordance with Section 4928.142(D), Revised Code, the Commission is to determine the actual percentages for each year. Furthermore, as discussed below, paragraph (E) of Section 4928.142, Revised Code, provides the Commission with additional authority to alter the blending percentage in order to mitigate an effect of any abrupt or significant change in the SSO price.

E. Section 4928.142(E), Revised Code, Alteration of the Blended Price Percentages

There is disagreement between the parties in this case regarding the interpretation of paragraph (E) of Section 4928.142, Revised Code, and, specifically:

(1) the meaning of the language "beginning in the second year of the blended price" and the timing of the Commission's consideration to alter the blended price percentages;

(2) whether the Commission can approve a two-year blending period as proposed by Duke; and

(3) the meaning of the phrase "to mitigate any effect of an abrupt or significant change in the utility's SSO price."

To understand the meaning behind the statutory language, paragraph (E) of Section 4928.142, Revised Code, must be read in conjunction with the requirements set forth in paragraph (D) of Section 4928.142, Revised Code.

1. Timing of Consideration to Alter Blended Price Percentages

Duke believes that the statute unambiguously says that the Commission can alter the blend beginning in the second year and that the alterations must be done prospectively. Duke argues that paragraph (E) of Section 4928.142, Revised Code, does not limit how long before the second year the alterations to the blending percentages may be made. (Duke Br. at 24-26.) FES agrees that nothing in the statute prevents the Commission from deciding the blending portions in Duke's MRO now (FES Br. at 12). Duke states that the clear and unambiguous language of the statute allows the Commission to act now to alter the blending percentages that are applicable in year three and beyond. Duke argues that, even if the Commission were to find ambiguity with regard to when it may alter the blending percentages, the factors enumerated in Section 1.49, Revised Code, support Duke's contention that the Commission can act now. (Duke Reply Br. at 25-26.)

Staff witness Strom states that, while Duke proposes that the Commission determine now that the requisite blend be altered in year three of the MRO, he believes that such a determination to alter the proportions of the blend is to be made based on the actual circumstances that exist at some future time. Mr. Strom states that current forecasts may show an expectation for future market and ESP pricing relationships; however, such forecasts are subject to error. The witness believes that using a forecast to make a current determination to alter the blending percentages several years in the future, regardless of what actual circumstances might arise in the future, would not be in compliance with the statute. Staff believes that Duke's request for a two-year blending period is premature as the Commission has no discretion to alter Section 4928.142(D), Revised Code, now and approve Duke's proposed plan to reach an auction market share in year three. Furthermore, Staff points out that Duke's application is deficient because Duke failed to provide a forecast of wholesale and retail prices in years four and five. Staff submits that all of the deficiencies in Duke's application cannot be remedied without a major overhaul of the application to comply with the MRO statutes and Commission rules; therefore, Staff advocates that the Commission not approve Duke's MRO as proposed. (Staff Ex. 2 at 3-4; Staff Br. at 10-11.) OPAE agrees with Mr. Strom's assessment and recommends that the Commission adopt the recommendations of Staff witness Strom (OPAE Br. at 2-3).

GCHC, Eagle, OMA, and OEG submit that the plain language of paragraph (E) of Section 4928.142, Revised Code, prohibits the Commission from considering adjustments to the blending schedule until the beginning of the second year of blending, which, under Duke's proposal would be June 1, 2013. Had it been intended that the Commission have the discretion to set any of the blending percentages at the outset and not wait until the second year, GCHC and Eagle reason that this would have been addressed in paragraph (D) of Section 4928.142, Revised Code. (GCHC Br. at 9; Eagle Br. at 2; OMA Br. at 4; OEG Br. at 3.)

OCC agrees that the statute does not allow the Commission to alter the proportions three to five years before the blending occurs. OCC states that the Commission can not alter the proportions before it is able to compare the price that comes out of the competitive bid to the current ESP price. According to OCC, the blending process is designed to be an incremental process where the Commission can adjust the SSO price, based on changing market conditions, for a specific period of time, and it is not intended to be based on market forecasts that are not reliable and applied one time before the blending begins. (OCC Br. at 40-41.)

Upon review of the statute and the arguments set forth by the parties, the Commission finds that we must wait until year two of the MRO to consider whether the blended price percentages set forth in paragraph (D) of Section 4928.142, Revised Code, should be altered pursuant to paragraph (E) of Section 4828.142, Revised Code.

The Commission's determination to alter the proportions of the blended SSO price must be based on actual evidence that exists at some future point. The evidence presented on the record in this case is all speculative and based on events that may, or may not, occur, such as: the possible convergence of the ESP and market prices; the, as yet to be filed by Duke and considered by the Commission, request by Duke to transfer its legacy generation assets; and the prospective transfer of Duke to PJM and Duke's election to purchase generation services in PJM markets, which has not yet been confirmed.

Duke cites its intent to request, sometime in the future, authorization from the Commission to transfer its legacy generation assets to an affiliate effective in 2014, as support for its move to full market-based rates in year three of the MRO. On the record, there was substantial opposition to Duke's proposal to transfer these generation assets prior to the end of the blending period. Duke has not sought to transfer its generation assets to a nonaffiliate or to amend its corporate separation plan in a manner consistent with Section 4928.02 and 4928.17, Revised Code. As the application requesting authority to transfer has yet to be filed, and any issues that may need to be addressed in our consideration of such an application have not yet been identified, it is premature for the Commission to even speculate on whether such an application would be approved. That being said, it is likewise inappropriate for the Commission to take the possible transfer of the legacy generation assets into consideration in this case when determining whether or not Duke's proposal for a two-year blending period is permitted.

Duke also argues that its forecast that the ESP price and the market price will converge in 2014 warrants the end of the blending period and the beginning of Duke's move to 100 percent market price thereafter. Whether or not the two prices do, in fact, converge in 2014, has yet to be seen and even the most reliable forecasts have proven to be incorrect. Duke witness Rose even agrees that electric prices are volatile and forecasts do change. For example, market prices in 2008, when Duke's ESP was approved, were forecasted to continue to increase; however, the exact opposite occurred and market prices decreased to the point where they are now below the current ESP price. While the eventual convergence of the ESP price and the market price may be a relevant factor for the Commission to take into consideration in determining what the percentage portions for years three through the end of the blending period should be, the Commission finds that it is premature for us to predict that this factor alone warrants the conversion to 100 percent market prices two years from now.

Moreover, the Commission notes that Duke witness Rose agrees that, after 2014, when he predicts the ESP price and the market price will converge and, thus, ratepayers should pay 100 percent the market price, there is potential for higher wholesale power prices, which will result in higher retail power prices since they typically track the wholesale prices. If, in fact, the market prices do continue to increase, the Commission believes that such an occurrence would warrant the Commission's review of the blending proportions and possible alteration of the proportions.

While it may be true that, in the future, power prices will remain lower and it may be advantageous for the Commission to consider altering, prospectively, the blending proportions, such speculation is not appropriate at this time, even if it was allowed by the statute. The statute requires that, in year two of an MRO, the Commission may consider altering the blending proportions. However, that time is not today.

2. Duke's Proposed Two-year Blending Period

a. Proponents for a Shortened Blending Period

Duke states that paragraph (D) of Section 4928.142, Revised Code, provides the Commission with the flexibility to "alter" the blending percentages by either increasing or decreasing the percentages. Duke asserts that defining "alter" to mean that the Commission can only extend the blending period beyond five years, would compel the Commission to restrict, qualify, or narrow the clear meaning of the statute. According to Duke, nothing in the statute mandates a minimum blending period of five years, nothing precludes a 100 percent auction-based price in year three, and nothing precludes acceleration of the blend in year three or any other year. Duke urges that the statute cannot reasonably be construed as barring a transition to full market prices in less than five years. (Duke Br. at 26-27.)

RESA supports Duke's proposal for a two-year blending period. RESA argues that prolonging the blend to market is not in the public interest of lowering consumer prices and promoting market efficiency, and makes it more difficult for market participants to enter into long-term contracts because of the uncertainty surrounding regulation. (RESA Br. at 17-18.) Likewise, Wal-Mart does not oppose Duke's use of an MRO for the SSO or the proposed blending period (Wal-Mart Ex. 1 at 3; Wal-Mart Br. at 2).

FES agrees with Duke's interpretation of the statute and goes even further advocating that, because there is a likelihood that market prices will be well below Duke's ESP price, the Commission can, and should, improve upon Duke's MRO by requiring that Duke procure 10 percent of its nonshopping load in year one and 100 percent of that load in year two. FES asserts that moving to full market rates in year two will benefit nonshopping customers by providing them with lower generation prices sooner than under the current ESP. FES submits that FirstEnergy's auction price, approved in Case No. 10-1284-EL-UNC (10-1284),[2] is a good proxy for the price that Duke could obtain during its initial MRO auctions. Thus, comparing the prices from the FirstEnergy auction in 10-1284, which resulted in a range of prices from $54.10 to $57.47 per MWh beginning in June 1, 2011, FES points out that FirstEnergy's price is lower than Duke's projected ESP price between 2012 and 2014, which is $.0734 per kWh (FES Br. at 6-8; Duke Ex. 4 at 10-11). FES maintains that, by setting rates based on a CBP, retail competition in Duke's service territory will further develop and customers will be provided more opportunities to choose, while at the same time retaining competitively priced SSO supply as an alternative option. FES believes that Duke's MRO will benefit both wholesale and retail competition in Duke's territory. (FES Br. at 2-3.) Further, FES maintains that, since Duke proposes to

[2] See *In the Matter of the Procurement of Standard Service Offer Generation for Customers of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company*, Case No. 10-1284-EL-UNC, Finding and Orders (October 22, 2010 and January 27, 2011).

stagger the auctions of multiyear products, an accelerated version of Duke's proposed MRO will mitigate volatility and any likelihood of an abrupt or significant change in the SSO price (Tr. III at 623; FES Br. at 8). FES insists that the statute contains no five-year minimum, pointing out that the only limitation in the statute regarding the duration of the blending period is a maximum provision prohibiting the blending period from lasting longer than 10 years (FES Br. at 11).

b. Opponents to a Two-year Blending Period

Many of the intervenors argue that a five-year minimum blending period is required by Sections 4928.142(D) and (E), Revised Code. They assert that, because the MRO proposed in this case does not comply with this requirement, Duke's MRO is deficient and must be rejected.

OEG submits that the purpose of the MRO blending transition is two-fold. First, it allows rates to move toward the market gradually using a diversified combination of prices consisting of a market component and the legacy ESP component. Second, it provides an emergency mechanism in the form of Commission jurisdiction over rates to protect consumers against unexpected price surges. (OPAE Br. at 6-7.)

OEG witness Baron submits that, since Duke's MRO proposes a 29-month blending period, the MRO fails to meet the requirements of Section 4928.142(D), Revised Code, which requires a five-year (60-month) minimum transition period in which the market prices are blended with the existing ESP prices. OEG, IEU, GCHC, Eagle, and OPAE agree that the statute requires a minimum five-year transition period before implementing 100 percent market rates. (OEG Ex. 1 at 4-6; OEG Br. at 4; IEU Br. at 5; GCHC Br. at 6; OPAE Br. at 2.) Mr. Baron advocates that the statute's provision that the Commission can evaluate the potential rate impact on customers annually beginning in the second year of the blending period is a necessary consumer protection because of the volatile nature of electric generation pricing. Mr. Baron insists, as does OPAE, that the Commission require a full five-year minimum blending period and that annual reviews be established and, if the Commission finds an abrupt or significant change in SSO rates, the Commission should then make the appropriate changes. (OEG Ex. 1 at 13, 15; OEG Br. at 7 and 11; OPAE Br. at 6.)

OMA agrees that the Commission's discretion to alter the blending percentages is optional and can not take place until some time in the future, if at all. Moreover, OMA notes that the Commission may only exercise its discretionary authority if it finds an "abrupt or significant change." Since electricity markets are volatile and dynamic by nature, OMA asserts that a finding of an abrupt and significant change as part of the instant case before the Commission would be imprudent, untimely, and contrary to Section 4928.142(E), Revised Code. OMA states that Duke's proposal for a two-year blending period is contrary to the statute and implicitly requests the Commission to abdicate it statutory obligation to establish a five-year blending period and to determine the actual percentages for years one through five of the blending period. (OMA Br. at 3, 5.)

Kroger witness Higgins agrees that Duke's proposal for a price-blending period that lasts only two years, instead of the five to ten years indicated in the statute, is not compatible with the policy of gradual transformation to an SSO market price for generation under Section 4928.142(D), Revised Code; therefore, Duke's MRO application should be rejected as deficient (Kroger Ex. 1 at 3-4; Kroger Br. at 2). Mr. Higgins believes that, under Section 4928.142(E), Revised Code, if significant changes were to occur in the SSO price it would the result of the new bid price component, not the legacy ESP price component; therefore, he reasons that the mitigation of price changes by altering the proportion of the blended price could only occur mathematically by reducing the bid price component, not by increasing it, as Duke proposes (Kroger Ex. 1 at 8; Kroger Br. at 6). Mr. Higgins notes that Duke has not explained how a statute that confers specific discretion to the Commission to act in 2013 can be exercised today (Kroger Ex. 1 at 9; Kroger Br. at 6). Mr. Higgins asserts that the blending period is important to ensure that a robust market materializes for customers (Kroger Ex. 1 at 11). While Duke reports that 64 percent of its ESP load has switched to a CRES supplier, Mr. Higgins notes that 60 percent of the switched customer load has been acquired by a single supplier, Duke's affiliate, DERS (Kroger Ex. 1 at 12).

GCHC and Eagle contend that the premise of Duke's argument to accelerate blending to 100 percent market rate after only 29 months because the legacy ESP price and the market price will converge, thereby negating any further need for blending, is both inherently illogical and at odds with the statutory language. GCHC notes that Duke relies on Mr. Rose's testimony to support the projections of expected retail prices through 2014; however, GCHC points out that Mr. Rose was also the witness in the *Duke ESP Case* that predicted, incorrectly, that the market prices in 2011 would be well above Duke's ESP price right now. (GCHC Br. at 12; Tr. I at 150.)

In addition, GCHC and Eagle believe that Duke's desire to go to 100 percent market in year three is not to provide customers with lower rates, pointing to Duke's intent to transfer its generation assets and take advantage of higher market prices not restricted by the legacy ESP price. (GCHC Br. at 15; Tr. 1 at 26; Tr. III at 631.) GCHC and Eagle point out that the record reflects that Duke objects to the ESP price because, when the market price is below the ESP price, Duke is vulnerable to shopping and, when the market price is above the ESP price, Duke cannot raise its rates to take advantage of the increase. GCHC and Eagle note that nothing prohibits Duke from lowering its rates. Furthermore, GCHC and Eagle indicate that Duke has been selling its excess generation service at market prices. (GCHC Br. at 15-16; Tr. II 388; Tr. III at 627; Tr. IV at 777.) Thus, since Duke has options to adapt to lower market prices, GCHC and Eagle assert that the only reason for

Duke's market rate proposal is its desire to follow the market price upwards when prices exceed the ESP price. According to GCHC and Eagle, that is why consumers need the protection of the blending schedule in Section 4928.142(D), Revised Code. (GCHC Br. at 15-16; Tr. IV at 747-748, 778, 793.)

GCHC and Eagle maintain that, even if the Commission was permitted to allow Duke to go to 100 percent market in year three, it would not be prudent to approve such a plan. GCGH and Eagle point out that, while Duke has provided no forecast of prices past 2014, it expects the trend in prices to continue upwards after 2014. Thus, they argue that Duke must wait until evidence is available that the fixed blending percentages will result in an abrupt or significant change in price. (GCHC Br. at 15; Eagle Br. at 2; Tr. I at 125, 140.)

Both IEU and OEG note that, while Duke proposes to freeze Riders Fuel and Purchased Power (FPP) and Environmental Investment Rider (EIR) if the blending period ends at year three, if there are benefits that could become available to Duke in the calculation of these riders, the MRO does not provide a process to include those benefits in the riders. Thus, OEG offers that adjustments to the ESP cut both ways and Duke's offer to freeze the ESP component of the blended rate may actually cost ratepayers money. (IEU Br. at 6; OEG Br. at 10.)

OCC states that the statute does not allow the Commission to alter the blending period, only the blending proportions. OCC asserts that the only way the blending period can be altered is if the Commission finds it necessary to alter the blending proportions and extend the blending period. (OCC Br. at 41.)

Staff believes that Duke's MRO is contrary to Sections 4928.142(D) and (E), Revised Code, because it prematurely calls for a predetermined two-year transition to market when a five-year blending plan and transition to market is first required. Staff notes that the core of Duke's MRO plan is the two-year transition to market and that all of the other parts of Duke's plan are structured around this two-year period. Staff argues that, not only is the core of Duke's plan deficient, but other parts of the plan that are required by statute also have deficiencies (Staff Br. at 2-3). Staff emphasizes that information required by Section 4928.142, Revised Code, and Rule 4901:1-35-03, O.A.C., for blending years four and five are unaccounted for in Duke's application, testimony, and exhibits. For example, Staff points out that Duke failed to provide projected statements of income, balance sheets, and sources of uses of funds for blending years four and five. In addition, Staff points out that Duke's pro forma projections are based on the assumption that Duke's legacy generation assets will be transferred in year three of the MRO and that all of the load in Duke's territory will be served via Duke's MRO. Staff states that Duke's proposed transfer of its legacy generation, at least during the duration of the five-year blending period, is material to the SSO charges derived from the auction process for blending years four and five that Duke failed to include in its plan (Staff Br. at 8-9). Thus, Staff submits that fixing the blending period of the plan requires the filing of a new application, because the remaining parts of the plan can not be reconfigured to a planned five-year period, which is required by statute (Staff Br. at 3). GCHC, Eagle, and OEG agree that Duke's application fails to comply with Section 4928.142(D), Revised Code, and Rule 4901:1-35-03(2)(j), O.A.C., which requires that Duke's application state how the company will satisfy blending requirements for the first five years of the application (GCHC Br. at 6; Eagle Br. at 2; OEG Br. at 9). OMA agrees that Duke's failure to provide the necessary information and pro forma financial projections required by Rules 4901:1-35-03(B)(2)(b) and (c), O.A.C., renders the MRO fatally deficient (OMA Br. at 6).

c. Conclusion on Duke's Proposed Two-year Blending Period

The Commission finds that the statute permits the alteration of the blending proportions to be modified in accordance with Section 4928.142(E), Revised Code. Thus, consistent with our conclusion regarding the timing of a determination to alter the blending percentages, a party could come forward, beginning in year two, and request that the Commission alter, prospectively, the proportions specified in Section 4928.142(D), Revised Code, in order to mitigate any effect of an abrupt or significant change in the SSO price that would otherwise result, or the Commission could make such a determination on its own.

The Commission agrees with Staff that, under Sections 4928.142(D) and (E), Revised Code, as well as Chapter 4901:1-35, O.A.C., Duke was required to file a five-year blending plan and transition to market. Failure to do so renders Duke's proposed MRO application in noncompliance with the statutory requirements.

3. Mitigate any Effect of Abrupt or Significant Change

Duke analyzes what is meant in paragraph (D) of Section 4928.142, Revised Code, by the phrase permitting the Commission to alter the percentages "to mitigate any effect of an abrupt or significant change in the . . . utility's standard service offer price . . ." Initially, Duke envisions that the legislature based the requirement for a blending period on the assumption that market prices and previous SSO prices would be substantially divergent, reasoning that, without that understanding, the lengthy blending requirement would be of negligible effect; therefore, Duke believes a change in this basic fact must be "significant." Duke argues the record shows that, in year three, either the ESP price will converge with the market price or the market price will be lower than the most recent ESP price. Duke submits that there is no evidence that the market price will exceed the ESP price from 2012 to 2015, and beyond. Duke contends that, in year three, if the market price is less than the ESP price, altering the blend to enable full market prices at that time would provide lower rates to customers. Even if the ESP rate and the market rate converge in year three, Duke offers that customers would be paying the market rate, as intended by the legislature. (Duke Br. at 27-29.) Likewise, FES submits that Section 4928.142(E), Revised Code, does not say that the proportions allocated to the market price may only be decreased or lessened; rather, it says that they may be altered, which could result in an increase or a decrease (FES Br. at 12).

Staff disagrees with Duke's assertion that Section 4928.142(E), Revised Code, is meant to mitigate against significant changes in customer rates based on Duke volunteering to waive its recovery of potential costs associated with Sections 4928.142(D)(1) through (4), Revised Code. Rather, Staff believes that this section is meant to mitigate any effect of an abrupt or significant change in Duke's SSO price as a result of unforeseen economic circumstances impacting market prices. (Staff Br. at 4.)

GCHC and Eagle state that an evaluation of the language "to mitigate any effect of an abrupt or significant change in the . . . utility's standard service offer price . . . ," requires an analysis of the prices that would result from the percentages specified in Section 4928.142(D), Revised Code. Furthermore, they point out that the word "mitigate" means to cause to become less harsh, or to make less severe or painful. Thus, GCHC and Eagle argue that the purpose of making any future change to the preestablished blending schedule must be to reduce the amount of change in prices that would otherwise result from the existing blending schedule. (GCHC Br. at 11.)

GCHC and Eagle point out that Duke witness Rose projects comparable retail market prices of $.0582, $.0634, and $.0717 per kWh in 2012, 2013, and 2014, respectively. Using statements by Duke witnesses Rose and Wathen that the blended MRO prices would be $.0719, $.0714, and $.0722 per kWh, in 2012, 2013, and 2014, respectively, GCHC and Eagle submit that the projected market prices would be a decrease in year one from Duke's legacy ESP price of two percent, a decrease in year two of 0.1 percent, and an increase in year three of 1.1 percent. (GCHC Br. at 13; Tr. III at 659-660.) Therefore, GCHC and Eagle offer that, for the Commission to alter the blending percentages from the fixed 30 percent in year three, it would have to first find that an anticipated 1.1 percent increase in Duke's SSO price would be an abrupt or significant change. GCHC and Eagle point out that Duke witness Wathen admitted that he would not characterize a two percent increase as abrupt or significant. (GCHC Br. at 13; Tr. III at 653-655.)

The Commission agrees that the primary reason for the blending requirement is the goal to, during the migration from the ESP price to a 100 percent market price, safeguard ratepayers from the risk of abrupt or significant increases in prices. Contrary to Duke's assertions, the Commission does not believe that the Commission was given authority under Section 4928.142(E), Revised Code, in order to alter the blending proportions solely for the purpose of moving the company expeditiously to a fully competitive market.

Duke also points to its willingness to forego making changes to the ESP price component of the blended SSO price during the blending period for changes in its fuel, purchase power, and environmental costs, as permitted by statute, if its two-year blending proposal is approved. Duke believes that, by waiving the collection of these charges, Duke has addressed the statutory criterion for alteration of the blending period, because its proposed blending period and CBP plan will not result in abrupt or significant rate changes for customers during the blending period. The Commission is appreciative of Duke's willingness to sacrifice any possible increase in such charges for the good of its customers. However, the Commission notes that the statute permits the SSO price to be adjusted upward or downward, as determined to be reasonable by the Commission, based on changes in known and measurable costs and subject to a significantly excess earnings test. The Commission believes that what is most important is that we move toward a competitive market environment that fully supports the policies of the state and consider the facts of the market on an annual basis as required by the statute, rather than relying on price forecasts that are known to change.

As provided in paragraph (E) of Section 4928.142, Revised Code, "notwithstanding any other requirement of [paragraph (D)], the commission may alter prospectively the proportions specified in [paragraph (D)] to mitigate any effect of an abrupt or significant change in the . . . utility's standard service offer price that would otherwise result in general or with respect to any rate group or rate schedule . . .." In accordance with this language, the Commission finds that the percentage proportions set forth in paragraph (D) of Section 4928.142, Revised Code, could be increased or decreased depending on what proves to be necessary in order to mitigate or reduce the effect of the SSO price change that would otherwise occur.

F. <u>Conclusion Blended Price, Sections 4928.142(D) and (E), Revised Code</u>

The statute requires that Duke's application set forth a five-year blending proposal; then two years down the road, in order to mitigate any effect of an abrupt or significant change, the company or any other party could request that the blending portions be altered. However, to request such a change now, at the outset of the proposed MRO, is premature and would necessitate that the Commission prejudge circumstances that are neither present currently nor reflected in the record.

We believe that one of the primary intents of the statutory language is to protect the company's customers from drastic rate changes. Duke's belief that the Commission was permitted to alter the blending period now is erroneous. Consumer protection is evidenced by the fact that the Commission may, *sua sponte*, require that the blending proportions be altered. The record in this case provides no insight into the market conditions after year two of the MRO, as Duke neglected to provide any information, as required by the statute and the rules pertaining to years three, four, and five of the statutory blending period. Duke attempts to use this hole in the record to support its position by stating that there is no evidence that the market price will exceed the ESP price from 2012 to 2015, and beyond; however, the only reason there is no evidence is because Duke did not comply with the requirements for the filing of an MRO and provide information for years three through five.

Duke chose to file an MRO, contrary to the advice of Staff which clearly stated in its comments and on brief that it believes an ESP would be more beneficial and offer significant advantages to Duke, stakeholders, and the public (Staff Ex. 2 at 2). Having decided to pursue an MRO, Duke is obligated to comply with requirements set forth in the statute and the Commission's rules. Pursuant to the statute and the rules, for its first MRO application, Duke must submit a five-year plan setting forth all of the requisite supporting documentation for all five years. Instead, Duke took the chance that its view of the statutory constraints was correct and only filed supporting documentation for three years.

As Duke points out, the statute provides that the Commission shall determine whether the application meets the necessary requirements. The Commission can only make this determination if the applicant first complies with the statute and submits all of the information required for the Commission's analysis and determination. The statute does not call for a determination in the situation where a utility files an incomplete application. In light of the fact that Duke has failed to file an application for a five-year MRO, as required by statute, setting forth all of the information necessary in order for the Commission to make a determination, Duke's application is not an application within the meaning of Section 4928.142, Revised Code, because, on its face, it is deficient. Therefore, we can not consider this filing to be an MRO filing under the statute and we have no choice other than to find that Duke's application does not meet the requirements of the statute. Since Duke has not presented a complete MRO application, the application is in noncompliance with the statute and this case can not proceed as filed.

As stated previously, IEU filed a motion to dismiss on January 4, 2011. Specifically, IEU asserts that Duke's application does not comply with Section 4928.142(D), Revised Code, which requires that "a portion of [Duke's] standard service offer load for the first five years of the market rate offer be competitively bid." In its application, Duke proposes to competitively bid a portion of its standard service offer load for only 29 months. Therefore, IEU argues that the Commission does not have jurisdiction to consider Duke's application.

In its memorandum contra IEU's motion, filed on January 7, 2011, Duke contends that its application meets the statutory criteria contained in Section 4928.142, Revised Code, and that, even if it did not meet the statutory criteria, the Commission does not lose jurisdiction over the application. RESA and Constellation also filed a memorandum contra on January 7, 2011, asserting that IEU offered no legal support for its premise that the Commission's jurisdiction would be limited if an application did not meet statutory requirements.

The Commission has found that Duke's MRO application is not in compliance with the statutory requirements and, therefore, this case can not proceed. Accordingly, the Commission finds that it is unnecessary for us to rule on IEU's January 4, 2011, motion to dismiss, as it is moot.

Even though we are unable to reach the merits of Duke's application, due to the deficiencies of the application, in order to provide useful guidance for any future application filed by Duke, we have gone to great lengths in this order to provide guidance on some of the issues raised by various parties. We note, however, that, while below we comment on some of the issues presented on the record in this case, our failure to comment on a given issue or opine on a particular position should not be construed as our approval or disapproval of such position. Rather, there are many issues that were raised by Staff and the intervenors that were not adequately refuted on the record; therefore, we encourage Duke to consider these issues in any future application and respond to them accordingly.

G. CBP Requirements, 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(s). The Commission is mandated by Section 4928.142(A)(2), Revised Code, to adopt rules concerning the conduct of the CBP and the qualifications of bidders, which foster supplier participation in the CBP and are consistent with the requirements of Section 4928.142(A)(1), Revised Code. Applicants filing an MRO are required to detail their compliance with the requirements of Section 4928.142(A)(1), Revised Code, and the Commission's rules promulgated under Section 4928.142(A)(2), Revised Code.

1. Open, Fair, and Transparent Competitive Solicitation, Section 4928.142(A)(1)(a), Revised Code

Duke witness Janson testifies that Duke's proposed MRO is based on an open, fair, and transparent competitive solicitation process that will: produce prices for customers that are more in line with the market; preserve customers' rights to shop; provide clarity for Duke's business; and afford greater regulatory certainty because it is not a short-term plan. According to Ms. Janson, the CBP plan incorporates staggered procurements, provides suppliers with a fair opportunity to compete for Duke's load obligations, mitigates price volatility, and yields stable and certain prices. (Duke Ex. 2 at 9-10.)

Integral to an open, fair, and transparent CBP is the equal and nondiscriminatory exchange of information and application of bidding requirements, according to Duke. To ensure that all prospective bidders will have access to the same information, the CBP plan incorporates bidder information and training sessions, and an active informational website will be available; in addition, mock auctions will be held prior to the first auction. So that all prospective bidders are on equal footing, the CBP plan includes appropriate confidentiality provisions. Furthermore, Duke notes that the rules pursuant to which the bidding will occur and bids will be evaluated are set forth in Duke's application so that no prospective bidder is advantaged. Duke also believes that the staggered auction format confirms the open, fair, and transparent nature of the CPB because it smoothens out potentially volatile market prices, provides for longer-term price stability, and encourages efficient pricing of the products. Moreover, since there is no requirement that bidders own generation assets to qualify for participation, no one supplier can be preferred over another. The CBP plan encourages diverse participation. (Duke Ex. 3 at 14-15; Duke Ex. 8 at 11.)

Duke witness Lee states that the major elements of the CBP plan include: the products and terms in the Master Standard Service Offer Agreement (MSSOA) that encourage participation; maintaining the CBP information website; conducting bidder information sessions and other prebidding activities to promote participation; developing communications protocols to ensure equal access to information; administering the two-part application process, including establishing financial and nonfinancial requirements; developing an auction design and bidding procedures that attract bidders; educating and training bidders through informational materials and mock auctions; customizing and testing the bidding platforms and help desk; providing starting prices to attract bidding; conducting each solicitation; and submitting a post-bid report to the Commission. (Duke Ex. 7 at 5-6; Duke Ex. 3 at Att. E and Att. F1.) In addition, Mr. Lee states that the CBP information website will include post-auction information that will help winning bidders understand their risk profile (Duke Br. at 16; Tr. I at 169). Duke also explains that all prospective bidders will be subject to the same prebid requirements and all successful bidders must adhere to and assume the same contractual commitments (Duke Ex. 3 at 14).

Duke witness Lee contends that the CBP is designed to encourage participation in the auction and ensure that no one bidder is advantaged. According to Mr. Lee, this is evidenced through the fact that physical generation assets are not required to participate in the CBP or to bid on and win tranches; financial participants can bid and win tranches. Furthermore, there is a level playing field for all participants in that they are all provided the same information, bid on standardized supply contracts, and are subject to identical financial and credit requirements. (Duke Ex. 7 at 17-18.)

With regard to any potential concern related to market power, Duke asserts that there has not been and can not be any suggestion of market power with regard to its affiliates. According to Duke, while its retail marketing affiliate has been certified for several years, it has only recently acquired more than a nominal share of the retail market. Duke also points out that the last Commission-ordered audit of the company's corporate separation plan confirmed compliance with the Commission's corporate separation rules. (Duke Ex. 3 at 16; Duke Reply Br. at 10.) Duke witness Jones testifies that Duke's corporate separation plan follows the requirements set forth in Rule 4901:1-37-04, O.A.C. Moreover, Duke asserts that its corporate separation plan is consistent with the policies of the state as articulated in Section 4928.02, Revised Code. Specifically, Duke explains that its corporate separation plan prohibits any anticompetitive subsidies flowing from Duke's regulated business to its retail electric services (Duke Ex. 18 at 7). Duke avers that its corporate separation plan does not, in any way, obviate compliance with the Commission's consumer protection rules that apply to both utilities and CRES providers. Duke explains that it will continue to comply with the Commission's rules and avers that its participation in an RTO serves to further mitigate any market power. (Duke Ex. 18 at 8-9.) Finally, Mr. Lee points out that the communications protocols for the CBP protect against market abuses by requiring that affiliates of Duke cannot be provided with any information regarding the CBP plan that would provide them an unfair competitive advantage (Duke Ex. 7 at 19; Duke Ex. 3 at Att. E). Ms. Janson asserts that Duke ensures that, in its rate structure, no generation-related costs will be recovered through distribution or transmission rates. (Duke Ex. 2 at 24.)

Duke submits that, in keeping with the policy objectives in Section 4928.02, Revised Code, with the independent auction process, which benefits from federal oversight of the wholesale power market, customers will be protected from potential market power abuses and unreasonable sales practices. In addition, Ms. Janson offers that Duke will continue to comply with the Commission's consumer protection rules that guard against unreasonable sales practices. (Duke Ex. 3 at 3; Duke Ex. 2 at 25.)

OCC maintains that, with the Commission's review and supervision of the CBP provided for in Rule 4901:1-35-11(D), O.A.C., the CBP will ensure that market deficiencies and market power problems are addressed. According to OCC, an ESP focuses too much on cost recovery for the electric distribution company to ensure a level playing field for all generation providers. The rider mechanisms provide the opportunity for cross-subsidization of Duke's competitive customers by Duke's SSO customers; thus, without the riders, Duke will be less likely to maintain market power. (OCC Br. at 14.)

Duke explains that, under the government aggregation process, municipalities, townships, or counties may negotiate for rates for the collective load of the nonmercantile customers in the area, a process that is governed by Section 4928.20, Revised Code. Duke avers that nothing in its proposed MRO inhibits governmental aggregation; instead the MRO will aid the process by establishing a market-rate generation tariff, encouraging the provision of improved pricing options. (Duke Ex. 18 at 9-11.)

In further support of the application, Duke points out that its MRO proposal includes TDP and dynamic retail pricing options and that it is open to participation by distributed and small generation facilities, and cost-effective and DSM resources in keeping with the state policy in Section 4928.02, Revised Code. Duke will continue its deployment of SmartGrid advanced energy infrastructure, which provides the necessary infrastructure for AMI to support TDP, as well as innovative energy efficiency and DSM service offerings. Finally, Duke expounds that the CBP plan contemplates Commission review, through the production of a post-auction report and the retention of a separate consultant. (Duke Ex. 3 at 3, 15-16; Duke Ex. 2 at 21-22.)

Staff points out that participation in Duke's TDP and dynamic retail pricing options is very low and almost nonexistent. Staff notes that Duke witness Bailey estimated that the participation in the TDP and dynamic retail pricing programs is less than 100 customers. Staff emphasizes that a program with little or no participation does not address the Commission's overall concern to provide customers with information they will need to control bills and make appropriate decisions regarding the purchasing of power. Thus, Staff is concerned about Duke's ability to demonstrate that the MRO provides an open, fair, and transparent competitive solicitation. (Staff Br. at 16-17.) In response, Duke asserts that the standard of openness, fairness, and transparency of the CBP relates to the process by which generation suppliers may bid for a tranche, not to consumers purchasing decisions and the presence of TDP and dynamic retail pricing options (Duke Reply Br. at 6).

RESA witness Ringenbach submits that Duke's MRO will create the regulatory certainty needed to preserve and expand the existing competitive retail electric market and provide customers with a greater variety of options for their electric supply. According to Ms. Ringenbach, under an ESP, a utility is discouraged from creating an SSO that goes beyond three years because anything longer triggers regulatory review and possible repricing. The witness contends that, not only was Duke's PTC during the ESP complex, but there were numerous riders, some of which were avoidable if the customer pledged not to return to the SSO for the remainder of the ESP. However, if a customer returns to the SSO prior to the close date of the ESP, there was a penalty, thus, the product the CRES provider could offer was limited. According to Ms. Ringenbach, the MRO ensures the SSO continues indefinitely with market-based procurement and that unavoidable generation costs that can kill a market are no longer a concern. The MRO also ensures a consistent SSO structure without an artificial three-year clock; thus, allowing customers to choose the contract term suited to the customer's use and market conditions. (RESA Ex. 1 at 5-6; RESA Br. at 2-3.)

Subject to several modifications, Constellation recommends the adoption of Duke's MRO proposal (Constellation Ex. 1 at 6). RESA recommends that Duke's MRO, as amended, be adopted, stating that it meets the statutory requirements and provides benefits to consumers (RESA Br. at 2). Likewise, OCC submits that Duke's MRO, subject to certain revisions, is preferable to an ESP, because it could provide lower prices to customers and it is more likely to further state policy under Section 4928.02, Revised Code (OCC Br. at 6-7).

Duke states that it considered alternative methods of procurement and concluded that the procurement option proposed in this MRO is appropriate (Duke Ex. 3 at 33). Options that were considered by Duke, other than the proposed descending-clock, slice-of-system approach, include a one-shot, sealed-bid format and active portfolio management by Duke and the use of requests for proposal (RFP). According to Duke witness Lee, the descending-price clock auction format offers several advantages over the one-shot, sealed bid format (Duke Ex. 3 at 29; Duke Ex. 8 at 8-11; Duke Ex. 7 at 20-22).

GCHC and Eagle point out that Duke barely discussed an active portfolio management and RFPs. By not even considering these and other alternatives, GCHC and Eagle argue that Duke has not established that its CBP would achieve the lowest and best price for consumers. (GCHC Br. at 27). In response, Duke states that there is no requirement that an MRO applicant prove that its choice is optimal, only that it discuss the options considered and explain he rationale (Duke Reply Br. at 32).

GCHC and Eagle point out that a reverse auction format allows a bidder holding a significant concentration of the generation to strategically withhold some of its generation to secure a higher price. They note that the record reflects that a significant concentration of the generation available for bidding is under the control of Duke. Therefore, GCHC and Eagle recommend that the Commission carefully consider whether the reverse auction format will protect customers from the potential of Duke to exercise market power, and provide for an open, fair, and transparent solicitation. (GCHC Br. at 25.)

GCHC and Eagle note that Duke has offered no evidence of the level of participation that would be expected in its auction. They point out that reliance on the results in FirstEnergy's auction is not appropriate because the FirstEnergy market is a different market, the proximity of non-Duke generation assets is different, the cost of transmission into the market is different, and the capacity committed to serving FirstEnergy's customer load is not available to bid in the Duke auction. GCHC and Eagle foresee a scenario where, under the auction format proposed by Duke, it may have the market power to artificially stop the auction early, thereby securing a higher clearing price than would occur under competitive conditions. GCHC and Eagle are concerned about market power, pointing out that, while the generation business is functionally separate from the regulated distribution business, the same management operates the generation business and the DERS CRES business. Furthermore, they note that Duke's corporate separation plan does not address business relationships between the generation side of Duke's business and DERS. Duke and DERS have bilateral supply contracts that they consider secret and will not disclose. GCHC and Eagle also state that the bidding rules do not prohibit Duke's generation business and DERS from affiliating with each other in the auction as long as it is disclosed. GCHC and Eagle offer that Duke should be required to demonstrate that its market is truly competitive and that Duke and its affiliate DERS cannot unduly influence the market clearing price by virtue of Duke's concentration of generation ownership. (GCHC Br. at 25.)

GCHC and Eagle note that, because Duke currently supplies only 40 percent of its load under its ESP prices, there is a wide range of possible demand that bidders would have to serve if shoppers return to the SSO service. Therefore, they assert that the slice-of-system approach to the auction shifts the standby risk to third-party bidders, who would assume the same uncertainty that Duke wishes to avoid in an ESP. According to GCHC and Eagle, this risk would have to be quantified and would be embedded in the auction price. (GCHC Br. at 26-27.)

Duke provided financial projections for generation during the MRO for the two-year period from January 1, 2012 through May 31, 2014. However, Duke states that, since the implementation of the CBP will not affect its financial projections for distribution and transmission, it did not address transmission or distribution impacts. (Duke Ex. 3 at 34 Duke Ex. 14 at 3-5; Duke Br. at 35.) According to Duke witness Savoy, provided the legacy generation assets are transferred at the end of the second year of the MRO as proposed by Duke, the transfer of the legacy generation assets will not affect the pro forma financial projections; however, the transfer will function to eliminate any generation-related items from the income statement and balance sheet (Duke Ex. 14 at 6-9; Duke Br. at 35). As stated previously, Staff and OMA submit that Duke's failure to provide projected statements of income, balance sheets, and sources of uses of funds for blending years four and five renders the MRO fatally deficient (Staff Br. at 8-9; OMA Br. at 6).

Duke submits that the requirement for a comparison of the projected adjusted generation service prices under the CBP plan to the projected adjusted generation service prices under its ESP is not applicable to this proceeding, because there is no requirement that an applicant for an MRO also prepare an ESP in order to compare the projected adjusted generation service prices under the ESP with the prices under the CBP (Duke Br. at 29-30). OEG witness Baron disagrees, stating that Duke did not comply with this requirement because it failed to present any legacy ESP rate projections or projected market prices under the CBP plan beyond 2014 (OEG Ex. 1 at 13).

Constellation witness Fein points out that the bidding rules proposed by Duke do not appear to provide anywhere near the amount of detail as was provided by FirstEnergy in its auction and as is provided under other similar CBPs in PJM states (Constellation Ex. 1 at 14; Duke Ex. 3 at Att. C). Accordingly, Mr. Fein recommends Duke provide auction participants with the following additional data and information: monthly information specific to a municipal opt-out aggregation program that includes peak load, hourly consumption, and population statistics; hourly load data for eligible and SSO load by customer class; customer counts, peak demand and network service peak load (NSPL) for eligible and SSO load by customer class; for network integration transmission service (NITS) charges, the expected allocation [below 138 kilovolts (kV)] by rate class; historical distribution losses and any allocated unaccounted for energy; for larger nonresidential customers, a distribution of the number of customers above and below 500 kW within a rate class; and hourly consumption, customer counts, peak demand broken out by customer class separated by eligible load and load served by CRES providers. Furthermore, Mr. Fein recommends Duke provide winning wholesale suppliers with the following additional data and information: peak load or hourly consumption data that is updated monthly beginning after the execution of the MSSOA that shows eligible load and load taking services from a CRES provider; initial settlement hourly data; from the time the MSSOAs are executed, daily estimations for the capacity peak load contribution data seven days forward; and the energy and capacity information that Duke provides to PJM related to suppliers' SSO obligations. Mr. Fein states that this additional information will allow bid participants to provide more accurate and competitive bids, and will allow winning suppliers to better manage risks of supplying load (Constellation Ex. 1 at 12-14; Constellation Br. at 5-7).

Constellation witness Fein recommends that Duke provide additional clarity regarding the authority of the auction manager, CRA International, Inc. d/b/a Charles Rivers Associates (CRA), in order to provide greater regulatory certainty and information. Specifically, Mr. Fein proposes that the CRA and/or Duke should not be allowed to develop a reservation price as part of the CBP. Mr. Fein further recommends that CRA should notify winning bidders when the required report has been provided to the Commission and commit to providing responses to frequently asked questions within two business days of submission. (Constellation Ex. 1 at 15-16; Constellation Br. at 8.) Constellation explains that a reservation price is an undisclosed price above which the utility would not buy power even if the auction closed with the proper number of bidders and there was no evidence of fraud or collusion. Constellation argues that the use of reservation prices is at odds with the statutory mandate that the CBP be open, fair, and transparent. Furthermore, Constellation believes that the use of a reservation price makes the auction less attractive to wholesale suppliers, because a bidder could go through the auction believing that it is providing the lowest price, only to find out that Duke, on its own, is rejecting the results because of the secret reservation price. Constellation believes that it is possible that Duke reject the original auction price won by a nonaffiliated supplier because the closing price was above the reservation price, then, on the replacement auction, award the tranches to its affiliate at a higher price. (Constellation Br. at 8.)

Duke asserts that it has incorporated the option of a reservation price in its MRO to prevent a large supplier from prematurely withdrawing from the auction, thus unilaterally prompting the roll back feature of the auction design. Duke witness Lee explains that, with a reservation price, there is some risk for a bidder to bring the auction to a close artificially; the reservation price is there to ensure the bidders are expressing their lowest bid. Thus, Mr. Lee states that, in that sense, a reservation price is a safeguard for ratepayers. (Duke Reply Br. at 11-12; Tr. I at 194-195.)

Staff notes that Duke does not propose to use a load cap, or limit on the number of tranches that can be won by a single bidder; rather, Duke will allow any supplier to win up to 100 percent of the competitively bid load. Staff supports the use of a load cap, pointing out that load caps have been applied in other similar situations, including in prior auctions by FirstEnergy, whereby the Commission required load caps of 65 percent and 80 percent.[3] Staff recommends a load cap as a means to encourage participation by bidders and to assure diversity of supply in the auction. (Staff Ex. 2 at 4; Staff Br. at 26.) OPAE agrees with Mr. Strom's recommendation (OPAE Br. at 7). Duke explains that it has not incorporated a load cap so as to ensure that the least-cost bidder emerges as the winning bidder (Duke Reply Br. at 12).

While it is not possible for the Commission to consider this filing an MRO application under Section 4928.142, Revised Code, because it is not in compliance with the statutory requirements, we will attempt henceforth to provide some guidance for any future filing regarding the competitive solicitation, as proposed in Duke's filing. Initially, we would note that, had this been an appropriate application, based on the record, Duke does not appear to have demonstrated that its proposal would result in an open, fair, and transparent competitive solicitation.

First, as stated previously, Duke has failed to provide vital information in its application regarding a five-year blending period that would enable the Commission to consider its proposal. For example, Rules 4901:1-35(B)(2)(b) and (j), O.A.C., require Duke to provide pro forma financial information of the effect of the CBP plan and a comparison of the projected market prices to the project legacy ESP prices. While Duke provided

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3 See *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Competitive Bid Process to Bid Out Their Retail Electric Load,* Case No. 04-1371-EL-ATA; *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Approval of a Competitive Bidding Process for Retail Electric Load,* Case No. 05-936-EL-ATA; and *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. 10-388-EL-SSO (*FirstEnergy 10-388 case*).

financial information for three years of the MRO, it neglected to provide all five years as required by statute. Furthermore, Duke insisted that the comparison of the projected market prices and the legacy ESP prices were not applicable to this proceeding; however, the Commission disagrees. In order to properly carry out state policy and the explicit dictates of the statute, all of this information must be presented in an application in order for it to be considered complete.

Section 4928.02, Revised Code, specifically includes the promotion of DSM, TDP, and the implementation of AMI as policies of this state. Rules 4901:1-35-03(B)(2)(e) and (i), O.A.C., require Duke to provide, as part of its application, information regarding its customer loads, TDP, dynamic pricing, alternative retail rate options, and price elasticity. As pointed out by Staff, Duke's TDP and dynamic pricing options are almost nonexistent, with participation of less than 100 of Duke's over 690,000 customers. It is necessary for customers to have the tools and information necessary to understand and control their electricity usage and ultimately their bills. This is especially true with a market-based structure where prices can be volatile. Customers must know their options and have the ability to make informed decisions. The extremely limited pervasiveness of Duke's alternative retail rate options and the fact that Duke has not demonstrated on the record in this case how its proposed MRO would promote the policy of the state, leads the Commission to find that Duke has not adequately shown that its MRO achieves an open, fair, and competitive solicitation.

An MRO solicitation should be open, fair, and transparent from the perspectives of both potential suppliers and consumers. From the consumer's perspective, the process should seek to facilitate transparent pricing that enables consumers to control their energy bills by managing their usage, reduce unfair cross-subsidies among consumers with different load shapes, and be open by not distorting incentives for customer-sited distributed generation. Duke has proposed procuring generation at a single price covering all hours, all SSO customers, and a number of different generation products. Duke did not even consider soliciting some or all of its SSO energy requirements through RTO-operated competitive markets and reflecting the results in TDP or dynamic pricing. We do not agree with Duke's assertion that it is obligated only to discuss the options it considered and explain its rationale. An approach which is far from optimal may not be fair or consistent with state policy. The policies set forth in Section 4928.02, Revised Code, ultimately will shape our application of the requirements, "open, fair, and transparent." We are not persuaded, at this time, that Duke's proposed method of procurement will ensure the availability of adequate, reliable, efficient, nondiscriminatory, reasonably priced, and unbundled retail electric service; ensure the development of distributed and small generation facilities; encourage innovation for demand-side retail electric service; encourage access to information, including pricing information, regarding the operation of the transmission and distribution systems; or facilitate the state's effectiveness in the global economy. Therefore, any future application must include information addressing these issues.

While we will discuss our consideration of Duke's move to PJM below, we note that, at this point, Duke has not yet adequately demonstrated that its voluntary business decision to procure generation services within PJM's markets, rather than in the Midwest Independent Systems Operator (Midwest ISO), is fair and consistent with state policy. Duke's choice to obtain generation services in the PJM RTO will impose certain capacity and other costs on consumers which might not have been incurred if Duke had elected to remain in the Midwest ISO. Duke has not yet made a sufficient case that its choice to obtain generation services in PJM is reasonable, such that any additional costs are recoverable from consumers.

The concerns voiced by Staff regarding the absence of a load cap in the CBP likewise concern the Commission. While Duke briefly responds in its reply brief that it did not include a load cap in order to ensure that the least-cost bidder emerges as the winning bidder, Duke failed to rebut Staff's major concern in this area; that is, to encourage the participation of bidders and assure diversity of supply in the auction. Without some limit on the number of tranches that can be won by a single supplier, it is possible that a single supplier could win up to 100 percent of the competitively bid load. Absent a reasonable load cap, the CBP may not elicit an open and fair solicitation in keeping with the statutory policy. Similarly, we find that Duke did not provide adequate information to rebut Constellation's concern regarding the reservation price. While we do not agree that a reservation price established subject to Commission supervision is necessarily inconsistent with the statutory mandate for an open, fair, and transparent process, additional information is needed regarding the process for establishing a reservation price and the consequences of invoking the reservation price, in order for us to make this determination.

Upon review of the bidding rules, the Commission finds that the issues raised on the record by the intervenors were not adequately addressed by Duke on the record. It is essential that the bidding rules include sufficient detail to allow auction participants to submit informed competitive bids and to provide winning suppliers with the information necessary to manage the risks associated with supplying its load. Therefore, without the inclusion of additional detail in the bidding rules, the Commission can not support a finding that the CBP complies with the statutory requirements.

Accordingly, the record reflects that Duke has not presented sufficient information on the record to satisfy the requirement of Section 4928.142(A)(1)(a), Revised Code, for an open, fair, and transparent competitive solicitation.

2. Clear Product Definition, Section 4928.142(A)(1)(b), Revised Code

Duke witness Lee explains that, for the bidding design, a version of the simultaneous, multiple-round, descending-price clock auction format will be used. Mr. Lee explains that it is simultaneous in that multiple products and/or multiple tranches are bid on simultaneously. As outlined in the bidding rules, for the auction to close, the number of tranches bid for each product at the announced price must be less than or equal to the supply for that product. Mr. Lee notes that, at the close of the auction, CRA, the auction manager, will provide a report to the Commission summarizing the bidding process and results, and proving a list of the least-cost bidder(s) and the number of least-cost tranches for each such bidder. (Duke Ex. 7 at 13-15; Duke Ex. 3 at Att. C.)

Duke explains that the CBP product being auctioned is an hourly, load-following, full requirements tranche of the company's SSO load. Duke proposes to establish a tranche as being equal to 1.00 percent of Duke's total SSO load obligation or a slice-of-system of Duke's hourly SSO load, i.e., Duke's nonshopping SSO retail load. The CBP auction will be for 10 tranches in year one and 20 tranches in year two. In year three and beyond, tranches for varying lengths of service will be offered in staggered procurements, which will result in Duke's entire SSO load being supplied pursuant to the CBP plan. According to Duke witness Northrup, there will be an equal distribution of one-, two-, and three-year contract durations in the third year of the MRO, with each contract equaling 30 percent of the total SSO load. (Duke Ex. 3 at 16-17; Duke Ex. 8 at 6-7.) The CBP uses a slice-of-system approach; thus, winning bidders will serve a share of each customer's SSO load in proportion to the share of the overall load won in the auction. Duke offers that, in accordance with the bidding rules, it will make the following information available to prospective suppliers: load data for an historical three-year period; historical hourly load data for its total retail load and SSO load; historical switching statistics; and historical load profiles. (Duke Ex. 3 at 35, Att. C; Duke Ex. 8 at 7.)

Duke explains that the auctions will be conducted on at least an annual basis, with the first auction occurring in June 2011. (Duke Ex. 3 at 12-13; Duke Ex. 16 at 8.) In each of the first two years of the MRO, Duke intends offer a single product and contracts covering 17 months and 24 months of service, respectively. Duke believes that, since the auctions in the first two years of its proposed MRO can not concern 100 percent of the company's SSO load, these single offerings in each year will attract more bidders, thereby ensuring a robust, competitive process. In the third year of the MRO, when it intends to acquire all of its SSO supply through the competitive process, Duke will offer three separate products in each auction. Duke believes that these additional offerings, of varying length, will provide increased opportunity for participation in the CBP; thus, ensuring the perpetuation of the competitive market and efficient pricing from the different contract terms, and benefitting Duke's SSO customers. (Duke Ex. 3 at 13; Duke Ex. 8 at 4.)

Staff witness Strom points out that there is no overlap between Duke's proposed year-one 17-month product and the flowing 24-month product. Mr. Strom believes that overlapping terms of the auction products can dampen any changes in market pricing from auction to auction. Therefore, the witness recommends that the initial auction product have a term of 29 months and that the number of tranches included in the second auction be reduced to 10. Furthermore, Mr. Strom proposes revisions to the schedule set forth by Duke that would be necessary to include the percentage requirements for the first five years of the MRO blending process in conformance with the statute. (Staff Ex. 2 at 6, Att. RWS-1.)

OCC believes that Duke's CBP should be modified to reduce customer risk and comply with the statute. First, OCC offers that customer risk could be mitigated and potentially bidder participation increased by increasing the number of solicitations per year. OCC advocates that Duke be required to hold at least two auctions per year when 30 percent or more of the SSO load is to be auctioned and, if 50 percent or more is to be auctioned in a year, then at least four auctions should be required. In addition, OCC recommends that Duke not be permitted to hold auctions during peak months. (OCC Br. at 14-16.) In response to this proposal, Duke states that OCC fails to cite any evidence to support its contention that there is significant risk to customers under Duke's schedule and fails to cite any record support for OCC's proposed auction schedule. Furthermore, Duke contends that OCC ignores the additional costs that would be incurred in conducting multiple auctions each year and offers no evidence to confirm that these costs would be offset by lower prices. (Duke Reply Br. at 17.)

Second, OCC submits that the Commission should inquire into the possibility of including a long-term product component into the auction (OCC Br. at 16). Conversely, Duke argues that OCC offers no evidence that suppliers under long-term contracts would not incorporate additional risk premiums to account for the uncertainty of, among other things, capacity prices that would be incorporated into contracts with duration of longer than three years (Duke Reply Br. at 18).

Constellation witness Fein recommends, and OCC agrees, that a collaborative process be used so that all stakeholders can discuss potential improvements to future CBPs (Constellation Ex. 1 at 42-42; Constellation Br. at 14-15; OCC Br. at 18).

The MSSOA sets forth the contractual obligations of successful suppliers and Duke with respect to each auction (Duke Ex. 3 at Att. F2; Duke Ex. 8 at 12). According to Duke, the products incorporated into the CBP plan, which are thoroughly described in the product definition of the company's MSSOA, include: unbundled energy, capacity, firm transmission service, and ancillary and resource adequacy services. Duke points out that it did not include nonmarket-based transmission service in its product definition; rather, Duke proposes to address NITS and certain other transmission costs billed to Duke by an

RTO under Federal Energy Regulatory Commission (FERC)-approved tariffs through the Base Transmission Rider (Rider BTR). (Duke Ex. 3 at 17; Duke Ex. 8 at 3.) Mr. Lee asserts that, as proposed by Duke, the bid products can be readily evaluated and priced by bidders (Duke Ex. 7 at 25).

Duke points out that, based upon the testimony submitted by potential CBP participants, who intervened in this case, Duke's revised the proposed MSSOA to incorporate many of the suggestions made by those parties (Duke Ex. 3 at Att. F-1; Duke Br. at 38). In the revised MSSOA, the auction format concerns load-following, full requirements service. To enable transparent pricing under the auction and not dissuade prospective bidders, Duke excluded renewable energy credits (RECs) from the product definition. According to Duke, separating the AER compliance obligation from the load auction provides greater transparency around compliance costs. In addition, such separation affords more assurance that the compliance targets will be met if Duke retains the AER compliance obligation. Moreover, the auction will be more straightforward to bidders if the REC requirement is not included, because the REC obligations are based on Duke's historical sales and the load auction is prospective. (Duke Ex. 3 at 26-27; Duke Ex. 8 at 9.) Finally, Duke notes that the MSSOA has a provision for default by a supplier and the remedies available to mitigate the impacts of such a default on customers (Duke Ex. 3 at 28; Duke Ex. 8 at 12).

While some of Constellation's concerns were addressed with the revised MSSOA, Mr. Fein recommends that Duke revise its proposed MSSOA in order to make it more consistent with other industry-standard agreements for wholesale supply and to provide greater clarity. According to the witness, such revisions will promote more robust competition and the most competitive SSO prices. (Constellation Ex. 1 at 17.) Initially, Mr. Fein notes that he supports the exclusion of NITS from the auction product. He recommends the following credit-related improvements to the MSSOA: removal of the independent credit requirement (ICR); adding thresholds for lower credit ratings; moving toward a weekly settlement process consistent with PJM practices; in the event the MSSOA does not include weekly settlements, adding provisions to accelerate payments on a weekly basis from Duke if Duke falls below investment grade; and clarifying the SSO supplier's need to provide notice to Duke of a change that would affect the SSO supplier's credit standing. (Constellation Ex. 1 at 18-19, 26-27.) Mr. Fein explains that the ICR should be eliminated from the MSSOA because Duke's credit exposure for the term of the MSSOA is already covered in daily mark-to-market (MtM) calculations; thus, the ICR in conjunction with the MtM calculations represents repetitive collateralization that may require suppliers to increase their bids and customers' costs, while providing little additional credit protection to Duke. In addition, Mr. Fein notes that CBPs that call for less utilization of a wholesale supplier's credit capacity will have a competitive advantage and likely see greater participation. (Constellation Ex. 1 at 23; Constellation Br. at 10.)

Constellation also points out that, while the MSSOA addresses the need for credit arrangements for suppliers, no similar standards are required of Duke even though suppliers will be advancing Duke energy for a period of time before the suppliers are paid. Therefore, Constellation requests that the Commission require a contingency plan that, should Duke's parent fall below an investment credit rating by major credit rating agencies, the payment schedule of the winning suppliers would be moved to weekly in line with the settlement date of PJM. (Constellation Br. at 11.)

Mr. Fein also recommends certain noncredit-related changes to the MSSOA, including that the notional quantity language should be removed or made optional, because to do otherwise compromises the future assignability of a contract (Constellation Ex. 1 at 29-34; Constellation Br. at 11). In addition, Mr. Fein suggests that certain provisions affected by the transition from the Midwest ISO to PJM need to be addressed, i.e., capacity obligations, timing of Duke's integration into PJM, and the nature of the delivery zones. Mr. Fein asserts that Duke should explain what happens if the integration into PJM does not occur on January 1, 2012. Constellation is concerned because Duke has not committed to and will not provide certain information related to suppliers' capacity obligations under the MSSOA upon Duke's transition to PJM, e.g., Duke has not committed to provide information regarding the amount of its load that will have decided to opt-out of its proposed capacity procurement plan awaiting approval at FERC. Further, there is ambiguity as to the final costs for capacity that suppliers will incur subject to their obligations under the MSSOA. Mr. Fein suggests that Duke could mitigate this concern by guaranteeing that, if its capacity procurement results in prices higher than those that cleared the applicable base residual auction, Duke will reimburse suppliers for the difference and pass through in its rates to consumers such difference. In addition, Mr. Fein is concerned that there is uncertainty with respect to the delivery zone that is identified in the MSSOA, because PJM has not yet defined the delivery load zone for Duke's territory. (Constellation Ex. 1 at 35-38.)

Mr. Fein further contends that the MSSOA should clarify the renewable energy requirements associated with the SSO supply and the effects of default. Finally, Mr. Fein recommends changes to the sample PJM invoice, as well as else where in the MSSOA, in order to clear up ambiguities and make these items in the MSSOA consistent with other provisions in the MSSOA. (Constellation Ex. 1 at 38-42.)

FES witness Swartz argues that Duke's MSSOA contains credit provisions that are unreasonably restrictive and onerous for potential suppliers. According to Mr. Swartz, these provisions would likely cause fewer suppliers to participate in the auction and the ones that do participate may bid less aggressively; thus, resulting in higher clearing prices. (FES Ex. 1 at 5, 8-10.) With regard to unsecured credit, Mr. Swartz explains that Duke proposes that the ICR and MtM credit exposure may be covered by such unsecured credit equal to a descending percentage of a supplier's tangible net worth, so long as the supplier has at least a BBB- rating from S&P and a Baa3 rating from Moody's. Mr. Swartz points out that suppliers that do not meet these credit rating requirements would need to post either cash or a letter of credit as collateral, and for most suppliers this would be prohibitively expensive. To solve this problem, Mr. Swartz proposed that the MSSOA should be revised to grant suppliers unsecured credit to cover all or a portion of: the ICR through the BB- credit rating of S&P and Fitch, and the Ba3 credit rating of Moody's; and the MtM credit exposure through the BB- credit rating of S&P and Fitch and the Ba3 credit rating of Moody's. (FES Ex. 1 at 11-14; FES Br. at 17.) In addition, Mr. Swartz submits that Duke should allow suppliers to use first mortgage bonds as an acceptable form of collateral, stating that these bonds are typically less expensive that letters of credit or cash and they will allow suppliers to use the value of their assets as security (FES Ex. 1 at 15; FES Br. at 18-19).

In response to the proposal that Duke allow for first mortgage bonds, Duke notes that FES witness Swartz acknowledged that credit requirements differ from company to company. Furthermore, Duke believes that the proposed revision would expose Duke and its customers to additional costs should suppliers that provide first mortgage bonds as a first form of security default. Duke also notes that first mortgage bonds were used as secondary form collateral in the FirstEnergy's CBP. (Duke Reply Br. at 13; Tr. IV at 802-803.)

Upon consideration of the CBP and the record in this case, the Commission finds that there are legitimate concerns raised by several parties which call to question whether the application has complied with Section 4928.142(A)(1)(b), Revised Code, and provided a clear product definition.

As pointed out by Staff, Duke has failed to provide the requisite information regarding a five-year blending period; therefore, at a minimum, the CBP does not conform to the statutory requirements in this regard. Furthermore, Staff recommends that there be an overlap between auctions in order to dampen any changes in the market pricing from auction to auction. The Commission agrees with Staff's concern for reducing the risk of abrupt or significant changes in SSO prices. It is clear that both the state policy in Section 4928.02, Revised Code, and the provisions for an MRO in Section 4928.142, Revised Code, support a reasonable transition to market-based rates that provide consumers clear and meaningful choices. Absent a showing on the record that the proposed evolution of the auction product complies with these directives, the Commission can not conclude that the proposed CBP provides a clear product definition.

In concert with the statute, Rule 4901:1-35-03(B)(2)(a), O.A.C., requires that Duke provide, as part of it application, not only an explanation of the wholesale procurement process, but alternative methods of procurements. Reviewing Duke's filing, the Commission finds that there is little discussion on the alternatives considered by the company; therefore, additional information regarding alternative methods of procurements is required. The Commission is concerned about the expense of a descending-clock auction for only 10 to 20 percent of the load; therefore, we believe alternative procurement methods, such as a sealed-bid RFP, for the first two years of the SSO must be considered. Moreover, the Commission notes that, in accordance with Rule 4901:1-35-03(B)(2)(l), O.A.C., the CBP plan must provide for funding of a consultant selected by the Commission, that will 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 would affect the solicitations; and other relevant criteria.

Constellation also raised other valid concerns regarding the MSSOA. For example, the Commission finds that the timing of Duke's MRO application and its proposed move to PJM make it difficult to consider the MSSOA a final draft document. Since Duke has not committed to and will not provide certain information related to a suppliers' capacity obligations under the MSSOA upon Duke's transition to PJM, the Commission can not conclude that Duke has provided a clear product definition in this application. Furthermore, the Commission agrees that Duke needs to clarify in the MSSOA the renewable energy requirements associated with the SSO supply and the effects of default.

Accordingly, the Commission finds that Duke has not presented sufficient information on the record to demonstrated that the CBP provides a clear product definition as required by Section 4928.142(A)(1)(b), Revised Code.

3. Standardized Bid Evaluation Criteria, Section 4928.142(A)(1)(c), Revised Code

According to Duke witness Lee, to participate in the CBP, bidders will need to satisfy financial and nonfinancial requirements through a two-part bidder application and qualification process. The purpose of this two-part process is for prospective bidders to demonstrate their ability and commitment to meet the requirements of participation in the CBP and of being an SSO supplier as set forth in the MSSOA. Part 1 of the application process requires a prospective bidder to: submit a completed application; provide contact information; agree to comply with the MSSOA and the rules of the CBP, including the communications protocols; demonstrate RTO status; provide financial and credit information; and make certification regarding confidentiality and other matters. (Duke Ex. 7 at 8-13.) The first part of the application process ensures that nonprice criteria are used to determine the qualifications of bidders to become SSO suppliers. Duke offers that this process imposes a level playing field for all bidders because they are reviewed against the same requirements and the same standardized basis. According to Duke, this standardized process is unambiguous in respect to identifying winning bidders because they are those bidders who are willing and able to supply the tranches at the winning bids.

Therefore, Duke believes that, with this prequalification process, the Commission's subsequent review should only concern the price. (Duke Ex. 3 at 17-18.)

If the prospective bidder satisfies Part 1 of the application process, Mr. Lee explains that, to continue participation in the CBP, it must submit Part 2, which requires it to: make certifications regarding its associations with other qualified bidders; submit an indicative offer that specifies the number of tranches it would be willing to serve at the minimum starting prices and at the maximum starting price; and post a prebid security in the form of a letter of credit or electronic wire transfer sufficient to support its indicative offer (the applicant may also be required to submit additional security in the form of a letter of intent to provide a guaranty and/or letter of reference). If an applicant successfully completes Part 2 of the application process to become a registered bidder, its prebid security establishes its eligibility, which is the maximum number of tranches it will be allowed to bid in the auction. Mr. Lee submits that the bid evaluation criteria proposed by Duke will result in the bids being evaluated on an objective, price-only basis (Duke Ex. 7 at 8-13, 26).

The Commission finds that, from the information provided on the record and, if the Commission were to approve the CBP proposal by Duke, it appears that Duke approach regarding the standardized bid evaluation criteria would be consistent with the requirements of Section 4928.142(A)(1)(c), Revised Code.

4. Oversight by an Independent Third Party, Section 4928.142(A)(1)(d), Revised Code

Duke has retained an independent consultant, CRA, to actively design, administer, and oversee the CBP to procure SSO supply for delivery periods beginning January 2012. Duke explains that CRA is not owned, managed, controlled, or directed by Duke, and CRA is not an affiliate of Duke or any of its affiliates. According to Duke, CRA has substantial experience in designing and implementing bids for generation service, including managing the auctions for the FirstEnergy ESP in the *FirstEnergy 10-388 case*. (Duke Ex. 3 at 18-19; Duke Ex. 7 at 4.) Duke witness Northrup states that Duke will provide the Commission, on a real-time basis, access to Duke employees and CRA in order to assist the Commission in its review of the CBP, including data, information, and communications relevant to the bidding process (Duke Ex. 8 at 4).

Staff is concerned that, if Duke's MRO is approved, the selection and function of the auction manager is noncompetitive. Duke proposes to use CRA as the sole auction manager. Staff points out that, under Duke's MRO construct, it is possible that a single auction manager, CRA in this situation, could have control over the CBP forever. The MRO lacks the option to choose a different auction manager. (Staff Br. at 15.)

The Commission finds merit in Staff's concern regarding the possibility that a single CRA manager could have control over the CBP permanently. We agree that, in order to substantiate that an independent third party will oversee the CBP, it is essential that provisions be made for allowing the selection of a different auction manager. Moreover, without provisions for Commission oversight in the selection of the auction manager, there is undue risk that the auction manager could lose its independence. In order to address this concern and comply with the statutory requirements, the Commission believes that the auction manager should be selected by the Commission, through an RFP issued by the Commission, and that the Commission should supervise the auction manager.

Accordingly, the record reflects that Duke has not adequately addressed the requirement for the oversight of the CBP by an independent third party, in accordance with Section 4928.142(A)(1)(d), Revised Code.

5. Evaluation of Submitted Bids, Section 4928.142(A)(1)(e), Revised Code

Duke explains that CRA will provide the Commission with the post-bidding report containing the information needed to evaluate the solicitation and select the least-cost bid winner(s), within 24 hours after the close of the bidding process. According to Duke, Staff and CRA will have access to the CBP, data, information, and communications relating to the CBP, on a real-time basis. Duke's CBP plan provides for an independent consultant to be retained by the Commission to evaluate the bids. According to Duke, the Commission will review and select winning bids only with regard to price. (Duke Ex. 3 at 20; Duke Br. at 18.)

The Commission finds that the information provided by Duke on the record appears to be consistent with the criterion regarding the evaluation of proposed bids as contemplated by Section 4928.142(A)(1)(e), Revised Code.

H. State Policy, Section 4928.02, Revised Code

Section 4928.02, Revised Code, sets forth 10 policy objectives for the state of Ohio pertaining for competitive electric service. As stated previously, in considering Duke's MRO application, policy objectives are the cornerstone for contemplating whether Duke has satisfied the requirements that must be met to implement an MRO. In fact, GCHC and Eagle argue that an electric utility can only be deemed to have met the statutory requirements of Section 4928.142(A), Revised Code, to the extent that its proposed MRO is consistent with the policies set forth in Section 4928.02, Revised Code (GCHC Br. at 22).

Duke asserts that its CBP is consistent with the policies of the state contained in Section 4928.02, Revised Code, and the record reflects that the MRO will either have no impact or relationship with the state policy, or the MRO will advance state policy (Duke Br. at 36). Duke witness Janson was the primary witness for Duke supporting the company's assertion that it has satisfied all 10 of the policy objectives espoused by Section 4928.02, Revised Code.

Ms. Janson explains that, under the MRO, Duke will remain the distribution company for customers and will have the same obligations regarding adequate capacity, reliable service, and nondiscrimination that is currently has. According to Ms. Janson, the MRO will only impact the pricing of Duke's generation services and such pricing will be nondiscriminatory and reasonable. (Duke Ex. 2 at 17.) Under the MRO, all unbundled generation rates, in the form of the SSO price, will be unconditionally avoidable for all customers, with the exception of a reconciliation rider that, under certain circumstances, can become avoidable (Duke Ex. 2 at 19).

Ms. Janson also states that diversity in supplies and suppliers in Duke's territory exists today, in that Duke currently has 13 active CRES providers in its territory. Ms. Janson anticipates that, under the MRO, there will be no diminution in the CRES providers' ability to operate in Duke's area. According to Ms. Janson, the MRO will provide competitive generation suppliers a new opportunity to sell their output. Furthermore, Duke will continue to offer services to small distributed generation facilities, in the vein of net metering and the interconnection tariff. She points out also that Duke has a tariff for residential customers who wish to sell RECs. (Duke Ex. 2 at 19-20.)

Duke witness Ritch states that Duke's plan to meet it AER requirements supports the policy objective of customer choice because customers will retain the option of obtaining generation resources through Duke's SSO offer or through alternative suppliers. If the customer selects service through Duke, Duke will be accountable to procure the requisite RECs; however, if the customer selects an alternative supplier, the alternative supplier will be accountable for meeting the AER requirements. Furthermore, Mr. Ritch notes, because most renewable resources are both distributed and small in nature, Duke's procurements of the requisite RECs to meet the company's obligations support the state policy. (Duke Ex. 9 at 11.)

Ms. Janson contends that the costs incurred by a generator that operates in a competitive market to comply with environmental mandates should be recovered through those market prices. Ms. Janson believes that the MRO provides a motivation for prospective suppliers to implement technologies that enable them to effectively participate in Duke's competitive solicitations. (Duke Ex. 2 at 25-26.) Similarly, Mr. Ritch points out that the company's plan to meet its renewable energy resource requirements supports this policy because such resources are among the best qualified generation technologies to thrive under potential environmental mandates (Duke Ex. 9 at 12).

OCC agrees that the MRO will better ensure the availability of unbundled and comparable retail electric service because it will not include the various expenses or expenditures permitted under an ESP. Under the ESP, Duke not only recovers the base generation PTC, but it collects other amounts through riders. According to OCC, these riders make it difficult for customers to compare the price they pay Duke for generation to the price being offered by alternative suppliers. However, under the MRO, these riders would be transitioned out and all of the costs associated with the riders will be incorporated into the one price based on the final bid price. (OCC Br. at 10-11.)

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. Ms. Janson asserts that the MRO will not affect how the company works with at-risk populations (Duke Ex. 2 at 27). However, OPAE points out that, while there has been some shopping in Duke's territory, only 29 percent of the residential load has switched. Thus, OPAE contends that it is likely that most residential customers will still be served by Duke's SSO in 2014 and beyond. Therefore, OPAE asserts that these customers should not be denied the consumer protections of the blended SSO price up to the maximum of ten years allowed by the statute. (OPAE Br. at 5.)

The Commission's consideration of the adherence of this MRO application to the overreaching state policy set forth in Section 4928.02, Revised Code, is intertwined throughout this order.

I. Compliance with Chapter 4901:1-35, O.A.C., Sections 4928.142(A) and (B), Revised Code

In accordance with Chapter 4928, Revised Code, the Commission promulgated rules in Chapter 4901:1-35, O.A.C., concerning applications filed for SSO. Specifically, in accordance with Section 4928.142(A), Revised Code, the Commission established Rules 4901:1-35-03(B)(2)(a) through (o), O.A.C., which require that each CBP plan to be used to establish an MRO contain the information set forth therein. As stated previously, Staff believes that, since the core of Duke's MRO plan is the two-year transition to market and this core element is deficient, all of the other parts of Duke's plan and the elements of the plan, which are structured around this two-year period, are likewise deficient (Staff Br. at 2-3). Staff emphasizes that information required by Section 4928.142, Revised Code, and Rule 4901:1-35-03(B)(2), O.A.C., for blending years four and five are unaccounted for in Duke's application, testimony, and exhibits. For example, Staff points out that Duke failed to provide projected statements of income, balance sheets, and sources of uses of funds for blending years four and five. (Staff Br. at 8-9). Staff submits that Duke must file a new application, because the remaining parts of the plan can not be reconfigured to a planned five-year period, which is required by statute (Staff Br. at 3). GCHC, Eagle, and OEG agree that Duke's application fails to comply with Section 4928.142(D), Revised Code, and Rule

4901:1-35-03(2)(j), O.A.C., which requires that Duke's application state how the company will satisfy blending requirements for the first five years of the application (GCHC Br. at 6; OEG Br. at 9). OMA agrees that Duke's failure to provide the necessary information and pro forma financial projections required by Rules 4901:1-35-03(B)(2)(b) and (c), O.A.C., renders the MRO fatally deficient (OMA Br. at 6).

Sections 4928.64 and 4928.66, Revised Code, and Rule 4901:1-35(B)(2)(n), O.A.C., set forth requirements that electric utilities must comply with regarding alternative energy portfolios, energy efficiency, and peak demand reduction. Duke submits that the MRO will not impact its commitment to meet the statutory AER, energy efficiency, and peak demand reduction requirement (Duke Ex. 3 at 30). Neither the company's energy efficiency model nor its programs will change as a result of the MRO. Rather, Duke intends to continue to execute its portfolio of residential and nonresidential programs approved by the Commission the *Duke ESP Case* and in 09-1999. (Duke Ex. 10 at 5-6; Duke Br. at 39.)

Mr. Ritch explains that, to date, Duke has utilized REC purchases obtained through brokers, aggregators, and owners of renewable energy resources as the primary means of meeting its AER obligations. According to Mr. Ritch, Duke evaluated both need and risk in its plan to implement methods to supplement these shorter-term REC transactions with longer-term commitments for 15 years in duration. (Duke Ex. 9 at 3, 7.) Duke believes that the MRO will allow the company to enter into long-term PPAs and conduct RFPs, which will encourage investment in the state. Duke intends to continue to acquire RECs on the short-term market and then, under the MRO, undertake longer-term transactions, such as PPAs and RFPs for its AER compliance obligations. Mr. Ritch states that, under the MRO, Duke has a greater level of assurance of cost-recovery because the applicable riders for recovering costs would not be subject to expiration as they are in an ESP structure. Mr. Ritch explains that, under the MRO Duke intends to recover the costs for purchasing RECs and any other costs for complying with the alternative energy standards via the new alternative energy recovery rider (Rider AER). (Duke Ex. 3 at 30; Duke Ex. 9 at 9-10; Duke Br. at 40.)

RESA supports Duke's plan to enter into long-term contracts, stating that it would encourage renewable energy development and increase the likelihood that Duke will continue to meet the increasing renewable portfolio standard requirements. RESA notes that Duke made it clear on the record that only with the assurance of long-term cost recovery would it be willing to enter into long-term contracts. OAE witness Helmich believes, and RESA agrees, that the regulatory risk associated with long-term contracts should be removed and Duke should be allowed to recover costs associated with long-term contracts for as long as the contracts are in effect. (OAE Ex. 1 at 4; RESA Br. at 2-5; Tr. II at 282.) Duke states that it does not object to the recovery of costs for long-term contracts over the term of the contracts, provided it is operating under an MRO where regulatory certainty is afforded (Duke Reply Br. at 64).

OEC submits that Duke's strategy to comply with its solar energy resource (SER) benchmarks through the purchase of short-term solar renewable energy credits (SRECs) is not adequate and will not ensure that Duke complies with its statutory SER benchmark requirements. OEC explains that solar developers need the certainty of long-term contracts and the assurance of future revenue streams in order for the solar industry to fully develop. Therefore, OEC advocates that Duke be required to enter into a certain number of long-term SREC transactions. According to OEC, upon the approval of an MRO, any cost-recovery risk concern that Duke might have would be minimal; therefore, Duke's justification for not pursuing long-term REC contracts would no longer apply. (OEC Br. at 3-6.) Duke disagrees with OEC's assertion that there is little risk to Duke if Duke is required to enter into a certain number of long-term SREC agreements. Duke states that, without long-term cost recovery assurance, Duke would incur unreasonable risk. (Duke Reply Br. at 64.)

Mr. Stevie submits that the energy efficiency programs offer incentives to customers to install equipment that is more energy efficient and the demand response programs support the peak load reduction objectives established by statute. For residential customers, Duke notes that it will continue to offer TDP options under the MRO, including: Rate TD-AM, a time-of-use rate for customers with installed and certified Smart Grid meters; a peak time rebaterate (Rate PTR); critical peak pricing rate (Rate CPP), a rate that provides rebates to curtailing usage during peak hours; and Rate TD-LITE, a time-of-use rate. Nonresidential customers will continue to have access to the PowerShare program under the MRO, as well as the Load Management Rider (Rider LMR) and the Real Time Pricing Program (Rate RTP). Mr. Stevie believes that the MRO structure will serve to encourage customers to explore different pricing and usage options. (Duke Ex. 3 at 32; Duke Ex. 10 at 14, 16.)

Rule 4901:1-35-11, O.A.C., establishes ongoing review and reporting requirements for a CBP plan subject to the statutory blending period. Paragraph (B) of this rule mandates, in part, that electric utilities with an approved CBP that includes a blending period must file with the Commission proposed adjustments to the SSO portion of the blended rates of its CBP on a quarterly basis for the duration of the price blending period. In addition, paragraph (C) of this rule requires that, one year after the filing of a CBP, and annually thereafter for the duration of the blending period, the electric utility shall file an annual report on its CBP. The annual report must include: a statement about the operation of the CBP to date, the generation service obtained, and the impacts of the CBP service and blended rates on customers; any bidder defaults or difficulties encountered; conditions and significant developments of the wholesale electric generation and transmission market; the financial condition of the utility; information on the upcoming solicitations;

the projected blended phase-in rates to be charged; the operation of any time-differentiated and dynamic rate design implemented under the CBP; and a status report of the market conditions.

Staff points out that both Section 4928.142(C), Revised Code, and Rule 4901:1-35-11, O.A.C., provide that Duke's MRO and CBP are subject to ongoing Commission review including quarterly and annual reporting requirements. Staff submits that it is not evident from Duke's application and testimony that Duke intends for its CBP to be subject to the required ongoing Commission oversight. For example, Staff points out that there is a sentence in the bidding rules that seems to indicate that Duke does not believe it is subject to oversight by the Commission. Therefore, Staff recommends, and OPAE agrees, that the Commission not approve the MRO without requiring that Duke comply with the rules. (Staff Ex. 2 at 5-6; Duke Ex. 3, Att. C at 1; Staff Br. at 13-15; OPAE Br. at 8.)

OCC agrees that Duke should be required to recognize its obligation to seek Commission approval for any significant revisions and modifications it intends to make to the CBP. The Commission's authority to monitor and supervise the CBP should not be limited, according to OCC. (OCC Br. at 17-18.)

OCC submits that Duke should not retain the decision-making authority as to whether Duke will apply sanctions to itself or other Duke affiliates for failure to comply with the bidding rules. According to OCC, this process would provide Duke with the temptation to improperly advantage itself at the expense of other bidders. OCC advocates that the Commission hold the power to impose sanctions and that the auction manager should be required to file any suspicion of rule violations with the Commission for action (OCC Br. at 19-20; Tr. I at 184.)

In response to these concerns, Duke notes that Duke witness Lee acknowledged the Commission's oversight once the MRO is approved. However, Duke submits that an efficient process mandates some discretion by the auction manager and Duke to revise the bidding documents, arguing that the auction process would become cumbersome and protracted if every modification to the bidding documents requires formal Commission review and approval. (Duke Reply Br. at 18-19; Tr. I at 190.)

As we stated throughout this order, the Commission finds that Duke's application does not comply with the statute and, therefore, this case can not proceed as filed. It is required that Duke provide the information dictated by the statute and delineated in the Commission's rules, in order for the Commission to determine if the application satisfies the statutory requirements. Duke readily concedes that it did not provide certain information because it was outside of its two-year proposal. Accordingly, the Commission can not find that Duke satisfied the requirements set forth in Rules 4901:1-35-03 and 4901:1-35-11, O.A.C. Moreover, the Commission notes that it is essential that any MRO application clearly reflect that the MRO and CBP are subject to ongoing Commission review, including quarterly and annual reporting requirements, in accordance with Section 4928.142(C), Revised Code, and Rule 4901:1-35-11, O.A.C.

J. Criteria for Eligibility for Market Rate Offer Plan, Section 4928.142(B), Revised Code

Section 4928.142(B), Revised Code, requires that an MRO application detail the electric utility's 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 an 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. In its application, Duke states that, although it is currently a member of the Midwest ISO, it recently received approval from FERC to realign its RTO membership with PJM. Accordingly, Duke believes that, at the time the MRO commences, it will be a member of PJM. However, in support of its application, Duke avers that, regardless of whether it is a member of PJM or the Midwest ISO at the time the MRO commences, both FERC-approved RTOs meet the statutory criteria. (Duke Ex. 3 at 20-21.)

No party disputed the fact that Duke is currently a member of the Midwest ISO, but has received conditional approval from FERC to realign with PJM. Moreover, no party disputed that both the Midwest ISO and PJM are FERC-approved RTOs. Therefore, while the Commission will address the issue of cost recovery regarding Duke's proposed RTO migration elsewhere in this opinion, the Commission finds that Duke's filing appears to be consistent with the requirements of Section 4928.142(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. In its application, Duke submits that both the Midwest ISO and PJM have adequate market monitor functions and the ability to take actions to identify and mitigate market power or market conduct to meet the statutory criteria. Specifically, Duke states that both RTOs have independent market monitors, Potomac Economics for the Midwest ISO, and Monitoring Analytics for PJM, who evaluate the performance of the markets and identify conduct by market participants or the RTO that compromise the efficiency or distort the outcomes of the market. (Duke Ex. 3 at 23-24.)

No party disputes that both PJM and the Midwest ISO have independent market monitors. However, at the hearing, IEU attempted to show how the independent market monitors may not be adequately functioning. At the hearing, IEU questioned Duke witness Janson regarding whether the Midwest ISO behaved inappropriately to retain Duke within the Midwest ISO. Ms. Janson testified that Duke received communications from the Midwest ISO "to not have us move from MISO to PJM certain, you call them concessions, I would say offers were made to try and make MISO as favorable as PJM would be in certain regards." (Tr. at 322-324.)

IEU also asserts that Duke's decision to move from the Midwest ISO to PJM was heavily influenced by Duke's desire to move its business into an RTO with an effective competitive retail generation market. Duke witness Janson testified that "for many of the reasons that the company made the decision to move to PJM we have been communicating with MISO our concern about its ability to be as effective in a competitive retail generation market as Ohio for quite some time." (Tr. at 322-324.)

The Commission finds that, despite IEU's assertions, Duke's filing appears to be consistent with Section 4928.142(B)(2), Revised Code, because both RTOs have market-monitor functions and the ability to take actions to identify and mitigate market power or the electric utility's conduct.

3. <u>Published Source of Pricing Information, Section 4928.142(B)(3), Revised Code</u>

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. In its application, Duke states that electricity pricing information is readily available in the public domain, through sources such as ICAP Energy, LLC, ICE, Platt, and the New York Mercantile Exchange, which include information regarding on-peak and off-peak energy products that represent contracts for future delivery and is updated regularly (Duke Ex. 3 at 24-25).

No party disputed the fact that published sources of pricing information are available. Therefore, the Commission finds that Duke's filing appears to be consistent with the requirements of Section 4928.142(B)(3), Revised Code.

K. Rate Design

Rule 4901:1-35-03(B)(2)(a), O.A.C., provides that a complete description of the CBP plan 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. This 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 unavoidable charge, if any, and why the charge is proposed to be unavoidable. Rule 4901:1-35-03(B)(2)(a), O.A.C., provides that the CBP plan shall include a discussion of TDP, 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.

In its application, Duke asserts that the proposed SSO generation rates in the MRO have virtually no unavoidable charges as the application proposes the creation of only one generation related rider that, in most circumstances, will be unavoidable. In discussing the retail rate design, Duke reiterates that the SSO price during the proposed MRO blending period is commensurate with the auction percentages, therefore, when 10 percent of the SSO load is auctioned in year one of the MRO, 10 percent of its blended SSO price will be determined by the market bid under that auction. The balance of the blended SSO price for that year is determined with reference to the company's most recent ESP price, as may be adjusted. Duke proposes that the most recent ESP price that is factored into the blend will be the ESP generation price in effect for the fourth quarter of 2011. (Duke Ex. 3 at 33-34.)

Duke witness Bailey explained that Duke's proposed CBP process will result in multiple clearing prices for each year of the SSO. To obtain the market price, the clearing prices will be averaged using the number of tranches purchased at each price as weighted to obtain the blended SSO price. Duke will then utilize a wholesale to retail rate conversion process to convert the blended SSO price to a retail rate or standard service offer generation charge (SSOGC). Mr. Bailey further explains that any capacity-related costs associated with the CBP will be allocated to the respective rate classes based on the average of their coincident peaks (CP), including distribution losses, for the months of June through September of the prior years (also known as the 4 CP method). These capacity costs will then be converted to energy charges based on the applicable kWh sales level for each class and further adjusted for commercial activity taxes, with energy charges calculated for each class based upon the remaining noncapacity CBP price adjusted for losses and commercial activity taxes. Both capacity- and energy-related charges will be further modified for seasonal and time-of-day factors for billing purposes. (Duke Ex. 15 at 3-5.)

Duke asserts that the use of the 4 CP method is appropriate because usage in Duke's territory has historically peaked during the summer period, and Duke's tariffs have provisions, like the ratchet for billing demand, tied to the summer period. Moreover, Duke sets forth that the 4 CP method is reasonably supported, based upon the FERC factor tests to determine the appropriateness of coincident peaks for cost allocation purposes. Duke witness Bailey also states that seasonality will be introduced into the pricing based upon seasonal factors developed over four years of PJM locational marginal price (LMP) data at the Dayton Hub. The hourly LMPs have been multiplied by the load of all wire-connected load to Duke to arrive at an hourly revenue. These revenue results are then aggregated based on the respective summer and winter periods and divided by sales in the same period to result in summer and winter factors. When applied to the CBP prices, these factors will convert the annual average CBP price to load-weighted prices for the respective summer and winter periods. Mr. Bailey avers that the same data can be used to adjust prices into on- and off-peak pricing periods. (Duke Ex. 15 at 5-7.)

Kroger argues that Duke's rate design proposal for the market price component of the MRO for demand-billed customers is unreasonable and should be modified by the Commission. Currently, a significant portion of Duke's ESP price is comprised of demand charges for those rate schedules that are billed on a demand basis, which Kroger contends is an appropriate design for ensuring a proper alignment between capacity-related costs and like charges. In contrast to the ESP prices, Kroger witness Higgins explains that the market price component of the MRO is priced solely on a kWh basis, which Higgins opines will have a substantial impact on customers who are currently billed under one of Duke's demand-billed rate classes. (Kroger Ex. 1 at 4; Kroger Br. at 9-10.)

Kroger asserts that, as the market price component of Duke's rates becomes greater, there will be a shift within each demand rate class wherein high-load factor customers will see their rates negatively impacted, but lower-load factor customers will receive a windfall benefit. Kroger witness Higgins testified that, by using the formulas provided by Duke in the application, he was able to show that, on a revenue-neutral basis, by the third year of the proposed MRO, the rate design change would increase overall rates for a customer taking service under the rate schedule for service at a secondary distribution service-small, with an 80 percent load factor by 15.2 percent while reducing rates by 7.6 percent for a customer with a 30 percent load factor. Similarly, Kroger asserts that these impacts would be typical of those experienced by any other demand-billed rate schedules. In sum, Kroger argues that this type of rate impact is unreasonable and results solely from Duke's rate design choice to eliminate retail demand charges for the market price component of the SSO. (Kroger Ex. 1 at 14-16; Kroger Br. at 11-12.)

Kroger witness Higgins explains that, during the transitional period, each SSO supplier must satisfy its capacity obligations through the purchase of capacity from Duke, with the capacity product priced as a demand charge in dollars per megawatt (MW). Following the transitional period, Mr. Higgins explains that each SSO supplier will satisfy its capacity obligation through PJM vehicles, including participation in PJM auctions. In those auctions, the capacity product that SSO suppliers must acquire in fulfillment of their obligations to Duke will be priced as a demand charge. According to Mr. Higgins, when these bids are submitted to Duke and they include capacity, as well as other nonenergy components, the bids will be submitted solely on an energy basis per Duke's requirements. Moreover, Mr. Higgins explains that, when that product is converted to a retail rate, it will be recovered from retail customers as a 100 percent energy charge, which will radically disrupt the current rate design. Mr. Higgins further opines that this is unnecessary because the capacity component will be separated for the purpose of allocating capacity-related costs to customer classes. However, rather than pricing the capacity component as a demand charge for demand billed customers, Duke proposes to convert the capacity costs into energy charges. Witness Higgins asserts that this is an improper rate design, as capacity-related costs should be recovered from demand-billed rate schedules through demand charges; to do otherwise results in undue cost-shifting within the rate schedule. (Kroger Ex. 1 at 14-18.)

To mitigate what Kroger perceives as a faulty rate design, Mr. Higgins recommends that the Commission modify Duke's proposed rate design for the market price component of SSO generation rates by requiring that, after capacity-related costs are allocated to each rate class, costs are recovered on a demand-bill rate schedule as demand charges, rather than converted to energy charges. Alternatively, Mr. Higgins recommends that the Commission require Duke to file a rate design rider for each demand-billed rate schedule that would be applied to the market price component of the SSO generation charge. The proposed rider would consist of a demand charge that reflects the demand charges currently in Duke's ESP generation rates accompanied by a per kWh energy credit, designed such that the sum of the demand charges and energy credits for each applicable rate schedule is revenue neutral for that rate schedule. The proposed rider would not transfer revenues between Duke and its customers, but would ensure revenue recovery among customers in a manner that is aligned with the demand charges in Duke's current generation rates, minimizing rate impacts from adoption of an MRO due solely to Duke's proposed rate designs. (Kroger Ex. 1 at 15-18.)

OCC supports Kroger's argument. OCC opines that Duke's rate design should accurately reflect the cost of providing generation service to large customers. OCC asserts that an appropriate means of achieving this goal is to bill using demand-based charges, which currently comprise a significant portion of Duke's ESP price. According to OCC, Duke's MRO proposal eliminates all demand-billed rates, which results in the sending of incorrect price signals to large customers, and fails to recognize the cost differences in serving large customers. Moreover, OCC avers that failure to bill large customers on a demand basis may result in inefficient demand for, and use of, generation resources. OCC gives the example of large customers who currently utilize multiple shifts of workers to avoid fluctuations in demand who will no longer be incented to do so, but may instead restructure operations to create greater peak demand. OCC contends that this aspect of Duke's application eliminates the principal source of responsiveness to differences in demand that has historically been in place for large customers and that is needed going forward to reduce the bid price. OCC claims that this fault in Duke's proposed tariffs will result in higher bid prices at auction. (OCC Br. 35-37.)

From a policy perspective, OCC argues that Duke's proposed rates will rely solely on kWh charges at a time when both the national and state focus is on providing customers with appropriate price signals so that electricity is used in a more economically efficient matter. OCC further emphasizes that this weakness in the design of Duke's rate structure will encourage increased energy usage from high-load customers and may dramatically impact capacity, cost-shifting, and will drive prices upward for all consumers. Accordingly, OCC requests that the Commission order Duke to modify its proposed rate design for the market price component of the SSO generation rates in order to send appropriate price signals to the market, as well as lower prices. (OCC Br. 35-37.)

GCHC and Eagle assert that the proposed generation rate design proposed by Duke does not advance the state policies enumerated in Section 4928.02, Revised Code. Specifically, GCHC and Eagle point out that Duke's proposed tariffs for the market price are based solely on per kWh charges, as opposed to the existing tariffs which include demand charges. Accordingly, GCHC and Eagle recommend that the Commission accept Kroger's request that the rate design include demand charges rather than billing all charges as energy charges. Moreover, GCHC and Eagle argue that the rate conversion process proposed by Duke to derive its retail rates is not an appropriate method because it is inconsistent with the rate conversion process used in deriving Duke's ESP prices. GCHC and Eagle state that Duke's proposal to use the 4 CP method to allocate capacity costs among customer classes is a significant departure from Duke's current usage of the 12 CP method, which has passed the FERC Test C for rate design and is consistent with how current Duke rates are calculated. Accordingly, GCHC and Eagle submit that Duke should convert auction prices to retail rates using the 12 CP method. (GCHC Br. at 21.)

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. In its reply brief, Duke asserts that it has justified its proposal to remove demand charges from the market-based portion of its SSO price, as Duke is moving to full market pricing and CRES providers do not typically express demand charges in their offers; therefore, Duke asserts that the removal of demand charges is appropriate. However, the Commission finds that Duke's proposed rate design does not further the state policy by providing customers who were traditionally served on a demand rate schedule an option to meet their needs without creating a significant rate increase. Therefore, because Duke 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. The Commission directs Duke to consider, in any subsequent application filed by Duke, either for an ESP or an MRO, its rate design with respect to its demand classes and address whether Duke's proposed rate design sends appropriate price signals. Moreover, Duke should further address the adequacy of the use of the 4 CP method in allocating capacity costs, as opposed to the 12 CP method, which has previously been approved by FERC. Finally, the Commission directs Duke to address the possibility of providing dynamic pricing options which reflect the time varying wholesale cost of electric service for large commercial and industrial customers with advanced or interval meters.

L. Riders

1. Rider RECON

Duke proposes the creation of an unavoidable reconciliation rider for over- or underrecovery of eliminated ESP-era riders (Rider RECON). Rider RECON will be used to true-up the costs and revenue for riders Rider PTC-FPP and system resource adequacy - system reliability tracker (Rider SRA-SRT) in the company's proposed MRO filing. According to Duke, Rider RECON would be set at $0 as of January 1, 2012, and Duke will make an application to recover/refund the collective balance of any over- or underrecovery no later than April 1, 2012. Duke proposes to bill the rate for Rider RECON for 12 months after implementation, after which Rider RECON will no longer exist. (Duke Ex. 17 at 11; Duke Ex. 16 at 27-28.)

Staff contends that Rider RECON should be fully avoidable while it is being collected from customers. According to Staff, Rider RECON will essentially combine Riders PTC-FPP and SRA-SRT, which are both generation-related riders in effect under Duke's current ESP. Staff asserts that Duke's generation-related costs should not be attributed to customers not taking generation service from Duke. Moreover, Staff points out that, under the current ESP, Rider PTC-FPP is completely avoidable and Rider SRA-SRT is conditionally avoidable, with the rates contained in Rider PTC-FPP being several magnitudes higher than the rates contained in Rider SRA-SRT. In further support of its position that Rider RECON should be avoidable, Staff explains that it is likely that any over- or underrecovery will be due to balances attributed to Rider PTC-FPP, as it tends to fluctuate more from quarter to quarter than Rider SRA-SRT. (Staff Ex. 1 at 4-5, Staff Br. at 17-18.)

Constellation also argues that Rider RECON should be made avoidable. In support of its position, Constellation explains that one of the attractive features of a fully auction supplied MRO is that the price paid by SSO customers for energy will no longer be subject to retroactive price adjustments based on previously incurred fuel, capacity, and other variable costs. However, as Constellation acknowledges, Duke is still seeking to true-up accounts through Rider RECON. Rider RECON contains only generation-related expenses. Accordingly, Constellation argues that Section 4928.03, Revised Code, prohibits cross-subsidization between regulated and nonregulated costs. Therefore, Constellation agrees with Staff and argues that the Commission should find Rider RECON to be avoidable. (Constellation Br. at 15-16). Wal-Mart, FES, RESA, Dominion, OMA, and OEG agree with Staff that Rider RECON should only be collected on a fully avoidable basis, similar to Rider PTC-FPP under the current ESP (OEG Br. at 17; Wal-Mart Br. at 5; FES Br. at 14; RESA Br. at 9; OMA Reply Br. at 6; Dominion Br. at 16).

If the Commission choses not to require Duke to make Rider RECON avoidable, Wal-Mart suggests that, in the alternative, the Commission should modify Rider RECON by applying it to customers who were competitively supplied prior to the implementation of the MRO, but did not qualify to avoid Rider SRA-SRT, because these customers will have caused some of these costs to be incurred. (Wal-Mart Ex. 1 at 6; Wal-Mart Br. at 5-6.)

With respect to the review of Rider RECON, Staff opines that Duke's application to set the rate for Rider RECON filed by April 1, 2012, should be subject to Staff and Commission review. (Staff Ex. 1 at 4-5, Staff Br. at 17-18). OPAE argues that the Commission should adopt Staff's recommendations with respect to Staff's review of Rider RECON (OPAE Br. at 9). Duke responds that it expects the Commission will continue its annual audit of amounts currently being collected under Riders PTC-FPP and SRA-SRT and will review amounts to be collected through Rider RECON (Duke Reply Br. at 39).

In considering Rider RECON, the Commission is mindful that Rider RECON is being proposed as a vehicle to true-up generation-related costs. Accordingly, the Commission agrees with the recommendation of Staff and other intervenors that such costs should not be borne by customers who do not take generation service from Duke. Although the Commission understands that Rider SRA-SRT is an unavoidable rider unless shopping customers opt out of the rider, the Commission is persuaded by Staff's assertion that the preponderance of the costs included in Rider RECON will be costs incurred under Rider PTC-FPP. Therefore, the Commission finds that Rider RECON could not be approved as proposed in the application.

2. Rider UE-GEN

To recover the cost of bad debt associated with its SSO service, Duke proposes the creation of an uncollectable expense (UEX) rider (Rider UE-GEN) to recover bad debt expenses associated with generation that were previously recovered by Duke's UEX electric distribution rider (Rider UE-ED). As proposed, Rider UE-GEN will be avoidable for customers taking generation service from a CRES provider. (Duke Ex. 17 at 11; Duke Ex. 16 at 28.)

In response to Duke's request to create Rider UE-GEN, Staff explains that Section 4928.142(D), Revised Code, sets forth the adjustments that a company may request for recovery under an MRO construct. Staff believes that a UEX rider for generation is not one of the adjustments specifically listed or contemplated under Section 4928.142(D), Revised Code. Therefore, Staff requests that the Commission not approve Rider UE-GEN as proposed by Duke. (Staff Br. at 18-19.) Both OEG and OPAE agree with Staff that the creation of a UEX rider for generation is not allowable under Section 4928.142(D), Revised Code. (OEG Br. at 17, OPAE Br. at 9.)

In contrast, RESA supports Duke's creation of Rider UE-GEN. Specifically, RESA asserts that Duke is not proposing to adjust the most recent SSO price, pursuant to Section 4928.142(D), Revised Code, by creating Rider UE-GEN. Instead, RESA believes that, with the creation of Rider UE-GEN, Duke is proposing to timely recover the cost of bad debt related to the MRO to be established through this case, a recovery mechanism that RESA contends is permitted under Section 4928.142(C), Revised Code. RESA argues that, in reviewing the creation of proposed Rider UE-GEN, the Commission should contrast the language of paragraph (D) with the language contained in paragraph (C) of Section 4928.142, Revised Code. In doing so, RESA claims that it is apparent that paragraph (D) refers to the "most recent standard service offer price" which is the currently established ESP, whereas the "standard service offer" reference in paragraph (C) refers to the MRO Duke is seeking to establish in the present case. Therefore, RESA concludes that the General Assembly recognized that the vehicle for recovering all such costs incurred by the electric distribution utility, as the result of, or related to, the CBP or to procuring generation service to provide the SSO, may include reconciliation mechanisms, other recovery mechanisms, or a combination of the two. In sum, RESA concludes that Section 4928.142, Revised Code, supports Duke's proposed creation of Rider UE-GEN to allow Duke to recover UEXs incurred as a result of the CBP or in procuring generation service to provide the SSO. (RESA Br. at 10-12.)

RESA also recommends amending Rider UE-GEN to include the tracking and recovery of UEXs for nonmercantile customers for whom Duke purchases accounts receivables. RESA explains that Duke currently purchases receivables for nonmercantile gas and electric customers for which it conducts consolidated billing. According to RESA, a variety of suppliers who supply residential and small commercial customers take part in Duke's programs to purchase accounts receivable. RESA states its belief that the purchase of receivables program offers CRES providers the opportunity to lower their costs to acquire customers. Moreover, RESA asserts that customers benefit from the program because it offers the customers the ability to have a single collection point for their electric charges. On the gas side, RESA explains that Duke purchases all accounts receivable at no discount, but collects all bad debt through a UEX rider. On the electric side, under the structure approved as part of the current ESP, Duke purchases electric receivables at a discount based on the projected levels of bad debt and carrying costs. In comparing the two programs, RESA believes that the advantage of the gas program, from the perspective of the suppliers, is that the receivable risk for customers that shop is the same as for the customers that remain with the utility, as the utility collects all bad debt through an unavoidable rider. RESA argues that the administration of a UEX rider, similar to that Duke utilizes with respect to its gas accounts, also has customer benefits, because customers do not have to clear the credit requirements of a CRES provider prior to enrolling with the provider. RESA claims that this allows lower-income customers to take advantage of the benefits of shopping for service once they have established service with Duke. Based on these beliefs, RESA proposes that Rider UE-GEN be modified to be an unavoidable rider for all nonmercantile customers, as this will socialize the cost of bad debt for nonmercantile customers and will assist in uniformly implementing the Commission's shut-off policy. RESA further explains that, since the purchase of accounts receivable would not apply to the accounts of mercantile customers, they would not be subject to Rider UE-GEN. (RESA Br. 10-15; RESA Ex. 1 at 10-11.)

Dominion echoes many of the same concerns articulated by RESA and argues that, if adopted as proposed, Rider UE-GEN would create a scenario wherein Duke would be able to recover the distribution component of customer bad debt, but there would exist no mechanism for the recovery of the generation component of shopping customer bad debt. Therefore, Dominion argues that Duke's Rider UE-GEN should be unavoidable, so that SSO customers are not subsidizing shopping customers and all bad debt is being uniformly recovered. Dominion explains that, as observed by Duke witness Ziolkowski, if Duke's UEX rider applies to the generation component of defaulting shopping customers' arrearages and is unavoidable, there would be no need for the traditional discount under which Duke purchases accounts receivable from CRES providers. Accordingly, Dominion suggests that Duke be allowed to implement Rider UE-GEN as an unavoidable rider to allow for recovery of the UEX generation arrearages of defaulting customers. (Dominion Br. at 9-12.)

Dominion also argues, similar to RESA, that there is no legal prohibition on Duke that prevents the creation of Rider UE-GEN. Specifically, Dominion claims that Duke is not precluded from establishing a rider for UEX because it is not expressly listed in Section 4928.142(D), Revised Code. Dominion contends that, although Section 4928.142(D), Revised Code, does identify four circumstances in which the ESP price piece of the blended SSO price can be adjusted, the permitted adjustments all relate to costs associated with the production of the electricity generated or otherwise procured to meet the generation requirements of SSO customers. According to Dominion, this does not mean that the legislature intended to foreclose a utility from recovering incremental increases in bad debt expense associated with the generation component of defaulting customer arrearages. Furthermore, Dominion asserts that, after the blending period ends, Duke will likely not fully recover the billed revenues necessary to meet its payments to the winning bidders in the auction that establishes the SSO price. Therefore, Dominion believes that Duke should be allowed to establish Rider UE-GEN to recover UEX from both shopping customers and nonshopping customers. (Dominion Br. at 11-14.)

In its reply brief, Duke explains that it would agree to make Rider UE-GEN unavoidable such that it recovers bad debt expenses associated with its SSO load and the CRES providers' accounts receivable. Under such a structure, Duke would purchase the accounts receivable of CRES providers at no discount and render payment to said providers on the 20th day following the month in which the billing occurs. This is a similar manner to which Duke handles its natural gas supply. (Duke Reply Br. at 45.)

FES explains that, for electric utilities, Rules 4901:1-21-18(H)(1)(a) through (d), O.A.C., provides that a customer's partial payment is credited in the following order: (1) supplier arrears; (2) utility arrears; (3) current balance for utility; and (4) current balance for supplier. FES notes that the Commission granted Duke a waiver from compliance with this rule; thus finding that, since the company purchased the receivables of competitive retail electric suppliers, Duke could follow the partial payment priority applicable to natural gas companies. For natural gas utilities, FES explains that payment priority is in the following order: (1) utility arrears; (2) current balance of utility; (3) supplier arrears; and (4) current balance for suppliers. Therefore, FES explains that electric suppliers currently must choose from two unworkable options regarding partial payment priority: accept Duke's current partial payment hierarchy, in which suppliers are paid last; or participate in Duke's purchase of accounts receivable (PAR) program, which may be more expensive than the UEX arising from the payment hierarchy. FES advocates that either the waiver should be revoked and Duke should be required to either abide by the partial payment hierarch applicable to all other electric utilities, or Duke should be required to implement a PAR that is fair to electric suppliers. (FES Ex. 3 at 6-8; FES Br. at 19-21.)

In considering the proposed creation of Rider UE-GEN, the Commission is mindful that, as proposed by Dominion and RESA, as an unavoidable rider, Rider UE-GEN furthers state policy by promoting competition. Specifically, if Duke purchases accounts receivable at no discount, this will likely increase CRES providers' usage of Duke's billing service. Additionally, greater access to consolidated billing for CRES providers, without a purchase of accounts receivable discount, creates a level playing field and allows greater freedom for customer shopping without undergoing a second credit evaluation by a CRES provider, thus promoting shopping among low-income consumers. Therefore, the Commission would support the creation of Rider UE-GEN as an unavoidable rider, designed to recover bad debt associated with customers taking generation service through the SSO and from CRES providers. Moreover, the Commission recognizes that if Duke recovered Rider UE-GEN consistent with the process set forth by Duke in its reply brief, it would resolve any issues regarding Duke's PAR.

3. Rider SCR

Duke's proposed supplier cost reconciliation rider (Rider SCR) provides a means for Duke to ensure that it recovers the exact cost of acquiring the portion of the load served by the winning auction bidders from nonshopping customers. Duke explains that the auction price ultimately billed to customers in the blending process will have been converted into different rates for certain customer classes based on various factors. Therefore, Duke will likely recover more or less revenue from customers attributable to the bidders' share of the SSO price than it will owe the bidders and proposes to use Rider SCR as a true-up mechanism. (Duke Ex. 17 at 8-9.)

Rider SCR will also be utilized to recover the costs associated with conducting, administering, and implementing the CBP plan, as well as the costs for any independent auction consultants. In relationship to the costs of CBP plan, Rider SCR will also recover any costs that Duke incurs in supplying load as a result of supplier default that are not otherwise recovered by the MSSOA. (Duke Ex. 17 at 9.)

Duke explains that, although Rider SCR is designed to be avoidable for customers taking generation service from a CRES provider, because of the nature of Rider SCR and how it could alter the PTC, Duke proposes to include a "circuit breaker" provision that would preclude a situation wherein the amount to be recovered under Rider SCR becomes so large that it drives up the SSO price and encourages additional customer switching. In that case, Duke posits that there would be fewer customers and less load in succeeding billing periods to recover the SCR deferral balance, causing Rider SCR rates to continue to increase while customers continued to switch to CRES providers. Accordingly, Duke proposes making Rider SCR unavoidable if the deferral balances exceed five percent of the actual cost of supplying generation service to the portion of system load served through the SSO. However, when the accumulated balance of the over- or underrecovery falls back below the five percent threshold for two consecutive quarters, Rider SCR will again be avoidable. For the purposes of this provision, Duke defines the actual cost of serving the SSO load as the sum of Rider GEN and Rider MRO revenues for a given quarter. In support of its proposed structure for Rider SCR, Duke asserts that the Commission approved a similar rider in the *FirstEnergy 10-388 case*. (Duke Ex. 17 at 9-10; Duke Ex. 16, 20.)

Duke witness Wathen explains, with regard to the necessity of Rider SCR, that, if all SSO customers were to pay exactly the same price per MWh for the bidders' share of their SSO load, there would be no need to reconcile the revenue and the cost for the auctioned load. However, because the dollar per MWh price received in the auction for the share of SSO load provided by the winning bidders will be converted into different rates for certain customer classes based on differences in loss factors and seasonality differences, this makes it unlikely that Duke will accurately recover from customers the price that it owes bidders. Therefore, Duke asserts that Rider SCR is only intended as a mechanism to make Duke, suppliers, and customers whole. (Duke Ex. 16 at 18-20.)

Staff supports the creation of Rider SCR with some modification. First, Staff states that it is not in favor of the "circuit breaker" concept proposed by Duke. Staff believes that Rider SCR should be fully avoidable under the MRO. In support of its position, Staff claims that, by allowing Duke to make Rider SCR unavoidable, even under limited circumstances, the Commission would be allowing Duke to shift business risks away from itself onto shopping customers. Second, Staff also contends that it does not support the inclusion of any undefined costs in Rider SCR, such as the costs Duke defines as "any other costs" directly attributable to the MRO auction or any interaction with suppliers related to the MRO auction. In essence, Staff voices concern over approving any undefined costs or authorizations that could amount to a blank check for Duke to recover costs. Third, Staff opposes any authorization of Duke to accrue carrying charges on proposed Rider SCR. Staff articulates its belief that any amounts flowing through Rider SCR will be relatively small and, therefore, carrying charges are not warranted for proposed Rider SCR. With respect to Staff's review of Rider SCR, Staff believes that charges/credits flowing through proposed Rider SCR will be minimal. Therefore, it does not believe that an annual prudence review is necessary. Rather, Staff asserts that it should be able to review proposed Rider SCR costs at its discretion and open a proceeding if warranted. With the foregoing modifications, Staff recommends approving Rider SCR. (Staff Ex. 1 at 8; Staff Br. at 19-20.) OPAE, IEU, Dominion, Constellation, and OMA aver that the Commission should adopt Staff's recommendations to modify Rider SCR (OPAE Br. at 10; Constellation Br. at 18; OMA Reply Br. at 7; Dominion Br. at 17; IEU Br. at 16-17).

OCC claims that the Commission should reject Duke's proposed "circuit breaker" provision that may result in Rider SCR becoming unavoidable. In support of its position, OCC points out that shopping customers receive no benefit from Rider SCR and have no relation to any of the costs Duke incurs in Rider SCR. Moreover, OCC argues that collecting Rider SCR from shopping customers is anticompetitive, in that it makes shopping customers pay for the same generation costs twice, once from its CRES provider and once from Duke. OCC contends that this double payment potential discourages shopping and is contrary to the state's policies as set forth in Section 4928.02, Revised Code. (OCC Br. at 43.)

Wal-Mart also opposes any plan to make Rider SCR unavoidable under any circumstances. Wal-Mart explains that making Rider SCR unavoidable inappropriately shifts risks that Duke, as a generation provider, faces in a competitive environment, to customers who have chosen to take generation from a CRES provider and also inappropriately makes shopping customers responsible for SSO-related competitive bidding and independent auction consultant costs. Accordingly, Wal-Mart proposes that the Commission reject Rider SCR, as proposed by Duke. However, if the Commission determines that Rider SCR should be approved, Wal-Mart suggests that the Commission should also determine that the rider is completely avoidable by competitively supplied customers under all conditions. (Wal-Mart Br. at 7-9.)

RESA asserts that, if the Commission is going to allow Rider SCR to become unavoidable, such a change should occur only upon approval by the Commission following a filing that demonstrated the threshold had been exceeded for two consecutive quarters. Moreover, RESA avers that the threshold for nonbypassability should be 10 percent, not five percent as proposed by Duke. Further, RESA suggests that Duke should be required to track and file the actual target percentage each quarter to ensure that any transitions from avoidable to unavoidable status is smooth and anticipated, as opposed to frequent, unpredictable transitions that reduce price stability for customers. (RESA Br. at 4-5.)

The Commission finds that the creation of Rider SCR, could not be approved, as proposed. Although Duke may wish to ensure that it recovers the exact cost of acquiring the portion of the load served by the winning auction bidders from nonshopping customers and recovers costs associated with conducting, administering, and implementing the CBP plan, as well as the costs for any independent auction consultants, the Commission agrees with the concerns put forth by Staff and believes that, if Duke wishes to pass "any other costs," Duke must specify what those costs are. With respect to carrying charges, the Commission does not believe that Duke should be permitted to accrue carrying charges on any under- or overrecovery flowing through Rider SCR. Allowing for the accrual of carrying charges provides an incorrect incentive with regard to accurate billing of customers.

In considering Duke's request to include a "circuit breaker" provision in Rider SCR, the Commission does not believe that such a provision would advance the policy of the state as articulated in Section 4928.02, Revised Code. Specifically, Section 4928.02(H), Revised Code, provides that it is the policy of the state to avoid anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service and vice versa. If Duke were permitted to recover the costs included in Rider SCR from shopping customers, under any circumstances, we believe that it would create an anticompetitive subsidy. Moreover, the ability to recover unlimited costs associated with

Duke's administration of its CBP process provides Duke no incentive to minimize costs incurred in the auction process. Finally, although Duke correctly points out that the Commission approved a stipulation allowing a similar circuit breaker in the *FirstEnergy 10-388 case*, the Commission reminds Duke that such a provision was part of a stipulation proposed by the parties and, moreover, was approved in the context of an ESP application, not an MRO application. Accordingly, the Commission does not believe that Rider SCR could be approved as a potentially unavoidable charge.

4. Riders GEN, FPP, and EIR

a. Rider GEN

Duke explains that its legacy generation rate will be billed through Rider GEN, which is the mechanism through which the ESP prices are blended into customers' bills to achieve the blend required during the transition from the current SSO to market. For each rate schedule listed in Rider GEN, the prices reflect the sum of base generation, Rider PTC-FPP, Rider PTC-AAC, Rider SRA-CD, and Rider SRA-SRT as of December 2011. Accordingly, for January 1, 2012 through May 31, 2013, these rates will be 90 percent of the December 2011 generation rates. For June 1, 2013 through May 31, 2014, the rates will be 80 percent of the December 2011 generation rates under Duke's proposed plan. The rates contained in Rider GEN will be applied consistent with each customer's normal billing determinants in accordance with existing practices. Rider GEN will be fully avoidable for customers taking generation service from a CRES provider and if the Commission adopts Duke's two-year blending proposal, Rider GEN rates are proposed to be frozen during the first two years of Duke's proposed MRO. (Duke Ex. 17 at 6.)

Staff argues that it should be able to review Rider GEN rates before they go into effect. Therefore, Staff contends that Duke should be required to submit to Staff, at least 20 business days before adjusting and/or docketing the tariffs of proposed Rider GEN, its calculations and assumptions. (Staff Br. at 26.) OPAE agrees with Staff's recommendations regarding Rider GEN (OPAE Br. at 13).

GCHC and Eagle argue that allowing Duke to freeze Rider GEN may result in greater benefits accruing to Duke than customers. In support of its assertion, GCHC and Eagle state that Duke's proposal to incorporate its fourth quarter rates into base generation rates may not be representative of rates over the long term and, as much is it may result in customers paying lower rates than if rates were adjusted, freezing rates may also result in consumers paying higher rates than if Duke did not freeze these rates. (GCHC Br. at 16.)

FES argues that the Commission should order Duke to utilize an average of the prior eight quarters to set the PTC-FPP component of Rider GEN, as opposed to utilizing only the rate in effect in December 2011. FES explains that, during the first two years of the proposed MRO, Rider GEN will be the main driver of Duke's generation price, comprising 90 percent of the price during the first year and 80 percent of the price during the second year. During both of those years, FES claims that approximately 44 percent of that price will be comprised of Rider PTC-FPP charges. Rider PTC-FPP charges have been volatile, according to FES, and that volatility has been mitigated by the quarterly update of the charge. However, under Duke's proposal, the Rider PTC-FPP charge would be frozen as of December 2011, and will remain at that level through May 2014. FES asserts that, if at the time of the freeze, Rider PTC-FPP levels are at unusually high or low levels, Duke customers will feel the effects for years. An unusually low Rider PTC-FPP price will result in an unusually low PTC which decreases the ability of CRES providers to offer savings that would encourage shopping. By contrast, FES avers that an unusually high Rider PTC-FPP price would result in an elevated PTC leading to more shopping but higher prices for nonshopping customers. Accordingly, FES proposes that the Commission order Duke to incorporate into Rider GEN the average of the last eight quarter prices for Rider PTC-FPP because using an average will mitigate any extreme fluctuations. (FES Br. at 15-16; FES Ex. 3 at 5.)

b. Riders FPP and EIR

Duke asserts that Rider FPP should be created to recover incremental fuel and purchased power costs above those costs that are implicitly recovered in the frozen Rider GEN rates. In its application, Duke explains that it also will establish Rider EIR to recover incremental environmental costs above those environmental costs that are implicitly recovered in the frozen Rider GEN rates. (Duke Ex. 17 at 12.)

If the Commission approves Duke's blending period as proposed in its application, Duke proposes freezing Riders FPP and EIR for the 29 months that less than 100 percent of its load is supplied via the auction process. Should the Commission disapprove Duke's proposed 29-month blending period, Duke asserts that it will not freeze the rates of Riders FPP and EIR, but will instead seek to recover costs that are incremental to those costs included in the frozen Rider GEN rates. If it becomes necessary for Duke to make adjustments to these rates, it will make quarterly filings to adjust Riders FPP and EIR. Duke explains that, because Rider FPP would only reflect Duke's share of resources used to provide SSO service, it would not be subject to the blending percentages, but instead, would be an avoidable charge that would be added to the blended SSO price. Similarly, Rider EIR would also be updated quarterly. (Duke Ex. 16 at 16-17.)

Staff argues that proposed Rider FPP should not be continued during any blending period and the placeholder for proposed Rider EIR should not be created. Staff asserts that, from Duke's application, the earliest these riders would be used is June 1, 2014, therefore, Duke should make a separate application to the Commission, if necessary, to create Riders FPP and EIR based on any final order granting the MRO blending period.

However, Staff also states that, should the Commission approve the creation of Riders FPP and EIR, either Staff or an outside auditor needs the ability to audit in separate proceedings all costs to ensure those costs are warranted and prudent. (Staff Ex. 1 at 12; Staff Br. at 21-22.) OPAE agrees with Staff's recommendations regarding Riders FPP and EIR (OPAE Br. at 11).

RESA requests clarification, through the Commission order, that Rider EIR is avoidable for shopping customers. In support of its belief that Rider EIR should be avoidable, RESA explains that Rider EIR collects environmental costs that are associated with generation and, therefore, should not be collectable from shopping customers. (RESA Br. 3.) Similarly, Constellation believes that the Commission should required Rider EIR to be fully avoidable for shopping customers (Constellation Br. at 17).

c. Conclusion Riders GEN, FPP, and EIR

At this time, the Commission is unclear regarding how the creation of Riders EIR and FPP will effect the rates to be collected as part of Rider GEN. Accordingly, should Duke file another application for an MRO, Duke is directed to clarify whether Rider GEN will fluctuate throughout the blending period, or whether Duke intends to freeze Rider GEN regardless of the blending period and seeks to recover through Riders EIR and FPP any incremental costs. In addition, Duke must demonstrate why it needs up to four riders (Riders EIR, RECON, FPP, and GEN) to incorporate, true-up, and reconcile the ESP price that will be blended into customer bills. The Commission believes that there should be a simpler was to achieve this goal. Therefore, Duke must show that any proposed adjustment or freezing of rates to recover known and measurable costs is reasonable, beyond an annual true-up of the amounts collected.

5. Rider MRO

Duke's market price portion of its blended SSO price will be applied through Rider MRO, which will be comprised of the auction prices after conversion to retail prices for each rate schedule. Accordingly, based on Duke's proposed blending schedule, the market price for the first year will be the retail auction price multiplied by 10 percent, and for the second year, will be the retail auction price multiplied by 20 percent. Beginning in year three, the retail auction will be the only source of the SSO price. The capacity and energy charges shown in Rider MRO will be applied to each customer's normal kWh billing determinants in accordance with existing practices. Rider MRO will be fully avoidable from customers taking generation service from a CRES provider. (Duke Ex. 17 at 7.)

Staff argues that Duke should be required to submit to Staff, at least 20 business days before adjusting and/or docketing the tariffs of proposed Rider MRO, its calculations and assumptions on how wholesale auction rates were translated into retail rates (Staff Br. at 26). OPAE agrees with Staff's recommendations regarding Rider MRO (OPAE Br. at 13).

Subject to the recommendations of Staff regarding its review, the Commission would approve the creation and recovery of the auction price through Rider MRO, under the construct of an approved MRO application.

6. Rider AER

Duke proposes the creation of Rider AER to recover its costs of complying with Ohio's alternative energy statutes. Duke avers that Rider AER will be an avoidable rider to recover the costs of the RECs associated with Duke's SSO load, and will be adjusted quarterly, including true-ups. (Duke Ex. 17 at 12; Duke Ex. 16 at 21.)

Staff asserts that costs incurred through any automatic quarterly adjustments, such as those proposed herein, should be reviewed in separate annual proceedings outside of the automatic recovery provision contained in Duke's MRO. Accordingly, Staff believes that the process and timeframes for these separate proceedings should be set by order of the Commission. (Staff Br. at 22.) OPAE agrees with Staff's recommendations regarding Rider AER (OPAE Br. at 11).

Under an appropriately structured MRO, subject to the modifications proposed by Staff, the Commission would approve the creation of Rider AER to recover alternative energy compliance costs. In approving Rider AER, the Commission would seek to subject the rider to annual review proceedings, which would be formulated as part of the order approving an appropriately structured MRO.

7. Transmission Cost Riders

We cannot address Duke's RTO membership, or its proposed transmission riders, without discussing some of the background regarding Duke's proposed movement from the Midwest ISO to PJM. In its application, Duke explains that it is expecting to be fully integrated into PJM by January 1, 2012, to coincide with the proposed effective date of this application. Duke avers that it has received preliminary FERC approval of its transition. Duke witness Jennings identifies three benefits, perceived by Duke, of joining PJM: (a) the joint ownership with PJM utilities of some of Duke's generation assets; (b) the benefit of all utilities in Ohio being a member of a single RTO; and (c) the benefit of PJM's forward-capacity market. (Duke Ex. 12 at 4, 21-22.)

Duke witness Jennings also explains the financial obligations that are connected with Duke's withdrawal from the Midwest ISO. First, the Midwest ISO will assess an exit fee upon Duke. Second, Duke will be obligated to pay its allocated portion of the MISO Transmission Expansion Plan (MTEP) fees for those transmission expansion projects approved when Duke was a Midwest ISO member. In addition, when Duke joins PJM, it will incur regional transmission expansion planning process (RTEPP) costs for projects currently underway in PJM, and projects going forward. In addition, Duke will also be allocated some of the costs incurred by PJM for the integration of Duke's transmission assets into PJM, as well as the allocated share of the ongoing PJM administrative fees. Duke seeks to recover these costs, along with other transmission-related costs, through riders proposed in this application. (Duke Ex. 12 at 9, 11.)

a. Rider BTR

Duke explains that its Rider BTR will be an unavoidable rider that recovers NITS costs and certain other costs billed to Duke under FERC-approved tariffs. Specifically, Rider BTR would also include all costs billed from either PJM or the Midwest ISO under FERC-approved tariffs except those costs billed from either RTO that are recovered under other riders. Duke witness Wathen testified that Rider BTR would include transmission expansion planning costs, either MTEP, RTEPP, or both, which are currently included in Duke's transmission cost recovery rider (Rider TCR). As proposed, Rider BTR will be updated in approximately June of each year. The update of Rider BTR will also include a reconciliation of the difference between costs actually billed by the RTOs and the revenue collected from consumers. (Duke Ex. 3 at 37; Duke Ex. 17 at 11; Duke Ex. 16 at 23-24.)

According to Duke, NITS costs were traditionally recovered from nonshopping customers via its Rider TCR and CRES providers effectively reimbursed Duke for their use of the transmission system to provide competitive retail service to their customers. Under Duke's proposed Rider BTR, Duke will recover its NITS revenue requirement directly from all customers, regardless of whether they are shopping or nonshopping customers. According to Duke, this would benefit CRES providers and auction participants because they would not have the obligation to recover NITS costs. Moreover, according to Duke, this will keep Duke's SSO price a true PTC, because it will exclusively be a generation price, rather than a combined generation and transmission rate. (Duke Ex. 16 at 22-23.)

With respect to the pass through of FERC-approved costs through Rider BTR, Duke claims that, in the stipulation approved in the *FirstEnergy 10-388 case,* staff opined that transmission costs approved by FERC are to be automatically passed on to the consumer. It appears that Duke relies on this statement to assert that the Commission has no discretion regarding the pass-through of these costs. Accordingly, it appears that Duke would attempt to pass MTEP and RTEPP costs, as well as RTO entrance and exit fees, on to customers through Rider BTR. (Duke Ex. 16 at 22-25.)

Staff supports the creation of Rider BTR on an unavoidable basis to recover the NITS revenue requirement and, similar to current Rider TCR, to be updated yearly, consistent with Rule 4901:1-36, O.A.C., subject to Staff review and audit. However, Staff recommends that any decisions regarding the appropriateness of future Midwest ISO exit fees, PJM entrance fees, and RTEP costs for inclusion in Rider BTR should be the subject of future Commission proceedings and should not be decided as part of the Commission's decision regarding Duke's MRO application. (Staff Br. at 23-25.)

OPAE asserts, and OCC agrees, that the Commission should adopt the recommendations of OEG witness Baron and Staff witness Turkenton and reject Rider BTR and require Duke to re-file its request for this Rider BTR in a separate proceeding. (OEG Ex. 1 at 23; Staff Ex. at 14-15.) Accordingly, OPAE argues that the issues raised by the creation of Rider BTR involve costs that are not fully determined yet and Duke is not seeking approval of the costs to be included in Rider BTR; therefore, the creation of Rider BTR should be addressed in another, separate proceeding. (OPAE Br. at 12-13; OCC Br. at 29.)

Eagle argues that any RTO transition costs recovered by Duke should be fully avoidable because Duke has caused these costs to be incurred through a unilateral business decision to change RTOs. Therefore, Eagle asserts that Duke should bear those costs and customers should be protected from those costs to the maximum extent possible. (Eagle Br. at 3-4.)

RESA recommends that the Commission adopt Rider BTR, as proposed in Duke's application, because it ensures that RTO transition costs will be applied neutrally and will create efficient and reliable customer pricing. Moreover, RESA believes that structuring cost recovery through Rider BTR will have the effect of allowing customers to easily compare costs because they will only be shopping for generation costs, not a combination of generation and transmission costs. (RESA Br. at 15-17.)

In response to the concerns articulated regarding Rider BTR, RESA claims that no party has expressed any objections to the structure of Rider BTR and, instead, parties have only objected to the potential transmission costs which may be passed through the rider. RESA asserts that the structure of Rider BTR encourages price transparency by charging all customers, whether shopping or nonshopping, NITS charges directly. Accordingly, RESA contends that the structure of Rider BTR allows both the SSO price and the price offered by CRES providers to reflect solely a generation price, and not a generation and transmission price. Therefore, RESA concludes that the Commission should approve Rider BTR, but specifically set the amount of costs to be recovered for a separate hearing, with the Commission retaining jurisdiction to consider the appropriateness of costs. (RESA Reply Br. at 7-9.)

b. Rider RTO

Duke's Rider RTO is an avoidable rider that recovers FERC-approved RTO costs billed to Duke by the RTO for Duke's share of SSO load. Duke submits that these costs are incurred in proportion to the SSO load and, therefore, Rider RTO will not apply to customers taking generation service from a CRES provider. Costs proposed to be recovered through Rider RTO include administrative fees, ancillary services, revenue sufficiency guarantees, etc., and the Midwest ISO's Transmission and Energy Markets Tariff (TEMT) or PJM's Open Access Transmission Tariff (PJM Tariff). (Duke Ex. 3 at 37; Duke Ex. 16 at 26; Duke Ex. 17 at 12.)

Duke's rationale for establishing the separate Rider RTO from Rider BTR is so that costs recovered based on SSO load are avoidable through Rider RTO, whereas costs that are not based on load are part of the unavoidable Rider BTR. Rider RTO, as proposed, will be trued up annually, around June of each year. (Duke Ex. 3 at 37; Duke Ex. 16 at 26; Duke Ex. 17 at 12.)

OPAE and Staff assert that Rider RTO should be subject to a yearly Staff review and audit, similar to Rider TCR (OPAE Br. at 13; Staff Br. at 25).

c. General Comments

Because, as proposed by Duke, both Riders BTR and RTO contain costs that must be approved by FERC, in conjunction with Duke's migration from MISO to PJM, arguments relating to those costs, as well as the uncertainty as to the amounts of those costs that can be approved will be addressed concurrently for both riders.

OCC's first concern regarding Riders BTR and RTO is the structure of the tariff language. The current tariff language for Rider TCR contains language that requires both Commission and FERC approval to pass through transmission costs to customers. According to OCC, the current proposed tariff language for Rider BTR only requires FERC approval of costs to be included in the rider. The proposed tariff does not contain language requiring Commission approval of costs. OCC points out that Duke witness Ziolkowski confirmed this interpretation of the language at the evidentiary hearing. In addition, OCC points out that the proposed tariff language for Rider RTO only requires FERC approval of cost recovery. OCC argues that the Commission should not waive or forego its jurisdiction to review the types of costs included in Rider BTR or Rider RTO by approving tariff language that does not explicitly acknowledge the Commission's review authority. (OCC Br. at 21-24.)

OCC also asserts that the Commission should not waive its authority to review the recoverability of costs resulting from Duke's business decision to join PJM by approving tariff language in this proceeding. In support of its position, OCC submits that Duke's decision to move to PJM could result in significant costs, and Duke has not demonstrated that its customers will benefit from its business decision to move from the Midwest ISO to PJM. Therefore, OCC opines that the Commission should not make any decisions that could be construed to waive its review of Duke's decision-making by approving Rider BTR, and its cost recovery, as proposed. (OCC Br. at 21-23; Duke Ex. 17 at Att. JEZ-2 at 86.)

In support of its assertion that the Commission should review all transmission-related costs, OCC cites Section 4928.05, Revised Code, which provides that the Commission has "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." OCC argues this gives the Commission the ability to review transmission costs incurred by Duke prior to passing those costs through to customers. Moreover, OCC submits that Rule 4901:1-36-03, O.A.C., specifically provides that the Commission can undertake prudence or financial review of the costs incurred and sought to be recovered by a utility through a transmission cost recovery rider. (OCC Br. at 23-25.)

In further support of its claims that the Commission should review any FERC-approved costs Duke intends to pass through to customers, OCC asserts that the *Pike County* doctrine[4] provides support for its position. Specifically, OCC argues that FERC has cited *Pike County* to stand for the proposition that a state commission may review a company's choice between two FERC-approved rates. Therefore, OCC asserts that *Pike County* provides additional support for its position that this Commission could review the prudence of Duke's decision to move to PJM and impose the financial impacts of that decision on its customers. (OCC Br. at 25-27.)

Therefore, OCC recommends that the Commission defer a ruling on the recoverability of the costs resulting from Duke's decision to move to PJM. OCC avers that the 90-day timeline for Commission consideration of an MRO application does not lend itself to the kind of review necessary to review Duke's decision to PJM and the imposition of those costs on Duke's customers. Moreover, any costs incurred in Duke's migration from the Midwest ISO to PJM are, at best, uncertain at the current time given FERC's conditional approval of the move and FERC's statement that Duke's recovery of RTO realignment cost recovery has not been determined. (OCC Br. at 28-33.)

4 *Pike County Light & Power Co. v. Penn. Pub. Util. Comm'n, 465 A.2d 735 (Pa. Commw. Ct 1983).*

Eagle and GCHC join in OCC's argument that, although Duke states that it is not seeking a prudence review of costs incurred in conjunction with its proposed RTO realignment, what Duke is seeking to do is remove any role for the Commission in approving the recoverability of these costs in any proceeding. Eagle and GCHC point out that the level of competition currently experienced in Duke's territory has been cultivated while Duke is a transmission owner in the Midwest ISO; therefore, Eagle suggests that the Commission should assure that the same, or similar level of competition will continue after Duke joins PJM. Accordingly, Eagle asserts that the Commission should not simply accept Duke's assertion that the market will be equally competitive in PJM, but should take steps to ensure that competition is not harmed by the transition prior to approving the MRO. Eagle suggests that the Commission should required Duke to put the Midwest ISO market participants in a competitively neutral position compared with what exists today, so that Duke cannot use existing competition to justify an MRO, while at the same time impair competition through its RTO realignment. Eagle and GCHC, therefore, recommend that the Commission reject Riders BTR and RTO at this time. (Eagle Br. at 2-3, 20.) OEG agrees with GCHC and Eagle that a prudence review is premature at this point, but that the Commission should reject Duke's proposed tariff language lest it foreclose a future prudence review. (OEG Br. at 19-21.)

Similarly, OEG asserts that Duke's decision to move from the Midwest ISO to PJM was a unilateral decision that may not be reasonable and in the best interests of its customers. Therefore, OEG believes that Duke's decision raises issues, with regard to prudence, that may justify the Commission disallowing recovery of some or all the Midwest ISO exit fees or MTEP charges from ratepayers. OEG asserts that, to date, none of the benefits of joining PJM have been quantified for comparison with the costs of the withdrawal from the Midwest ISO. Therefore, OEG believes that the Commission should have the opportunity to conduct a review, consistent with *Pike County,* regarding Duke's decision to realign. Accordingly, OEG recommends that the Commission should adopt the recommendations of OEG witness Baron and reject Riders RTO and BTR and require Duke to refile its request for these Riders in a separate proceeding. OEG further asserts that the Commission should not approve the manner in which Duke proposes that the amounts of Riders BTR and RTO would be established. (OEG Ex. 1 at 23; OEG Br. at 12-15.)

OEG argues that all riders that collect the costs of obtaining generation service must be fully avoidable. Specifically, OEG asserts that, with the exception of Riders BTR and RTO, all of Duke's proposed riders involve the recovery of costs associated with generation. According to OEG, state energy policy set forth in Section 4928.02, Revised Code, specifically addresses cross-subsidization of regulated and nonregulated service and prohibits public utilities from using revenues from competitive generation service components to subsidize the cost of providing noncompetitive distribution service, or vice versa. OEG contends that Riders BTR and RTO should not be approved due to concerns over cross-subsidization. (OEG Br. at 16-19.)

In considering Duke's RTO transition, Constellation asserts that two uncertainties need to be addressed by Duke. First, Constellation points out that the capacity charge which Duke will charge suppliers who use Duke capacity in order to supply retail customers in the Duke service area is undefined. Second, Constellation points out that there are many outstanding issues regarding Duke's move to PJM. Specifically, Constellation explains that the Midwest ISO will charge Duke an exit fee, Duke will continue to be responsible for MTEP charges authorized while it was a member of the Midwest ISO, and Duke will begin paying RTEP charges in PJM. In response to this uncertainty, Constellation explains that the Commission should approve the basic tariff structure that Duke proposes for recovery of transmission costs and should clearly state, in approving the tariff structure, that it is not making any determination regarding Duke's ability to collect costs related to its voluntary RTO move. Duke should then, according to Constellation, be required to apply for specific authorization of costs when costs are known. (Constellation Br. at 12- 14.)

In response to Duke, OMA argues that the record is devoid of any explanation by Duke as to how the cost of its move from the Midwest ISO to PJM will effect transmission rates. In effect, OMA believes that the Commission is being asked to approve an MRO when a potentially significant increase in transmission rates remains a possibility, should Duke be allowed to recover MTEP, RTEPP, the Midwest ISO exist fees, and PJM integration fees associated with its transition to PJM from Ohio ratepayers. Moreover, OMA asserts that it is Duke's burden to prove that the transition to PJM will not complicate the CBP process, which OMA argues Duke has not done. Accordingly, OMA contends that the Commission should not allow Duke to recover the costs of its move to PJM, or in the alternative, should defer that judgment to a future proceeding. (OMA Reply Br. at 4-5.)

OMA asserts that Duke's failure to project how its realignment from the Midwest ISO to PJM will impact its transmission rates places Duke's proposed MRO in violation of Rules 4901:1-35-03(B)(2)(b) and (c), O.A.C., because the Commission is left in the position of having to approve a CBP when a potentially significant upward push on rates remains a possibility. OMA asserts that the realignment costs are expected to be in the tens to hundreds of millions of dollars and have the potential to dramatically alter the rates for Duke's retail customers for decades. Further, OMA submits that Duke Kentucky agreed not to seek reimbursement of the cost of its realignment from Kentucky customers. Therefore, OMA asserts that Duke should be prohibited from recovering any of the costs associated with its move from the Midwest ISO to PJM from Ohio ratepayers. (OMA Br. at 6-8.)

IEU also asserts that ratepayers should not be burdened with any of the costs associated with Duke's move from the Midwest ISO to PJM, without a Commission determination that the costs of realignment are proportional to the benefits for ratepayers. Specifically, IEU argues that Duke's application is part of Duke's plan to subsidize Duke's unregulated generation business by transferring control of its transmission assets from the Midwest ISO to PJM for the purpose of enhancing generation revenues. IEU further argues that Duke's distribution customers, under Riders BTR and RTO as proposed in the MRO, would pay the costs of Duke's RTO move while Duke's unregulated generation business and shareholders get the benefits that are created by the RTO move, resulting in the end result of an unlawful subsidy flowing through Duke's riders paid by Duke's customers for the benefit of Duke's unregulated generation business. Therefore, IEU asserts that the Commission should reject Duke's application because it does not comply with state policy contained in Section 4928.02, Revised Code, which requires an SSO to satisfy nondiscrimination and comparability requirements. (IEU Br. at 14-16.)

d. Conclusion Transmission Cost Riders

As an initial matter, the Commission agrees with the concerns of OMA that Duke has not met its burden of proving that the RTO transition will not complicate the auction process. The Commission can envision many scenarios wherein Duke is not in the position it expects to be in, as proposed in its application. Duke has done little to address those concerns. The Commission hopes that, in future filings, Duke will consider whether an MRO is the best option, given that it is in the midst of realigning with the PJM RTO and has not yet determined cost recovery for such a move, either at FERC or with this Commission.

In considering Duke's proposal to establish Riders BTR and RTO, the Commission is mindful of what it believes to be the purpose of an application under Section 4928.142, Revised Code: the setting of generation rates. Duke made an application under this section. Duke did not make an application pursuant to Section 4928.05, Revised Code, which provides, in pertinent part, as follows:

> 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.

The Commission believes that a proper application to recover transmission costs should be made pursuant to Section 4928.05, Revised Code. Accordingly, Riders BTR and RTO would not be approved as part of this application or as part of any MRO application. Moreover, the Commission believes that the General Assembly intended the FERC-approved tariff pass-through contained in Section 4928.05, Revised Code, to include ordinary costs, not extraordinary costs. Therefore, when Duke makes a proper application to this Commission to recover the costs associated with its move from the Midwest ISO to PJM, it will be required to demonstrate that its incurred costs are not extraordinary, and that its decision to move to the PJM RTO was reasonable and prudent, before it can recover any of the costs of its move from ratepayers.

IV. CONCLUSION

Duke has failed to file an application for a five-year MRO, as required by statute, setting forth all of the information necessary in order for the Commission to make a determination; therefore, Duke's application is not an application within the meaning of Section 4928.142, Revised Code. Since the Commission can not consider this filing to be an MRO filing under the statute, we have no choice but to conclude that Duke's application does not meet the requirements of the statute. Since Duke has not presented a complete MRO application, the application is in noncompliance with the statute and this case can not proceed as filed.

FINDINGS OF FACT:

(1) On November 15, 2010, Duke filed an application for an MRO in accordance with Section 4928.142, Revised Code.

(2) On November 22, 2010, a technical conference was held regarding Duke's application and, on December 7, 2010, a prehearing conference was held in this matter.

(3) On September 15, 2008, intervention was granted to IEU, OEG, OPAE, Kroger, OEC, FES, GCHC, Constellation, OCC, DERS, Dominion, Wal-Mart, OMA, RESA, AEP Ohio, AEP Retail, Cincinnati, Eagle, PWC, and OAE.

(4) The hearing commenced on January 4, 2011, and concluded on January 19, 2011.

(5) Briefs and reply briefs were filed on January 27, 2011, and February 3, 2011, respectively.

CONCLUSIONS OF LAW:

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

(2) In its filing, Duke states that it made this filing pursuant to Section 4928.142, Revised Code, which authorizes electric utilities to file an MRO as their SSO, whereby retail electric generation pricing will be based upon the results of a CBP.

(3) Chapter 4928, Revised Code, and Chapter 4901:1-35, O.A.C, set forth the specific requirements that an electric utility must meet in order to demonstrate an MRO application complies with the statute.

(4) Duke failed to file an application for a five-year MRO, as required by statute; therefore, Duke's application is not an application within the meaning of Section 4928.142, Revised Code.

(5) Duke's application is in noncompliance with the statute and this case can not proceed as filed.

(6) The unredacted versions of the following documents should be granted protective treatment for a period of 18 months: Volumes II and III of the transcript, filed under seal on January 13, and 14, 2011, respectively; IEU Exhibits 1 through 10, filed under seal on January 13, 2011; IEU's brief filed under seal on January 27, 2011; and the reply briefs filed by IEU and Duke under seal on February 3, 2011.

ORDER:

It is, therefore,

ORDERED, That Wal-Mart's motion requesting that its brief be accepted as timely filed be granted. It is, further,

ORDERED, That the unredacted versions of Volumes II and III of the transcript, filed under seal on January 13, and 14, 2011, respectively; IEU Exhibits 1 through 10, filed under seal on January 13, 2011; IEU's brief filed under seal on January 27, 2011; and the reply briefs filed by IEU and Duke under seal on February 3, 2011, be granted protective treatment. The docketing division shall maintain these documents under seal for a period of 18 months from the date of this order, or until August 23, 2012. It is, further,

ORDERED, That Duke's filing in this case is in noncompliance with the statute and this case can not proceed as filed. 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

Steven D. Lesser, Chairman

Paul A. Centolella

Valerie A. Lemmie

Cheryl L. Roberto

CMTP/KLS/vrm

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FEB 23 2011

Reneé J. Jenkins
Secretary

Appendix A

AMI	Advanced Metering Infrastructure
Rider AER	Alternative Energy Recovery Rider
AER	Alternative Energy Resource
Rider BTR	Base Transmission Rider
CP	Coincident Peaks
CBP	Competitive Bid Process
CRES	Competitive Retail Electric Service
CRA	CRA International, Inc. d/b/a Charles Rivers Associates
DSM	Demand-Side Management
ED	Electric Distribution
ESP	Electric Security Plan
EIR	Environmental Investment Rider
FERC	Federal Energy Regulatory Commission
FPP	Fuel and Purchased Power
ICR	Independent Credit Requirement
ICE	Intercontinental Exchange
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
Rider LMR	Load Management Rider
LMP	Locational Marginal Price
MRO	Market Rate Offer
MtM	Mark-to-Market
MSSOA	Master Standard Service Offer Agreement
MW	Megawatt
MWh	Megawatt Hour
Midwest ISO	Midwest Independent Systems Operator
MTEP	Midwest ISO Transmission Expansion Plan
TEMT	Midwest ISO's Transmission and Energy Markets Tariff
NITS	Network Integration Transmission Service
NSPL	Network Service Peak Load
O.A.C.	Ohio Administrative Code
PJM	PJM Interconnection
PJM Tariff	PJM's Open Access Transmission Tariff
PTC	Price-to-Compare
POLR	Provider of Last Resort
PAR	Purchase of Accounts Receivable

PPA	Purchased Power Agreement
Rate CPP	Rate Critical Peak Pricing
Rate RTP	Rate Real Time Pricing
RTEPP	Regional Transmission Expansion Planning Process
RTO	Regional Transmission Organization
RPM	Reliability Pricing Model
REC	Renewable Energy Credit
RFP	Request for Proposals
SER	Solar Energy Resource
SREC	Solar Renewable Energy Credit
SSO	Standard Service Offer
SSOGC	Standard Service Offer Generation Charge
Rider SCR	Supplier Cost Reconciliation Rider
SRT	System Reliability Tracker
SRA	System Resource Adequacy
TDP	Time-Differentiated Pricing
Rider TCR	Transmission Cost Recovery Rider
UEX	Uncollectible Expense