BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of Application of Duke Energy Ohio, Inc. for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan, Accounting Modifications, and Tariffs for Generation Service.	))))))	Case No. 14-841-EL-SSO
In the Matter of Application of Duke Energy Ohio, Inc. for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20.	))))	Case No. 14-842-EL-ATA

OPINION AND ORDER

The Public Utilities Commission of Ohio, having considered the above-entitled application, the applicable law, and the record in these proceedings, and being otherwise fully advised, hereby issues its Opinion and Order.

APPEARANCES:

Amy B. Spiller, Deputy General Counsel, and Elizabeth H. Watts, Rocco O. D'Ascenzo, and Jeanne W. Kingery, Associate General Counsel, 139 East Fourth Street, 1303-Main, Cincinnati, Ohio 45202, on behalf of Duke Energy Ohio, Inc.

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

McNees, Wallace & Nurick, LLC, by Samuel C. Randazzo, Frank P. Darr, and Matthew R. Pritchard, 21 East State Street, 17th Floor, Columbus, Ohio 43215, on behalf of Industrial Energy Users-Ohio.

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

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

Carpenter Lipps & Leland LLP, by Rebecca L. Hussey, 280 North High Street, Suite 1300, Columbus, Ohio 43215, on behalf of The Kroger Company.

Trent A. Dougherty, 1207 Grandview Avenue, Suite 201, Columbus, Ohio 43212, on behalf of Ohio Environmental Council.

Mark A. Hayden, Jacob A. McDermott, and Scott J. Casto, FirstEnergy Service Company, 76 South Main Street, Akron, Ohio 44308, on behalf of FirstEnergy Solutions Corporation.

Douglas E. Hart, 441 Vine Street, Suite 4192, Cincinnati, Ohio 45202, on behalf of The Greater Cincinnati Health Council.

Bruce J. Weston, Ohio Consumers' Counsel, by Maureen R. Grady and Joseph P. Serio, Assistant Consumers' Counsel, 10 West Broad Street, Suite 1800, Columbus, Ohio 43215, and Bricker & Eckler, LLP, by Dane Stinson and Dylan F. Borchers, 100 South Third

Street, Columbus, Ohio 43215, on behalf of the residential utility customers of Duke Energy Ohio, Inc.

Behrens, Wheeler & Chamberlain, by Rick D. Chamberlain, 6 N.E. 63rd Street, Suite 400, Oklahoma City, Oklahoma 73105, and Roetzel & Andress LPA, by Donald L. Mason and Michael R. Taven, 155 East Broad Street, 12th Floor, Columbus, Ohio 43215, on behalf of Wal-Mart Stores East, LP and Sam's East, Inc.

Carpenter Lipps & Leland LLP, by Kimberly W. Bojko and Jonathan A. Allison, 280 North High Street, Suite 1300, Columbus, Ohio 43215, on behalf of Ohio Manufacturers' Association.

Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff, Michael J. Settineri, and Gretchen L. Petrucci, 52 East Gay Street, Columbus, Ohio 43216, on behalf of Retail Energy Supply Association, and Constellation New Energy, Inc., and Exelon Generation Company, LLC.

Steven T. Nourse, Matthew J. Satterwhite, and Yazen Alami, American Electric Power Service Corporation, 1 Riverside Plaza, 29th Floor, Columbus, Ohio 43215, on behalf of Ohio Power Company.

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

Kegler, Brown, Hill & Ritter LPA, by Andrew J. Sonderman and Margeaux Kimbrough, Capitol Square, Suite 1800, 65 East State Street, Columbus, Ohio 43215, on behalf of People Working Cooperatively, Inc.

Kevin R. Schmidt, 88 East Broad Street, Suite 1770, Columbus, Ohio 43215, on behalf of Energy Professionals of Ohio.

Judi L. Sobecki, 1065 Woodman Drive, Dayton, Ohio 45432, on behalf of The Dayton Power and Light Company.

Joseph Oliker, 6100 Emerald Parkway, Dublin, Ohio 43016, on behalf of Interstate Gas Supply, Inc.

Joseph M. Clark, Direct Energy, 21 East State Street, 19th Floor, Columbus, Ohio 43215, and Eckert, Seamans, Cherin & Mellott, by Gerit F. Hull, 1717 Pennsylvania Avenue, N.W., 12th Floor, Washington, D.C. 20006, on behalf of Direct Energy Services, LLC, and Direct Energy Business, LLC.

Williams, Allwein, and Moser, LLC, by Christopher J. Allwein and Todd M. Williams, 1500 West Third Avenue, Suite 330, Columbus, Ohio 43212, and Tony Mendoza, 85 Second Street, Second Floor, San Francisco, California 94105, on behalf of Sierra Club.

Mike DeWine, Ohio Attorney General, by M. Howard Petricoff, Special Assistant Attorney General, Vorys, Sater, Seymour & Pease, LLP, 52 East Gay Street, Columbus, Ohio 43216, on behalf of Miami University and the University of Cincinnati.

Justin Vickers, 35 East Wacker Drive, Suite 1600, Chicago, Illinois 60601, on behalf of Environmental Law & Policy Center.

Gregory J. Poulos, 471 East Broad Street, Suite 1520, Columbus, Ohio 43054, and Carpenter Lipps & Leland LLP, by Joel E. Sechler, 280 North High Street, Suite 1300, Columbus, Ohio 43215, on behalf of EnerNOC, Inc.

Samantha Williams, 20 North Wacker Drive, Suite 1600, Chicago, Illinois 60606, on behalf of National Resources Defense Council.

Bricker & Eckler, LLP, by Dane Stinson, 100 South Third Street, Columbus, Ohio 43215, on behalf of Ohio Development Services Agency.

OPINION:

I. BACKGROUND

A. History of Proceedings

Duke Energy Ohio, Inc. (Duke or Company) is a public utility as defined in R.C. 4905.02 and, as such, is subject to the jurisdiction of this Commission.

On May 29, 2014, Duke filed an application for a standard service offer (SSO) pursuant to R.C. 4928.141. This application is for an electric security plan (ESP) in accordance with R.C. 4928.143. Duke's current ESP was approved in *In re Duke Energy Ohio, Inc.*, Case No. 11-3549-EL-SSO, et al., Opinion and Order (Nov. 22, 2011) (*ESP 2 Case*) (OMA Ex. 2).

By Entry issued June 6, 2014, the attorney examiner established the procedural schedule in these cases. On June 12, 2014, a technical conference was held regarding Duke's application. By Entry issued August 5, 2014, four local public hearings were scheduled in these matters for September 8, 9, 10, and 18, 2014. Duke submitted proofs of publication for the hearings on October 10, 2014. In total, at the four local public hearings, 27 witnesses testified.

The following entities were granted intervention by Entry dated August 5, 2014: 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. (Constellation) and Exelon Generation Company, LLC (ExGen) (jointly, Exelon); Ohio Consumers' Counsel (OCC); Wal-Mart Stores East, LP and Sam's East, Inc. (Wal-Mart); Ohio Manufacturers' Association (OMA); Retail Energy Supply Association (RESA); Ohio Power Company (AEP); city of Cincinnati (Cincinnati); People Working Cooperatively, Inc. (PWC); Environmental Law & Policy Center (ELPC); EnerNOC, Inc. (EnerNOC); Direct Energy Services, LLC and Direct Energy Business, LLC (Direct Energy); Miami University and The University of Cincinnati (Miami/UC); Natural Resources Defense Council (NRDC); Interstate Gas Supply, Inc. (IGS); Energy Professionals of Ohio (EPO); Dayton Power and Light Company (DP&L); Sierra Club (Sierra), and the Ohio Development Services Agency (ODSA). By Entries issued August 5, 2014, and October 20, 2014, and at the evidentiary hearing on October 28, 2014, the motions for admission pro hac vice on behalf of Samantha Williams, Justin Vickers, Rick D. Chamberlain, Tony G. Mendoza, and Michael J. Castiglione were granted.

The evidentiary hearing was initially scheduled to commence on September 8, 2014, and, by Entry issued August 5, 2014, the evidentiary hearing was rescheduled to October 7, 2014, at the request of some of the parties. Subsequently, at the prehearing conference held on August 12, 2014, the commencement of the evidentiary was rescheduled to October 22, 2014. The evidentiary hearing was held, as rescheduled, on October 22, 2014, through November 12, 2014, with rebuttal on November 20, 2014. Briefs and reply briefs were filed on December 15, 2014, and December 29, 2014, respectively.

B. Procedural Matters

1. Interlocutory Appeal

On September 23, 2014, Duke filed a motion to compel discovery from OCC, stating that OCC refused to provide substantive responses to certain discovery requests, claiming such responses are privileged from discovery under the joint defense or common interest doctrine. Duke explains the discovery requested OCC to identify all communication it has had with any other intervenors and all agreements into which it had entered with other intervenors in these proceedings. Duke argues the joint defense agreement (JDA), which OCC entered with OMA and OPAE, confirms that there is no proper common legal interest; thus, there is no permissible bar from disclosure. Duke submits the common interest that allegedly binds the parties to the JDA of OCC, OMA, and OPAE is administrative efficiency. According to Duke, the common interest doctrine relied on by OCC only extends to identical legal interests and not commercial interests. Duke maintains there is no identical legal interest between OCC, OMA, and OPAE. Duke asserts the information requested is relevant or reasonably calculated to lead to the discovery of admissible evidence; therefore, OCC should be compelled to provide the information.

On September 29, 2014, OCC filed a memorandum contra Duke's September 23, 2014 motion to compel discovery, stating the information requested by Duke does not involve seeking information that goes to the merits of these cases, but only communications between certain intervening parties. The information requested is protected by a JDA and, therefore, OCC argues it is not discoverable. According to OCC, there is overwhelming precedent that supports its position, the parties have a valid common interest, and public policy encourages the broad application of the common interest doctrine. On October 1, 2014, Duke filed a reply to OCC's memorandum contra Duke's September 23, 2014 motion to compel.

By Entry issued October 20, 2014, the attorney examiner, inter alia, granted Duke's motion to compel OCC to provide the documents to the extent the documents requested do not include information reflecting the parties to the JDA's legal strategies in these cases. Accordingly, by noon on Tuesday, October 21, 2014, OCC was required to provide Duke with responses to the discovery requests. In the event OCC claims that some of the documents that are responsive to Duke's discovery request are protected under the agreement because they reflect the signatory parties' legal strategies in these cases, OCC was to provide Duke and the attorney examiner with a privilege log of the information withheld. In addition, OCC was to provide the attorney examiner with the withheld information for an in camera review of the documents.

On October 21, 2014, OCC provided Duke with redacted documents and provided the attorney examiner with the withheld information for the in camera review, as required by the October 20, 2014 ruling (Tr. I at 46). At the hearing on October 22, 2014, OCC argued the redacted information subject to the privilege log reveals legal strategy and, therefore, should be subject to the common interest privilege (Tr. I at 47).

After review of the information provided in the privilege log and consideration of the arguments made by OCC, at the hearing on October 22, 2014, without ruling on the merits of the arguments made by Duke and OCC, the attorney examiner stated that, while at one point in time the information redacted by OCC may very well have been information the parties were discussing regarding how to move forward with a specific pleading, that information is already in the open record. Furthermore, the attorney examiner found that, given this specific situation where the disputed information is already in the open record, there is no need to protect the information, therefore, the information should be turned over to Duke. However, the attorney examiner emphasized that this ruling should not be construed to set any precedent for future proceedings as it is based strictly on the facts of this situation and the information reviewed in these cases. (Tr. I at 47-48.)

Ohio Adm.Code 4901-1-15 provides that any party who is adversely affected may take an immediate interlocutory appeal to the Commission from any oral ruling that grants a motion to compel discovery or denies a motion for a protective order. Any party wishing to take an interlocutory appeal must file the appeal within five days after the ruling is issued.

On October 27, 2014, OCC filed an interlocutory appeal of the attorney examiner's oral ruling at the evidentiary hearing on October 22, 2014. In support of the appeal, OCC asserts it is in the interest of preserving the benefits of JDAs for facilitating consensus-building among parties with like interests and for the efficiencies inherent in joint legal work. According to OCC, the ruling can be interpreted to require OCC to provide discovery documents that are privileged from disclosure under attorney-client and/or trial preparation privilege. OCC maintains reversal of the ruling is necessary to prevent severe prejudice to OCC and others. OCC explains: the attorney-client privilege protects against disclosure of communications between attorney and client; the work-product privilege protects attorneys' work; and the common interest doctrine is an extension of the attorney-client and work product privileges, and permits parties and their counsel to share privileged information without waiving the privileges. In addition, OCC contends the joint defense privilege is an extension of the attorney-client privilege and the attorney work-product privilege. OCC argues the JDA, which was entered into between OCC, OMA, and OPAE, protects the documents at issue in this pleading. To assert the joint defense privilege, a party must show that the information was shared in the course of a joint defense effort, the information was designed to further the efforts, and the privilege has not been waived. OCC offers that the information at issue is numerous emails exchanged by counsel and parties subject to the JDA regarding the filing of a motion to reject Duke's ESP, and regarding the counsels' impression of Duke's motivation and leverage in this litigation. Therefore, the emails consist of attorney opinion work product and attorney-client communications designed to further the parties' efforts pursuant to the JDA and are privileged. Moreover, OCC notes that it has not waived the applicable privileges. OEG, OMA, IEU, and RESA filed letters in support of OCC's interlocutory appeal.

On October 29, 2014, OPAE filed a memorandum contra OCC's appeal, stating that its interests were not explicitly addressed in OCC's appeal filed on October 27, 2014, and requesting the Commission overturn the attorney examiner's ruling. Duke filed a reply to

OPAE's filing stating that, having missed the time for the filing of an interlocutory appeal, OPAE now decides to file a "memorandum contra" that purports to oppose Duke's application for an ESP. Duke submits OPAE exaggerates the attorney examiner's ruling and ignores the attorney examiner's clear directives, as the ruling did not order the discovery of all confidential email communications and does not threaten future collaboration between intervenors. Therefore, Duke asserts OPAE's memorandum contra is barred by the time frames for the filing of an interlocutory appeal and should be dismissed. Upon review of OPAE's filing, it is evident by its wording that OPAE's intent was to essentially file its own interlocutory appeal; however, since it was past the time for the filing of an interlocutory appeal, OPAE termed it a "memorandum contra." Such a pretense is not appropriate and, therefore, the Commission finds that OPAE's memorandum contra should not be considered in our determination of this interlocutory appeal issue.

In its memorandum contra OCC's interlocutory appeal, Duke points out that, despite the attorney examiner's explicit disclaimer of any precedential authority, OCC expresses concern over the impact of the ruling on parties practicing before the Commission. In addition, Duke maintains the joint defense and common interest doctrine privileges do not apply where the confidential information has already been disclosed in public filings. Moreover, Duke asserts that, even if the privileges do attach, they have been waived by communications with counsel outside the purported joint defense group, noting that, among the redacted documents are communications with counsel for IGS, AEP, and Kroger, none of which are signatory parties to the JDA. Therefore, Duke argues the attorney examiner's ruling should be undisturbed because the ruling does not allow Duke to discover any information protected from disclosure that has not already been disclosed.

Initially, the Commission notes that a review of the record in these cases reflects a propensity of the parties to litigate procedural issues, including this issue. The Commission disagrees that there is any harm in the release of the information that is the subject of this interlocutory appeal. Despite the fact that, as noted by the attorney examiner and, in fact, admitted by OCC, the information is contained in the open record in these cases, we will still allow the information to remain under seal. However, this determination should in no way be a reflection on whether or not we agree or disagree with the arguments raised by OCC or Duke on this issue. Rather, in light of the fact that the record is closed in these matters, we are declining to rule on the merits of the parties' arguments.

2. Motions for Protective Order

At the hearing held in these matters, the attorney examiner granted the motions for protective treatment of certain information presented on the record in these dockets in the following documents: Duke Exs. 16A-17A, 21A; OCC Exs. 4A-5A, 7A-8A, 10A-27A, 29A-31A, 39A, 41A, 43A-44A; OEG Ex. 1A; IGS Exs. 4A, 7A-8A, 12A; Sierra Ex. 4A; and OMA Exs. 3A-8A. In addition, the attorney examiner granted the motions for protective treatment of portions of the following transcripts that contained testimony referencing confidential information: III, V-VII, IX-XII, and XV. Finally, on December 15, 2014, IGS, OCC, and Sierra filed briefs under seal, and IGS and Sierra filed motions for protective order.

In reviewing the briefs filed in these cases, it is evident IGS and Sierra did not have the opportunity to collaborate with Duke prior to the filing of the briefs to ensure that only the information granted confidentiality at the hearing would be kept under seal in the briefs. Thus, at this time, the Commission finds that Duke should review the unredacted versions of the briefs filed by IGS and Sierra and provide each of those parties with a revised redacted version that is consistent with the rulings on confidentiality in these cases. Duke should conduct such a review and provide those parties with the revised redacted versions by April 15, 2015. Upon receipt of the revised redacted versions of their briefs, IGS and Sierra shall file the revised redacted versions in these dockets by April 20, 2015.

Upon consideration, the Commission finds that the briefs filed by IGS, Sierra, and OCC should be afforded protective treatment and the attorney examiners' rulings with regard to the motions for protective order for portions of the exhibits and transcripts are affirmed. Ohio Adm.Code 4901-1-24(F) provides that, unless otherwise ordered, protective orders issued pursuant to Ohio Adm.Code 4901-1-24(D) automatically expire after 24 months. Therefore, confidential treatment shall be afforded for a period ending 24 months from the date of this Order or until April 3, 2017. 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 the parties.

3. <u>Disclosure of OVEC Entities</u>

On brief, OCC asserts the attorney examiner erred by preventing disclosure of the identities of entities seeking to transfer their Ohio Valley Electric Corporation (OVEC) generation assets and the entities that denied consent to them, as well as the identities of the entities' representatives communicating regarding such requests. Specifically, OCC points to the attorney examiner's ruling concerning testimony provided by witnesses Brodt and Whitlock, who were called as-on-cross by OCC, and OCC Exs. 10-21, 27, and 44. (OCC Br. at 119-120; Tr. IX at 2528, 2541.) OCC argues that, under R.C. 4905.07 and 4901.12, the information should be open to inspection by interested parties and their attorneys and the documents are public records. OCC notes the Ohio public records laws are to be supported by a strong presumption in favor of disclosure. *State ex rel. Williams v. Cleveland*, 64 Ohio St.3d 544, 597 N.E.2d 147 (1992). OCC continues that Ohio Adm.Code 4901-1-24(D)(1) limits redactions for confidentiality to only information that is essential to prevent disclosure of information that is alleged confidential. However, according to OCC, the attorney examiner unreasonably and unlawfully granted Duke's request to protect the identities of those sponsoring companies and their representatives as confidential trade secret information. OCC points to R.C. 1333.61(D) for the definition of a trade secret, noting the six-factor test used by the Commission in its consideration of this definition. *State ex rel. Plain Dealer v. Ohio Dept. of Ins.*, 80 Ohio St.3d 513, 687 N.E.2d 661 (1997). OCC argues there is no evidence that the information has economic value or otherwise warrants protection as a trade secret. According to OCC, a complete public record on whether Duke made good faith efforts to transfer its OVEC interest is important to consideration of the merits of Duke's proposed Price Stabilization Rider (PSR). Therefore, OCC asserts the Commission should reverse the attorney examiner's ruling. (OCC Br. at 121-123.)

The Commission finds OCC's argument to be without merit. Initially, we note the ruling objected to by OCC occurred on the tenth day of hearing in these cases. We are confident that, by this point in the proceedings, the attorney examiner was vastly familiar with the evidentiary record and was ensuring that only minimal information that warranted protective treatment was consistently treated as such. Attorney examiners have discretion in determining, in keeping with the statute and the rules, whether information should be treated as confidential. In this situation, the attorney examiner rendered the ruling based on the facts and record in these cases, and the Commission is not going to second guess the ruling at this juncture. Accordingly, OCC's request should be denied.

4. Rebuttal Testimony

On brief, OCC argues the attorney examiner erred by allowing Duke to present witnesses on rebuttal. Specifically, OCC asserts Duke witness Morin's testimony (Duke Ex. 40), testifying to return on equity (ROE), while presented on rebuttal, was essentially presenting direct testimony. (OCC Br. at 123-124.) At the hearing, OCC's motion to strike portions of Dr. Morin's testimony as improper rebuttal testimony was denied; therefore, OCC asserts the Commission should reverse the attorney examiner's ruling (OCC Br. at 124; Tr. XVI at 4199-4205). If the testimony is permitted in the record, OCC argues it should be accorded little weight, given that it was essentially direct testimony and OCC was precluded from properly reviewing it since it was presented on rebuttal. In support of its request, OCC asserts that, since Duke has the burden of proof regarding the rate or return, the testimony should have been part of its direct case. Instead, OCC believes Duke incorrectly assumed that the rate of return from its most recent electric distribution case, *In re Duke Energy Ohio, Inc.*, Case No. 12-1682-EL-AIR, et al., Opinion and Order (May 1, 2013) (*Distribution Rate Case*), was the starting point for the rate of return. However, OCC notes the rate of return in the *Distribution Rate Case* was part of a stipulation and, by the terms of that stipulation, it was not to be used as precedent in future proceedings. OCC asserts the Commission should protect the integrity of the settlement process by determining Duke improperly relied on the rate of return in the *Distribution Rate Case*. According to OCC, the rate of return should be modified to reflect the lower business risk faced by Duke. (OCC Br. at 124-126.)

In response, Duke asserts the attorney examiner did not err in admitting Dr. Morin's testimony. Duke notes that, unlike traditional base rate cases, the statutory requirements for an ESP application do not require, as part of the initial application, an entire rate of return analysis. R.C. 4928.143(B)(2)(h) sets forth what the Commission must find in approving a distribution rider, i.e., reliability, alignment of expectations, and sufficient dedication of resources. That subsection authorizes the Commission to approve a just and reasonable ROE and the Commission's rule, Ohio Adm.Code 4901:1-35-03(C)(9)(g), does not identify additional requirements as to an ROE that must be included in an ESP application. According to Duke, it supported its proposed ROE with reference to the ROE approved in the *Distribution Rate Case*. However, Duke asserts OCC's opposition to the proposed ROE offered no calculation of the ROE, other than to say that it must be lower. On rebuttal, Duke believes it confirmed the ROE proposed is reasonable and believes OCC is now contesting Duke's rebuttal testimony because OCC recognizes this. According to Duke, rebuttal testimony is within the discretion of the attorney examiner and is permissible for purposes of contradicting the opponent's evidence. *In re Bell Atlantic Corp., et al.*, Case No. 98-1398-TP-AMT, Entry (July 16, 1999). OCC offered evidence to contradict Duke's evidence, claiming that, had the Distribution Capital Investment Rider (Rider DCI) been offered in the last base rate case, it would have yielded a lower ROE. Therefore, Duke is permitted to refute this allegation through rebuttal testimony. (Duke Reply Br. at 107-108.)

Upon consideration of OCC's request and Duke's response, the Commission finds the request to be without merit. There is no certain rule as to when rebuttal testimony may or may not be presented. Rather, it depends on the circumstances in a given proceeding. As pointed out by Duke, it is within the discretion of the attorney examiner whether rebuttal testimony is appropriate in a given case. The Commission finds no error in the attorney examiner's ruling in this situation and, therefore, OCC's request should be denied.

II. DISCUSSION

A. Applicable Law

R.C. Chapter 4928 provides an integrated system of regulation in which specific provisions were designed to advance state policies of ensuring access to adequate, reliable, and reasonably priced electric service in the context of significant economic and environmental challenges. In reviewing Duke's application, the Commission is cognizant of the challenges facing Ohioans and the electric industry and is guided by the policies of the state as established by the General Assembly in R.C. 4928.02, as amended by Amended Substitute Senate Bill 221 (SB 221).

In addition, SB 221 enacted R.C. 4928.141, which provides that, beginning on January 1, 2009, electric distribution utilities (EDUs) must provide consumers with an SSO, consisting of either a market rate offer (MRO) or an ESP. The SSO is to serve as the EDU's default service. R.C. 4928.143 sets out the requirements for an ESP. Pursuant to R.C. 4928.143(B)(1), an ESP must include provisions relating to the supply and pricing of generation service. The ESP, according to R.C. 4928.143(B)(2), may also provide for the automatic recovery of certain costs, a reasonable allowance for certain construction work in progress, an unavoidable surcharge for the cost of certain new generation facilities, charges relating to certain subjects that have the effect of stabilizing or providing certainty regarding retail electric service, automatic increases or decreases in components of the SSO price, *provisions to allow securitization of any phase-in of the SSO price, provisions* relating to transmission-related costs, provisions related to distribution service, and provisions regarding economic development. R.C. 4928.143(C)(1) provides that the Commission is required to approve, or modify and approve, the ESP, if the ESP, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under R.C. 4928.142.

In accordance with R.C. 4928.06 and 4928.141, the Commission promulgated rules, which are contained in Ohio Adm.Code Chapter 4901:1-35, for the purpose of considering SSO filings made by EDUs in conformance with R.C. Chapter 4928.

B. <u>Summary of the Local Public Hearings</u>

Four local public hearings were held to allow Duke's customers to have the opportunity to express their opinions regarding the issues in these proceedings. Two evening hearings and an afternoon hearing were held in Cincinnati and another evening hearing was held in Middletown. At these hearings, public testimony was heard from individuals on behalf of Sierra, Ohio Citizens Actions, Ohio Aggregate and Industrial Minerals Association, and Public Citizens Energy and Climate Program. Numerous individual consumers from Duke's service territory also gave testimony. In addition to the public testimony, many customers filed letters expressing their concerns regarding the Company's proposal. A majority of the testimony and letters were in opposition to Duke's proposed ESP, in particular the proposed PSR. Several small businesses and trade groups gave their support for Duke's proposal to terminate the Load Factor Adjustment Rider (Rider LFA).

C. Analysis of the Application

As discussed in further detail below, Duke proposes a three-year term for this ESP, beginning June 1, 2015, to May 31, 2018. Duke explains that the ESP extends certain components of the *ESP 2 Case*, either eliminates or refines other elements, and adds new provisions for enhancing Duke's distribution reliability. Duke will rely upon a competitive bidding process (CBP) plan for procuring the supply necessary to serve the SSO load. (Duke Ex. 6 at 3.)

1. Price Stabilization Rider

(a) Duke

Duke proposes a nonbypassable PSR that would extend beyond the term of the proposed ESP, such that the term for the PSR would correspond with the period during which Duke receives energy and capacity under the Inter-Company Power Agreement (ICPA) with the OVEC, June 30, 2040 (IEU Ex. 5; Duke Ex. 1 at 14; Duke Ex. 6 at 11, 13; OCC Ex. 43 at 3). Through the PSR, Duke will provide customers the net benefit of all revenues accruing to the Company as a result of its ownership interest and contractual entitlement in OVEC, less all costs associated with the entitlement. In addition, Duke proposes additional contractual arrangements could be included in the PSR to increase the benefits available to customers. (Duke Ex. 1 at 13; Duke Ex. 6 at 11.)

Duke, along with 12 other entities (sponsoring companies), owns stock in OVEC; Duke's share is currently 9 percent. OVEC and its wholly-owned subsidiary, Indiana Kentucky Electric Corporation (IKEC), were created in the 1950s to provide power for uranium enrichment facilities located near Portsmouth, Ohio. OVEC owns two coal-fired generating units that have a combined nameplate capacity of nearly 2,000 megawatts (MW). (Duke Ex. 6 at 10-11; Duke Br. at 23.) OVEC has 11 coal-fired generating stations, five at Kyger Creek (Kyger), in Cheshire, Ohio, and six at Clifty Creek (Clifty), near Madison, Indiana (Staff Ex. 1 at 4; OEG Ex. 1 at 12). Until 2003, when the Department of Energy (DOE) canceled the contract, DOE was the primary consumer of the power from OVEC (Duke Ex. 6 at 11). Each sponsoring company now receives its entire portion of OVEC capacity and generation for its own supply portfolio, and the fixed and variable costs associated with Clifty and Kyger are allocated to the sponsoring companies based on their respective equity interests (OEG Ex. 1 at 12; Duke Ex. 6 at 11). Duke is entitled to capacity from the OVEC-owned generating stations commensurate with its contractual entitlement, or approximately 200 MW. Duke is also entitled to a share of the energy produced by the OVEC-owned stations, although it is not obligated to take energy. However, if it does not take energy, Duke must pay OVEC's variable cost of producing energy. (Duke Br. at 23.)

Duke seeks approval of the PSR, under R.C. 4928.143(B)(2)(d), which allows an ESP to include terms, conditions, and charges relating to, among other things, bypassability, as would have the effect of stabilizing or providing certainty regarding retail electric service. Duke states the PSR is intended to mitigate anticipated, yet undefined, volatility in the wholesale market. Duke offers the PSR meets the three specific criteria recognized by the Commission in assessing adherence to R.C. 4928.143. First, the PSR involves a term, condition, or charge by providing all customers the net benefits of Duke's OVEC entitlement. Second, the rider concerns the issue of bypassability delineated in the statute, as the corollary to bypassability is nonbypassability. Therefore, according to Duke, a term, condition, or charge relating to a nonbypassable rider is properly included in an ESP. Third, the PSR would have the effect of stabilizing or providing certainty regarding retail electric service. (Duke Br. at 18-19.) According to Duke, the PSR will function as a countercyclical hedge, such that, in rising market price environments, the benefits under the rider will be positive, thereby offsetting other rates derived from market prices (Duke Br. at 24).

Duke states that, to ensure a fully-competitive auction process for SSO supply, it proposes that the energy, capacity, and ancillary service to which it is currently entitled from OVEC not be used for such supply obligations; rather, Duke proposes to sell 100 percent of its share into the market (Duke Ex. 1 at 13; Duke Ex. 6 at 11). The difference between the revenue generated from such sales and the costs allocated from OVEC to Duke will be flowed through to customers (Duke Ex. 6 at 12). According to Duke witness Henning, in a rising price environment, Duke's margins from its contractual entitlement will be positive and the net amount passed through the PSR should similarly increase (Duke Ex. 2 at 10).

Duke contends the PSR provides three primary benefits. First, it will act as a hedge to mitigate some of the volatility in overall rates that customers pay for generation service, because the amounts flowing through the rider will reflect market conditions. Thus, in a rising market price environment, when the margins from Duke's contractual entitlement from OVEC are positive, the net rider amount should increase to the benefit of customers. Duke asserts this will temper the volatility of generation rates, thereby adding stability and certainty with regard to the overall price of retail electric service. In order to enable customers to benefit from those periods of increasing market volatility, Duke proposes that the term of the PSR extend beyond the term of this ESP. (Duke Ex. 1 at 13-14; Duke Ex. 6 at 13-14.) Duke explains the costs for its share of OVEC are relatively stable as it is allocated a share of fixed costs, which are generally stable, and variable costs, which are mostly fuel (Duke Ex. 6 at 14). Second, Duke submits the proposal is competitively neutral, because Duke's entitlement share will continue to be sold into the wholesale markets and the proposal will not impact the competitive retail electric service (CRES) market (Duke Ex. 6 at 15; Duke Br. at 19). According to Duke, its proposal will not interfere with CRES providers' ability to compete for customers, as the nonbypassable PSR will neither reward nor penalize customers' decisions regarding choice (Duke Ex. 1 at 13). As for the wholesale market, as of the effective date of the ESP, Duke will not have generation business; therefore, there cannot be any subsidy between its noncompetitive electric business and its generation business. Finally, Duke notes the benefit to Ohio of having the reliable power available from the OVEC generating assets. (Duke Ex. 6 at 15.)

Duke witness Henning opines that retail customers are significantly influenced by current wholesale market design fundamentals for energy and capacity, which are creating a volatile and uncertain environment, as the PJM Interconnection, LLC (PJM) market design does not place any additional value on resource diversity. In addition, 24,932 MW of capacity in the PJM zone is expected to retire between 2011 and 2019; 92 percent will occur by June 1, 2015, with the overwhelming majority being coal plants. According to the witness, retirement of these coal plants places greater reliance on a single fuel source, such as natural gas-fired generation, and this reduction in fuel diversity will most likely lead to more episodes of the volatility and uncertainty experienced with the polar vortex in January 2014 (2014 polar vortex). Duke notes that, in response to the energy supply vulnerabilities exposed by the cold period in January 2014, PJM is proposing to implement a capacity performance initiative that is likely to lead to increased wholesale capacity prices. Mr. Henning submits that repeating an event like the 2014 polar vortex without all the retiring coal generating capacity undeniably increases volatility in both energy and capacity. This volatility will have an effect on the retail level, as prospective wholesale suppliers could incorporate risk premiums into their bids and CRES providers will likely structure contracts so they can recover additional costs. (Duke Ex. 2 at 4, 9; Duke Br. at 21-22.) Without a change, Mr. Henning submits all stakeholders should expect to incur increasing costs and experience volatility for generation supply (Duke Ex. 2 at 5). Moreover, Duke states there are legal proceedings pending at the Federal Energy Regulatory Commission (FERC), referring to FERC Order No. 745, that further confirm the volatile and uncertain nature of the wholesale market (Duke Br. at 22; Tr. VI at 1696, 1698-1699). In response to these challenges, Mr. Henning states Duke is proposing to provide an ESP that strikes the appropriate balance between customers, investors, competitive suppliers, and the state of Ohio. According to Mr. Henning, Duke's proposal mitigates some of the volatility in overall rates customers pay for generation and it could be extended to include similar financial arrangements with other generators to provide further protection for customers. (Duke Ex. 2 at 5, 10; Duke Br. at 24.)

Duke maintains its proposal does not contravene the Commission's objective to transition Ohio to a competitive retail market construct. Duke offers that none of Duke's share of OVEC's capacity and energy will be used to displace any SSO service and no physical capacity or energy from OVEC will be delivered to any retail customer; therefore, there will be no double recovery. Duke will collect no revenue from any retail customer for generation service except for generation service provided by SSO auction winners. Thus, all of the revenue collected for generation service provided by SSO auction winners will be passed through to those suppliers. (Duke Ex. 6 at 12.)

With regard to extending the PSR beyond the term of the ESP, Duke points to its Alternative Energy Resource Rider (Rider AER-R) approved in the *ESP 2 Case* as an example of a rider the Commission authorized to continue beyond the term of the ESP so that customers could benefit from the stability afforded by the rider during an uncertain and challenging time (Duke Ex. 2 at 11). Staff and GCHC respond that the Rider AER-R is distinguishable from the PSR, because Rider AER-R is bypassable and is intended to only recover costs that occurred during the term of the plan approved in the *ESP 2 Case*. However, the PSR would be nonbypassable and would, if the OVEC projections are accurate, potentially recover costs beyond the term of the proposed ESP. (Staff Br. at 24; Staff Reply Br. at 12; GCHC Br. at 9; Tr. I at 263-264.)

Duke proposes to file, on a quarterly basis, a projection of the revenue expected from selling its share of the OVEC output into the PJM markets and the expenses it expects to be billed from OVEC. The difference between the expected revenue and the expected cost for the upcoming quarter will be divided by the projected kilowatt hour (kWh) sales for the same quarter to calculate the per kWh rate. Duke notes that customers taking service above distribution voltage levels will have slightly lower prices to account for the lower line losses at their service level. As actual data is available, Duke will true-up the rider to ensure there is no over- or under-recovery. (Duke Ex. 6 at 16.)

(b) Intervenors and Staff

(i) OEG's Position

Other than Duke, no party in these cases supports the PSR as filed. Staff and the intervenors, with the exception of OEG, argue the PSR violates Ohio and federal law, is an improper cross-subsidy, and is unsupported by the evidence and should be rejected (Staff Ex. 1 at 10; Kroger Ex. 1 at 4; OCC Ex. 43 at 13; IGS Ex. 12 at 3; Wal-Mart Ex. 1 at 3; Sierra Ex. 4 at 3; Direct Energy Ex. 1 at 5; IEU Br. at 2; OMA Br. at 17; OEC Br. at 4; OPAE Br. at 16; Sierra Br. at 4; Wal-Mart Br. at 8; Direct Energy Br. at 13; GCHC Reply Br. at 4). While OEG finds merit with the PSR, Exelon points out that even OEG would revamp the rider in such significant ways that it is practically a different proposed rider (Exelon Reply Br. at 2).

OEG supports the concept of the PSR, with certain modifications, stating that it represents a financial limitation on customer shopping that would have the effect of stabilization or providing certainty regarding retail electric service rates for customers, consistent with R.C. 4928.143(B)(2)(d) (OEG Ex. 1 at 4; OEG Br. at 1, 5). OEG offers that the PSR would result in all customers paying a price for retail electric generation that is approximately 3 percent cost-based from OVEC and 97 percent market-based from the FERC-regulated PJM wholesale market. OEG submits that the financial impact of the PSR will not be significant, noting that Duke projects the PSR will be a charge for the first three years and then a credit to customers in 2019 through 2024. (OEG Ex. 1 at AST-2; OEG Br. at 2, 6.) The average annual cost of the charge in the first three years is only $7.33 million, which is about a $0.30 per month charge for the typical 1,000 kWh per month residential household (OEG Br. at 2; Tr. XI at 3114).

OEG notes, in accordance with Duke's forecast analysis from January 2014 (Duke OVEC analysis), OVEC's combined demand and energy costs are expected to be above market prices in the next several years; therefore, the OVEC net benefits are expected to be negative, i.e., market prices will be less than OVEC costs, in 2015 through 2018, but positive in 2019 and in all years thereafter (OEG Ex. 1 at 15, Att. AST-2). However, OEG thinks the Duke OVEC analysis of the benefits is conservative, especially in light of the fact that it was developed before the full impact of the 2014 polar vortex. Given the amount of capacity being retired in PJM, OEG believes there will be upward pressure on capacity prices that will increase the net benefits of the hedge beyond Duke's forecast. (OEG Ex. 1 at 16-17.) According to OEG, based on the Duke OVEC analysis, the expected OVEC net benefits over the 8.5 years from June 2015 through the end of 2023, would be approximately negative $6 million or negative $627,000 per year (OEG Ex 1 at 18, 20, Atts. AST-2, AST-3). OEG believes OVEC's generation represents a stable source of power from facilities that have recently been upgraded with pollution control equipment that allows them to comply with the upcoming standards. In addition, there are no significant capital expenditures expected over the next decade, the forecast of demand charges is relatively flat, the cost of coal is likely to be stable, and the coal plant retirements will put upward pressure on the capacity and energy market prices, so OVEC's all-in generation costs are likely to be at or below market prices in the near future. (OEG Ex. 1 at 13; OEG Br. at 8.)

OEG believes that, while the current costs of the OVEC power supplies are greater than the market benefits of the supplies, such is likely to change because a significant amount of coal-fired generation in the PJM system is retiring and market supplies for energy and capacity are tightening; thus, driving up market prices and increasing the benefits with the OVEC generation. Also, given that a portion of the OVEC assets is a fixed cost and the remainder is based on low-cost coal at a relatively fixed price, the OVEC generation is likely to provide countercyclical benefits. Thus, as energy market prices rise, either because of severe weather conditions or generating capacity scarcity, the OVEC plants will be dispatched more and their all-in $/megawatt hour (MWh) price of generation will decline. OEG submits customers with a balanced, blended portfolio of market purchases and OVEC generation would experience offsetting influences that would stabilize their electricity prices and help weather economic storms. OEG believes that, while marginal cost or spot energy markets can be a valuable component of a supply portfolio of a utility or end user, state-regulated hedging products or fixed-cost supplies should be part of the portfolio as well. (OEG Ex. 1 at 4-5, 7.)

OEG explains the PSR, with OEG's proposed modifications, does not change the physical amount for energy or capacity a shopping customer must buy or the amount of energy or capacity that must be supplied in the SSO auctions for nonshopping customers (OEG Ex. 1 at 6). According to OEG, the PSR should have no effect on CRES providers and it would provide rate stabilization benefits for Duke's customers, while having no adverse effect on the market (OEG Ex. 1 at 15). The PSR would also be neutral in terms of wholesale competition, as no wholesale supplier will benefit or be harmed (OEG Br. at 6). First, OEG recommends the rider be established as a noncancellable rider that should be formally instituted for a reasonable period of time, i.e., start in June 2015 and continue to the end of 2024, or for 9.5 years. OEG espouses the rider should be locked because, if customers are going to be exposed to the early years of negative benefits, they should be assured of the opportunity to benefit from the expected positive benefits in future years. OEG argues going too far into the future may expose Duke's customers to unknown risks, e.g., decommissioning costs, and environmental compliance costs. (OEG Ex. 1 at 5, 16, 18-19; OEG Br. at 14-15.)

Next, OEG suggests a levelization approach that would flatten the PSR and remove what is otherwise likely to be a front-loaded cost to customers under the current plan. OEG believes this approach would advance the long-term benefits and bring the rider closer to a market-neutral hedge in all years. (OEG Ex. 1 at 5; OEG Br. at 15.) With this approach, Duke would advance future savings to customers in the current year; thus, there would be a regulatory balancing account included in the arithmetic of the rider whereby Duke would be made financially whole by earning its weighted average cost of capital on the cumulative balance on the account. This approach is revenue-neutral to Duke. Under this approach, the combination of the levelized return and the levelized net benefits would yield an initial PSR of $1.593 million per year. The first year would be adjusted for the 2015 partial year and for a 10 percent participation rate, which OEG recommends be allocated to Duke's shareholders as an incentive to keep costs low. (OEG Ex. 1 at 6, 19-21.) At the end of each quarter, there would be two true-up components, i.e., the three-year amortized differences and the trued-up return would be added to the original levelized PSR (OEG Ex. 1 at 20-21, Att. AST-3). Exelon disagrees with OEG's levelization proposal, stating that, while the short-term losses may prove to be accurate or even understated, the long-term profits may never arrive. Thus, this approach could end up being a subsidy by future distribution service customers for today's customers' capacity costs. Moreover, Exelon submits it is questionable whether R.C. 4928.02, which prohibits subsidies between wire services and generation service, permits such a scheme. (Exelon Reply Br. at 8.)

In addition, OEG asserts that any customer with more than 10 MW of load per single site should be given the chance to self-insure and not participate in the hedge. This would be a one-time election and such customers would either be in or out of the hedge for the entire 9.5 years. The percent of load for customers who choose not to participate would be added to Duke's shareholders' 10 percent. (OEG Ex. 1 at 22; OEG Br. at 15.) In response Miami/UC state that, since they own their own generation, they are already hedged for future capacity costs and do not need to take ownership of the OVEC units; therefore, they request the PSR be rejected. However, if it is not, Miami/UC propose that either the few customers with large-scale generation be allowed to bypass the PSR or OEG's exemption for 10 MW or greater customers be accepted. (Miami/UC Br. at 6-7.) Exelon agrees the PSR should be bypassable for all customers and not just customers with 10 MW of demand (Exelon Reply Br. at 8). OCC submits residential customers should have the same right to choose the best position between regulation and market that the large industrial customers would have (OCC Reply Br. at 13).

RESA, Staff, and OCC insist OEG's proposals be rejected (RESA Br. at 20; Staff Reply Br. at 15; OCC Reply Br. at 13). RESA states OEG's proposals: do not comport with R.C. 4928.143(B)(1), as they do not contain a provision to test the ESP; will force all customers, except those OEG members that opt out, to pay Duke's generation costs; and force customers who cannot opt out to pay for OVEC generation for significantly longer than Duke is proposing (RESA Br. at 20). OCC argues extending the PSR through 2024 would: subject customers to years of unlawful charges; be inconsistent with the term of the proposed ESP; be contrary to the requirement in R.C. 4928.143 that any provision not exceed the term of the ESP; and exacerbate the risk and harm to customers. OCC points out OEG witness Taylor did not prepare an independent analysis of OVEC costs or revenues, or review Duke's workpapers until after the filing of his testimony and deposition, and his opinions were not informed by the depositions or testimony pertaining to the Duke OVEC analysis. (OCC Reply Br. at 11-12; Tr. VII at 1943-1946.) IEU disagrees with OEG's claim the PSR is a limitation on shopping, as authorized under R.C. 4928.143(B)(2)(d), noting OEG failed to demonstrate how the rider would operate as such and Duke stated the PSR would not affect shopping (IEU Reply Br. at 20; OEG Br. at 5; Duke Ex. 6 at 12).

Duke asserts the flaw in OEG's proposal for Duke to retain 10 percent of the PSR is that it cannot be achieved because Duke does not control OVEC or the costs it incurs. In addition, Duke points out the PSR is structured as a long-term hedge to June 2040, where the commitment is reciprocal and Duke is committing to its customers the net benefits. Thus, OEG's shorter 9.5 year firm termination date does not work. OEG's levelized proposal conflicts with the purpose of the PSR, according to Duke, as OEG's proposal would not allow the credit to flow back to customers when retail generation prices are rising. Finally, OEG's proposal to exempt certain customers would be contrary to the intent of the rider, which is to apply it to all customers to eliminate any impact on competition. (Duke Reply Br. at 68-69.)

(ii) R.C. 4928.141 and 4928.143

Wal-Mart argues the PSR should be rejected because there has been no showing by Duke that the provision is "necessary to maintain essential electric service to consumers****," as required for SSOs under R.C. 4928.141(A) (Wal-Mart Br. at 8). Moreover, Wal-Mart, IEU, OEC, and Sierra assert the PSR does not relate to the supply and pricing of electric generation service, under R.C. 4928.143(B)(1), because it is not an offer of electric generation service (Wal-Mart Br. at 8; OEC Br. at 4; IEU Br. at 7; Sierra Br. at 20; Duke Ex. 6 at 12). Furthermore, Cincinnati asserts neither R.C. 4928.141 nor 4928.143 contains any provisions that would authorize the PSR, as it has no relationship with either generation or distribution service (Cincinnati Br. at 7).

IGS explains Duke's argument is that the PSR meets the three criteria of R.C. 4928.143(B)(2)(d) because: it is a term or charge; it relates to bypassability since it is a nonbypassable charge; and it stabilizes retail electric rates. While the PSR meets the first criterion as a term or a charge, IGS submits it does not meet the second criterion regarding bypassability. IGS submits R.C. 4928.143 includes two provisions, (B)(2)(b) and (c), that authorize generation-related nonbypassable charges in an ESP under certain circumstances. IGS argues inclusion of a nonbypassable charge under (B)(2)(b) and (c) implies exclusion under (B)(2)(d). *Citing Montgomery Co. Bd. of Commr.'s v. Pub. Util. Comm.*, 28 Ohio St.3d 171, 175, 503 N.E.2d 167 (1986). On the third criterion, IGS submits the PSR does not provide stability or certainty with respect to retail electric service, pointing out Duke has not demonstrated the PSR relates to retail electric service, as the PSR involves Duke's interest in a wholesale purchased power agreement (PPA). Even assuming the PSR relates to retail electric service, IGS maintains it does not provide stability or certainty. IGS points out customers do not purchase energy on an hourly basis in the wholesale energy markets; rather, they have long-term fixed price contracts, pursuant to which CRES providers can hedge customers' usage requirements. IGS asserts the PSR inserts uncertainty and volatility into customers' bills, since there is no way of knowing if it will be a charge or credit, and it will undermine the stability and certainty CRES providers already give their customers through fixed-price contracts. (IGS Reply Br. at 7, 9-10.) IEU, Staff, and Sierra agree Duke failed to demonstrate that the PSR will have the effect of providing stability or certainty in the provision of retail electric service as required under R.C. 4928.143(B)(2)(d) (IEU Reply Br. at 6; Staff Reply Brief at 7; Sierra Reply Br. at 3). Sierra advocates the Commission follow precedent and find that R.C. 4928.143(B)(2)(d) permits approval of a hedge mechanism only where the proposal provides for fixed rates or allows recovery of fixed costs. *Citing In re Columbus S. Power Co.*, Case No. 11-346-EL-SSO, et al. (*AEP ESP 2 Case*), Entry on Rehearing (Jan. 30, 2013) at 16. (Sierra Reply Br. at 5.)

R.C. 4928.143(B)(2) identifies nine provisions of an ESP that may be authorized and, according to IEU and OEC, the PSR is not authorized under any of these provisions (IEU Br. at 8-12; OEC Br. at 4-5). ELPC agrees Duke has failed to demonstrate that the PSR fits into one of the categories in R.C. 4928.143(B)(2), noting that Duke's reliance on section (B)(2)(d) is misplaced because the PSR does not limit customer shopping, does not relate to bypassability, and has no relation to retail electric service (ELPC Br. at 2, 10-13; Tr. II at 429-430). In addition, Wal-Mart notes that financial hedging arrangements do not fall within one of the nine allowable categories of ESP provisions set forth in R.C. 4928.143(B)(2) (Wal-Mart Br. at 9). For example, Kroger states that R.C. 4928.143(B)(2)(a) provides that an ESP may include the cost of purchase power supplied under the offer, including the cost of energy and capacity, and including purchased power acquired from an affiliate. However, Duke proposes that the energy, capacity, and ancillary service to which it is entitled from its contractual rights in OVEC not be used for such supply obligations; instead, Duke proposes to sell such services associated with the OVEC contract into the market. (Kroger Br. at 8-9.) Staff, OMA, and OCC emphasize the PSR does not relate to default service (Staff Reply Br. at 5; OMA Br. at 19; OCC Br. at 8-10).

OPAE calls Duke's assertion that R.C. 4928.143(B)(2)(d) applies because the PSR is a nonbypassable rider absurd, noting that all utility charges are either bypassable or nonbypassable (OPAE Reply Br. at 7). Kroger states, and Staff agrees, Duke's suggestion that the PSR would be proper whether it is bypassable or nonbypassable, as both relate to bypassability under R.C. 4928.143(B)(2)(d), renders the term bypassability meaningless (Kroger Reply Br. at 5; Staff Reply Br. at 3). The Ohio Supreme Court has stated that a cardinal rule of statutory construction requires that a statute should not be interpreted to yield a result that is absurd. *Citing Mishr v. Poland Bd. of Zoning Appeals*, 76 Ohio St.3d 238, 240, 667 N.E.2d 365, 367 (1996); *Canton v. Imperial Bowling Lanes, Inc.* 16 Ohio St.2d 47, 53, 242 N.E.2d 566, 570 (1968). (Staff Reply Br. at 3; IEU Reply Br. at 3.) IEU agrees, stating Duke's interpretation of R.C. 4928.143(B)(2)(d) would result in violations of several other provisions in Ohio law that restrict the Commission's authority to authorize generation-related nonbypassable charges, i.e., R.C. 4928.02(H) and 4928.39 (IEU Reply Br. at 3).

According to Duke, the Ohio Supreme Court has confirmed R.C. 4928.143(B)(2) allows for unlimited inclusion of the items listed in the statute, as the statute merely delineates the types of categories that may be included in an ESP. *Columbus S. Power Co. v. Pub. Util. Comm.*, 128 Ohio St.3d 512, 2011-Ohio-1788, 947 N.E.2d 655, at ¶33. The theory advanced by Staff and intervenors would require that any component in an ESP must be expressly and clearly described in the statute. Thus, according to Duke, proposals agreed to in past ESPs would be unlawful, including the CBP plan that is not expressly provided for in the statute. (Duke Reply Br. at 56-57.)

(iii) State Policy

GCHC, Kroger, OMA, OCC, Sierra, ELPC, IGS, and OPAE maintain the PSR violates R.C. 4928.02(H), which prohibits Duke from using revenues from competitive generation service components to subsidize the cost of providing noncompetitive distribution service, or vice versa (GCHC Br. at 11; Kroger Br. at 11-12; OMA Br. at 20; OCC Br. at 20; Sierra Br. at 15; ELPC Br. at 3, 15; IGS Ex. 12 at 4, 7; OPAE Reply Br. at 10). Staff, IGS, Wal-Mart, Constellation/RESA, OCC, IEU, OEC, OPAE, and Exelon assert Duke's proposed PSR is inconsistent with the Commission's objective of transitioning all of Ohio's EDUs to a fully-competitive retail market construct and violates the state's policy goals in R.C. 4928.02(H) (Staff Ex. 1 at 11; Staff Br. at 2, 15; IGS Ex. 12 at 7; Wal-Mart Ex. 1 at 9; RESA Ex. 3 at 10; OCC Ex. 43 at 35; IEU Br. at 12; IGS Br. at 20; OEC Br. at 11; OPAE Br. at 8-9; Exelon Br. at 5). IEU and OPAE submit the PSR would result in an anticompetitive subsidy between a noncompetitive retail electric service and a service other than retail electric service (IEU Br. at 12; OPAE Br. at 15). GCHC argues distribution customers should not be forced to subsidize Duke's independent investment in generation supply that has nothing to do with the provision of distribution service. To avoid cross-subsidization, GCHC asserts the PSR must be fully bypassable. (GCHC Br. at 11.) Sierra argues the PSR would reverse the transition to competition because it requires customers to subsidize potentially uneconomic generation, subjects customers to the risk of owning generation over the long term without any control over decisions that affect costs and revenues, and is an inappropriate mechanism to manage volatility in a competitive environment (Sierra Br. at 15-17).

Staff and OCC note the Ohio Supreme Court criticized similar anticompetitive subsidies and reversed a Commission decision that allowed AEP to charge all of its distribution customers for costs related to the potential construction of a generation facility. The Court held it was unlawful for the Commission to allow "revenues from noncompetitive distribution service to subsidize the cost of providing competitive generation service component." *Indus. Energy Users-Ohio v. Pub. Util. Comm.*, 117 Ohio St.3d 486, 2008-Ohio-990, 885 N.E.2d 195. (Staff Br. at 16; OCC Br. at 17.) OCC also cites *Elyria Foundry Co. v. Pub. Util. Comm.*, 114 Ohio St.3d 305, 2007-Ohio-4164, 871 N.E.2d 1176, in support of this argument (OCC Br. at 17).

In addition, Staff, IEU, OCC, and Exelon point to *In re Ohio Power Co.*, Case No. 10-1454-EL-RDR (*Sporn*), Finding and Order (Jan. 11, 2012), for precedent wherein the Commission rejected AEP's request to establish a nonbypassable charge that would recover plant closure costs from all distribution customers (Staff Br. at 17; IEU Br. at 13; OCC Br. at 18). IEU states that, as the Commission found in *Sporn*, a generation-related nonbypassable rider is the equivalent of a distribution rider since it is billed and collected from all customers. *Sporn*, Finding and Order at 19. Therefore, if the Commission authorized a nonbypassable PSR, the rider would violate the prohibition of the recovery of generation-related costs through a nonbypassable rider contained in R.C. 4928.02(H). IEU notes the Commission's decision in *Sporn* determined the provisions of R.C. 4928.143(B)(2)(d) cannot be interpreted to override the prohibition of the recovery of generation-related costs through a nonbypassable rider set out in R.C. 4928.02(H). (IEU Reply Br. at 5.) Duke asserts the Commission's decision in *Sporn* is factually inapposite to the circumstances in these cases. Unlike AEP in *Sporn*, Duke is not seeking cost recovery for any component of generation service that it owns or otherwise controls and Duke has not invoked R.C. 4928.143(B)(2)(c), which was the subsection at issue in *Sporn*. Duke acknowledges that, in *Sporn*, the Commission noted AEP's request was contrary to R.C. 4928.02(H), because it would enable recovery of generation-related costs through distribution rates. However, in the instant cases, the OVEC-owned generating units are not providing service to Duke's retail customers and, therefore, the PSR will not recover costs for the generation component of electric service. (Duke Reply Br. at 62-63.)

OPAE asserts that, in accordance with the policy of the state set forth in R.C. 4928.02, the Commission must ensure the ESP addresses the affordability of electric service or the protection of at-risk populations. According to OPAE, Duke's proposed ESP will increase the cost of electricity for all consumers without addressing the impact on consumers, especially low-income, at-risk residential consumers. (OPAE Br. at 3-4; OPAE Reply Br. at 4-5.) In addition, IEU notes that R.C. 4928.20(K) requires the Commission to consider the effect of the ESP on large-scale governmental aggregation of any nonbypassable generation charge. However, Duke failed to comply with these requirements and Ohio Adm.Code 4901:1-35-03(C)(6) to demonstrate the effect of the PSR on large-scale governmental aggregation. According to IEU, Duke provides conflicting statements regarding compliance with the statute. IEU maintains Duke failed to carry its burden of proof and the Commission cannot determine what the effect of the PSR is on large-scale governmental aggregation. (IEU Reply Br. at 18-19; Duke Ex. 1 at 19.)

Duke opines state policies are intended to guide the Commission and they do not mandate any particular outcome or preclude the Commission from arriving at outcomes consistent with its mission. With regard to R.C. 4928.02(H), Duke states that, under this provision, the legislature warned against anticompetitive subsidies flowing between noncompetitive and competitive retail electric service, which includes the recovery of generation-related costs through distribution or transmission rates. However, the PSR is not providing retail generation service, as customers will continue to receive their competitive generation service through either the SSO auctions or CRES contracts. None of the energy and capacity associated with Duke's OVEC entitlement will be used to directly supply customers; therefore, it cannot displace the energy and capacity supplied via competitive auctions or contracts. Consequently, there is no anticompetitive subsidy. Moreover, Duke submits the statute specifically identified the desire to prevent the collection of generation charges through distribution or transmission rates; however, the designation of the PSR as a nonbypassable rider does not render it such a rate. (Duke Reply Br. at 59-60.)

(iv) Duke's OVEC Analysis

Given that Duke's OVEC analysis is speculative, OPAE and GCHC assert there is no evidence upon which to base a factual decision on the impact of the PSR on distribution customers beyond the negative impact during the term of the ESP (OPAE Reply Br. at 16; GCHC Br. at 6; Tr. I at 255-256; Tr. III at 666-668). OCC points out, and Sierra agrees, that Duke produced no estimates of the impact of the PSR on customer rates in its application or testimony, and assumed that any impact would be $0 (OCC Br. at 28; Tr. II 351-352; OCC Ex. 43, Att. JFW-2; Sierra Ex. 4 at 3, 6; Sierra Br. at 6). OCC and IEU offer Duke has not performed any analysis to demonstrate that customers are subject to price volatility, show examples or estimates of the potential impact of the PSR on the stability of rates, or suggest that the PSR would provide customers with value as a hedge (OCC Ex. 43 at 27-28; IEU Br. at 5). IGS agrees Duke filed no projections of the rate impacts of the PSR, noting the PSR is not a hedge for customers; rather, it is a hedge to guarantee Duke's earnings (IGS Br. at 26-27; Tr. I at 223, 225-226; Tr. XII at 3899).

By failing to present any evidence regarding the projected rate impact of the PSR, OCC and Wal-Mart argue, Duke failed to carry its burden of proof in accordance with R.C. 4928.143(C)(1) (OCC Br. at 28-29; Wal-Mart Br. at 3). In discovery, Duke provided, for the first time, the Duke OVEC analysis (OCC Exs. 4-4A; OCC Ex. 43 at 6, Att. JFW-2 at 2-4; OCC Br. at 28-29). OCC notes that, when called as-on-cross, Duke's employee who sponsored the discovery response could not properly support the Duke OVEC analysis (OCC Br. at 29-30, 32-34; OCC Ex. 4; Tr. IX at 2455-2456, 2458-2460, 2467-2468; Tr. X at 2833-2934).

OCC and GCHC note that, under Duke's estimate, the cumulative net cost to customers of Duke's OVEC entitlement over the ESP period would be $22 million, and it would reach $29 million by the end of 2018 (OCC Ex. 43 at 7, 17; OCC Ex. 4; OCC Br. at 37; GCHC Br. at 6; Tr. I at 256; Tr. II at 590, 671-672; Tr. IX at 2515; OEG Ex. 1 at Att. AST-2; Sierra Ex. 4 at 7). According to the Duke OVEC analysis, the annual net revenue is forecast to become positive in 2019 and remain positive through 2024, with the cumulative total net revenue over 2015 through 2023 being zero. If future costs and revenues are discounted on a present value basis using a 5 percent discount rate, the cumulative net revenue remains negative, at negative $7 million, through 2024, according to the Duke OVEC analysis. (OCC Ex. 43 at 7, 17, Att. JFW-1.) Sierra states the Duke OVEC analysis shows, for the first four years of the PSR, customers would be charged $26.4 million and, in years

5 through 10, customers would receive credits totaling $18.4 million. Thus, Sierra offers that, through 2024, the cumulative net present value of the PSR is negative. (Sierra Ex. 4 at 4, 7; Sierra Br. at 6; OCC Ex. 4.)

OCC offers the following regarding the Duke OVEC analysis: any analysis of a resource's future costs and market revenues relies on uncertain assumptions; some of the assumptions are out of date; some of the information suggests that a simplified model was used in the analysis; Duke's share of the OVEC unforced capacity is not properly reflected; there are questionable aspects to the assumed outage; because of the multiple sponsors under the ICPA, inefficiencies are introduced that lead to additional costs that were ignored; and costs for carbon reductions were not reflected (OCC Ex. 43 at 9-10, 19-24, 37; OCC Br. at 14, 34-42; Tr. V at 1374; Duke Ex. 14 at 34). In fact, as-on-cross witness Mr. Brodt from OVEC agreed that OVEC's revenues and cost forecast beyond five years would not be very reliable (OCC Br. at 38; Tr. V at 1213). Thus, according to OCC, the Duke OVEC analysis is an unreliable estimate of the potential future net costs to customers (OCC Ex. 43 at 24; OCC Br. at 13).

In support of its assertion that Duke's projected capacity revenue generated from OVEC has problems, IGS notes that neither Clifty nor Kyger participates in the base residual auction (BRA) as typical capacity resources. Clifty is located in Indiana, in what is referred to as part of the Midcontinent Independent System Operator (MISO), and Kyger, while in Ohio, is not considered a PJM plant. Thus, because these resources are considered external resources, there is a risk they may not be permitted to participate in the BRA, or PJM energy markets, and receive capacity compensation. According to IGS, removal of this revenue stream would negatively impact the cash flow of these plants, because MISO, the most likely alternative market, does not have a comparable capacity market and generally has lower energy prices. (IGS Ex. 12 at 12-13; IGS Ex. 14 at 14-15; IGS Br. at 31.) IGS submits Duke's cash flow projections understate the cost of the PSR, because it overstates OVEC's generation output, and the capacity revenue is overstated (IGS Br. at 28-30; IGS Ex. 12 at TH-5). IGS also notes that there is a significant balloon payment that comes due in 2040, thus, there is potential additional liability that may be assigned to customers in the future (IGS Br. at 31; IGS 12 at 15-16, Ex. TH-9). Sierra agrees Duke's view of the energy and capacity markets is likely too optimistic and inflates the value of the OVEC plants, stating that, if any of Duke's assumptions turn out differently and lead to reduced revenues and/or costs, it is likely customers would never break even (Sierra Reply Br. at 4, 7-13; Sierra Ex. 4 at 8-21, Att. SEJ-8). Kroger agrees the benefits alleged by Duke are dependent on assumptions several years into the future, including market price assumptions and costs from proposed environmental rulemakings (Kroger Ex. 1 at 7; Kroger Br. at 11).

RESA contends there is no guarantee the PSR will be a credit during the term of the ESP, pointing out the costs for OVEC power have increased and, if such costs are more than what the market is willing to pay, OVEC's power may not be purchased in the market; however, Duke will still incur costs from OVEC under the ICPA, but there will be no offsetting revenues (RESA Br. at 9-10; IEU Exs. 8-13; Tr. III at 660). Moreover, RESA notes that, if one of the OVEC plants were to retire, the ICPA obligated the sponsoring companies to pay decommissioning costs as part of the demand charges and, under the PSR, Duke would pass along the decommissioning costs to customers. RESA submits that, if the Commission approves the PSR and commits ratepayers to the remaining life of these 60-year old plants, it should specifically order that Duke's shareholders alone pay for decommissioning and mitigation costs. (RESA Reply Br. at 10.)

OCC, OPAE, and Exelon agree that treating the OVEC net costs in this manner would eliminate Duke's incentive to minimize costs and maximize the operation of the resource and the net revenues, and may eliminate regulatory oversight (OCC Ex. 43 at 11, 33-34; OPAE Br. at 12; OCC Br. at 23-24; Exelon Br. at 6). OCC argues that, since Duke's relationship to the OVEC plants, including the ICPA and its partial ownership of OVEC, are essentially equivalent to partial ownership of the OVEC plants, such costs, other than fuel, associated with the plants are typically subject to traditional regulation. OCC notes that the fixed costs, and variable operations and maintenance costs, are under the utility's control and they are not unpredictable or volatile; thus, they are not appropriate for recovery from customers under a cost tracker mechanism such as the PSR. (OCC Ex. 43 at 34; OCC Br. at 24-25.)

According to OCC, since customers under the SSO will be served under one- to three-year full-requirement contracts that would reflect forward prices, they would not be exposed to substantial market price volatility. However, the OVEC net cost will reflect potentially volatile PJM market revenues, netted from relatively stable OVEC plant costs. OCC notes that the OVEC output would generally be offered into the PJM day-ahead and real-time markets and such prices can reflect extreme weather, unexpected outages, and other unanticipated circumstances. Thus, the PSR would add a potentially volatile element to customers' bills. (OCC Ex. 43 at 12, 28-29; OCC Br. at 12-13; OPAE Br. at 10.) Customers choosing CRES could choose offerings that hedge prices and provide greater stability; however, the PSR could move contrary to, or in the same direction as, the market-based prices (OCC Ex. 43 at 12, 30-31). Therefore, to the extent the PSR affects the volatility of the rates paid, it would be a very modest impact, according to OCC (OCC Ex. 43 at 13, 30-31; OCC Br. at 16). Moreover, IEU explains that, if it is a hedge, the PSR, based on Duke's 9 percent OVEC entitlement, would hedge no more than 8.67 percent of Duke's total retail sales (IEU Br. at 6, 29; Tr. II at 461-462; Tr. III at 607-608).

RESA submits the costs for Kyger and Clifty have not been stable and, in fact, have been above market over the last five years, with approximately a 53 percent increase over that period. Thus, RESA disagrees with Duke's assertion that the units have stable capacity costs that will not rise as quickly as other PJM generation. RESA offers that there is no record evidence that, starting with the next BRA, the two OVEC units will clear the auction, let alone be profitable. (RESA Reply Br. at 8-9.) According to IEU, the average cost of power by OVEC under the ICPA to sponsoring companies is sensitive to the total output of the plants. IEU states that, although the average costs charged to all OVEC sponsoring companies was \$62.86/MWh in 2012, up from \$50.86/MWh in 2011, Duke's average cost of generation under the ICPA was substantially higher at \$70.92/MWh for 2012, and over \$70.00/MWh in 2013. (IEU Br. at 4, 27; IEU Ex. 5 at 2; IEU Ex. 6 at 2; IEU Ex. 13.) In addition, IEU points out the demand portion of OVEC is far from stable, noting that, due to Duke's reduction in the amount of energy service it scheduled with OVEC, its demand-related costs increased from \$24.36/MWh in 2009 to \$41.62/MWh in 2012, or by 71 percent (IEU Br. at 5, 27; IEU Ex. 13; Tr. V at 1356-1357; Duke Ex. 14, Sch. 1 at 2).

Since the OVEC entitlement results in a net cost to customers over the ESP period, OCC asserts the analysis calls into question whether the OVEC plants, or some units, should instead be retired or repowered (OCC Ex. 43 at 25). Moreover, OEC offers that, if the PSR is approved and customers subsidize the OVEC units, this would allow the units to remain operational even though their actual operating costs would exceed the revenues earned in the competitive market. The units would remain open, even though they are noneconomic, and wholesale prices would be kept artificially lower, thus, discouraging other market participants from investing in new generation resources. (OEC Reply Br. at 6.) In response to Duke's assertion that the PSR will achieve retail rate stability when wholesale capacity rates spike upward in the next few years due to PJM's projection of generation being retired, RESA notes that Duke only focuses on retirements and fails to mention the amount of capacity being added. According to RESA, considering the strong level of additional capacity being added, there is no factual support that PJM is on the verge of a capacity shortage. (RESA Reply Br. at 8; IGS Ex. 1.)

Staff submits there is no way to determine if Duke's proposal is the best option for customers, noting the Commission should have the ability to compare different options. However, the Commission does not have that ability because Duke is not proposing any request for proposal or CBP. An auction or request for proposal would allow the Commission to make an informed decision about the value of the PSR proposal and to establish a base price that customers will pay in generation-related costs. (Staff Reply Br. at 16-17.)

(v) Hedge

ELPC, Constellation/RESA, and OMA argue the PSR is not a hedge against market price volatility (RESA Ex. 3 at 6; OMA Br. at 22; RESA Br. at 7, 9; ELPC Br. at 5; ELPC Reply Br. at 2-3). ELPC states the PSR provides a hedge that is only as valuable as the return to customers from the market, and it is subject to swings in the market, including the potential for substantial losses if the OVEC facilities underperform or are subject to severe regulatory restrictions. ELPC asserts there are better hedges available, e.g., renewables and demand response face less risk, and Duke would have found them if it had conducted a competitive process. (ELPC Br. at 5-7.)

RESA and Sierra note that 23 percent of Duke's customers are served under the SSO auctions and are not served with market-priced generation (RESA Br. at 8; Staff Ex. 1 at 10; Sierra Reply Br. at 4-5). Since those SSO customers are not subject to the potential market price volatility the PSR is allegedly intending to hedge, RESA submits it cannot be a market hedge for Duke's SSO customers. As for shopping customers, RESA points out the fixed-cost CRES contracts in effect, without a pass-through provision, will not experience volatility, yet the PSR would be an additional component on their bills. (RESA Br. at 7-8, 11; Tr. II at 472-475; RESA Ex. 3 at 13.) Exelon agrees the PSR introduces volatility that does not currently exist for customers on competitive fixed-price contracts (Exelon Br. at 9). RESA also explains that customers that self-generate would have to pay for the PSR, but they are not subject to the potential market price volatility (RESA Br. at 8). In addition, RESA notes customers could buy options from a financial institution or install distributive generation to achieve long-term retail electric service cost stability (RESA Reply Br. at 11). IEU agrees that the price spikes that may occur due to decreased fuel diversity and changes in PJM and FERC regulations, which Duke mentions to support the PSR, are largely irrelevant to retail customers because retail customers purchase power through the SSO or CRES contracts (IEU Reply Br. at 9). Moreover, GCHC and Wal-Mart note that, to the extent CRES providers have hedged against price volatility, the cost of those hedges is built into their costs (GCHC Br. at 7; Wal-Mart Ex. 1 at 9). Thus, GCHC argues Duke's proposal would require customers of CRES providers to pay Duke for a second hedge (GCHC Br. at 7; Tr. III at 676-677).

GCHC submits the value of OVEC as a hedge is de minimis, as OVEC represents only about 7 percent of Duke's native load, which is too small to be an effective hedge (GCHC Br. at 7; Tr. I at 461-462; Tr. XII at 3404). GCHC submits the OVEC contract is a poor hedge mechanism and the PSR is a pretext to justify shifting responsibility for the OVEC losses to customers. According to GCHC, a typical hedge contract has a known cost and known benefit, wherein there is usually a premium cost to obtain the contract and a strike price, so that the terms of the hedge are clear and it is known when the hedge is in the money. However, in the case of the OVEC entitlement, the hedge concept depends on the notion that, if market prices increase, OVEC would be profitable and would yield positive cash flow. GCHC notes, in this case, it is indefinite under what conditions that would occur, as there is no strike price. Compared to an express hedge product, use of the OVEC entitlement is inferior, according to GCHC. It is speculative when, if ever, those conditions will exist and Duke's projections do not show that happening until well beyond the term of this ESP. (GCHC Br. at 5-6; Tr. VII at 2016-2017.) OPAE submits, given that the entire analysis beginning in 2019 is speculative, there is no evidence upon which the Commission can base a factual decision on the impact of the OVEC subsidy on Duke's distribution customers beyond the negative impact during the term of the ESP (OPAE Br. at 12). Cincinnati agrees there is no empirical evidence on the record to support Duke's claim the PSR will act as a hedge against price volatility (Cincinnati Br. at 3). GCHC notes that, when Duke proposed this hedge, it had no projections of its value and it chose to rely entirely on intuition that it would act as a hedge (GCHC Br. at 6; Tr. II 589; Tr. III at 652-653, 670).

RESA further notes that the PSR does not encourage resource diversity, as Duke's OVEC entitlement will continue to be sold into the PJM market (RESA Br. at 12; Tr. I at 99). OEC points out there is no proposal in Duke's ESP for more energy efficiency, demand side management, or renewable generation, even though the influx of diverse resources into the market could have an even greater hedging benefit if coupled with the coal plants (OEC Br. at 14; Tr. I at 118-119). According to OEC, Duke's proposed hedge is not about an insurance policy for customers, but for shareholders who would otherwise be holding the bag for the cost of an aging coal fleet facing increasing costs from environmental regulations. OEC submits the potential environmental costs will undermine any potential ability for the aging OVEC coal plants to serve as a volatility hedge. (OEC Br. at 14-16.)

Finally, IEU asserts the PSR would place unregulated generation providers at a competitive disadvantage (IEU Br. at 15). IGS and IEU agree allowing Duke's generating units to receive guaranteed recovery of costs from all customers would harm all other generators that do not have guaranteed cost recovery (IGS Ex. 12 at 6; IEU Reply Br. at 12-13). In addition, OCC asserts Duke's claim that the PSR arrangement is competitively neutral is not a benefit, as it simply means the arrangement is benign with respect to retail competition. If the PSR is approved, OCC recommends it be modified to be cost-neutral, thus, reducing the cost and risk to customers and restoring some incentive for Duke to control costs and maximize operation and revenue. OCC offers this could be accomplished by setting a benchmark for the PSR net cost and using a sharing mechanism for net costs or benefits relative to the benchmark. (OCC Ex. 43 at 13-14, 42; OCC Br. at 42.) RESA does not support OCC's proposal, stating it could still result in additional costs for Duke's customers (RESA Br. at 22).

While Staff agrees that energy prices in the PJM footprint have been volatile recently, it believes that a more effective approach for mitigating price volatility is the staggering and laddering approach adopted in past SSO procurement auctions (Staff Ex. 1 at 12-13; Staff Br. at 6). RESA, OEC, OPAE, and OCC agree the staggering of auctions and laddering of products provides a more effective hedge against price volatility (RESA Br. at 11; OEC Br. at 13; OPAE Br. at 10; OCC Br. at 2).

OEG responds that, while staggering and laddering may help mitigate price volatility for nonshopping SSO customers, they are limited by the fact that all of the auction results that make up the blended price stem from the PJM wholesale market, wherein market price is significantly higher than OVEC costs over a long period of time. OEG submits the PSR is a cost-based hedge, which is not available through the SSO auction or a fixed-price contract with a CRES provider, that protects both SSO and shopping customers. The PSR is a unique hedge that reflects the difference between the relatively stable OVEC costs and the relatively volatile PJM market. (OEG Br. at 10-11.)

Duke acknowledges that, while an auction format has a price smoothing effect in that resulting SSO prices reflect, at times, combined auction clearing prices, the laddering format cannot counteract increasing wholesale capacity market prices. Duke asserts Staff disregards the fact that events influencing the wholesale market also influence retail rates. Although reliance on a basic laddering approach may have functioned well in the past, Duke contends, circumstances are changing and it would be unreasonable to reject an option to counter the impending consequences. (Duke Reply Br. at 67.)

(vi) Reliability

RESA and OEC agree the PSR will not assist with generation reliability for Ohioans (RESA Br. at 12-13; OEC Br. at 5; Tr. I at 98; Tr. II at 412-413; Duke Ex. 41 at 4, 8). Constellation/RESA note, to the extent reliability is truly an issue, PJM has a process for studying reliability and providing a reliability must run contract for any units necessary (RESA Ex. 3 at 15). IEU and IGS agree reliability concerns do not support the PSR, noting that PJM has more generation in the construction queue than the amount expected to retire and, if there is a concern the generation will not serve the balance of the region that includes Ohio, such concern is being addressed by new generation resources sited in Ohio (IEU Br. at 15; Tr. I at 78-81; IEU Exs. 3-4; Tr. X at 2697; IGS Reply Br. at 11). GCHC notes Duke's primary claim that OVEC would protect against price spikes was the 2014 polar vortex; yet, the OVEC units had outages during that event and retail customers were not directly exposed to daily price volatility caused by such events (GCHC Br. at 7; Tr. III at 621-622). Moreover, IEU points out PJM survived the 2014 polar vortex storm and is addressing the effects of adverse weather conditions on system reliability and volatility of prices (IEU Br. at 15).

Staff notes that all the necessary resources required for reliability during the term of this ESP have already been procured for the entire PJM footprint, including Duke.

Therefore, granting the PSR will not increase the reliability of the grid in the PJM footprint. (Staff Br. at 10; RESA Br. at 13; Tr. XVI at 4263.) Moreover, Staff submits the Commission has the tools necessary to address other potential reliability needs in the future, i.e., the Commission could approve a nonbypassable rider to fund construction of a new generating facility. Staff submits this process is more effective than the PSR because it requires proof that a capacity need exists, construction would involve a CBP, and the facility would actually supply power to Duke's customers. (Staff Br. at 10; Tr. XII at 3393-3396.)

(vii) Other Statutory Provisions

RESA argues the PSR is contrary to Ohio's restructuring paradigm set forth in R.C. 4928.03, which separates electric service into open-market competitive services and regulated utility services, noting the statute specifically lists generation as a competitive service. According to RESA, since the alleged purpose of the PSR is to moderate the price of generation, it is a competitive service, not a utility service. In addition, RESA submits the PSR violates R.C. 4905.22, which prohibits unreasonable charges by a utility. (RESA Br. at 17-19.)

Kroger submits the PSR would make all customers, including shopping customers, responsible for Duke's legacy generation costs long after the period for transition cost recovery ended, which was December 31, 2010, pursuant to R.C. 4928.40 (Kroger Ex. 1 at 4, 6; Kroger Br. at 13-14). IEU asserts the PSR is barred by R.C. 4928.38 and the stipulation approved in *In re Cincinnati Gas and Elec. Co.*, Case No. 99-1658-EL-ETP, et al., (*ETP Case*) Opinion and Order (Aug. 31, 2000). IEU states, under R.C. 4928.32 to 4928.40, an EDU had a single opportunity to collect transition revenue from customers if it could demonstrate it had transition costs and the EDU had a limited time during which it could collect such revenue. According to IEU, in 2000, Duke sought, but gave up, any claims it had to secure generation-related transition revenue through its settlement in the *ETP Case*. IEU claims Duke is seeking to recover additional transition revenue through the PSR when the revenues it recovers from PJM are less than the amounts it pays OVEC. Since Duke did not present a claim for transition revenue that complies with the statutory requirements, the time for recovery of transition revenue has expired, and Duke stipulated that it would not seek generation-related transition revenue in the *ETP Case*, the PSR cannot lawfully be authorized. (IEU Br. at 16-19.) OMA, OCC, OPAE, and ELPC agree the Commission cannot grant additional transition revenues, as such would be contrary to R.C. 4928.38 (OMA Br. at 20; OCC Br. at 18; OPAE Br. at 9; ELPC Br. at 15).

Duke responds that, as the PSR was not proposed pursuant to R.C. 4928.32 or 4928.40, IEU's argument that Duke has not supported its request for transition revenue is not helpful. According to Duke, the PSR is proposed as a financial hedge as permitted under R.C. 4928.143, and the PSR is not proposed pursuant to the transition statutes and nothing about the rider is designed to recover stranded costs. (Duke Reply Br. at 66.)

(viii) <u>Entitlement/Corporate Separation</u>

GCHC notes that Duke proposed the PSR continue as long as it holds its OVEC entitlement. GCHC offers that Duke has the ability to sell or transfer its interest in OVEC by satisfying the conditions of the ICPA. As long as Duke's investment in OVEC is cash flow negative, Duke has incentive to keep the PSR, thus, shifting the losses to distribution customers. If the OVEC investment turns positive, Duke would have incentive to monetize its investment by selling or transferring the investment out of the reach of the Commission. (GCHC Br. at 7-8; RESA Br. at 14; Tr. I at 117-118.) RESA agrees, noting that Duke already has authority from FERC to transfer the OVEC entitlement to another entity (RESA Br. at 14; Tr. II at 492).

GCHC contends Duke's corporate separation plan (CSP) prohibits the PSR, noting that, heretofore, Duke has treated OVEC as a part of its unregulated business (GCHC Br. at 12; Duke Ex. 12; Tr. II at 385; Tr. III at 673-675). In fact, Duke's CSP lists OVEC as an affiliate (GCHC Br. at 12; Tr. IV at 954, 957, 1023). GCHC asserts that, for purposes of Duke's CSP, OVEC is an affiliate and Duke cannot condition the provision of distribution service to customers assuming financial responsibility for OVEC. Even though Duke claims the OVEC interest is a minority interest, GCHC states there is no reason why a majority and minority interest in affiliates should be treated differently for purposes of the prohibition on tying arrangements. (GCHC Br. at 13.)

Duke contends GCHC's argument that OVEC is an affiliate of Duke has no legal basis. According to Duke, FERC has agreed that no sponsoring company of OVEC is an affiliate of OVEC, as they do not have the necessary control. *Citing* FERC Case No. ER 11-344, (May 23, 2011). (Duke Reply Br. at 64; Duke Ex. 14.) Duke witness Hollis confirmed Duke does not own any part of OVEC, has no control over OVEC, and OVEC is not an affiliate of Duke (Duke Reply Br. at 65; Tr. IV at 969, 971, 975). Moreover, Duke notes that its current CSP was adopted pursuant to R.C. 4928.17 and fulfilled the requirements of Ohio Adm.Code Chapter 4901:1-35 (Duke Reply Br. at 65).

(ix) <u>Allocation/Rate Design</u>

Constellation/RESA believe that, when a customer takes supply from a CRES supplier, the customer is receiving all of the generation-related service from that company. Direct Energy, OEC, and OPAE agree, if a customer is forced to continue to pay Duke for generation-related supply charges, like the PSR, plus pay the CRES provider for generation service, the customer is effectively paying twice for the same service. (RESA Ex. 3 at 10; Direct Energy Ex. 1 at 5-6; OEC Br. at 10; OPAE Br. at 14.) If some form of a

PSR is approved, IGS asserts it should be limited to just OVEC costs (IGS Ex. 12 at 19; IGS Br. at 32). In addition, Kroger, IGS, and Wal-Mart recommend it be a bypassable rider (Kroger Ex. 1 at 8; IGS Ex. 12 at 19; Wal-Mart Ex. 1 at 3). OCC disagrees, noting that Duke's proposed allocation of the PSR is on a $/kWh basis to all customers. OCC believes this would be the only reasonable basis to allocate this profit or loss sharing mechanism, since no capacity or energy is actually utilized to serve any customer. According to OCC, allocating the charge to just SSO customers or just shopping customers would improperly suggest the charge is associated with serving either the SSO or non-SSO market. (OCC Ex. 46 at 24; OCC Br. at 99-100; OCC Reply Br. at 45.) OCC contends, unless all customers are given the right to choose whether to take the PSR, all customers should have to pay for the PSR (OCC Reply Br. at 46).

If the PSR is approved as a nonbypassable rider, Kroger recommends it have an allocation and rate design approach that reflects the fixed cost component of the PSR, claiming Duke's recommendation to allocate and design the entirety of the PSR on the basis of energy does not reflect cost causation. However, as the PSR represents the difference between the demand and energy costs OVEC allocates to Duke, and the revenue from wholesale capacity and energy sales of Duke's OVEC entitlement, the PSR is not strictly energy related. Thus, Kroger offers two options. First, calculate the difference between the demand-related OVEC costs allocated to Duke and the revenue from the sale of Duke's OVEC capacity entitlement, which would be allocated to customer classes on the basis of demand and designed as a per kW rate for demand customers. The difference between energy-related OVEC costs allocated to Duke and the revenue from the sale of Duke's energy entitlement would be allocated to customer classes on the basis of energy and designed as a per kWh rate. Alternatively, the net difference between the total OVEC costs allocated to Duke and the total revenues generated from the sale of Duke's entitlement could be apportioned into demand- and energy-related components, based on the demand and energy proportions of OVEC costs allocated to Duke. The demand- and energy-classified portions of the PSR would be allocated and designed based on their respective classifications. (Kroger Ex. 1 at 4, 8-9.)

Direct Energy recommends that, if any of the OVEC costs are shifted to consumers, it should first be applied to service for percentage of income payment plan (PIPP) customers. According to Direct Energy, this would ensure the power paid for is actually used by the customers who pay for it and that customers who have no other choice receive the power to avoid interrupting CRES customers' contracts. In addition, PIPP is a fairly consistent load, so concerns of over- or under-supply should be minimal. In addition, PIPP load is not likely to leave the utility and is, therefore, suitable for long-term commitment to OVEC power. Direct Energy explains that the PIPP share would be approximately one-third of Duke's OVEC supply and the remainder would be the responsibility of shareholders and sold to the market. (Direct Energy Ex. 1 at 9-10; Direct

Energy Br. at 13-14.) According to Direct Energy, its proposed mechanism would not usurp the authority of ODSA to aggregate PIPP load and set the price for PIPP load, because the Commission's decision to procure PIPP load in this manner would only apply until ODSA exercised its statutory right to aggregate PIPP customer load for generation service. Once ODSA's procurement was effective, the PSR would go away and Duke would be free to sell that power into the markets. (Direct Energy Br. at 15; Direct Reply Br. at 6-7; Tr. IX at 2664-2665.)

ODSA argues Direct Energy's proposal should be rejected because it is unreasonable, unlawful, and indefensible. ODSA submits Direct Energy's proposal is unlawful as it eliminates ODSA's ability to aggregate PIPP customers pursuant to R.C. 4928.54, because it would commit PIPP customers to take OVEC power through 2040, thus, eliminating ODSA's statutory right to aggregate. ODSA notes that Direct Energy admitted its recommendation cannot be implemented without ODSA's consent; however, no evidence is offered to support that the proposals are consistent with ODSA's statutory directive and Direct Energy presents no rationale to lead ODSA to accept the proposals. According to ODSA, Direct Energy's proposal would violate the statutory directive that ODSA ensure that energy services be provided to low-income consumers in an affordable manner under R.C. 4928.02 and 4928.58. (ODSA Br. at 4-6; Tr. IX at 2618-2619.)

(x) *ESP 2 Case*

Staff, IGS, OMA, and OCC assert that Section VIII of the stipulation approved in the *ESP 2 Case* required that all generation assets be transferred out of Duke no later than December 31, 2014 (Staff Ex. 1 at 6; Staff Br. at 2, 11; Tr. XII at 3420-3423; IGS Ex. 12 at 6; OMA Br. at 25-26; IGS Br. at 24; OCC Br. at 44). Thus, regulated cost-of-service recovery for Duke's generation assets should cease to exist at that time; however, Staff notes that Duke is now proposing to reregulate some of its generation assets, its 9 percent OVEC interest (Staff Br. at 3-4). Whether Duke owns directly or owns equity/stock in a generating asset, it is Staff's opinion that Duke owns entitlement to all energy and capacity that comes out of the generating asset (Staff Ex. 1 at 6; Staff Br. at 11). Staff notes, and OMA agrees, that, contrary to the assertions of Duke, there was no provision in Section VIII of the stipulation in the *ESP 2 Case* that specifically excluded from the transfer requirement Duke's entitlement in the OVEC generating station (Staff Ex. 1 at 6-7; OMA Br. at 18). Therefore, Staff opines that Duke should either transfer or sell its OVEC entitlement by December 31, 2014, or file a request for waiver similar to the one AEP filed in *In re Ohio Power Co.*, Case No. 12-1126-EL-UNC (Staff Ex. 1 at 7; Staff Br. at 14).

OCC emphasizes that, under the stipulation in the *ESP 2 Case*, Duke's wholly-owned generating assets, as well as its contractually-owned interests, were to be transferred, with specified exceptions, which are not alleged by Duke in this case, i.e., if substantial increased liabilities would result from the transfer of Duke's interest in OVEC or if the terms of the OVEC contract prevented Duke's interest from being transferred (OCC Br. at 47-49). In response, Duke avers that, upon review of the relevant provision of the stipulation in the *ESP 2 Case* referred to by OCC, it is clear that the contractual obligations at issue here are those that relate to the legacy generation assets being transferred (Duke Reply Br. at 73-74; OCC Ex. 2 at 25-26). According to Duke, the language, taken as a whole and read in context, confirms the intent was to avoid any conduct that would be perceived as violating corporate separation. To allow any other interpretation yields the irrational conclusion that Duke would be required to transfer most contracts, e.g., labor contracts related to its utility business. Even if the Commission agrees Duke must transfer the ICPA, Duke points out there is no obligation to do so, because the terms of the ICPA provide that Duke could only transfer the ICPA to an affiliate if the affiliate is creditworthy or if Duke remains financially liable for all obligations under the ICPA. (Duke Reply Br. at 74.)

OCC states that the record reflects Duke did not make a good faith effort to transfer its interest in OVEC to an unregulated affiliate or third party under the terms of the ICPA. OCC espouses that, in light of Duke's failure to pursue consent of the OVEC sponsoring companies to transfer, the Commission should direct Duke to take measures to obtain such consent. (OCC Br. at 48-55.) Although Duke claims the directive to divest in the *ESP 2 Case* does not extend to the OVEC entitlement, IEU notes that Duke sought and received authority from FERC to transfer its OVEC entitlement to a subsidiary, Duke Energy Piketon. However, Duke later reported that it did not intend to transfer the OVEC entitlement, which leaves Duke obligated to pay its portion of the costs of operations of OVEC. *See Cinergy Corp., et al.,* 140 FERC ¶61,180, Order (Sept. 5, 2012). (IEU Br. at 3; OCC Br. at 48; Tr. X at 2731.)

IGS points out that the stipulation in the *ESP 2 Case* required Duke, the EDU, to cease providing CRES and to operate solely as an EDU in the business of providing noncompetitive service, and to implement separate accounting requirements for services other than Duke's noncompetitive service. However, the PSR does not relate to noncompetitive service, it relates to generation service, which is a competitive service under Ohio law, and would allow Duke to continue to account for OVEC-related costs and revenues on the books of the EDU. IGS asserts, and OEC and Exelon agree, Duke is obligated to transfer its generating assets and entitlements out of the EDU to achieve full legal corporate separation as contemplated by R.C. 4928.17(A). (IGS Br. at 25-26; OEC Br. at 8-9; Exelon Br. at 4-5.)

Staff notes that, as part of the stipulation in the *ESP 2 Case*, Duke was permitted to collect $330 million from customers for its Electric Stability Service Charge (ESSC), thus, settling Duke' capacity revenues issue. According to Staff, the ESSC was an important element that would ensure Duke achieved a fully-established competitive electric market where market forces dictate the success or failure of Duke's former generation assets, not the Commission. (Staff Br. at 3.)

Duke explains that the stipulation in the *ESP 2 Case* required Duke to transfer its generating assets, which were defined in the stipulation as encompassing those assets directly owned by Duke. The stipulation was silent with regard to Duke's contractual entitlement in OVEC. Duke believes this is understandable, since Duke does not directly own the Kyger or Clifty facilities. Thus, Duke contends the stipulation in the *ESP 2 Case* cannot reasonably be interpreted as necessitating the transfer of Duke's interest in OVEC. In addition, Duke points out that, if OVEC were an affiliate, as GCHC contends, Duke would have no obligation to transfer it under the stipulation in the *ESP 2 Case,* because generation owned by affiliates was expressly and intentionally excluded from the assets to be transferred pursuant to the stipulation. (Duke Reply Br. at 71-72; OCC Ex. 2 at 9, FN 9, 25.)

Duke further states the Commission does not have the authority to compel Duke to transfer its contractual entitlement in OVEC. The rules for corporate separation limit a utility's ability to compete for retail generation service in its own territory but it has the right to participate in wholesale generation markets by owning generation, owning entitlements to generation, and competing for retail generation service in service territories other than its own. Duke believes the entitlement to OVEC's generation under the ICPA is similar to the entitlement Duke has under the contract for SSO supply. (Duke Reply Br. at 75.)

(xi) Federal

IGS submits that states lack authority to authorize contracts for differences, which provide supplemental compensation in addition to the amounts a generation resource can obtain from participating in PJM wholesale markets. *Citing PPL Energy Plus v. Soloman,* 766 F.3d 241 (3d Cir. 2014) (*Soloman*). (IGS Ex. 12 at 8.) Staff, IEU, OPAE, OCC, Exelon, Cincinnati, and OMA point to a United States (U.S.) Court of Appeals decision that held Maryland's scheme to subsidize generators participating in PJM markets was preempted by the Federal Power Act (FPA) for their position the PSR is likewise preempted. *PPL EnergyPlus, LLC v. Nazarian,* 753 F.3d 467 (4th Cir. 2014) (*Nazarian*). (Staff Br. at 18-21; IEU Br. at 21-22; OPAE Br. at 13; OCC Br. at 5-6; Exelon Br. at 6-7; Cincinnati Br. at 4-5; OMA Reply Br. at 6-8.) IEU, IGS, and Cincinnati expound that attempts by states to increase the compensation of a generation owner for wholesale capacity and energy services are preempted because they invade a field of regulation within the exclusive jurisdiction of FERC. *PPL EnergyPlus, LLC v. Hanna,* 977 F. Supp.2d 372 (D.N.J. 2013) (*Hanna*), *aff'd, Solomon,* 766 F.3d 241 (3d Cir. 2014). (IEU Br. at 20-24; IGS Br. at 22-23; Cincinnati Br. at 6-7.) Exelon explains that, in *Nazarian,* the Maryland Public Service Commission (PSC) ordered EDUs to enter into 20-year contracts with a generation plant owner and ordered the EDUs to pay the difference between the generator's sale of power in the PJM wholesale market and the contract price; the difference was to be passed on to ratepayers. In *Nazarian*, the federal court decided the Maryland PSC fixed a value for the generator's wholesale capacity and energy and that was not within the commission's authority, as it was in the exclusive jurisdiction of FERC. In *Hanna*, the New Jersey legislature passed a law allowing the New Jersey Board of Public Utilities to order the EDUs to enter into contracts with a generation plant owner to pay the difference between the new generator's sale of power in the wholesale market and the contract price. The federal court found the statute null and void, stating it was preempted by federal law. Exelon asserts *Nazarian* and *Hanna* are factually similar to Duke's PSR, in that the financial risk of the wholesale generator is being transferred to state retail customers via an order of the Commission, and because Duke will be receiving a full hedge and guaranteed cost return on the OVEC power, with no incentive to offer this generation into the market. The main difference is that, in Maryland and New Jersey, the state sought to build a new power plant to improve reliability. (Exelon Br. at 6-7.)

According to OCC, Duke's proposed PSR would violate the Supremacy Clause of the U.S. Constitution Article VI, upon which FERC's preemptive authority is based (OCC Br. at 6). Moreover, IEU notes the Ohio Supreme Court acknowledges such preemption. *Mkting Research Services, Inc. v. Pub. Util. Comm.*, 34 Ohio St.3d 52, 517 N.E.2d 540 (1987). (IEU Br. at 6, 20-24.) OMA and Sierra agree the Commission is prohibited from approving the PSR, which would increase Duke's total compensation for wholesale electric service, since the Commission is preempted from regulating the wholesale price of capacity and energy by the FPA (OMA Br. at 21; Sierra Br. at 21-22).

Conversely, Duke and OEG submit the PSR will not violate the FPA and it is not similar to the situations in *Nazarian* and *Hanna* (OEG Br. at 11; Duke Reply Br. at 46). According to OEG, in *Nazarian* and *Hanna*, the state commissions attempted to establish supplemental wholesale rates and mechanisms to true-up costs at the wholesale levels, which they cannot do as that is the province of FERC. With the PSR, the true-up function would be solely at the retail level between Duke and its customers, pursuant to state law, and the rate paid by Duke to OVEC would be pursuant to a cost-of-service rate filed with FERC. The PSR structure does not alter or modify the FERC-filed rates. In addition, the state commissions in *Nazarian* and *Hanna* were attempting to establish state methods to subsidize the construction of new generation, which undermined the price signals provided by the FERC-approved Reliability Pricing Model (RPM) market construct; however, the PSR is not to encourage new generation, but to stabilize rates by acting as a hedge. Duke points out that, unlike the generating assets at issue in *Nazarian* and *Solomon*, the generation underlying the PSR has been in existence and is not controlled by Duke. In addition, unlike the federal cases, there is no set amount Duke will receive; rather, the capacity revenues in the PSR will be determined by PJM's competitive auction process.

(Duke Reply Br. at 50-51.) Moreover, OEG and Duke assert that, unlike in *Nazarian* and *Hanna*, PJM's FERC-approved minimum offer price rule (MOPR), set forth in *PJM Interconnection, LLC*, 143 FERC ¶61,090, Order (May 2, 2013), does not apply to the PSR because the MOPR applies to new gas generation, not existing coal resources such as the OVEC units (OEG Br. at 12-13; Duke Reply Br. at 51). IGS submits it is irrelevant that the PSR pertains to existing generation resources not subject to the MOPR, as the violation of federal law occurs by establishing a supplemental rate for a generation resource, thus, the Commission enters into FERC's jurisdiction (IGS Reply Br. at 14).

IGS, Staff, and OCC state that, if the PSR is approved, the Commission will have limited authority to effectively audit OVEC-related costs (IGS Br. at 31; OCC Br. at 26; Staff Reply Br. at 11). IGS notes that, as admitted by Duke's witness, if the Commission evaluates the prudence of OVEC's costs, the Commission would not have the authority to interject what Duke pays OVEC, as it would be preempted by FERC (IGS Br. at 31-32; Tr. III at 645). While the Commission may have authority to disallow costs for imprudence, such a decision would only reduce Duke's ROE (IGS Br. at 32).

Duke maintains the claims of preemption by Staff and intervenors are meritless. The scope of jurisdiction of FERC over the electric industry is not so absolute that it eliminates the Commission's authority to approve the PSR. According to Duke, with the FPA, Congress vested federal control with FERC to regulate the sale of electricity at wholesale in interstate commerce, but preserved state authority over many aspects of the electric energy industry. Therefore, states retain jurisdiction over local matters. *Citing Solomon* at 246-247. Duke opines that preemption concerns a comparison of federal and state laws and the basic assumption is the Congress did not intend to displace state law. *See PLIVA, Inc. v. Mensing*, 131 S. Ct. 2567, 2570, 180 L.Ed.2d 580 (2011); *Farma v. Nokia, Inc.*, 625 F.3d 97, 116 (3d Cir. 2010). (Duke Reply Br. at 44-45.)

Duke submits R.C. Title 49, specifically R.C. Chapter 4928, is limited in its scope to retail energy matters; thus, it does not run afoul of the FPA or FERC's jurisdiction over the wholesale electricity market. Moreover, Duke maintains the PSR does not and cannot set wholesale capacity prices. The PSR is structured to have no impact on clearing prices for new, wholesale capacity, the amounts paid by Duke under a FERC-approved agreement, or other market participants' motivation to add new or retire old generation, which are under FERC's jurisdiction. (Duke Reply Br. at 49-50.) Duke emphasizes nothing about the PSR can or will determine the wholesale prices for capacity or energy, as its PSR proposal does not undermine the BRA process or Duke's intention to offer its share of energy into the PJM day-ahead and real-time markets every day. Therefore, Duke asserts the PSR is materially different than the state programs at issue in *Nazarian* and *Solomon*, both legally and technically. (Duke Reply Br. at 53-54.)

(xii) Other Concerns

Staff, Sierra, and Kroger opine that granting the PSR shifts the risk associated with the OVEC generating stations to Duke's customers (Staff Ex. 1 at 11; Sierra Ex. 4 at 3; Kroger Br. at 10, 12). RESA agrees that the real purpose of the PSR is to provide Duke with revenue certainty (RESA Br. at 15; Tr. I at 106-107; Tr. II at 519-520). Constellation/RESA submit that the possibility that OVEC generation may produce a gain does not change the fact that it is a generation risk (RESA Ex. 3 at 11). Given that Staff recommends denial of the PSR, Staff submits that, since the risks associated with that generation would be borne by the owners of Duke, the owners should also receive the rewards. Thus, Staff also recommends that all expenses and revenues associated with Duke's interest in OVEC be excluded from the significantly excessive earning test (SEET) calculation. (Staff Ex. 1 at 12; Staff Br. at 5.)

While Duke has requested the right to terminate the ESP one year early, OCC contends that, if the PSR is approved, Duke should only be allowed to terminate the PSR if authorized by the Commission, after all parties have the opportunity to be heard. Allowing Duke to terminate the PSR early would potentially allow Duke to impose the net cost of OVEC plants on customers for some period and then, if conditions change and the plants are anticipated to become economic, terminate the PSR and retain the net benefits. Early termination would also create an incentive to maximize capital and maintenance expenses while such costs are being passed on to customers. (OCC Ex. 43 at 44-45.)

Staff notes that Duke proposes that the PSR "could be expanded to include similar financial arrangements with other generators to provide further protection for Ohio customers." However, with the September 11, 2014 filing with FERC to sell all of Duke Energy Commercial Asset Management's (DECAM) generators to Dynegy Resource I (Dynegy), expanding Rider PSR is no longer an option for Duke. (Staff Ex. 1 at 4-5; Duke Ex. 2 at 10.) Constellation/RESA, Direct Energy, and Exelon are likewise concerned about Duke's proposal to expand the PSR to include additional PPAs, stating that, even if the PSR is approved, Duke's request to potentially expand for other PPAs must be rejected (RESA Ex. 3 at 6; Direct Energy Ex. 1 at 8; RESA Br. at 19). IGS agrees, since Duke has indicated it has transferred its other generating assets and there is a definitive purchase agreement to sell the remaining generating assets to Dynegy, there is no reason to leave the door open for Duke to include additional PPAs in the future (IGS Br. 32-33).

If the PSR is approved, Staff sets forth areas of concern and recommended conditions that could mitigate Staff's concerns. Since Duke has filed an application with FERC to sell the DECAM assets to Dynegy, Staff's concern for expanding the PSR to include other Duke-owned generation assets is no longer applicable. However, as for Duke's interest in the OVEC generating stations, Staff recommends the Company be required to request, in its corporate separation docket, a waiver for the requirement set forth in Section VIII of the stipulation in the *ESP 2 Case*. Next, if the Commission grants Duke's waiver from the requirement to transfer its interest in OVEC to an affiliate and grants the PSR, the term of the rider should be no longer than the term of this ESP. In addition, as proposed by Duke, the fixed and variable expenses will be components of a wholesale contract between Duke and the entity managing Duke's interest in OVEC; thus, the contract would be under the jurisdiction of FERC. If the Commission believed any of those expenses were not prudent, it would have to file at FERC to challenge the items and the burden would be on the Commission. Therefore, Duke should be required to accept that all fixed and variable expenses could be audited by the Commission and accept a Commission finding to the extent there is disagreement between Duke and the auditor. Further, all revenues from Duke's interest in OVEC will be components in the wholesale contract; thus, to mitigate Staff's concern, Duke would not have an incentive to use a profit-maximizing bidding strategy, Staff would periodically monitor/evaluate the bidding strategies used for the OVEC units with those used by other generation owners in PJM. (Staff Ex. 1 at 13-16; Staff Br. at 7-8, 25-26.)

In response to Staff's proposals, RESA notes that limiting the term of the PSR to the term of the proposed ESP would simply reward Duke for not having divested the OVEC entitlement, while requiring customers to pay for the entitlement and receive none of the credits. Second, while Staff is not concerned with additional arrangements being proposed for the PSR because Duke has filed an application with FERC to sell all of the DECAM assets to Dynegy, Staff has overlooked that the Dynegy transaction has not gone through and may not go through.[1] Moreover, there is nothing to stop a Duke affiliate from acquiring other generation assets and Duke proposing additional arrangements during the lengthy period proposed by Duke for the PSR. In addition, RESA submits the monitoring and evaluations proposed by Staff will open up new and complicated evaluations of wholesale bidding, which is better avoided by rejecting the PSR. (RESA Br. at 21-22.)

(c) PSR Conclusion

The Commission thoroughly considered Duke's request for approval of the PSR, which, as proposed by Duke, would extend beyond the term of the ESP to June 30, 2040, and flow through to customers, on a nonbypassable basis, the net benefit or cost from Duke's sale of its OVEC contractual entitlement into the PJM market less all associated costs. Duke also seeks approval to expand the PSR in the future to include similar financial arrangements. The PSR, according to Duke, provides three primary benefits. First, it provides a financial hedge against market volatility and tempers the prices customers will see in generation rates, thereby adding price stability and certainty and

[1] On March 27, 2015, FERC authorized Dynegy's acquisition of the DECAM assets. *In re Dynegy, Inc. et al.*, 150 FERC ¶61,231, Order (Mar. 27, 2015).

allowing customers to take advantage of market opportunities. Second, Duke submits the OVEC proposal is competitively neutral and will not impact the CRES market or CRES providers' ability to compete for customers. Finally, the proposal benefits Ohio by providing reliable power from the OVEC generating assets. (Duke Ex. 1 at 13-14; Duke Ex. 6 at 13-15.) In reviewing Duke's proposed PSR and the considerable evidence of record offered by Duke, Staff, and intervenors with regard to the proposal, the Commission has been guided by two key considerations, specifically whether the PSR may be authorized under R.C. 4928.143(B)(1) or (B)(2) and, if so, whether Duke's proposal would provide the purported benefits or otherwise further the policy of the state.

Initially, the Commission must determine whether the proposed PSR mechanism may be considered a permissible provision of an ESP, in accordance with R.C. 4928.143(B)(1) or (B)(2). The Commission has the authority to approve, as a component of an ESP, only items that are expressly listed in the statute. *Columbus S. Power Co.*, 128 Ohio St.3d 512, 2011-Ohio-1788, 947 N.E.2d 655. Duke focuses primarily on R.C. 4928.143(B)(2)(d) as its statutory basis for the PSR.

Under R.C. 4928.143(B)(2)(d), the Commission can approve, as a component of an ESP, terms, conditions, or charges relating to limitations on customer shopping for retail electric generation service, bypassability, standby, back-up, or supplemental power service, default service, carrying costs, amortization periods, and accounting or deferrals, including future recovery of such deferrals, as would have the effect of stabilizing or providing certainty regarding retail electric service. Thus, considering the plain language of the statute, we find that there are three criteria with which the PSR must comply. Specifically, an ESP component approved under R.C. 4928.143(B)(2)(d) must first be a term, condition, or charge; next, relate to one of the enumerated types of terms, conditions, and charges; and, finally, have the effect of stabilizing or providing certainty regarding retail electric service. *See, e.g., In re Ohio Power Co.*, Case No. 13-2385-EL-SSO, et al., (*AEP ESP 3 Case)*, Opinion and Order (Feb. 25, 2015); *AEP ESP 2 Case*, Entry on Rehearing (Jan. 30, 2013) at 15-16; *In re Dayton Power & Light Co.*, Case No. 12-426-EL-SSO, et al. (*DP&L ESP Case*), Opinion and Order (Sept. 4, 2013) at 21-22.

The Commission finds that the first requirement of R.C. 4928.143(B)(2)(d) is met, as the PSR would consist of a charge incurred by customers under the ESP. The PSR, as proposed by Duke, would appear as a charge on customer bills, and there is no dispute among the parties on this point. Although Duke projects that the PSR would provide a net charge over the course of the ESP term, the Company estimates that the rider would result in a net credit to customers by the beginning in 2019 (OCC. Ex. 4). Thus, the record indicates that the PSR would consist of a charge to customers.

Taking the requirements of R.C. 4928.143(B)(2)(d) somewhat out of turn, the Commission will next address the third criterion, which is whether the PSR charge would have the effect of stabilizing or providing certainty regarding retail electric service. We find that the PSR, as a financial hedging mechanism, is proposed to have the effect of stabilizing or providing certainty regarding retail electric service. Duke explained that the PSR will function as a countercyclical hedge, such that, in rising market price environments, the benefits under the rider will be positive, thereby offsetting other rates derived from market prices (Duke Br. at 24). Duke witness Henning surmises that, in a rising price environment, Duke's margins from its OVEC contractual entitlement will be positive and the net amount passed through the PSR should similarly increase (Duke Ex. 2 at 10). The PSR, therefore, is intended to mitigate, by design, the effects of market volatility, providing customers with more stable pricing and a measure of protection against substantial increases in market prices.

Although several intervenors dispute the value of the proposed hedging mechanism and its use as a means to promote rate stability, there is no question that the PSR would produce a credit or charge based on the difference between wholesale market prices and OVEC's costs, offsetting, to some extent, the volatility in the wholesale market. The impact of the PSR would be reflected as a charge or credit for a generation-related hedging service that stabilizes retail electric service, by smoothing out the market-based rates paid by shopping customers to their CRES providers, as well as the market-based rates paid by SSO customers, which are determined by a series of auctions that reflect the prevailing wholesale prices for energy and capacity in the PJM markets. Because Duke has demonstrated that the proposed PSR would, in theory, have the effect of stabilizing or providing certainty regarding retail electric service, the Commission finds that the third criterion of R.C. 4928.143(B)(2)(d) has been met.

Finally, to meet the second requirement of R.C. 4928.143(B)(2)(d), the proposed PSR must relate to at least one of the following: limitations on customer shopping for retail electric generation service, bypassability, standby, back-up, or supplemental power service, default service, carrying costs, amortization periods, and accounting or deferrals. While Duke argues the PSR mechanism addresses bypassability, Duke submits the Ohio Supreme Court has confirmed that R.C. 4928.143(B)(2) allows for unlimited inclusion of the items listed in the statute, as the statute merely delineates the types of categories that may be included in an ESP. *Citing Columbus S. Power Co.*, 128 Ohio St.3d 512, 2011-Ohio-1788, 947 N.E.2d 655, at ¶33. (Duke Br. at 18-19; Duke Reply Br. at 56.)

The Commission finds that R.C. 4928.143(B)(2)(d) authorizes electric utilities to include, in an ESP, terms related to "bypassability" of charges to the extent that such charges have the effect of stabilizing or providing certainty regarding retail electric service. *DP&L ESP Case*, Opinion and Order (Sept. 4, 2013) at 21. As discussed above, both shopping and SSO customers may benefit from the PSR because it would have a stabilizing effect on the price of retail electric service, irrespective of whether the customer is served by a CRES provider or the SSO. Therefore, the Commission agrees with Duke that the proposed PSR, if approved, should be nonbypassable, as authorized by the second criterion of R.C. 4928.143(B)(2)(d). However, we also agree with Staff that, since nearly any charge may be bypassable or nonbypassable, "bypassability" alone is insufficient to fully meet the second criterion of R.C. 4928.143(B)(2)(d).

Nonetheless, the Commission agrees that the proposed PSR is a financial limitation on customer shopping for retail electric generation service. Although the proposed PSR would impose no physical constraints on shopping, the rider does constitute, as OEG explained, a financial limitation on shopping that would help to stabilize rates (OEG Br. at 5; Tr. VII at 1875). Under Duke's PSR proposal, shopping customers will still purchase all of their physical generation supply from the market through a CRES provider. Although the proposed PSR would have no impact on customers' physical generation supply, the effect of the PSR is that the bills of all customers would reflect a price for retail electric generation service that is approximately 3 percent based on the cost of service of the OVEC units and 97 percent based on the retail market (OEG Br. at 6). Effectively, then, the proposed PSR would function as a financial restraint on complete reliance on the retail market for the pricing of retail electric generation service. In light of our determination that the PSR is a financial limitation on customer shopping pursuant to R.C. 4928.143(B)(2)(d), we find that the second criterion of R.C. 4928.143(B)(2)(d) is satisfied.

Having determined that R.C. 4928.143(B)(2)(d) provides the requisite statutory authority, we next consider, based on the record evidence, whether Duke's PSR proposal is reasonable and whether customers would, in fact, sufficiently benefit from the rider's financial hedging mechanism. At the outset, the Commission notes that the power generated by the OVEC units will not be used to supply electricity to Duke's SSO customers. Rather than provide a physical hedge, i.e., providing generation, the OVEC units, in conjunction with the PSR, are intended to function purely as a financial hedge against market price volatility. Although Duke and OEG argue that the PSR would protect customers from price volatility in the wholesale market, there is no question that the rider would impact customers' rates through the imposition of a new charge on their bills. What is unclear, based on the record evidence, is how much the proposed PSR would cost customers and whether customers would even benefit from the financial hedge.

The Duke OVEC analysis reflects that the net cost to customers of Duke's OVEC entitlement over the course of the ESP period would be approximately $22 million rising to $29 million by the end of 2018, with net benefits from 2019 through 2024 of approximately $28 million (OCC Ex. 4). It is undisputed that Duke's projections are based on data assumptions that attempt to predict OVEC's costs and revenues, as well as PJM prices for energy and capacity, over the three-year period of the ESP and beyond. In light of the uncertainty and speculation inherent in the process of projecting the net impact of the proposed PSR, the Commission is unable to reasonably determine the rate impact of the rider.

Although the magnitude of the impact of the proposed PSR cannot be known to any degree of certainty, the Commission agrees with OCC, IEU, and other intervenors that the evidence of record reflects that the rider may result in a net cost to customers, with little offsetting benefit from the rider's intended purpose as a hedge against market volatility. On balance, the record reflects that, during the three-year period of the ESP, the PSR would result in a net cost to customers and that, only over a longer timeframe, would customers perhaps benefit from a credit under the rider. Duke, however, proposes a three-year ESP term and seeks to reserve the right to terminate the ESP after two years, as discussed further below. However, Duke proposes that the PSR extend beyond the term of the ESP, stating that the PSR is structured as a long-term hedge to June 2040, emphasizing that the OVEC commitment is reciprocal and Duke is committing to its customer the net benefits. According to Duke, any shorter termination date does not work. (Duke Reply Br. at 69.)

The Commission must base our decision on the record before us. *Tongren v. Pub. Util. Comm.*, 85 Ohio St.3d 87, 706 N.E.2d 1255 (1999). With that in mind, we are not persuaded that the PSR proposal put forth by Duke in the present proceedings would, in fact, promote rate stability, as Duke claims, or that it is in the public interest. There is considerable uncertainty with respect to pending PJM market reform proposals, environmental regulations, and federal litigation, as Duke acknowledges, and, in light of this uncertainty, the Commission does not believe that it is appropriate to adopt the proposed PSR at this time. Also, as Staff and several intervenors point out, there are already existing means, such as the laddering and staggering of SSO auction products and the availability of fixed-price contracts in the market, that provide a significant hedge against price volatility (Staff Ex. 1 at 12-13; RESA Br. at 11; OEC Br. at 13, OPAE Br. at 10; OCC Br. at 2).

In sum, the Commission is not persuaded, based on the evidence of record in these proceedings, that Duke's PSR proposal would provide customers with sufficient benefit from the rider's financial hedging mechanism or any other benefit that is commensurate with the rider's potential cost. We conclude that Duke has not demonstrated that its PSR proposal, as put forth in these proceedings, should be approved under R.C. 4928.143(B)(2)(d). Nevertheless, the Commission does believe that a PSR proposal, if properly conceived, has the potential to supplement the benefits derived from the staggering and laddering of the SSO auctions, and to protect customers from price volatility in the wholesale market. We recognize that there may be value for consumers in a reasonable PSR proposal that provides for a significant financial hedge that truly stabilizes rates, particularly during periods of extreme weather (Duke Ex. 2 at 4-5, 9-10; OEG Ex. 1 at 16). A review of the record in Duke's previous ESP proceedings, as well as the ESP proceedings of other EDUs, reflects that rate certainty and stability are essential components of an ESP. *See, e.g., In re Duke Energy Ohio, Inc.*, Case No. 08-920-EL-SSO, et al. (*ESP 1 Case)*, Opinion and Order (Dec. 17, 2008) at 38; *ESP 2 Case*, Opinion and Order (Nov. 22, 2011) at 46; *AEP ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 32, 77; *AEP ESP 3 Case*, Opinion and Order (Feb. 25, 2015) at 25.

Accordingly, the Commission authorizes Duke to establish a placeholder PSR, at an initial rate of zero, for the term of the ESP. We note that the Commission has, on prior occasions, approved a zero placeholder rider within an ESP. *ESP 1 Case*, Opinion and Order (Dec. 17, 2008) at 17; *ESP 2 Case*, Opinion and Order (Nov. 22, 2011) at 51; *AEP ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 24-25; *AEP ESP 3 Case*, Opinion and Order (Feb. 25, 2015) at 25; *In re Ohio Edison Co., et al.*, Case No. 08-935-EL-SSO, et al., Second Opinion and Order (Mar. 25, 2009) at 15. The Commission emphasizes that we are not authorizing, at this time, Duke's recovery of any costs through the placeholder PSR. Rather, Duke will be required, in a future filing, to justify any requested cost recovery. All of the implementation details with respect to the placeholder PSR will be determined by the Commission in that future proceeding. In its filing, Duke should, at a minimum, address the following factors, which the Commission will balance, but not be bound by, in deciding whether to approve Duke's request for cost recovery: financial need of the generating plant; necessity of the generating facility, in light of future reliability concerns, including supply diversity; description of how the generating plant is compliant with all pertinent environmental regulations and its plan for compliance with pending environmental regulations; and the impact that a closure of the generating plant would have on electric prices and the resulting effect on economic development within the state. The Commission also reserves the right to require a study by an independent third party, selected by the Commission, of reliability and pricing issues as they relate to the application. Duke must also, in its PSR proposal, provide for rigorous Commission oversight of the rider, including a proposed process for a periodic substantive review and audit; commit to full information sharing with the Commission and its Staff; and include an alternative plan to allocate the rider's financial risk between both Duke and its ratepayers. Finally, Duke must include a severability provision that recognizes that all other provisions of its ESP will continue, in the event the PSR is invalidated, in whole or in part, at any point, by a court of competent jurisdiction.

The Commission finds that our adoption of a PSR, to the limited extent set forth herein, is consistent with the state policy specified in R.C. 4928.02 and, in particular, with our obligation under R.C. 4928.02(A) to ensure the availability to consumers of reasonably priced retail electric service. In response to the arguments raised by various intervenors that the PSR would violate R.C. 4928.02(H), which requires the Commission to ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies, we find that, contrary to intervenors' claims, the rider would not permit the recovery of generation-related costs through distribution or transmission rates. As discussed above, the PSR, whether a charge or a credit, would be considered a generation rate. Moreover, we disagree with the assertion that the PSR would permit Duke to collect untimely transition costs in violation of R.C. 4928.38. As discussed above, the PSR constitutes a rate stability charge related to limitations on customer shopping for retail electric generation service and may, therefore, be authorized pursuant to R.C. 4928.143(B)(2)(d), although, on other grounds, we do not find it reasonable to approve the PSR as proposed by Duke in these proceedings. Some of the parties have also raised the issue of federal preemption. The Commission declines to address constitutional issues raised by the parties in these proceedings, as, under the specific facts and circumstances of these cases, such issues are best reserved for judicial determination.

Finally, the Commission notes that our decision not to approve, at this time, Duke's recovery of any costs, including OVEC costs, through the PSR is based solely on the record in these proceedings, and does not preclude Duke from seeking recovery of its OVEC costs in a future filing.

Further, the Commission notes Staff and intervenors have raised the issue of whether Duke was required under the stipulation in the *ESP 2 Case* to transfer its OVEC entitlement out of Duke. While the record reflects arguments supporting both sides of this issue, the Commission finds that, in light of the fact that the stipulation and the current ESP are coming to an end, it is not necessary for us to evaluate the intent of the stipulating parties in the *ESP 2 Case*. Rather, suffice it to say, it was not the Commission's intent in adopting the stipulation in the *ESP 2 Case* to exempt Duke from pursuing the divestiture or transfer of the OVEC contractual entitlement. Therefore, at this time, we direct Duke to pursue transfer of the OVEC contractual entitlement or to otherwise pursue divesture of the OVEC asset. Duke should file a status report regarding the transfer or divestiture of the OVEC asset, in these dockets, by June 30 of each year of the ESP, with the first such filing to occur by June 30, 2015.

2. <u>Generation Service Supply</u>

(a) <u>Competitive Bid Process Proposal</u>

Duke proposes to procure all of the supply needed for its SSO customers, including Duke's PIPP customers, via a CBP that is consistent with the procurement methodology employed by Duke in the *ESP 2 Case* (Duke Ex. 2 at 5; Duke Ex. 3 at 6). The CBP entails descending-price clock auctions, with: the first two auctions being conducted prior to the delivery period commencing June 1, 2015; an additional two auctions prior to the delivery period commencing June 1, 2016; and the final auctions prior to the delivery period commencing June 1, 2017 (Duke Ex. 1 at 6). Duke witness Lee asserts multiple procurements reduce the risk that SSO prices will be significantly impacted by short-term market conditions at the time an individual procurement is conducted (Duke Ex. 3 at 8-9). Mr. Lee notes that, although load caps may place upward pressure on the auctions' clearing prices, supplier diversity provides some risk mitigation benefits to Duke and the customers. Thus, Duke proposes to adopt an 80 percent load cap on an aggregated load basis across all auction products for each auction date, such that no bidder may bid on and win more tranches than the load cap. (Duke Ex. 3 at 30.) The auction product would be an hourly, load-following, full-requirements tranche of the Company's SSO load for full-requirements service, where a tranche is equal to 1.00 percent of Duke's total SSO load obligation, i.e., Duke's nonshopping load, which includes Duke's PIPP customers. Full-requirements service consists of capacity, energy, ancillary service, and market-based firm transmission services, as defined in the Master SSO Supply Agreement (MSA). (Duke Ex. 1 at 7; Duke Ex. 3 at 8.) Duke reserves the right to terminate the ESP at the conclusion of the second year of the ESP. Thus, Duke explains the bidding process timeline may need to be truncated if the Company elects to pursue this option. (Duke Ex. 1 at 7.)

According to Duke witness Lee, the CBP plan is designed to promote open, fair, and transparent competitive solicitations with clear product definitions, standardized bid evaluation criteria, oversight by an independent third party, and evaluation of the submitted bids prior to the selection of the least-cost bid winner(s) (Duke Ex. 3 at 6). Duke explains that the CBP plan provides for the equal and nondiscriminatory exchange of information and the application of bidding requirements. All prospective bidders will be subject to the same pre-bid requirements and all successful bidders must adhere to the same contractual commitments. Duke retained CRA International, d/b/a Charles River Associates, to design, administer, and oversee the CBP. The CBP plan also contemplates Commission review through the production of a post-auction report and retention of a separate consultant. (Duke Ex. 1 at 6-7.)

Generally, Staff believes Duke's CBP is appropriate and consistent with what Duke and other EDUs have used in the past (Staff Br. at 49). However, Staff recommends Duke's CBP include the potential for modification during the ESP period, as the Commission deems necessary, in order to respond to any unforeseen conditions that may otherwise detrimentally impact the auction process. Staff states this is similar to the requirement in the *DP&L ESP Case*, wherein the Commission retained the right to modify and alter the load cap or any other feature of the CBP for future auctions based on the Commission's continuing review of the CBP, including its review of the reports on the auction provided to the Commission by the independent auction manager. *DP&L ESP*

Case, Opinion and Order (Sept. 4, 2013) at 16-17. (Staff Ex. 3 at 6; Staff Br. at 51.) Exelon supports Staff's proposal (Exelon Br. at 19.).

Staff recommends that, rather than allowing 100 percent of the SSO supply to terminated at the end of the currently proposed ESP period, in order to transition from the currently proposed ESP to the next ESP without a rate volatility impact, the auction laddering and blending process should continue past the end date of the proposed ESP period (Staff Ex. 3 at 5, Att. RWS-1; Staff Br. at 49-50). While Exelon agrees Staff's suggestion could allow for better transitions between ESPs, Exelon believes that, rather than just extending the laddering and blending process indefinitely, there should be an opportunity for modifications or adjustments based on issues that arise. Exelon states a more appropriate middle ground could be developed and suggested in the future. (Exelon Br. at 18.)

According to Staff, it is not clear from the application that the CBP auctions will be advertised. Therefore, Staff recommends Duke or the auction manager be required to place at least one advertisement in an appropriate publication for each auction. (Staff Ex. 3 at 6; Staff Br. at 51.) Exelon agrees with Staff's suggestion, as long as a well-circulated publication is utilized, stating that it will promote the auction and provide a greater opportunity for participation by diverse bidders (Exelon Br. at 19).

Duke submits that the recommendations of Staff and Exelon, which are allegedly aimed at reducing risk and uncertainty, would only serve to inject more risk and more uncertainty, which yields higher auction prices. Specifically, Duke argues extending the procurement period beyond the ESP term is unsubstantiated, invites risk, and deprives Duke of its right to propose the structure of its future SSOs. Therefore, to mitigate against the risk that is likely to result from undefined circumstances, the Commission should consider identifying the conditions pursuant to which future changes to the CBP plan may be made. With regard to Staff's proposal for advertisements, Duke notes Staff provided conjecture, but no proof, concerning the potential value of this recommendation. To the extent the suggestion would yield more bidder participation and, thus, it is cost justified, Duke does not object. However, at this time, Duke believes it is premature given the lack of effectiveness and detail offered by Staff. (Duke Reply Br. at 8-11.)

IGS proposes the Commission conduct a retail auction, rather than wholesale auctions, to procure SSO service, so that CRES suppliers could serve SSO customers directly. In the alternative, IGS proposes a retail price adder (RPA), which is a fee charged to suppliers of SSO service that reflects the cost of providing retail electric service in the market, be adopted. According to IGS, both of these proposals will encourage customers to engage in the retail market and tilt the anticompetitive advantage away from the SSO service. (IGS Ex. 10 at 21-22.)

In response to IGS's proposal, Duke points out that, in the stipulation in the *ESP 2 Case*, IGS agreed to use a wholesale auction structure similar to that proposed by Duke in these cases (Duke Reply Br. at 5-6; OCC Ex. 2 at 4-5). According to Duke, IGS offers no justification for deviating from such commitment. Duke argues the proposal by IGS runs afoul of Commission precedent and the law. *Citing In re Investigation of Retail Elec. Serv. Mkt.*, Case No. 12-3151-EL-COI, (*CRES Market Case*) Finding and Order (Mar. 26, 2014) at 19. Moreover, Duke notes IGS failed to introduce any structure for its proposed retail auctions into the record in these cases. Further, Duke contends the retail auction proposal does not encourage competition, as there would be one auction prior to the commencement of the ESP term, thus, ignoring the potential for new load to enter Duke's service territory. With regard to the proposed alternative RPA adder, Duke states this proposal is not fully developed and there is no statutory provision allowing an ESP to include artificial pricing adjustments to benefit CRES providers. (Duke Reply Br. at 6-7.)

Upon consideration of Duke's proposal to implement full auction-based pricing for its SSO customers, including PIPP customers, for the ESP period beginning June 1, 2015 through May 31, 2018, the Commission finds the proposal is reasonable and should be adopted with the following modifications. The CBP process, including the products offered and the timing of the auctions, should be designed to minimize uncertainty and potential rate volatility for SSO customers. Duke's proposed auction schedule, however, places too much emphasis on 12-month products in the later auctions, which may have the adverse effect of higher prices and greater rate volatility. Accordingly, the Commission finds that Duke's proposed auction schedule should be modified. Specifically, the first auction should occur in advance of the end of the current ESP term on May 31, 2015, and offer a mix of 12-month (34 tranches), 24-month (34 tranches), and 36-month (32 tranches) products, with delivery to commence on June 1, 2015. The second and third auctions should occur in November 2015 and March 2016, respectively, and each offer a 24-month (17 tranches) product. Finally, the fourth and fifth auctions should occur in November 2016 and March 2017, respectively, and each offer a 12-month (17 tranches) product. In addition, the Commission finds that Duke should propose its next SSO sufficiently far in advance of the conclusion of this ESP, in order to blend the final procurements of the instant ESP with the initial procurements of the next SSO. Duke is, therefore, directed to file its next SSO application, pursuant to R.C. 4928.141, no later June 1, 2017. If a subsequent SSO is not authorized by the Commission by April 1, 2018, Duke shall procure, through the CBP process, 100 tranches of a full-requirements product for a term that is not less than quarterly or more than annually to be deliverable on June 1, 2018, until a subsequent SSO is authorized.

Finally, consistent with our determinations in both the *DP&L ESP Case* and the *AEP ESP 3 Case*, the Commission reserves the right to review and modify any feature of the CBP process, as we deem necessary, based upon our continuing oversight of the process, including any reports on the auctions provided to the Commission by the independent auction manager, Duke, Staff, or any consultant retained by the Commission. *DP&L ESP Case*, Opinion and Order (Sept. 4, 2013) at 16-17; *AEP ESP 3 Case*, Opinion and Order (Feb. 25, 2015) at 31. As for Staff's recommendation for advertisements of the CBP auction, the Commission directs Duke to work with Staff to develop a protocol for advertising the auction that will promote the auction, with the goal of attracting more participants to engage in the auction. In response to IGS's proposal for a retail auction, at this time, the Commission finds that the SSO auction, as proposed by Duke, with the modifications set forth herein, should be adopted for purposes of this ESP; however, the Commission will continue to explore all options for possible future consideration.

(b) Master SSO Supply Agreement

The MSA sets forth the contractual obligations of successful suppliers and Duke with respect to each auction. Provisions in the MSA include a contingency plan in the event of supplier default and creditworthiness standards. (Duke Ex. 3 at 12-13.) In addition, the MSA includes a provision that enables cancellation of all contractual obligations, without recourse to any party (Duke Ex. 1 at 7).

ExGen states that the MSA largely mirrors what has been used in previous Duke auctions and it strikes the appropriate balance between various interests. However, certain provisions in the MSA have been altered in a way ExGen does not believe benefit the competitiveness of auctions. (Exelon Ex. 1 at 2; Exelon Br. at 15.) ExGen recommends eight changes to the MSA. First, ExGen proposes the phrase "including, without limitation, through participation in the base residual auctions administered by PJM" be deleted in the sixth recital paragraph. ExGen reasons that SSO suppliers will be charged by PJM for capacity to meet their SSO supplier responsibility share; therefore, an SSO supplier's participation, or lack thereof, in the PJM capacity auctions will have no direct impact on its obligations under the MSA. (Exelon Ex. 1 at 3, Att. 1.) Duke responds that the language referenced is a statement of undisputed fact that explains that each SSO supplier will have capacity-related obligations and it does not dictate how the obligations will be met. Duke argues this language has been approved by the Commission and accepted by suppliers and there is no legitimate reason to change it now. (Duke Reply Br. at 11.) The Commission finds, as explained by Duke, the proposed revision is unnecessary; therefore, it should not be adopted.

Second, ExGen proposes paragraph 2.4, referring to Duke's unilateral right to an early termination, be deleted (Exelon Ex. 1 at 3, Att. 1). Staff agrees stating this provision introduces unnecessary risk and uncertainty into the SSO supply procurement process that could impact participation levels in the auctions, as well as the winning bid prices. Staff asserts, if this provision is implemented, the entirety of Duke's SSO supply would terminate as of May 31, 2017; thus, introducing unnecessary rate volatility. If this provision is retained, Staff recommends it only be allowed to do so with the concomitant requirements that any subsequent ESP include the same CBP for procurement of Duke's SSO supply and that the auction blending process continue unabated. (Staff Ex. 3 at 3-5; Staff Br. at 49-50.) Duke asserts this recommendation by ExGen and Staff should be rejected (Duke Reply Br. at 12). The Commission will address this issue further below.

Third, ExGen proposes the definition of ESP be modified to reflect that the beginning of the ESP period is June 1, 2015 (Exelon Ex. 1 at 3, Att. 1). Duke agrees with this recommendation (Duke Reply Br. at 13-14). The Commission finds this recommendation is reasonable and should be adopted.

Fourth, ExGen proposes PIPP customers be defined and the definition of SSO customers be modified to include PIPP customers (Exelon Ex. 1 at 3-4, Att. 1). The Commission agrees with Duke that this proposed edit is not necessary and should not be adopted (Duke Reply Br. at 13).

Fifth, ExGen proposes generation deactivation and emergency load response be added back to the list in paragraph 3.2(d)(i) of charges for which Duke will retain responsibility, as it is an unhedgeable risk to SSO suppliers and, therefore, must properly rest with the utility; moreover, striking it creates inconsistency with attachment F of the MSA (Exelon Ex. 1 at 4, Att. 1). Duke disagrees, stating, as a market participant, ExGen must be expected to bear risks, including those associated with providing SSO supply. Further, Duke asserts its proposal is appropriate as it acknowledges that the PJM invoice, presented for illustrative purposes, will need to be consistent with the MSA. (Duke Reply Br. at 12-13.) At this time, the Commission finds that Duke's proposal to eliminate emergency load response from the list of charges in the MSA for which Duke will be responsible is reasonable, as we find that such charges should be the responsibility of the SSO supplier. However, consistent with our determination for other EDUs regarding charges for generation deactivation, the Commission finds that Duke's proposal to eliminate generation deactivation from the MSA list should be denied, as such charges should continue to be the responsibility of the EDU. *See AEP ESP 3 Case*, Opinion and Order (Feb. 25, 2015) at 67.

Sixth, ExGen proposes paragraph 3.9 be deleted after the initial sentence; Duke should not be permitted to unilaterally revise the declaration of authority, unless such change is necessary to maintain consistency between the declaration of authority and the parties' obligation under the MSA (Exelon Ex. 1 at 4, Att. 1). Duke maintains the Company has the right to protect its customers as it deems fit and part of that responsibility includes ensuring auction participants are properly credentialed. Duke asserts there is value in allowing Duke the appropriate business flexibility to run its auctions in a manner consistent with good business practices. (Duke Reply Br. at 13.) The Commission finds that ExGen's proposal should not be adopted. To the extent Duke exercises this provision to protect SSO customers by ensuring proper credentials by auction participants, the Commission finds that the language is appropriate.

Seventh, ExGen proposes paragraph 6.2(c) be deleted because, to the extent billing adjustment or resettlement is warranted, PJM is in the best position to perform such recalculation, in which case Duke would be the appropriate party to approach PJM with such request (Exelon Ex. 1 at 4, Att. 1). Duke opposes this proposal, stating the language is consistent with that proposed in Duke's certified supplier tariff (CST) and such consistency must be maintained as PJM bills both wholesale suppliers and CRES providers (Duke Reply Br. at 13). The Commission finds that the language set forth in paragraph 6.2(c) is appropriate; therefore, ExGen's proposal should not be adopted.

Eighth, ExGen proposes the values in attachment B, seasonal billing factor, be populated and provided to prospective bidders sufficiently in advance of the deadline for bid submissions (Exelon Ex. 1 at 5, Att. 1). In response, Duke states that, consistent with Duke's last ESP, such values will be supplied at the appropriate time to allow suppliers to bid appropriately (Duke Reply Br. at 13-14). The Commission agrees the information should be provided sufficiently in advance to allow suppliers to bid appropriately; however, Duke's current process satisfies this requirement, thus, revision to the MSA is unnecessary.

Staff recommends a change to the communications protocol in the MSA regarding how the post-auction Commission consultant reports are to be handled. In Duke's application, Attachment E at 6, the protocol provides that the auction manager shall review the consultant's post-auction report and Duke shall also receive a copy of the report. Staff suggests the word "shall" be substituted by the word "may" in the last part of paragraph 3.6. According to Staff, this change would allow for the possibility, but would not require, that the consultant could show the auction report to the auction manager or Duke in order to confirm information used in the report. (Staff Br. at 52; Tr. XIII at 3807-3809; Duke Ex. 1, Att. E.) Duke states this change is acceptable, to the extent Duke and its auction manager retain the right to receive and review the report (Duke Reply Br. at 14). The Commission finds that Staff's recommended change is reasonable and should be adopted.

3. Generation Service Pricing

Duke proposes to continue the following four bypassable generation riders, which were approved in the *ESP 2 Case*: Retail Capacity (Rider RC); Retail Energy (Rider RE);

Supplier Cost Reconciliation (Rider SCR); and Rider AER-R. Duke explains that it is not proposing any changes to Riders SCR or AER-R; however, minor revisions are being proposed to Riders RC and RE to recognize Ohio's fully-competitive retail market and to align the recovery mechanisms. (Duke Ex. 1 at 8.)

(a) Retail Capacity and Retail Energy Riders

Riders RC and RE recover the cost for capacity and energy, respectively, supplied to the SSO load (Duke Ex. 1 at 8). Duke explains that the clearing price for each competitive wholesale auction is an aggregate number, in terms of $/MWh. In order to allow for more transparency and comparability into the components of SSO supply, Duke proposes to unbundle the costs of full-requirements service into two separate riders, consistent with its current process. Duke seeks to continue Rider RC for the mechanism to recover capacity costs embedded in the winning auction price, although with limited modifications to the current methodology's allocation and rate design. (Duke Br. at 5, 8.) Duke proposes to change the manner in which capacity costs are allocated in the calculation of Rider RC and to change the rate design for both Rider RC and RE (Duke Ex. 6 at 18).

(i) Retail Capacity Rider Allocation

For Rider RC, Duke proposes to change the allocation factor used for allocating the cost of the underlying capacity in the SSO auction price in order to reflect the manner in which such costs are actually incurred (Duke Ex. 6 at 18). Currently, Duke allocates capacity costs to the rate classes based on a methodology that was stipulated to in the *ESP 2 Case* (Duke Ex. 18 at 9). In the instant cases, Duke proposes to allocate the capacity costs that resulted from the PJM RPM prices based on each class's 5 coincident peaks (CP)[2] demand, assuming no shopping (Duke Ex. 6 at 18; Duke Ex. 18 at 8-9). Duke believes this revision recognizes the regulatory principle of cost causation (Duke Br. at 6). Duke reasons that, since all of the capacity used to serve retail load during the term of the ESP will be acquired from PJM and the charges for capacity billed by PJM to meet the total load obligation is essentially based on Duke's load at the time of PJM's five highest system hourly peaks, the most equitable method for allocating capacity cost is to base it on how much each customer class contributes to those five PJM CPs (Duke Ex. 6 at 18-19; Duke Ex. 2 at 10; Duke Br. at 6). Moreover, CRES providers pay PJM for capacity based on factors influenced by PJM's 5CP method; therefore, SSO costs should be allocated to customer classes in the same manner to avoid a disparity between SSO rates and CRES offers. In addition, the easiest way for customers to compare a CRES offer to an SSO offer is on a $/kWh basis; however, the existing combination of demand and energy charges makes that comparison difficult and it has the potential to make the SSO prices disproportionately high for very low-load factor customers. (Duke Ex. 6 at 20.) RESA

2 The 5CP method uses the five days with the highest peaks during the year (OCC Ex. 46 at 11).

agrees that the 5CP method for allocating costs, which is the way PJM determines capacity prices, would be in accordance with the ratemaking principle of cost causation (RESA Reply Br. at 12).

OCC and OPAE advocate that Duke's Rider RC proposal be rejected (OCC Ex. 46 at 17; OPAE Br. at 16). OCC explains that, in the *ESP 2 Case*, Duke initially proposed that generation-related capacity be allocated on the basis of a 12CP method,[3] which would have meant a 46.76 percent allocation factor for residential customers. However, the stipulation in the *ESP 2 Case* provided a 39.12 percent allocation factor for residential customers. OCC states that, in the instant cases, Duke is proposing a 5CP method, which results in a 45.37 percent allocation factor for residential customers. (OCC Ex. 46 at 5-6; OCC Br. at 91.) OCC contends Duke has not offered any basis why the allocation of generation-related capacity costs, if it were appropriate, should be treated any differently than in prior cases where the 12CP method was used (OCC Ex. 46 at 12; OCC Br. at 92). OCC submits the rationale in the *ESP 2 Case* to have a capacity cost rider was that Duke was self supplying its own capacity requirements under a fixed resource requirement (FRR) plan. However, in the proposed ESP, Duke is terminating its FRR and fully going to market for both energy and capacity. Therefore, there is no state regulation or specific cost structure and/or allocation that can be made based on demand, as capacity and energy come as a package and are sold on the basis of energy. OCC asserts any attempt by Duke to relate these all-inclusive energy prices to the previous FRR is meaningless. (OCC Ex. 46 at 7; OCC Br. at 90-91.)

OCC argues it is not appropriate to allocate and charge customers SSO supplier charges on a capacity cost basis when such charges are billed to Duke on an energy basis (OCC Ex. 46 at 3; OCC Br. at 89). OCC explains that each winning wholesale supplier in an SSO auction will provide a complete full-requirements SSO supply, including energy, capacity, transmission ancillaries, and other transmission services. The wholesale suppliers combine these generation products in a package and, under the auction format, bid to a single $/MWh price. Duke pays wholesale supplier counterparties a fixed $/MWh price for the package of generation products; the individual components, i.e., capacity, energy, ancillaries, are not separately priced. OCC points out the auctions solicit supply for tranches of the aggregated SSO load, not customer class loads. (OCC Ex. 32 at 14-15; Duke Ex. 3 at 8-9.) Since the competitively-bid wholesale rates are charged to customers on an energy basis, there is no reason to split the costs into capacity and energy components and charge customers based on the 5CP method. Moreover, this process is inconsistent with the way wholesale costs are passed through to Duke and the way Duke passes those costs on to customers. Therefore, since capacity costs are charged to Duke on an energy basis and Duke does not pay any directly-billed capacity cost in order to supply

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3 The 12CP method uses the peak hour of each month (OCC Ex. 46 at 11).

its SSO load, it is not appropriate to charge customers for these costs on any basis other than the manner in which they are charged to Duke, i.e., as energy charges, $/MWh. OCC submits that, even if one accepted the notion Duke incurs capacity costs apart from capacity built into the CBP auction prices, Duke's calculation of such costs is overstated because: Duke calculated the total value for Duke-Ohio and Duke-Kentucky and then allocated those hypothetical dollars only to the Ohio jurisdictional customers; Duke has not demonstrated that the allocation is consistent with cost-causation principles; and the underlying data has not been produced and what was produced in the *Distribution Rate Case* was not reliable and biased. (OCC Ex. 46 at 3, 8, 11-16; OCC Br. at 89, 93-94.) Duke disagrees that the data was not reliable, noting that, in its analysis, OCC is comparing apples to oranges, as the 2012 data, which was weather-normalized, used in the *Distribution Rate Case* was one year later than the 2011 actual data used by OCC for comparison. Moreover, Duke states the evidence on the record discredits OCC's assertions that the Duke-Kentucky load was used in the calculation of Rider RC. (Duke Reply Br. at 20-21; Tr. XII at 3531-3538.)

OCC and OPAE agree that, while the basic methodology for calculating the capacity charge in these cases does not change from what was established in the *ESP 2 Case*, Duke's proposed modified class allocation percentages are highly adverse to the residential class, as the proposal increases the residential share of capacity costs from 39.12 percent, which was established in the *ESP 2 Case*, to 45.37 (OCC Ex. 32 at 15-17; OPAE Br. at 16). The residential capacity charge under Duke's proposal would be 1.52 cents/kWh, compared to a total company charge of 1.22 cents/kWh. OCC offers that Duke's proposed modification would equate to a $3/MWh cost premium that would translate into an $11 million per year increase in costs for residential SSO customers. This translates to a 24.5 percent capacity charge cost premium for residential customers compared to about 9.5 percent under the stipulation in the *ESP 2 Case*. OCC and OPAE assert the price premium should not be approved, as there is no showing the premium is required by SSO suppliers to serve residential customers. (OCC Ex. 32 at 18-19; OPAE Br. at 17, OCC Br. at 116.) According to OCC, the cost-causation principle applies to cost-of-service regulation and there is no evidence the winning bidders in the SSO auctions would charge residential classes a cost premium as compared to nonresidential customers. OCC believes this is an assumption on Duke's part, in that Duke's allocation proposal is an administratively-determined price adjustment and not the result of bidding behavior for the wholesale full-requirements contracts that will supply the SSO loads. (OCC Ex. 32 at 19.) OPAE asserts using the 5CP method proposed by Duke simply shifts costs from nonresidential customers to residential customers because it reduces the average rate for customers as their load factors increase. In addition, OPAE notes bidders in the SSO auction are exposed to unpredictable load changes over the term due to customer migration and such risk is priced into bids. Large nonresidential customers have a greater tendency to migrate, while half of residential and small commercial customers remain on Duke's SSO. (OPAE Reply Br. at 18, 20.)

OCC acknowledges that the load factor information is important to suppliers and is priced into bids, and states that, all else being equal, the relatively lower load factor for the residential class may merit a capacity cost premium as compared to a higher load factor. However, in its methodology, when setting the class-specific SSO rates, Duke does not consider two critical factors that affect market pricing: the larger size of residential SSO load; and the lower migration risk of residential SSO customers. OCC submits, since the residential class is more than 70 percent of the SSO kWh sales, absent the residential class, Duke's auction would be quite small and much less attractive to potential bidders. OCC points out bidders are exposed to unpredictable SSO load changes over the term due to customer migration and large nonresidential customers have a greater chance to migrate; thus, the risk will be priced into the bids. While all customer classes are permitted, and do, migrate, medium and large nonresidential customers have a greater tendency to shop; thus, those classes are far less certain and potentially volatile. According to OCC, half of the residential and small commercial customers remain on the SSO and these customers are already paying more and would pay more under the PSR. OCC maintains there is no showing that bidders in the auction require a price premium to serve the residential or small commercial classes. (OCC Ex. 32 at 20-21; OCC Br. at 117-118.)

OCC offers two alternative remedies to Duke's allocation proposal. First, OCC's preferred option would be to not include the capacity allocation adjustment in the customer class pricing, thus, reducing the residential SSO price. Second, another market-based alternative would be to have a separate power supply procurement for the residential class. OCC explains, for this option, the auction would be conducted in the normal manner, but with separate residential and nonresidential products identified. (OCC Ex. 32 at 21-22; OCC Br. at 118-119.)

OEG opposes OCC's recommendation, submitting the proposal would socialize capacity costs among all customers and require higher load factor customer classes to subsidize lower load factor customer classes that, on average, use system resources less efficiently. OEG points out that the SSO manager, Mr. Lee, testified the SSO auction requires a bundled bid to attract bidders and minimize the risk that there will be insufficient interest in one or more of the individual products. (OEG Br. at 29-30; Tr. II at 320-321.) OEG asserts OCC's argument that the larger size of the residential SSO load and assumption that residential customers carry lower migration risk to justify the proposal ignores known capacity cost differences between customer classes and is extremely speculative. Finally, OEG submits OCC makes no attempt to quantify the rate impact of the proposal on nonresidential SSO customers. OEG supports Duke's proposed allocation, stating that, like every other Ohio utility, Duke allocates capacity and energy costs to SSO customers according to well-established, quantifiable, cost-causation principles. (OEG Br. at 30-31.) Duke agrees with OEG's analysis (Duke Reply Br. at 19-20).

In response to objections to the rate allocation and rate design issues, Duke notes that it is financially indifferent to how the rates for Riders RC and RE are structured, noting that these riders simply pass through to customers costs imposed by wholesale auction winners providing SSO service. Nevertheless, Duke believes it has a responsibility to propose a cost allocation and rate design that is fair to all participants and promotes competition without unfairly advantaging or disadvantaging SSO auction winners or CRES providers. (Duke Reply Br. at 15.)

With regard to the Rider RC allocation, Duke emphasizes that, contrary to the assertions by OCC and OPAE, the calculation is based directly on PJM's market price for capacity. Duke points out that the full-requirements product supplied by SSO auction winners includes a component for capacity and the nature of the capacity market in PJM is such that the capacity price established in the RPM is a reasonable proxy for the actual, even if unknowable, cost. (Duke Reply Br. at 15-16.)

As for OCC's comparison of the methodologies proposed and used in the *ESP 2 Case* versus in the instant cases, Duke explains the difference is that Duke's initial 12CP allocation proposal in the *ESP 2 Case* was based on the assumption that capacity would be provided from Duke's own resources. However, the source of capacity in the current proposal is exclusively from the market. Consistent with the long-standing regulatory principle that costs for utility service should be allocated in a manner consistent with how the costs are incurred, Duke argues it is undisputable that PJM charges its wholesale customers for capacity based on the 5CP method. Since each class's contribution to the 5CP is what determines that overall cost of capacity charged by PJM, it makes sense that the costs to be included in Rider RC should be allocated in a similar manner. Moreover, Duke submits OCC's comparison of the proposal in these cases and the allocation agreed to in the *ESP 2 Case* has no merit and no precedential value, noting that the signatory parties in the *ESP 2 Case* reduced the residential ratepayers' share of capacity costs in the process of arriving at an overall resolution of the larger issues. (Duke Reply Br. at 17-18.)

In response to OCC's assertions referring to the fact that Duke will no longer be an FRR entity, Duke notes that capacity is a necessary component of SSO service and there is a cost to provide that capacity, regardless of whether Duke supplies that capacity as an FRR entity or auction winners supply that capacity as part of their bid (Duke Reply Br. at 18).

Upon consideration of the arguments raised regarding Duke's proposed allocation methodology for Rider RC, the Commission finds that Duke's proposal is reasonable and should be approved. While OCC and OPAE point to the Commission's approval of the 12CP method in the *ESP 2 Case* to support their claims, the Commission notes that such approval was in consideration of the stipulation entered into between the parties in those cases. In these cases, however, based on the record, the Commission finds that it is reasonable for Duke to calculate its allocation of Rider RC based on the 5CP method, which is based on PJM's market price for capacity. Moreover, as the record reflects, such methodology is structured to avoid a disparity between SSO rates and CRES offers and provide customers with an effective mechanism to compare SSO and CRES offers.

(ii) Retail Capacity and Retail Energy Riders Rate Design

Duke proposes two rate design changes. First, Duke proposes to modify the rate design for Rider RC such that the retail rates are converted into energy-only rates; thus, generation-related charges would be based on kWh consumption (Duke Br. at 6). Duke asserts this revision is consistent with the rate design approved in *In re Ohio Edison Co., et al.*, Case No. 12-1230-EL-SSO, et al., (*Ohio Edison ESP Case*), Opinion and Order (July 18, 2012), as well as the one proposed in the *AEP ESP 3 Case*, Case No. 13-2385-EL-SSO, et al., Application (Dec. 20, 2013) (Duke Ex. 1 at 9).

For certain nonresidential customers, Duke proposes to replace the demand charges for those customers served under Rates Secondary Distribution (DS), Primary Distribution (DP), and Transmission Voltage (TS) with energy-only rates based on kWh charges (Duke Ex. 1 at 9; Duke Ex. 18 at 8). With this change, all generation-related charges for all SSO customers will be based on kWh consumption (Duke Ex. 6 at 19, 24). According to Duke, these changes to Rider RC will better align the overall SSO rates with offers that customers receive from CRES providers (Duke Ex. 1 at 9). Duke maintains this modification to the rate design for Rider RC will protect very low load factor customers from high Rider RC charges, but it will continue to provide high load factor customers with price benefits similar to those they enjoy under the current rate. According to Duke, all else being equal, most customers will experience little to no change with this proposal for rate design, but it will positively impact customers most at risk for experiencing very high average rates. (Duke Ex. 6 at 19; Duke Ex. 18 at 10; Duke Br. at 6-7.)

RESA/Direct Energy oppose Duke's proposal to replace Rider RC demand charges for nonresidential customers served under Rates DS, DP, and TS with kWh based charges (RESA Ex. 1 at 15). RESA states that, in accordance with the stipulation in the *ESP 2 Case*, Duke uses 1CP to allocate and calculate demand charges to Rates DS, DP, and TS, while the demand charges for the other customer classes are allocated and calculated on a per kWh basis (RESA Br. at 23; Tr. VI at 1592-1593). RESA explains that Duke's proposal requires that each member of a class get an allocation of the class responsibility for capacity costs based on load factor. According to RESA, using load factor is a side step away from actual cost causation. RESA submits load factor is not a surrogate for interval data. (RESA Reply Br. at 13.) RESA argues Duke's removal of the demand component in Rider RC for Rates DS, DP, and TS customers, and instead using a 5CP load factor, will result in SSO customers having less granularity in their SSO charges, will thwart an SSO customer's ability to make comparisons, and will not make Duke's rates more like those of CRES providers (RESA Ex. 1 at 17-18; RESA Br. at 23). RESA explains the demand component in Rates DS, DP, and TS is intended to collect capacity costs (RESA Br. at 23; Tr. XIII at 3790). Further, RESA/Direct Energy explain capacity reduction products provide customers with the ability to reduce their peak load contribution (PLC), which is used to determine how much capacity the load serving entity needs to be purchased to serve the retail customer; the higher the PLC number the higher capacity costs to serve that customer. They note that commercial and industrial customers use products to reduce PLC. PJM uses the 5CP where demand is the highest throughout the months of June through September to determine a customer's capacity obligation for the following June to May. If a customer reduces its usage during the 5CP, it reduces its PLC number and its capacity costs. According to RESA, Duke's proposed change will result in a single kWh SSO charge based on a rate-class-specific PLC, not a customer-specific PLC. According to RESA/Direct Energy, Duke's proposal sends the wrong price signals, skews the price to compare, and provides less of an incentive to reduce usage during peak times. RESA notes this proposal comes just as Duke is nearing complete installation of smart meters, and that it is contrary to the purpose of allowing customers to have usage data to control their usage, as well as Ohio and federal energy policy. In addition, RESA offers that Duke's proposal frustrates CRES providers' ability to craft an offer for a customer based on the customer's actual contribution. (RESA Ex. 1 at 15-17; RESA Br. at 20-24.) Therefore, RESA urges the Commission to set the goal that Duke move to pricing capacity on the actual contribution to the PJM 5CP instead of allocating by class and conducting a second level within the class which is not based on peak usage (RESA Reply Br. at 13).

Staff states that the Rider RC rate is an hours-use rate for DS, DP, and TS rate classes; therefore, the customer's demand is instrumental in determining the customer's monthly charge. Staff explains that, although the Rider RC rate is charged as a $/kWh rate, the rate design includes a declining-block rate structure and the actual kWh rate a customer pays is, in part, based on the customer's demand. Accordingly, Staff submits, as a result, this design should perform as Duke alleges by protecting low-load factor customers and providing benefits for high-load factor customers. Staff disagrees with RESA that the rate design proposed by Duke will eliminate the incentive for customers to reduce usage. Staff espouses that, since the rate design proposed by Duke is an hours-use rate design for customer classes with demand meters, reducing demand and increasing load factor will result in lower customer costs. Therefore, the incentive to reduce the demand will still exist under Duke's proposed rate design. (Staff Reply Br. at 19-20.)

In response, Duke submits RESA ignores the impact of the current rate design on low-load factor customers, as well as the market itself. According to Duke, the proposed rate design maintains the existing incentives to reduce demand and the proposed rates are designed to reward customers for improving load factors. Duke asserts the rate design ensures that neither CRES providers nor SSO auction winners have an advantage or disadvantage when competing for retail load. (Duke Reply Br. at 21-22.)

The Commission finds Duke's proposal to modify the rate design for Rider RC such that the demand charges for Rates DS, DP, and TS will be replaced with energy-only rates, kWh charges, is reasonable and should be approved. We find that Duke's proposed rate design appropriately takes into consideration the market and balances the interests of all customers, including the low-load factor and high-load factor customers. Moreover, as explained by Staff, this new rate design continues to incent customers to reduce demand and it will not inhibit CRES providers from designing their service offerings as they wish.

Duke's second rate design change addresses the current rate design for residential and small commercial customers for Riders RC and RE, which consist of stepped summer and winter rates. Duke proposes to maintain the current seasonal stepped rates, but modify the design to reduce the differences between the stepped rates. Specifically, this rate design change affects customers taking service under Rates Residential Service (RS), Residential Service - Low Income (RSLI), Residential Three-Phase Service (RS3P), Optional Residential Service with Electric Space Heating (ORH), and Secondary Distribution Service - Small (DM). (Duke Ex. 1 at 9; Duke Ex. 18 at 15-16; Duke Br. at 7.) For example, Rider RC, for Rates RS, RS3P, and RSLI, would change to just one summer rate, regardless of usage; for Rate ORH, would change to just one summer rate and the winter usage level, at which the rate changes would be increased by 50 percent; and, for Rate DM, there would be just one summer rate, instead of three winter rates, and a higher threshold for reaching the second block of the winter rate (Duke Ex. 18 at 15, Att. JEZ-1 at 100-105; Duke Br. at 7). Duke submits these changes better align the SSO rates with the reality of a purely competitive market for retail generation service; thus, facilitating the comparison of SSO rates and CRES offers, which benefits competition (Duke Ex. 6 at 19; Duke Ex. 18 at 15-16; Duke Br. at 7).

RESA/Direct Energy believe Duke's proposal to reduce, but not eliminate, the seasonal differences in the Rider RC rates for residential and small commercial customers is unwise. RESA asserts the compression proposed by Duke does not correspond with developing customer-specific rates by CRES providers, will thwart customer efforts to rely on usage data to control usage, will eliminate the incentive for customers to reduce peak usage, and will not correspond to how rates are developed and offered by CRES providers. Duke's proposal also ignores that PJM bases the capacity obligation on summer peaks only; thus, ignoring how the market works and shifting costs between customers. (RESA Ex. 1 at 15; RESA Br. at 25.)

Duke disagrees, stating that customers will have no less access to data under the proposed rate design than they currently have. In addition, Duke notes customers will continue to have incentives to reduce energy consumption. Finally, Duke points out the Apples-to-Apples charts reveal that all of the existing offers from CRES providers for residential and small commercial service are simple flat rates, which are no different than the rates being proposed by Duke. (Duke Reply Br. at 22-23.)

Staff does not oppose the rate design changes for Riders RE and RC in concept. However, Staff notes that, based on the typical bills provided by Duke, it appears that the proposed rate design changes for Riders RE and RC may result in increases to certain customers that could exceed 12 percent (Staff Ex. 3 at 6; Duke Ex. 18, Att. JEZ-3; Staff Br. at 47-48). While Duke is proposing to reduce the differences between stepped rates for certain rate schedules to better reflect rates that are being offered in the competitive retail market, the result is that certain customers, i.e., Rates ORH, DM, and Common Use Residential (CUR), could experience large increases. To mitigate the large increases for customers, Staff recommends a reduction in the difference in rate blocks at a slower pace than is being proposed by Duke. For example, the design could be phased in evenly over two years for any rate class that may receive substantial impacts as a result of the rate design changes. (Staff Ex. 2 at 6; Staff Br. at 47-48.) In response, RESA notes Staff acknowledged that its analysis focused on the specific effect the changes would have on customers and not whether the new rates would reflect the cost of service or properly allocate costs to individual customers. Therefore, RESA submits Staff's agreement in concept should not simply be adopted, as greater review and analysis is required. (RESA Br. at 25-26; Tr. XIII 3791-3792.) In response, Staff states a cost-of-service study is performed during a distribution rate case, and such a study is not necessary to determine the appropriateness of the proposed rate design. Staff believes the 5CP methodology properly allocates capacity costs to the classes and a complicated cost-of-service study is not necessary. With regard to RESA's assertion the rate design does not properly allocate costs to individual customers, Staff acknowledges the rate design does not attempt to individually assign costs to each customer based on each customer's contribution to the 5CPs. Rather, the costs are allocated to the various classes based on the class's contribution to the 5CP. Staff does not believe it would be feasible for Duke to calculate a separate monthly capacity charge for each customer. However, if, in the future, each customer could be accurately measured on each of the 5CPs so that each customer could be accurately billed for the costs it created, and it could be done cost effectively, then it could be explored at that time. (Staff Reply Br. at 20-21.)

While the Commission is in agreement that Duke's proposal to modify the rate design for Riders RC and RE to reduce the differences between the stepped rates is reasonable in concept, the Commission is concerned the rate design changes for certain customers may result in large increases. Therefore, we find that Staff's proposal to phase in the rate design changes over a two-year period is appropriate. Accordingly, Duke shall file modified rates to be effective for the first billing cycle in June 2015. Duke should submit to Staff a copy of the modified rates 15 days prior to filing.

(b) Supplier Cost Reconciliation Rider

Rider SCR is a conditionally bypassable rider, which means, if certain conditions are satisfied, Rider SCR contains language that turns it into a nonbypassable rider (Duke Ex. 1 at 8; RESA Br. at 27). Rider SCR reconciles and recovers costs related to the competitive auctions for the SSO. Duke is not proposing any modification to Rider SCR. As currently structured, as long as the balance of Rider SCR is less than 10 percent of Duke's overall actual SSO revenue, i.e., all revenue collected for SSO service under Riders RE, RC, RECON (Reconciliation), and AER-R for the most recent quarter for which data is available at the time of the filing, Rider SCR is bypassable. However, if the balance of Rider SCR becomes equal to or greater than 10 percent, Duke will apply to the Commission to modify the rider such that it becomes nonbypassable. (Duke Ex. 1 at 8; OMA Ex. 2 at 12-13.) Therefore, Duke proposes to continue to recover any difference between the payments made to suppliers for SSO supply and the amount of revenue collected under Riders RC and RE, as well as any prudently incurred costs associated with conducting the CBP auctions and any costs resulting from supplier default, plus carrying charges at Duke's overall cost of long-term debt (Duke Br. at 9).

Constellation/RESA believe, in the future, Rider SCR could saddle non-SSO customers with the cost of SSO generation. They point out that Rider SCR, which covers generation costs for the SSO and becomes nonbypassable if there are too few SSO customers left, 10 percent, to pay the full cost of the service, was a negotiated item in the *ESP 2 Case*. To date, the 10 percent cost trigger has not been reached and Rider SCR has not been charged to non-SSO customers. Therefore, Constellation/RESA request the Commission no longer allow an automatic nonbypassable charge simply because of shortfalls in the SSO revenue stream. Constellation/RESA recommend, if there are irreversible shortfalls in the SSO program, Duke, at that time, file an application and present a solution that is in the public interest. (RESA Ex. 3 at 5, 7, 16; RESA Br. at 28.) Thus, if the 10 percent trigger is reached, the Commission could adopt remedies other than making the rider fully nonbypassable (Exelon Reply Br. at 12). RESA contends the conversion provision is not necessary, because a revenue-deficit situation may not arise. RESA submits having only one fix for a revenue-deficit situation preestablished is not reasonable, as it is not known what will cause a future revenue deficit triggering the nonbypassable provision or what will be the best way to solve any future deficit. (RESA

Br. at 29.) Constellation/RESA point out that a similar rider was proposed in the *DP&L ESP Case* and the Commission rejected the rider, but authorized a bypassable rider for auction-related costs, supplier default costs, and carrying costs (RESA Ex. 3 at 17).

Duke points out that, on cross-examination, Constellation/RESAs' witness agreed that Duke is entitled to recover these costs (Duke Reply Br. at 23; Tr. X at 2694). Duke submits that these are simply pass-through costs and introducing unnecessary litigation has the potential to significantly delay the recovery of costs incurred by Duke in its provision of SSO service. Moreover, Duke asserts allowing an unreasonably large balance, i.e., greater than the 10 percent threshold, of under-recovery to flow through Rider SCR on a bypassable basis while the litigation is occurring, would risk undermining the competitive balance between SSO auction winners and CRES providers. (Duke Reply Br. at 23-24.)

Upon consideration, the Commission finds that Duke's proposal to continue Rider SCR in its current form is reasonable and should be approved. In the event it appears the 10 percent threshold will be reached at some point during the term of this ESP, the Commission will closely monitor the situation and obtain information for consideration in future cases.

4. Riders to be Retained, Eliminated, or Modified

Duke explains that, in the *ESP 2 Case*, the Commission approved the following nonbypassable riders: Rider UE-GEN (Uncollectible Generation Expense), which recovers those expenses from all retail customers, including shopping customers served by CRES providers participating in Duke's purchase of receivables (POR) program; Rider LFA, which reconciles both a demand charge and an energy credit for nonresidential customers served under Rates DS, DP, and TS; and Rider DR-ECF (Economic Competitiveness Fund), which recovers costs associated with interruptible load, as designated by eligible transmission voltage customers. Of these three riders, Duke proposes to continue Rider UE-GEN, and the associated POR program, in substantially the same form approved in the *ESP 2 Case*. However, Duke asserts Riders LFA and DR-ECF are obsolete and should be eliminated. (Duke Ex. 1 at 10.)

In addition to eliminating Riders LFA and DR-ECF, Duke proposes to eliminate the following six riders: Electric Emergency Procedures for Long-Term Fuel Shortages (EEPF), because the provisions are moot since Duke no longer owns generation; ESSC, because it terminates at the end of 2014 pursuant to the stipulation approved in the *ESP 2 Case*; Save-a-Watt Energy Efficiency Program (DR-SAW and DR-SAWR), because these two riders terminated at the end of 2011 and 2013, respectively; PIPP customer discount, because it terminates after May 31, 2015, when the PIPP load will be combined with the other SSO load supplied through the SSO auction process; and Energy Efficiency Revolving Loan Program (EER), because it terminated after December 2010. (Duke Ex. 18 at 6-8.)

Duke also proposes to add language to Rider Net Metering (Rider NM) to clarify the billing process for net metering customers. For instance, the tariff states that credits for excess generation shall be calculated based on Rider RE. However, since Duke's generation rate is collected through both Rider RC and Rider RE, the tariff will be clarified to reflect that credits will be based on Riders RC and RE. (Duke Ex. 18 at 17-18.)

The Commission finds that Duke's proposal to continue Rider UE-GEN is reasonable and should be approved. In addition, Duke's proposal to eliminate Riders EEPF, ESSC, DR-SAW, DR-SAWR, and EER, as well as the PIPP customer discount is reasonable and should be approved. Finally, we find that Duke's proposed clarification of Rider NE is appropriate and it should be approved. With regard to Riders LFA, DR-ECF, and the POR, as well as other riders and programs addressed in Duke's application, those items will be discussed below.

5. Distribution Service

(a) Distribution Capital Investment Rider

Duke proposes a nonbypassable Rider DCI, pursuant to R.C. 4928.143(B)(2)(h). Duke is seeking to recover a return on capital investment in order to support 19 programs Duke considers vital to maintaining customer reliability. Duke believes it is only able to meet current reliability standards because of its SmartGrid deployment and that, in order to continue meeting these standards, it needs to be proactive. Duke witness Arnold states that, through surveys and customer interactions, the Company believes its customers have high and increasing expectations regarding how reliable Duke's service should be. He also submits that Duke's current system is aging and vulnerable in certain areas and the Company can prevent future problems by modernizing its infrastructure. He notes that much of the Company's equipment is over 30 years old and becoming obsolete. He explains that the Company also has more difficulty obtaining replacement parts. Mr. Arnold does not believe Duke can continue to meet customer expectations without proactively addressing its infrastructure through this rider. The Company does not guarantee that reliability or customer satisfaction will improve, but asserts customers will benefit from an infrastructure that is more efficient and resilient. (Duke Ex. 21 at 9-10, 17-19.)

In regards to its current reliability performance, the Company conveys it is doing well. Duke notes that the Commission measures reliability using the Customer Average Interruption Duration Index (CAIDI) and the System Average Interruption Frequency

Index (SAIFI). For both of these criteria, Duke declares that it meets the Commission's standards. (Duke Ex. 21 at 7-8.)

Duke also avers that its expectations are aligned with customer expectations. Mr. Arnold remarks that Duke participates in an annual J.D. Power study of customer satisfaction. He states the Company also conducts a quarterly survey of customers for the Commission, in addition to performing its own assessment. The results of the surveys, according to Mr. Arnold, show that, while most Duke customers are satisfied with the Company's reliability, expectations are rising. He states increased reliability and quicker responses are now in higher demand. The Company submits modernizing its infrastructure as quickly and efficiently as possible is necessary to meet the rising expectations of its customers. Duke calls attention to Staff witness Baker, who also believes Duke's reliability expectations are in alignment with its customers. (Duke Ex. 21 at 11-15; Duke Br. at 13; Staff Ex. 7 at 5.)

According to Duke, Rider DCI will recover the incremental revenue requirement on distribution investment, as well as the associated depreciation and property tax expenses not otherwise recovered through base rates. The Company is not proposing to recover operating and maintenance expenses through this rider, or to recover for its SmartGrid program. Duke witness Laub states that this will be calculated by subtracting the revenue requirement for rate base that is recovered through base rates from the revenue requirement associated with the projected rate base at the end of the quarter. The baseline to measure the incremental costs, according to Ms. Laub, will be the sum of return, income taxes, depreciation, and property taxes. She expresses the rate of return will be 10.68 percent. Further, she explains the revenue requirement contains an ROE component. Duke reasons that a 9.84 percent ROE is appropriate, as that was the approved ROE in the *Distribution Rate Case*. Duke witness Morin suggests that, with the current economic and industry conditions, a reasonable ROE would be between 9.6 and 11.0 percent; thus, Duke's proposal is fair. The Company further submits this ROE is lower than those approved for other utilities with similar riders. Duke says it will allocate the revenue requirement in the same way it does in Schedule E of the *Distribution Rate Case*. The Company offers that it will submit quarterly filings to the Commission and that the rider will be trued-up for actual costs, with an audit completed by the Commission. (Duke Ex. 9 at 3-5; Duke Br. at 15-16; Duke Ex. 40 at 3; Duke Ex. 21 at 35.)

GCHC, OCC, OMA, and OPAE state that Rider DCI should be denied, because it does not meet the requirements under R.C. 4928.143(B)(2)(h). The oppositional parties further assert that Duke has not demonstrated a true need for this rider and the recovery Duke desires should be properly sought through a distribution rate case. (GCHC Br. at 14; OCC Br. at 74; OMA Br. at 9-10; OPAE at 18-19.)

OCC argues that, while the statute requires Duke to show that the rider is necessary to improve reliability, Duke is currently financially stable and already able to meet reliability demands. OCC witness Mierzwa states that Duke does not currently have reliability issues. He points out that Duke has met the reliability standards set forth by the Commission and has actually shown steady improvement in reliability since 2005. While the Company submits that it is only able to meet reliability standards due to the implementation of its SmartGrid system, OCC notes that Duke was unable to show or quantify what impact the system has on reliability. OPAE, OMA, and GCHC offer similar sentiments, noting that Duke is not in a dire financial situation that necessitates a rider such as this one. (OCC Br. at 74; OCC Ex. 49 at 9-11; Tr. VIII at 2154; GCHC Br. at 14; OMA Br. at 9-10; OPAE Br. at 20-21.)

OCC and OMA also disagree with Duke's assertion that the Company's expectations are aligned with its customers, as statutorily required. Staff, however, agrees with Duke that customers have increasingly higher expectations regarding reliability and, thus, their expectations are in alignment. OCC and OMA argue Duke ignores customers' desires to prevent rate increases. OCC believes Duke's reliance on the JD Power survey is flawed, as that survey was not limited to Duke's Ohio customers and it did not take into account how customers felt about rate increases. OCC looks to the Commission-mandated quarterly surveys and points out, among other details, that roughly half of the respondents were not willing to increase costs in order to prevent a one-hour outage. OCC contends customers place more importance on costs than reliability and, therefore, their expectations are not aligned with the Company's. (OCC Br. at 81-85; OMA Br. at 12-13; Staff Reply Br. at 18; Staff Ex. 7 at 5; Tr. VIII at 2212; OCC Ex. 45 at 16.)

OCC notes that, in determining whether to approve the rider, R.C. 4928.143(B)(2)(h) also requires the Commission examine whether the Company is dedicating sufficient resources to the reliability of its system. OCC and OMA both comment that many of Duke's DCI-supported programs do not go towards modernizing or improving reliability; rather, they just go towards maintaining its current infrastructure. They submit that maintenance costs should be recovered through a rate case, not a rider. The parties further point out that Duke does not guarantee the rider will improve reliability or customer satisfaction. Nor, according to OCC, can Duke point toward any quantitative benefits the rider will produce. (OCC Br. at 75, 78; OMA Br. at 13-14.)

Multiple parties also argue against Duke's proposed ROE. OCC witness Kahal asserts that Rider DCI allows the Company to make frequent and timely rate adjustments and recover costs quicker. OCC points out that both Staff and Duke acknowledge this. Mr. Kahal further explains that this lowers Duke's business risks and is beneficial to shareholders. This recovery mechanism, according to Mr. Kahal, did not exist when the 9.84 percent ROE was created in the stipulated *Distribution Rate Case*. If it had been, he suggests, the ROE likely would be lower. He further notes that, as part of the stipulation, the agreed-upon ROE was not to be used as precedent in future proceedings. If the Commission does approve the rider, OCC requests that the ROE be reduced to correlate with the Company's reduced business risks. OPAE and OMA suggest likewise. (OCC Ex. 32 at 10-11; OCC Reply Br. at 34-35; Tr. XIII at 3772; Tr. II at 393; OPAE Br. at 22; OMA Br. at 11.)

GCHC, OMA, and Kroger recommend that, if Rider DCI is approved, the rate design should be changed to a simple equal percentage increase of base distribution rates. Duke's proposal is for each customer class's allocation to be the same as used in Schedule E of the *Distribution Rate Case*. Kroger witness Higgins offers that Duke's proposal is flawed in that the rate design locks in each class's share of the costs and does not account for changes in the relative size of each class's load. Further, Kroger notes that the costs allocated to each class are not proportional to each class's share of the revenue. GCHC states significant changes in the customer classes have occurred since the *Distribution Rate Case* and Schedule E should not be applicable in these cases. Kroger, OMA, and GCHC submit that a fixed percentage of base distribution rates would be fairer to each customer class and would allow the Company to recover the same amount of revenue. (Duke Ex. 9 at 6; Kroger Ex. 1 at 10-11; Kroger Br. at 3-5; GCHC Br. at 14-15; OMA Reply Br. at 28.) OCC offers a separate proposal, noting that Duke's suggested allocation is based off of total distribution revenue, which includes many expenses not included in the rider. OCC witness Yankel recommends going off of an allocation schedule that resulted from a cost-of-service study completed by Duke for the *Distribution Rate Case*. This study, he submits, provides a more accurate representation. GCHC believes OCC's plan should be denied, as the study was previously challenged and ultimately not adopted due to a stipulation. OCC counters that Mr. Yankel's proposal is the only one that is consistent with cost-causation principles. (OCC Br. 94-96; OCC Ex. 46 at 19-20; GCHC Br. at 15.)

Staff does not oppose Rider DCI, but suggests several modifications. First, Staff states the proposed rider should not include general plant. OCC and OMA concur with the modification. Staff witness McCarter testified that assets in the general plant account are more appropriately recovered in a distribution rate case. Staff, OCC, and OMA emphasize that general plant expenditures such as office furniture and security equipment are too far removed from the purpose of the rider, which is increasing reliability of distribution service. (Staff Br. at 27-30; Staff Ex. 6 at 3; OMA Br. at 10; OCC Br. at 79-80; OCC Ex. 45 at 20.) Duke submits that general plant was approved in similar riders from other EDUs and Staff supported its inclusion in those cases (Duke Reply Br. at 33-34).

Staff also suggests that Rider DCI should sunset at the conclusion of the ESP. OMA and Wal-Mart agree with the suggestion. Staff's proposal is that, at the conclusion of the ESP, Duke should file a rate case to recover any incremental plant. (Staff Br. at 32; Staff Ex.

6 at 5; OMA Reply Br. at 28; Wal-Mart Br. at 7.) Wal-Mart witness Criss expresses concern that Duke could recover a more substantial portion of its distribution revenue requirement. Mr. Criss believes Duke should file a base rate case at the conclusion of the ESP to better analyze the reduction in regulatory lag on Duke's ROE. (Wal-Mart Br. at 6-7; Wal-Mart Ex. 1 at 6.) Duke states that R.C 4928.143(B)(2)(h) allows for such riders to continue past the conclusion of the ESP under which it was filed and that updating distribution systems is an ongoing and dynamic endeavor. Therefore, Duke submits that a sunset date would be inappropriate and limiting to the goals of Rider DCI. (Duke Reply Br. at 34-36.)

Staff, with agreement from OCC and OMA, further recommends Rider DCI be modified to have a cap on the amount that Duke can recover in a year. OCC witness Mierzwa testified that the rider, as proposed, would collect $22 million in 2015, $41 million in 2016, $20 million in 2017, and $21 million in the first five months of 2018. The parties are concerned that these totals could increase further without a hard cap. Staff witness McCarter, factoring in Staff's proposal to eliminate general plant from Duke's recovery, proposes a hard cap of $17 million in 2015, $50 million in 2016, $67 million in 2017, and $35 million for the first five months of 2018. (Staff Br. at 32; OCC Ex. 45 at 8; OCC Br. at 74-75; OMA Reply Br. at 28; Staff Ex. 6 at 5-6.)

Another recommendation from Staff is for plant balances to be based off of actual costs, not projected costs. OCC and OMA also agree that, in calculating the revenue requirement, the Company should be limited to costs that are actually incurred. Mr. Mierzwa posits Duke could overcharge customers if it relied simply on projected costs. Along those lines, OCC requests that property taxes not be included until the property being taxed is recognized as taxable by the appropriate authority. (Staff Br. at 30; Staff Ex. 6 at 3; OCC Ex. 45 at 18-20; OCC Reply Br. at 36, 38; OMA Br. at 10.)

Staff's final requested modification regards filing requirements. With two other major distribution infrastructure riders already in place in Ohio, Staff requests Duke submit quarterly filings on or about February 10, May 10, August 10, and November 10 of each year. In reply, Duke asks for the filing dates to occur at the beginning of the month, to which Staff does not object. After 60 days, according to Staff, the quarterly filings would be automatically approved. Staff asks that the annual audit take place with the August filing. The audit would be completed by either Staff or an independent auditor chosen by Staff. Under Staff's proposal, recommendations or objections to the audit would need to be filed within 120 days of the filing. According to Staff, if, after 150 days, the parties are unable to resolve any issues, the matter would be set for hearing by the Commission. If no one raises any issues, the rates would go into effect without adjustment. In the filings, Staff seeks for Duke to continue to use the jurisdictional allocations and accrual rates for each account and subaccount that were approved in the

Distribution Rate Case. Each filing, per Staff, should include the same information that was provided in the instant cases for each account and subaccount and contain workpapers that shows jurisdictional allocation, accrual rates, and reserve balances of each account and subaccount. Staff asserts the filings should contain information regarding any rider used to collect costs recorded in the Distribution Plant Accounts, by rider and as a grand total. In order to ensure compliance with revenue caps, Staff proposes Duke provide data showing the revenue collected from the rider by month and to date. In order to review the appropriateness of the rider recovery, Staff recommends Duke highlight and quantify any proposed changes to its capitalization policy prior to implementing the change. (Staff Br. at 30-31, 33; Staff Ex. 6 at 4, 6; Tr. XIV at 3930.)

The Commission finds that Duke's proposed Rider DCI is reasonable, and should be adopted, but modified as set forth below. As authorized by R.C. 4928.143(B)(2)(h), an ESP may include the recovery of capital costs for distribution infrastructure investment to improve reliability for customers. A provision for distribution infrastructure and modernization incentives may, but need not, include a long-term energy delivery infrastructure modernization plan. In deciding whether to approve an ESP that contains any provision for distribution service, R.C. 4928.143(B)(2)(h) directs the Commission, as part of its determination, to examine the reliability of the EDU's distribution system and ensure that customers and the EDU's expectations are aligned and that the EDU is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system.

The Commission finds that Duke's expectations and customers' expectations are sufficiently aligned. In examining the reliability of the Company's distribution system, the Commission notes that Duke consistently meets the SAIFI and CAIDI standards. Further, the Commission finds that customers have high expectations regarding the utility's reliability. We do take notice that rising costs affect customer expectations. However, in terms of reliability, the Commission finds that both Duke and customers increasingly expect the Company to meet high standards of reliability.

The Commission further finds that the Company is dedicating sufficient resources towards reliability. Duke is correct to aspire to move from a reactive to a more proactive maintenance program. As we have noted with other, similar programs, we believe it is detrimental to the state's economy to require the utility to be reactionary or allow the performance standards to take a negative turn before we encourage the EDU to proactively and efficiently replace and modernize infrastructure and, therefore, we find it reasonable to permit the recovery of prudently incurred distribution infrastructure investment costs. *AEP ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 47. The Commission finds the adoption of Rider DCI and the improved service that will come with the replacement of aging infrastructure will facilitate improved service reliability and further align the Company's and its customers' expectations.

The Commission accepts Duke's recommended ROE at 9.84 percent and finds it to be fair and reasonable. The *Distribution Rate Case*, where this ROE originated, serves as a useful guide, although it was not precedential. We find that the effect this rider has on Duke's business risk does not have a substantial enough impact to warrant lowering the ROE. The testimony of Dr. Morin shows Duke's proposed ROE is on the lower end of what would be expected (Duke Ex. 40 at 3), and, further, the ROE is lower than what is approved in similar riders for other utilities. *Ohio Edison ESP Case*, Opinion and Order (July 18, 2012) at 10; *AEP ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 27.

Regarding Rider DCI's rate design, the Commission will adopt the design advocated by Kroger and GCHC which provides an equal percentage increase on distribution rates to all rate classes. This method, compared to those proposed by Duke and OCC, appears to be a better option, as it more accurately reflects the allocation of base distribution revenues from the *Distribution Rate Case*. Further, it generates the same amount of revenue as Duke's proposal.

The Commission agrees with Staff and others that general plant should not be included in the rider. The inclusion of general plant would go beyond the intent of the statute, which is geared towards reliability infrastructure. Such recovery would be better considered and reviewed in the context of a distribution rate case where the costs can be evaluated in the context of the Company's total distribution revenues and expenses, and the Company's opportunity to recover a return on its investment can be balanced against the customers' right to reasonably priced service. The function of Rider DCI is to proactively modernize infrastructure in order to improve reliability; the Commission does not find that the inclusion of general plant furthers that objective. In addition, the Commission agrees with Staff that the calculation of the revenue requirement should be based off of actual plant balances, not, as Duke proposes, projected plant balances. The Commission believes using actual costs instead of projected costs is a more practical approach and prevents overcharging.

The Commission also agrees with Staff and others that there should be a hard cap on how much the Company can recover in a year. This ensures that spending is prudent and not too onerous for customers. The Commission adopts Staff's recommendations for the annual caps. Therefore, the cap in 2015 will be $17 million, $50 million in 2016, $67 million in 2017, and $35 million for the first five months of 2018. The Commission will also accept Staff's recommendations regarding filing requirements. The filing requirements will be adopted in full, as set forth above, but allowing for Duke to submit its filings on the first of the month, as opposed to the tenth.

(b) Distribution Storm Rider

Duke also puts forward a nonbypassable Distribution Storm Rider (Rider DSR), which is intended to assist Duke in recovering the financial impact caused by major storms. Currently, the Company has $4.4 million set aside annually in its base distribution rates for major storm operations and maintenance recovery. Duke's proposal, as outlined by Duke witness Laub, is to defer the costs above and below that amount through a regulatory asset account until the next base distribution case. However, if the yearly balance surpasses $5 million in either direction, the Company would file with the Commission to recover or return that excess. Duke proposes that any balance in the account would accrue a carrying cost at the Company's long-term cost of debt as approved in the *Distribution Rate Case*. Duke notes that this rider does not include any capital expenses, as those would be addressed in either Rider DCI or a rate case. (Duke Br. at 16-17; Duke Ex. 9 at 6-7.)

OPAE submits that Rider DSR is not necessary and should be denied, as it believes distribution rates should be determined strictly through base rate proceedings. OPAE offers that, if the rider is approved, it should be modified. Staff and OCC also submit modifications to the rider. (OPAE Br. at 23-24.)

Staff, OCC, and OPAE believe Rider DSR should be subject to a substantive review. OCC witness Mierzwa states there should be a separate proceeding where Duke's major storm costs are properly reviewed. He posits that, without such a review, the chances increase of improper costs being included. OPAE echoes these concerns. Staff witness Hecker recommends that, once Duke's deferral amount exceeds $5 million, Staff should conduct a full audit of the expenses and offsetting revenues. (OCC Br. at 86-88; OCC Ex. 45 at 23-24; OPAE Br. at 23-24; Staff Br. at 37; Staff Ex. 4 at 4.) Duke responds that waiting for such a situation to occur unnecessarily complicates the process, as witnesses may no longer be available and accounts may not be as fresh. Duke believes a yearly audit is more prudent. (Duke Reply Br. at 39-40.)

In regards to what Duke can recover from Rider DSR, Staff makes several propositions. Staff witness Hecker first suggests that recovery should only take place through Rider DSR. Mr. Hecker proffers that only incremental labor should be included in the deferral. According to Mr. Hecker, the straight-time portion of the first 40 hours of work during a week of storm repairs or double-recovery should not be included, whereas any premium time and time above 40 hours used for storm repairs would be allowed to be recovered. Mr. Hecker also submits that overtime accrued by management should not be recoverable, as management is paid to do a specific job, as opposed to work a specific number of hours. Regarding reimbursements that Duke receives for providing mutual assistance, Mr. Hecker states such funds should be offset with what the Company can recover. Staff maintains Duke is double-recovering because the Company recovers for the first 40 hours of labor through base rates and recovers again when reimbursed from the other utility. Regarding carrying costs, Staff requests they not start until the end of a year that finishes above or below $4.4 million. Staff further asks that no carrying charges occur during a recovery period. (Staff Br. at 36, 39-42; Staff Ex. 4 at 3, 5-8.)

Duke has no objection to Staff's suggestion that costs only be recovered through Rider DSR. Duke also agrees that only incremental work should be recoverable, but believes that management overtime should be as well because the Commission has allowed it in the past and the Company has a specific, written policy that compensates management for working overtime on major storm repairs. However, Duke disagrees with Staff's assertions regarding alleged double recovery, stating that workers assisting other utilities must still complete their regular duties. (Duke Reply Br. at 39, 41-42.)

The Commission finds that Duke's Rider DSR is reasonable and should be approved, subject to the modifications described herein. The Commission agrees recovery should be done through Rider DSR and finds that Duke should file an application with the Commission seeking recovery under the rider when the balance of the asset or liability is over $5 million. The Company will bear the burden of showing that any cost was reasonably and prudently incurred and incremental to any cost recovery through base rates. The application should include a monthly rider charge when the amount is positive or a monthly rider credit when the amount is negative. The Commission finds that Staff should audit the included amounts on an annual basis. In regards to carrying costs, the Commission finds that they should occur at the long-term debt rate approved in the *Distribution Rate Case* and they should not begin until the conclusion of the calendar year that a deferral is determined and they should cease once the recovery begins.

Regarding Staff's recommendations on recoverable costs, the Commission finds that eligible costs must be incremental. When calculating the storm deferral, the Commission directs Duke to exclude employees' straight-time labor from working on storms in the Company's service territory. Consistent with Commission precedent, if Duke seeks to recover the expenses associated with overtime compensation paid to employees, including management, during a major storm event, the Company must demonstrate that, under the specific facts and circumstances of the major storm event in question, the overtime compensation was paid in accordance with the Company's nondiscretionary major storm restoration overtime policy, and was a reasonable and prudent expense associated with safely and efficiently restoring electric service to customers. *In re Ohio Power Co.*, Case No. 12-3255-EL-RDR, Opinion and Order (Apr. 2, 2014) at 25-26. Further, regarding mutual assistance revenues, the Company must show that any such revenues are not a reimbursement of labor hours that are already reflected in base rates. Finally, Duke should maintain and provide to Staff, on an annual basis, a detailed accounting of all storm expenses, including incidental costs and capital costs, and should also provide a detailed accounting of expenses incurred and revenues received for providing mutual assistance to other utilities.

(c) Load Factor Adjustment Rider

In its proposal, Duke is not offering several riders that were available under the previous ESP. Among the more contested suggested terminations is Rider LFA, whose immediate termination is opposed by Staff, GCHC, Kroger, OEG, OMA, and Miami/UC. According to Duke, the rider was originally the result of a negotiated settlement in the *ESP 2 Case* and was created in order to incentivize larger customers to reduce their load factor. Duke states that Rider LFA's influence on usage behavior was not market-based and, thus, went against goals of the Company and the Commission. Therefore, the Company seeks to terminate the rider, subject to a final true-up. (Duke Br. at 34; Duke Ex. 6 at 21-22.) Staff witness Donlon agrees with the eventual termination but suggests the rider slowly be phased out. Mr. Donlon submits reducing the rider by 33 percent in the first year, 33 percent in the second year, and 34 percent in the third year, with a final true-up at the end. According to Mr. Donlon, this would prevent the nonresidential customers who benefitted from Rider LFA from having a drastic rate change. (Staff Ex. 5 at 3.) GCHC, Kroger, and OMA agree with Staff's proposal (GCHC Br. at 15; Kroger Br. at 5-6; OMA Br. at 15). OEG's proposal is to have Rider LFA only apply to customers under Rates DP and TS, not DS, and to reduce the demand charge to $8/kilovolt-amp (kVa) in year one, $6/kVa in year two, and $4/kVa in year three. According to OEG witness Baron, Rate DS customers are smaller, more likely to be negatively affected by Rider LFA, and represent over 98 percent of those that were previously affected by the rider. Mr. Baron says the phase down for the other customers creates a more reasonable transition and better allows them to prepare for higher rates. Miami/UC prefers OEG's proposal over Staff's proposal. (OEG Br. at 26-28; OEG Ex. 2 at 20-23; Miami/UC Br. at 2-5.) Duke, however, maintains that Rider LFA should be terminated completely with the conclusion of the current ESP (Duke Reply Br. at 90).

The Commission agrees that Rider LFA should eventually terminate, but concurs with Staff and others that the rider should be gradually phased out. We believe it is reasonable to avoid any major rate shock for customers who were previously given incentive to adjust their load, especially noting that the rider is revenue neutral for the Company. The Commission accepts the recommendations of Staff and finds its proposal preferable. Therefore, the rider will continue as it did under the current ESP, but shall be reduced by 33 percent in the first year, 33 percent in the second year, and finally 34 percent in the third year. After that, the rider shall conclude with a final true-up.

(d) Backup Delivery Point Rider

Duke proposes to continue multiple riders in this ESP, including its Backup Delivery Point Rider (Rider BDP). Duke submits one modification to the rider that differentiates it from the *ESP 2 Case,* namely the reference on how GCHC member hospitals were to be treated under the rider. Duke states that GCHC was exempted in *ESP 2 Case* due to an agreed-upon stipulation; however, there is no such current agreement in these cases. GCHC says that a hospital with a typical load of 6,000 kW would be charged an additional $300,000 to $400,000 per year without the exemption. GCHC believes Duke is already recovering this revenue in its base rates and this increase to the hospitals allows Duke to recover twice. Duke opines the rider is unchanged and it is just the special exemption for GCHC that is being removed, as the stipulation would no longer be in effect. (Duke Reply Br. at 105; Duke Ex. 20; Tr. VI at 1625; GCHC Br. at 15-16.) The Commission understands that the previous exemptions were the result of a bargained stipulation that will no longer be in effect. Therefore, the Commission finds that Duke's proposed modifications to Rider BDP are reasonable and should be approved.

(e) Distribution Decoupling Rider

The Company also aims to continue Rider DDR, which, according to Duke, is intended to adjust rates between rate cases, thus, removing any incentive by Duke to increase volumetric consumption. Duke says it intends to maintain this rider until the next distribution base rate case. Duke offers that the rider should not apply to customers of Rates DS, DP, and TS. NRDC supports the extension of Rider DDR. It believes the rider allows Duke to help customers become more energy efficient. (Duke Br. at 17-18; Duke Ex. 18 at 19-21; NRDC Br. at 1-5.) The Commission finds that Duke's request to continue its Rider DDR is reasonable and should be approved.

(f) Large Customer Interruptible Load Program

Duke is proposing to eliminate its large customer interruptible load program that was established in the *ESP 2 Case*. The end of this program would also result in the termination of the Company's Economic Competitiveness Fund Rider (Rider DR-ECF), through which the program's costs were recovered. The program gave customers a chance to receive an above-market credit for allowing Duke to use interruptible load in Duke's FRR plan. Currently, there are four customers in the program. Duke notes that it will cease being an FRR entity on June 1, 2015, and, thus, will no longer need the demand resources. The Company further explains that stopping this arrangement furthers the development of a competitive electric market by eliminating nonmarket-based incentives. (Duke Br. at 34; Duke Ex. 6 at 22.)

OCC supports Duke's request to terminate the program. OCC contends the program was created via stipulation and was always intended to end with the conclusion of the current ESP. It asserts that, because Duke is a distribution-only utility, the Company would receive no benefit from the program and the credits given to customers would only serve as a subsidy. (OCC Br. at 97-99; OCC Ex. 46 at 29-30.)

OEG requests the Commission require the program to continue. OEG explains that, while Duke will cease to be an FRR entity, it will then become an RPM entity. According to OEG, the Company could still bid the load it receives from its customers into the RPM market as a capacity resource. With the anticipated retirement of a significant amount of coal capacity, OEG believes that interruptible load will become more valuable for reliability. Further, OEG states interruptible resources can lower market prices during peak times and lower the demand for more capacity resources. OEG asserts that the benefits of the program exist whether Duke is an FRR entity or an RPM entity. OEG also believes the program would give the participating customers rate stability. According to OEG, the capacity market is already unpredictable and, if the program is discontinued, the previously-participating customers may choose not to engage in the PJM demand response programs, thus, depriving other customers of the benefits of that interruptible load. OEG submits the Commission should continue the program, with modifications. Namely, OEG proposes participating customers would be subject to unlimited emergency-only interruptions year round, as opposed to only in the summer, and the level of interruptible credit, 50 percent of net cost of new entry (Net CONE) would remain the same. OEG's proposal would require Duke to continue Rider DR-ECF in order to recover costs. Further, OEG's modification would force Duke to bid the interruptible capacity into the PJM auction and credit the revenue back to customers. (OEG Br. at 16-25; OEG Ex. 2 at 4, 8, 13-14, 19.)

Duke stands by its request to cancel the program, subject to a true-up, when the new ESP term begins (Duke Reply Br. at 91). OCC again asserts there will be no benefit to continuing the program, explaining that, with Duke no longer being an FRR entity, the program does nothing to improve reliability. OCC believes the PJM demand response program is the more appropriate way for customers to evaluate interruption. (OCC Reply Br. at 47-48.)

Upon consideration of the issues raised, the Commission finds that the large customer interruptible load program should continue. As OEG discusses, the program offers numerous benefits and furthers state policy. Although Duke will no longer be an FRR entity, the advantages of the program are still available. We accept the modifications proposed by OEG, which makes participating customers subject to unlimited emergency-only interruptions year round. Furthermore, we find that the level of credit should remain at 50 percent of Net CONE. Rider DR-ECF will also need to continue, through which

Duke may apply for cost recovery. The Company should also bid the additional capacity resources associated with the program into PJM's BRAs held during the ESP term, with any resulting revenues credited back to customers through Rider DR-ECF.

(g) Demand Response

OEG recommends the Commission ensure that state-established demand response programs for shopping and nonshopping customers remain available, even if PJM is required to change its tariffs as a result of federal proceedings. OEG adds that demand response programs provide both reliability and efficiency benefits. (OEG Br. at 23-24.)

The Commission notes that the U.S. Court of Appeals for the District of Columbia Circuit has vacated FERC Order No. 745, which established a means for regional transmission organizations to compensate demand response resources in wholesale electricity markets. *Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014). Specifically, the court determined that demand response is solely a retail matter subject exclusively to state jurisdiction. The U.S. Solicitor General, on behalf of FERC, filed a petition for a writ of certiorari at the U.S. Supreme Court on January 15, 2015.

The Commission agrees with OEG that demand response plays an important role in ensuring reliability, while also encouraging state economic development. We find that, because of the possibility that federal proceedings may significantly alter the jurisdiction of demand response, a new placeholder pilot demand response rider should be established. The Commission emphasizes that this is merely a placeholder rider and that no cost allocation or recovery shall occur at this time. Within 30 days of a final order from the U.S. Supreme Court or an order denying petitions for certiorari, Duke or the Commission may open a new docket to revisit any provisions in these proceedings that relate to demand response and load management mechanisms within the Company's service territory.

6. Rate Structure

Duke asserts that it has properly analyzed and discussed how its ESP, as proposed, will affect rates. The Company affirms that it will have the lowest residential rates and among the lowest nonresidential rates. Duke also submits that its rate structure will further the state's policy regarding retail competition, service reliability improvements, and retail service stability and predictability. (Duke Br. at 24-26; Duke Ex. 18 at JEZ-4; Duke Ex. 2 at 13.)

OCC believes the Company's ESP should be modified in order to produce a reasonably priced SSO. OCC states that, although Duke has the lowest residential rates, the rates are still not affordable for many customers. OCC witness Williams states that

20.2 percent of Duke's customers are negatively affected by the current rates and 14.3 percent of Duke's customers were disconnected for nonpayment in 2013. OCC notes that the disconnect rate was the highest in Ohio. OCC further explains that 4.6 percent of Duke's customers are enrolled in the PIPP Plus program because they have difficulty paying their utility bill in full. Also, according to OCC, Duke's rates have increased at twice the rate of inflation over the past five years. OCC avers that the Commission should eliminate various riders, in particular Rider DCI, as those riders will negatively affect customer rates and the associated costs are best recovered via a rate case. OCC also proposes the Commission reject the rate allocation methodology for Rider RC. (OCC Br. at 68-73; OCC Ex. 35 at 9, 11.) OPAE offers similar arguments, submitting that Duke's plan does not protect at-risk populations. OPAE believes rate affordability is of particular concern in Duke's service area, as the poverty level there is higher than the national average. OPAE states that affordability is already an issue and Duke's Riders RC and DCI will only increase rates for customers. OPAE requests that the riders be denied or, alternatively, that at-risk populations be exempt from payment. (OPAE Br. at 3-7.)

Wal-Mart believes Duke's rate structure is unnecessarily complex, making it overly difficult for commercial customers to navigate. Wal-Mart submits the Commission should order Duke to file a base rate case, which it says is not only good policy, but in line with statutory goals. (Wal-Mart Br. at 4-6; Wal-Mart Ex. 1 at 5-6.)

The Commission finds that the concerns expressed by OCC and OPAE have been thoroughly addressed through the discussion in this Order regarding Duke's various proposals. The Commission finds that the proposed ESP, with the required modifications, creates a reasonably priced rate structure for customers. The Commission specifically considered the impact the ESP would have on at-risk populations, in line with R.C. 4928.02. As to Wal-Mart's proposal, the Commission declines to require Duke to file a distribution rate case by a specific date, but does encourage Staff and intervening parties to recommend ways to simplify Duke's rate structure in the next rate case.

7. Term of the ESP

Duke's application requests the ESP be approved for a three-year term, with the unilateral option to terminate the ESP one year early. If Duke decides to terminate the ESP early, all MSAs pertaining to delivery between June 1, 2017, and May 31, 2018, would be declared null and void. According to Duke, it would only have the ability to terminate the ESP early if a "substantial change" in state or federal law occurred that affects SSOs or rate plans concerning SSOs. The change could occur via, among other things, statute, rule, court decision, Commission decision, or FERC decision. Duke asserts that the market environment is very dynamic and it is necessary to take such risk-mitigation measures. If such a change occurs and Duke seeks to terminate the ESP early, the Company states it would file a notice with the Commission by September 1, 2016, and, with that notice, also submit an application for a new SSO. As stated in its application, the decision to terminate the ESP early would solely be Duke's. (Duke Br. at 35-36; Duke Ex. 1 at 16.)

Numerous parties argue against Duke's ability to terminate the ESP after two years under several rationales. OCC argues, among other things, that the possibility of the ESP being three years or just two years essentially creates two separate ESP requests. Because Duke's application and evidence is primarily geared to the three-year ESP term, OCC submits the Company has not met its burden of proof regarding the two-year ESP term. OCC's position is that the two-year ESP request is invalid because Duke did not provide any analysis in order for the Commission to do the mandated ESP versus MRO comparison. Therefore, according to OCC, the request for a two-year ESP should be denied. The Company submits the Commission is to look at the application as a whole. The conditional option to terminate the ESP early is just a part of its entire application, Duke asserts, and it does not create two different requests. (OCC Br. at 106; Duke Reply Br. at 95-96.)

Kroger, OCC, OMA, and RESA all argue there is no statutory authority that allows Duke to terminate its SSO early. The parties point out that R.C. 4928.143(B)(2) outlines what an ESP may provide. The parties all argue that the statute does not specifically give Duke the authority to terminate the ESP early and, without such authority, Duke's request is legally invalid. OCC avers that there is only one circumstance where an ESP may be terminated early by a utility. In that situation, the ESP must be for three years or less, and the Commission must find that the Company's earnings exceed the SEET ROE threshold. Multiple parties also submit that, if Duke is overly concerned about the environment two years from now, it should have only requested a two-year term. (OCC Br. at 107; Kroger Br. at 7; OMA Br. at 7-8; RESA Br. at 26-27.) The Company responds that R.C. 4928.143 does not require an ESP last for a particular term and, therefore, without any statute particularly precluding such an option, Duke's request for a two-to-three year term is statutorily allowed (Duke Reply Br. at 95).

What defines a substantial change is too nebulous and gives Duke too much leeway to unilaterally terminate the ESP, argue Direct Energy, Exelon, Kroger, OCC, OMA, and RESA. The parties believe Duke could very broadly determine what constitutes a substantial change in law regarding rate plans or SSOs. The Company's request, according to the parties, does not offer any objective criteria or examples for the Commission or interested parties to know what exactly constitutes a substantial change. They argue this allows Duke to find a way to terminate the ESP early if the utility believes the plan is no longer beneficial to the Company. (Direct Br. at 16; Exelon Br. at 14; Kroger Br. at 7; OCC Reply Br. at 52; OMA Br. at 5-6; RESA Br. at 26.) Duke avers that its application is not ambiguous about when the Company can terminate the ESP and that the possibilities are explicitly laid out (Duke Reply Br. at 92-93).

Exelon, OMA, and RESA think Duke's window of opportunity to file a notice of termination and to get a new ESP approved is unrealistically small. Duke would file its notice of termination on September 1, 2016, and would need to have the Commission approve its new ESP by June 1, 2017, according to RESA witness Campbell. It is impractical to expect a new ESP application to be filed, litigated, and approved in that nine-month period, the parties assert. Because of the impracticalities, the oppositional parties believe the option should not be available to Duke. (RESA Br. at 27; RESA Ex. 3 at 20-21; Exelon Br. at 14; OMA Br. at 7.) The Company disagrees with these assertions (Duke Reply Br. at 93).

Numerous parties contest Duke's termination option because they believe it creates an unnecessary volatility in the markets and could negatively affect various contracts. Staff asserts that, if the Company enacts the termination provision, the entirety of the SSO supply would conclude on May 31, 2017, when all current MSAs would become null and void. Staff points out that all of the supply would then be subject to prevailing market prices. OCC notes that some of the auctions in Duke's CBP plan include products with three-year contracts that would extend into the third year of the ESP period with the potential to be terminated. OCC believes this would create uncertainty for SSO wholesale suppliers, CRES providers, and customers. The increased risk, according to RESA witness Campbell, would cause a decrease in competitive bidding, possibly resulting in increased costs to customers. Further, he states it may prevent customers from entering into beneficial longer-term contracts with CRES providers. Staff, Exelon, Kroger, and OMA second these concerns. (OCC Br. at 108-109; OMA Br. at 6-7; Exelon Br. at 14; Kroger Br. at 9-10; Staff Br. at 49; Staff Ex. 3 at 3-4; RESA Ex. 3 at 20.) Duke argues the risk created by the possibility of an early termination is not quantifiable; there is always a risk in the bidding process and the markets are often volatile (Duke Reply Br. at 93; Tr. XIII at 3815-3816).

The Commission finds that Duke's request for the unilateral option to terminate the ESP a year early is not reasonable, should be denied, and should be removed from the MSA. The conditions under which Duke could terminate the ESP early are overly broad, as what constitutes a substantial change was largely left undefined by the Company. Additionally, with the high number of Commission decisions, FERC decisions, court decisions, rules, and laws that affect SSOs and base rates, the Company would be given excessive discretion to find reasons to terminate the ESP early if conditions were no longer favorable. Further, the tentative term of the ESP would likely create uncertainty in the market, as argued by Staff and other parties. This could lead to unnecessarily higher costs for customers. The Commission notes that Duke can pursue other means to seek relief if there are substantial changes to the law and the Company feels it needs to protect its interest or its customers' interests.

8. Corporate Separation

As the Company notes, Ohio Adm.Code 4901:1-35-03(C)(4) requires an ESP application to discuss the status of its current CSP. The Company's last amendment to the CSP was filed on April 16, 2014, and has been approved by the Commission, according to Duke witness Hollis. Mr. Hollis reveals that the utility is still in the process of transferring its last legacy generating asset and will file an amended CSP after that transfer is complete. Mr. Hollis explains the Company's CSP was audited in 2009-2010 by an independent auditor and the results of the audit were approved by the Commission. He also notes that no waivers of the plan have been granted and that, in his opinion, the CSP is in compliance with all rules and laws. Specifically, he looks at the state policies espoused in R.C. 4928.02(H) and (I). In regards to R.C. 4928.02(H), Mr. Hollis notes that Duke does not use any revenues from its distribution business towards any affiliate that operates in the CRES market. As to R.C. 4928.02(I), he states Duke ensures it complies with all of the Commission's consumer protection rules for both distribution utilities and CRES providers. For purposes of the ESP application, Duke believes it has met the burden of proof for the Commission requirements regarding corporate separation. (Duke Br. at 39; Duke Ex. 11 at 3-5; Tr. IV at 845-846.)

IGS and RESA believe Duke is in violation of the CSP due to what they believe are unfair and unlawful billing practices by the Company. IGS witness White states that Duke Energy One, an affiliate of Duke, currently places charges for noncommodity services, Strike Stop and Underground Protection Service, on the EDU bill. He says placing noncommodity charges on the EDU bill is not an option that is afforded to CRES providers such as IGS. RESA and IGS argue this constitutes preferential treatment for a Duke affiliate, and is, thus, a violation of R.C. 4928.02(H). Although Duke currently has an approved CSP, the parties submit it would be unreasonable for the Commission to knowingly approve an ESP for a utility violating CSP requirements. (IGS Br. at 10-11; IGS Ex. 10 at 11-14; RESA Br. at 5-6.)

In reply, Duke avers that this is not the proper forum for these concerns by IGS and RESA. Duke states their issues most resemble a complaint under R.C. 4905.26. According to the Company, only the current status of the CSP is what is relevant in these proceedings and the Company's current CSP has been approved by the Commission. Regarding preferential treatment towards an affiliate, Duke explains that Duke Energy One is not a CRES provider and, thus, its treatment should not be compared to one. Further, Duke says it has not completely rejected offers by other providers to allow noncommodity charges on the EDU bill. (Duke Reply Br. at 103-105.)

The Commission finds that Duke has met its burden of proof regarding the CSP as it pertains to the Company's ESP application. Regarding IGS's and RESA's concerns, the

Commission affirms that, as discussed further below, this is not the proper forum to address those issues.

9. Operational Support Plan

Ohio Adm.Code 4901:1-35-03(C)(5) requires the utility to demonstrate whether an operational support plan (OSP) has been implemented and whether there are any problems with that implementation. The OSP is required under R.C. 4928.13(A)(3) as part of the utilities' transition towards deregulation. Duke submits that its OSP was most recently approved in 2008 and has been implemented. Since implementation, Duke reports there have not been any notable problems. (Duke Br. at 39-40; Duke Ex. 13 at 3-4.) The Commission agrees that the Company has fulfilled its obligations regarding its OSP.

10. Government Aggregation

An ESP applicant must submit, pursuant to Ohio Adm.Code 4901:1-35-03(C)(6) and (C)(7), a description of how the utility will address governmental aggregation and a description of how large-scale generation will effect any proposed generation charge. Duke witness Wathen states that Duke is currently not seeking any deferrals under R.C. 4928.144 and, therefore, R.C. 4928.20(I) is not applicable to the ESP application. Mr. Wathen further explains that R.C. 4928.20(J) is also not applicable to the Company's application, as it is not seeking a charge for standby service. Regarding R.C. 4928.20(K), Mr. Wathen says Duke's application does not result in rules that would encourage or promote aggregation. No intervenor contested this issue. Duke thusly avers that it has fulfilled the filing requirements for government aggregation. (Duke Br. at 40-41; Duke Ex. 6 at 30-31.) The Commission agrees.

11. Significantly Excessive Earnings Test

Duke notes that, in its two previous ESP cases, the Commission approved the manner in which the SEET would be applied to the Company, which is completed on an annual basis in a separate proceeding. Duke proposes to continue operating the test in the same fashion as the past two ESPs, where the SEET ROE threshold was held at 15 percent. (Duke Br. at 32-33.)

OCC asserts that the SEET threshold should not be established in an ESP proceeding. OCC submits that the threshold should be established in the separate annual proceedings regarding the SEET. OPAE agrees with OCC. According to OCC, it is unlawful to establish a prospective, forward-looking SEET threshold. Further, OCC believes that the previous ESP cases should not be binding for these proceedings, as those ESPs were the results of stipulations that specifically stated that the findings were not to be relied on for future cases. OCC also asserts Duke's reliance on previous ESPs is insufficient to meet the burden of proof to establish a SEET threshold. (OCC Br. at 110-111; OPAE Br. at 25.)

If the Commission does rule on the SEET threshold, OCC believes Duke's proposal of 15 percent is too high. OCC witness Kahal asserts Duke's proposed riders and its divestment of generation decrease the utility's business risks and, thus, the ROE threshold should also decrease. OCC recommends the threshold be set at 12 percent, which is the same that was set for DP&L in the *DP&L ESP Case*. OPAE also believes such a threshold would be more appropriate than what Duke is proposing. On rebuttal, Duke witness Morin offers that the Company's new riders will not reduce business risks. He further explains that the Company's business risks should not affect what the threshold is and that 15 percent for the ROE threshold is appropriate. (OCC Br. at 111-114; OCC Ex. 32 at 31-32.)

The Commission finds that, since we have not authorized or renewed a service stability rider, it is not necessary to establish a SEET threshold in these ESP proceedings. Accordingly, Duke's SEET threshold for each year of the ESP will be determined within the context of each annual SEET case.

12. Service Reliability

OEC proposes that, with Duke's successful SmartGrid infrastructure implementation, the Company should be required to report annually on various performance metrics. OEC witness Munson outlined 21 metrics that he believes the utility should report on. The metrics would cover administrative, cost-related, and environmental statistics. He reports similar findings are required in Illinois. Mr. Munson believes this reporting would be beneficial to the Commission, customers, and Duke. Duke would benefit, according to Mr. Munson, by being able to demonstrate savings to customers. Further, he says the resulting information would assist Duke in complying with new environmental legislation that is likely to pass soon. Mr. Munson does not believe these reports would be burdensome to the Company, because he says Duke has to report similar performance metrics to fulfill a federal grant requirement. (OEC Br. at 17-22; OEC Ex. 1 at 3-5.) Duke responds that OEC's witness does not fully understand what is already required in Ohio and that how things are done in Illinois is not applicable to Ohio. Therefore, Duke requests OEC's proposal be disregarded. (Duke Reply Br. at 105-106; Tr. XII at 3357-3358.)

The Commission finds that, at this time, it will not require Duke to file the various performance metrics, as requested by OEC. The Commission understands the Company's SmartGrid infrastructure could yield useful information, but does not find this is the proper time or forum to address those concerns.

13. Other Issues

(a) Market Energy Plan

RESA submits a proposal for a market energy plan (MEP) that would introduce shopping to eligible customers. RESA witness Pickett outlined the plan, explaining that, if a residential or small business customer who is not being serviced by a CRES provider calls Duke for any reason other than an emergency or for termination, that customer will be offered a three percent discount on the price-to-compare for six months if that customer enrolls in the MEP. If that customer chooses to participate in the MEP, that customer would be immediately enrolled with either the CRES provider of his or her choosing or with an assigned CRES provider. Customers could leave the program at any time, without a termination fee, and could also switch providers, if they desired. RESA submits Duke would offer a start-up and maintenance plan to the Commission to determine costs. Customers benefit from the program, according to Mr. Pickett, by getting access to competitive products, by being guaranteed a discounted rate, and by being educated about available products. He further mentions the program benefits the state policy of promoting competition and diversity. Mr. Pickett notes a similar plan was created in Pennsylvania and is successful. He also states that many of the details still need to be developed. (RESA Br. at 31-33; RESA Ex. 4 at 8-13.)

OCC and OPAE believe RESA's proposal should be denied. OCC notes that many of the details of the program are vague and that there is little analysis to back-up the current proposal. According to OCC, the proposal weakens the benefit of an SSO. OCC believes CRES providers want the utility to market their services for them and this distorts the line between utility and commodity. OCC further says the three percent discount may not actually be the best discount a customer could obtain and, thus, it goes against the desired effect to encourage shopping. Rather, OCC suggests, it merely gets a customer locked into a rate that will later auto-renew without the discount. This could result in higher costs and customer confusion, according to OCC. OPAE believes the proposal only succeeds in getting customers to leave the SSO, and does not encourage competition, as RESA claims. (OCC Br. at 100-103; Tr. XIII at 3662-3663; OPAE Br. at 29-30.)

At this time, the Commission will not adopt the MEP. As admitted by RESA, many of the details of the proposal still need to be properly developed (RESA Ex. 4 at 12). Thus, as it stands, it is not clear exactly how the MEP would operate. Beyond that, the Commission finds that this is not the proper venue for such a proposal to be introduced. The Commission directs interested parties toward the Market Development Working Group (MDWG), which was created in the *CRES Market Case*, Finding and Order (Mar. 26, 2014) at 23. We believe the MDWG is the better forum to evaluate the proposed MEP and to determine whether such a proposal should be brought before the Commission in a separate case.

(b) Unbundling

IGS asserts Duke's ESP application does not fulfill the requirements of R.C. 4928.02(B), because the Company does not ensure the availability of unbundled and comparable retail electric service. IGS avers that, in order to provide retail services, Duke incurs a significant amount of noncommodity costs that it improperly collects through distribution rates instead of the SSO price. IGS states Duke limits its SSO cost to just a pass-through of wholesale capacity and electric costs even though providing electric service also requires a company to incur, among other things, technology costs, call center costs, and overhead costs. IGS explains that CRES providers sustain the same noncommodity costs as Duke, but they are unable to recover those costs through distribution rates. Therefore, IGS believes shopping customers end up paying for those noncommodity charges twice. IGS notes that other states, including New York, Illinois, Maryland, and Pennsylvania, have unbundled certain costs from the distribution rates and instead attached them to the default supply service. Although Ohio statutorily requires that services be unbundled, IGS argues the state is lagging. (IGS Br. at 13-17; IGS Ex. 10 at 22-23.) At this time, the Commission believes these issues are better suited for another forum, such as a distribution rate case, and, therefore, we decline to adopt the proposal from IGS.

(c) Enroll From Your Wallet

RESA, believing there are still numerous obstacles preventing customers from shopping, proposes a program titled Enroll From Your Wallet that would allow customers to enroll with a CRES provider without presenting a utility account number. RESA witness Picket states that, currently, customers wishing to enroll with a CRES provider must furnish a utility account number and that many willing customers are unable to find the number or remember the number. He proposes a pilot program where the customer would give the CRES provider authorization to find the account number. The CRES provider would use a portal created by Duke to get the account number and enroll the customer. The provider would maintain records of the authorization and the customer contract, and would produce the documents if any claims arose. RESA believes this program is more convenient for customers and makes it easier for them to shop. RESA requests the Commission start the pilot and create a working group with Staff, Duke, RESA, OCC, and other interested parties to complete details of the pilot. According to RESA, that working group would then submit a final proposal for approval by the Commission. (RESA Br. at 30-31; RESA Ex. 4 at 6-8.)

OCC and OPAE are both against the Enroll From Your Wallet proposal. OCC notes that RESA did not provide any information showing that shopping is being hindered by customers' inability to find a customer account number. OCC further submits that requiring an account number provides a level of protection for customers against slamming. OPAE argues similarly. OCC believes that many customers use their utility bill to find their account number and that the bill contains useful information that will assist customers in making informed decisions regarding whether they want to enroll with a CRES provider or not. (OCC Br. at 104-105; Tr. XIII at 3656; OPAE Br. at 29.)

The Commission declines to authorize RESA's Enroll From Your Wallet program at this time. A similar proposal was made in the Commission's *CRES Market Case* and the Commission, at that time, decided against starting such a program. The Commission continues to have concerns regarding slamming and customer privacy. Further, it appears many key details are still unknown and few stakeholders are in agreement with the proposal. The Ohio Electronic Data Exchange Working Group was previously directed by the Commission to cooperate together on working out the specifics of a website registration system. Here, the Commission encourages those stakeholders involved to continue to work together to create a more fully developed plan. *CRES Market Case*, Finding and Order (Mar. 26, 2014) at 35.

(d) Purchase of Receivables and Billing

Duke currently operates a POR program, where it purchases the accounts receivable of CRES providers and processes the collection efforts on its own. Duke avers this program has been extremely successful and is used by all but two of 55 CRES providers in its service territory. The Company seeks to make the POR program mandatory for all CRES providers that intend to use Duke's consolidated billing services. Duke further proposes that providers in the POR program be limited to providing only commodity services on their bills. Duke asserts this ensures purchases are for their intended purposes. (Duke Br. at 33, 36-37; Duke Ex. 13 at 6-7.)

OPAE believes the entire POR program should be invalidated and terminated. OPAE submits the program subsidizes CRES providers and unfairly raises the distribution costs for customers. According to OPAE, the program prevents competition and, therefore, goes against state policy. In the alternative, OPAE asks that Duke be required to implement a discount rate that completely covers the CRES providers' bad debt. This would prevent the need for Rider UE-GEN, through which Duke collects the bad debt expenses. (OPAE Br. at 25-26.)

Direct Energy, IGS, and RESA are opposed to the suggested change to the POR program. Direct Energy believes what constitutes a commodity charge is vague. Considering that, if a CRES provider puts an inapplicable charge on the bill, it would violate its obligations under the accounts receivable purchase agreement, Direct Energy explains Duke is given too much discretion. Direct Energy further argues that, because many customers do not want separate bills, CRES providers are limited from offering innovative noncommodity services. Direct Energy believes this harms the competitive market and does a disservice to customers. Duke customers in particular, according to Direct Energy, are set up for innovative, cost-saving programs because of the SmartGrid system that allows customers to examine and manage their energy use efficiently. IGS and RESA argue, similarly, that state policy encourages the expansion of innovative, useful products for customers and this proposed change restricts that. (Direct Energy Br. at 6-11; IGS Br. at 6-8; RESA Br. at 4-5.)

With regard to billing, Direct Energy, IGS, and RESA also argue that Duke's proposal to exclude noncommodities from consolidated billing is unfair and preferential to Duke affiliates. They note that the Company's affiliate, Duke Energy One, currently has noncommodity charges on its bill, i.e., Strike Stop Service and Underground Protection Service. IGS believes this contravenes Ohio law that prevents a utility from giving an undue advantage to an affiliate. Further, as discussed earlier, the parties believe this violates the Company's CSP. IGS and RESA submit that, although Duke claims it does not have the technology, because Duke Energy One is able to place noncommodities on Duke's bill, it is feasible for Duke to separate the commodity charges from the noncommodity charges in order to delineate POR program purchases. At a minimum, the opposing parties request the Commission deny the proposed tariff amendment. IGS goes further and asks for the tariff to be changed to specifically allow noncommodities on the bills. IGS also requests the Commission direct Duke to allow CRES providers to be able to be customers' single billing entity. This would allow CRES providers to offer more products and services to customers and further the competitive market, according to IGS. (Direct Br. at 6-11; IGS Br. 5-13; IGS Ex. 10 at 6-15; RESA Br. at 4-5; RESA Ex. 1 at 6-8.)

Duke explains it is necessary to exclude noncommodities from the bill because it would otherwise be unfair to other ratepayers. Duke states that the unpaid bills obtained through the POR program are collected through a rider attributed to all Duke customers, Rider UE-GEN. According to the Company, it would be unfair to force customers to pay various CRES providers' noncommodity charges. Duke also asserts it does not have the technology to separate commodity and noncommodity charges on its POR program purchases. Regarding Duke Energy One, Duke explains that its affiliate is not a CRES provider and does not provide retail electric services. Because Duke Energy One's charges are purely noncommodity, Duke says, those charges are naturally separated for the Company's billing department. Duke also avers that the requirement to have consolidated billing applies only to electric services. In sum, Duke asks the Commission to allow its requested tariff amendment and deny the requests of Direct Energy, IGS, and RESA. (Duke Reply Br. at 96-100.)

The Commission finds that Duke's request to amend its CST to make POR mandatory for CRES providers using the consolidated billing service should be denied.

Although a high percentage of CRES providers using the consolidated bill service choose to also enroll in the POR program, the Commission does not feel it is reasonable at this time to force the decision. Duke's main rationale for making POR mandatory is to develop operational consistency and to prevent spending additional administrative costs. At this time, very few providers choose not to enroll in POR; however, situations and markets can change and the burden on Duke to allow such an option currently does not rise to a level that should restrict freedom of choice. (Duke Ex. 13 at 6-7.)

The Commission further finds that, at this time, the Company's assertion that bill-ready billing should be limited to only electric commodity charges is reasonable. The Commission notes that the tariff defines what "commodity" means and later provides examples of what is considered "noncommodity." Because all customers must bear the cost of unpaid bills, and because the evidence in these cases reflects that Duke does not have the technology to separate commodity and noncommodity charges, the Commission does not find it reasonable to allow various noncommodities to be added to the bills. In regards to the Company's affiliate, Duke Energy One, the Commission points out that, because it does not provide retail electric service, the entity is not parallel to a CRES provider. For the above reasons, the Commission finds that Duke's request to amend the tariff is reasonable.

(e) Usage Data

Duke also submits a proposal to change the definition of an "interval meter" as it appears in the CST. The Company notes that, when the tariff was originally filed, only one type of interval meter existed: solid state recorders (SSRs). These meters were primarily installed with commercial customers to provide data to PJM. Since then, Duke reports it deployed its SmartGrid program which has advanced meter infrastructure (AMI). Duke asserts that, due to Commission rules regarding data compilation, it was necessary for the Company to differentiate between the two meters because they each have different capabilities. Therefore, as it pertains to the CST, Duke seeks to have the interval meter definition refer specifically to the older meters, the SSRs. (Duke Br. at 37-38; Duke Ex. 13 at 8, Att. DLJ-1 at 3.)

RESA believes this change seeks to prevent Duke from needing to supply CRES providers with usage data and requests the Commission deny the change. RESA states that, if this tariff change is approved, CRES providers will only be able to access usage data from SSRs. RESA notes the utility was previously ordered to provide usage information from interval meters to CRES providers and Duke is trying to avoid the Commission's Order in the *CRES Market Case* by altering how an interval meter is defined. (RESA Br. at 34-35; Tr. IV at 1053-1054; RESA Ex. 1 at 9-10.) Duke is aware that CRES providers are seeking more usage data, however, the Company does not believe this is the proper forum to address those concerns. Duke states that, because the two meters have different capabilities, it wanted to clear up the definitions. The Company asserts ongoing proceedings already exist where the CRES provider access to usage data is being discussed, and Duke believes those concerns are better addressed in those proceedings. (Duke Reply Br. at 101-102; Tr. IV at 1054-1056.)

Also in regards to usage data, OEC proposes that the data be made available to customers and third parties. OEC avers the owner of consumption data is the customer and customers should have full access to that data. OEC witness Munson proposes an Open Data Access Framework. Mr. Munson submits the access would allow customers, and third parties with authorization, to better analyze their energy usage and to spark innovation. He notes that a similar framework was implemented in Illinois. (OEC Br. at 22-25; OEC Ex. 1 at 3.) Duke responds that the proposal is not applicable for an ESP case and that the proposal, as described, does not fit into the structure of the Commission's regulations (Duke Reply Br. at 105-106).

At this time, the Commission declines to accept Duke's request to change the tariff's definition of an interval meter. With Duke's deployment of its SmartGrid program, it is the Commission's expectation that, as adopted in our Order in the *CRES Market Case*, the provision of usage data would likewise progress. *CRES Market Case*, Finding and Order (Mar. 26, 2014) at 36. However, in light of the fact that the issues regarding the Company's usage data and, specifically, the definition of an interval meter are being addressed *In re Duke Energy Ohio, Inc.*, Case No. 14-2209-EL-ATA, we find that it is more appropriate to address Duke's proposal in that proceeding, rather than this one, in the hopes of resolving the issues. Likewise, OEC's proposal concerning the reporting of usage data should be addressed in that same proceeding.

(f) Resettlement

The Company requests another change to the CST where, if Duke seeks to pursue settlement with PJM, all suppliers will agree to participate. PJM would still control the resettlement process, according to Duke, but the process will be smoother and more predictable if participation is not discretionary. (Duke Br. at 38; Duke Ex. 13 at 9.) RESA disagrees with the proposed change, arguing that it is one-sided. RESA believes the Company or CRES provider should be able to initiate resettlement, not just Duke. Further, RESA says CRES participation in resettlement should remain discretionary. (RESA Br. at 36.) The Company counters that the proposed change is actually beneficial for CRES providers. Currently, according to Duke, if a provider initiates resettlement, it must obtain the voluntary cooperation of all other CRES providers. Duke states it is trying to simplify the resettlement process for the interested parties. (Duke Reply Br. at 101-102.)

The Commission declines to adopt Duke's proposed amendment. The Commission understands that it can be burdensome to acquire all of the necessary consents in order to pursue resettlement, but we find it is not reasonable to force a CRES provider's consent where it may not exist.

(g) Economic Development

The Commission notes that R.C. 4928.143(B)(2)(i) authorizes the inclusion of economic development programs in ESPs, and we find it prudent to modify Duke's ESP to include an economic development program, which will create private sector economic development resources to support and work in conjunction with other resources to attract new investment and improve job growth in Ohio. Accordingly, the Commission finds that Duke should implement an economic development fund, which will be funded by shareholders at $2 million per year, or a portion thereof, during the term of this ESP. This funding is consistent with our directives in the *ESP 2 Case*, as well as our treatment of other EDUs and shall not be recoverable from customers. *ESP 2 Case*, Opinion and Order (Nov. 22, 2011) at 43; *AEP ESP 3 Case*, Opinion and Order (Feb. 25, 2015) at 69-70; *DP&L ESP Case*, Opinion and Order (Sept. 4, 2013) at 42-43. Any funds that are not allocated during a given year shall remain in the fund and carry over to be allocated in subsequent years.

III. IS THE PROPOSED ESP MORE FAVORABLE IN THE AGGREGATE AS COMPARED TO THE RESULTS THAT WOULD OTHERWISE APPLY UNDER R.C. 4928.142?

Duke asserts that its proposed ESP is more favorable in the aggregate than the results that would otherwise apply under R.C. 4928.142. Duke acknowledges that, in accordance with R.C. 4928.143(C)(1), it has the burden of proving that its proposed ESP, including the pricing, terms, and conditions, "***is more favorable in the aggregate as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code." According to Duke, this comparison takes into consideration the quantifiable elements, as well as the unquantifiable benefits of an ESP. *Citing Columbus S. Power Co.*, 128 Ohio St.3d 402, 2011-Ohio-958 945 N.E.2d 501, at ¶27. As for the quantitative benefits, Duke asserts the ESP is necessarily equivalent to the results from an MRO, noting that both the ESP and an MRO employ a CBP plan that would yield competitively-priced, market-based generation service, and Riders DCI and DSR are available under either scenario. (Duke Ex. 1 at 14-15; Duke Ex. 6 at 25; Duke Br. at 27.) Moreover, the ESP is better qualitatively, because it: enables timely investment in Duke's distribution system, thus, improving the safety and reliability of the system, while protecting Duke's financial integrity; provides customers with price stability and certainty for both shopping and nonshopping customers, affording them the benefits of Duke's OVEC entitlement through the competitively neutral PSR; modifies the rate design that will result in costs for SSO supply being charged consistent with the manner in which they are incurred and in a manner that is reflective of the offers customers may receive from

CRES providers; eliminates nonmarket based riders or arrangements; and establishes generation-related costs based on market forces (Duke Ex. 1 at 15; Duke Ex. 6 at 27; Duke Br. at 27-32; Tr. II at 544).

Staff believes that, when all provisions of the ESP are considered, along with Staff's proposed recommendations, the ESP is more favorable in the aggregate than an MRO. Staff states that, given the generation rates for 100 percent of the SSO load are based on market-based auction prices, there should be no difference in quantitative benefits between an ESP and MRO. Staff notes that it did not perform an analysis as to whether the ESP, as proposed by Duke without Staff's modifications, would pass the MRO test; therefore, if the Commission approves the PSR, Staff would need to perform the test again. (Staff Ex. 2 at 3; Staff Br. at 57-58.)

As for the qualitative benefits, Staff considered the new Rider DCI, which provides an economical and efficient process for the Company to make investments in its distribution system; thus, improving the safety and reliability of the distribution system. In addition, an ESP, as opposed to an MRO, provides a mechanism where Duke's tariff can be further refined to be more reflective of the current competitive environment; thereby providing more benefits for customers than may be available under an MRO. For example, Duke proposes to modify the rate design of its generation rates to better reflect what customers could expect to see in the competitive market; however, under an MRO, the generation rates charged to customers would be the market rates that result from an auction and there would be no ability to phase out the current rate design, which could subject customers to substantial rate impacts. An ESP also allows for flexible ratemaking, providing a process for utilities to propose riders that may provide a more efficient method of cost recovery, and for all stakeholders to provide input on proposed riders. (Staff Ex. 2 at 3-4.)

OCC offers that the traditional analysis of the ESP versus MRO test requires consideration of three elements: the SSO price of generation; other quantitative provisions; and qualitative provisions. OCC asserts Duke argues that, because the SSO generation price is the same under either an ESP or MRO and, because no other provisions of the ESP are quantifiable, its ESP must be approved based solely on the qualitative benefits. However, OCC maintains Duke's claimed qualitative benefits are either not beneficial or could be provided if the SSO were in the form of an MRO. (OCC Reply Br. at 14-15.)

GCHC, OCC, IEU, and Kroger submit that the ESP does not meet the statutory test for an ESP, as it is not more favorable in the aggregate than an MRO (OCC Ex. 48 at 4; GCHC Br. at 17; IEU Br. at 2; Kroger Br. at 15; OCC Br. at 59). GCHC states that R.C. 4928.142, authorizing an MRO, does not permit the inclusion of single-issue ratemaking, noting that Duke acknowledges that the PSR and Rider DCI could not have been proposed under an MRO (GCHC Br. at 17-18; Tr. I at 147; Tr. II at 446, 449, 557). While Duke submits these riders are neutral because they could exist under an ESP or MRO, GCHC disagrees, as these riders could not be approved in a standalone MRO proceeding, without a separate base rate case (GCHC Br. at 18; Tr. II 439-441, 445, 536; Tr. XIII at 3793). GCHC asserts, since the PSR and Rider DCI could not be approved in an MRO proceeding, the only proper comparison is between the ESP proposal Duke made, with the riders, and an MRO using a CBP that does not include the riders. GCHC argues Duke's comparison of its ESP to what could be done in an MRO plus a base rate case is contrary to statute. GCHC points out Staff agrees that, if the value of the PSR is negative, then an ESP with the PSR would be less favorable than an MRO. (GCHC Br. at 18-19; Tr. XIII at 3796.) GCHC submits Duke attempts to lay claim to intangible benefits of the riders, while ignoring the costs of the riders to ratepayers; however, R.C. 4928.143(C), which authorizes an ESP, requires consideration of the entire plan, including pricing. GCHC offers that the price of Duke's ESP with riders is necessarily higher than the price of an MRO without the riders. Therefore, Duke's ESP fails the comparison with an MRO. (GCHC Br. at 19.)

OMA contends Duke's analysis of the ESP versus an MRO failed to consider the effects of many provisions in the proposed ESP (OMA Reply Br. at 34). OMA submits the costs of the PSR and Rider DCI must be considered as quantifiable costs in the MRO analysis, because these are costs that would not be paid under an MRO scenario (OMA Br. at 28). OMA notes Rider DCI will result in a net rate increase to customers compared to current rates, and it is not available under the MRO statute. As described by OMA, Duke alludes to the benefits of Rider DCI, but does not quantify such benefits. Moreover, OMA notes in the *Ohio Edison ESP Case,* Opinion and Order (July 18, 2012) at 55-56, the Commission determined that no such quantifiable benefits exist between recovering distribution investment through a rider, rather than a distribution rate case, and Duke has not committed to refrain from filing a distribution rate case during the term of the proposed ESP. (OMA Reply Br. at 35; Tr. XIII at 3784.) IEU maintains the costs of the PSR, which are estimated to be at least $22 million, must be included on the ESP side of the ESP versus MRO test (IEU Br. at 33-34). OCC agrees that Duke's proposed ESP produces results that are less favorable in the aggregate than the expected MRO results by $22 million. While OCC understands the customers would pay the same for generation under an ESP and an MRO because they both use the CBP, if the PSR is approved, then customers would pay $22 million more in costs over the ESP period than they would under an MRO. Therefore, OCC and IEU submit the quantitative test under the statute is not met and the ESP can not be deemed more favorable in the aggregate than an MRO. (OCC Ex. 48 at 4, 7-8; OCC Br. at 59-60; IEU Br. at 34, 39-40.)

OCC argues the measurement of quantitative rate impacts of an ESP as compared to an MRO is critical to Duke's ability to meet its burden of proof. However, OCC points out that Duke failed to present any evidence in its case in chief regarding the projected rate impact of the PSR. Therefore, OCC contends Duke failed to carry its burden to quantify an essential part of its proposal and one that significantly affects the results of the MRO test. Accordingly, OCC argues Duke failed to meet its burden of proof in accordance with R.C. 4928.143(C)(1). (OCC Br. at 28-29.) OCC asserts the Commission's precedent dictates that, when an ESP provision is quantifiable and not available under an MRO, the provision must be included as a cost of the ESP. *Citing Ohio Edison ESP Case*, Opinion and Order (July 18, 2012). Even if the Commission found some measure of qualitative benefits to Duke's application, considering the qualitative benefits are insufficient to overcome the significant costs the PSR would impose, OCC asserts Duke's application must be denied or modified to comply with the statutory test. (OCC Reply Br. at 15.)

As for qualitative benefits, OCC believes, to the extent those benefits exist, they would be equally available under the scenario of an ESP or an MRO (OCC Ex. 48 at 5, 10). Contrary to Duke's assertions, OCC and IEU argue Rider DCI cannot be considered a qualitative benefit because Duke admits in its application that it is also available under an MRO, as Duke could seek approval of a rate increase for investments in its distribution systems by filing a distribution rate case (OCC Ex. 48 at 11; Duke Ex. 1 at 15; IEU Br. at 38; OCC Br. at 64). OCC notes that Duke projects that, during the term of the ESP, it would collect $272 million in revenue through Rider DCI. Under an ESP, Duke's revenue collection under Rider DCI is accelerated, as compared to collection under an MRO scenario. OCC also states that the PSR should not be considered a qualitative benefit to the ESP because the PSR will not provide price stability and certainty, but instead will impose costs and risks onto customers. (OCC Ex. 48 at 13; OCC Br. at 60-61.) Moreover, OCC notes that Duke's analysis of the benefits of an ESP versus an MRO are really just a comparison of the proposed ESP to the ESP approved in the *ESP 2 Case*. OCC asserts that most of the benefits claimed by Duke should not be considered as a benefit under the ESP that is not also available under an MRO. Specifically, OCC notes that changes to the rate design of SSO generated-related rates for Riders RC and RE, and elimination of certain riders are benefits over the current ESP. Moreover, such changes are available under an MRO. Therefore, these changes should not be considered as benefits of the ESP that are not available under an MRO. (OCC Ex. 48 at 16; OCC Br. at 61, 65-68.) IEU agrees the rate design changes espoused by Duke in its alleged nonquantitative benefits are also available under an MRO and, therefore, are not nonquantitative benefits of the proposed ESP when compared to an MRO (IEU Reply Br. at 25).

OCC points out Duke recognizes in its brief that a provision must fall within R.C. 4928.143(B)(2) to be included in an ESP; however, Duke relies on R.C. 4928.02 as authority for including alleged qualitative benefits in the ESP, namely, modifications to Riders RC, LFA, DR-ECF, and NM, as well as retention of the POR (OCC Reply Br. at 24-25; Duke Br. at 10). Because the modifications to these riders and the retention of the POR do not fall within the nine items listed in R.C. 4928.143(B)(2), OCC contends they cannot be considered in the ESP versus MRO test. Moreover, OCC points out that, even if these alleged qualitative benefits did fall within R.C. 4928.143(B)(2), they would be excluded from the test because they can also be offered under an MRO (OCC Reply Br. at 25). OCC also states that the POR cannot be considered a benefit of the ESP, because it is already being offered. (OCC Reply Br. at 25-26.)

IEU and OMA agree that Duke has failed to demonstrate that the proposed ESP provides any nonquantifiable benefits to customers that outweigh the substantial quantitative costs when compared to an MRO. According to OMA, neither the PSR, Rider DCI, or Duke's unilateral early termination right provide any qualitative benefits. Thus, IEU asserts Duke has failed to sustain its burden of proof. (IEU Br. at 35-37; OMA Br. at 29.)

Kroger states that, in the event the Commission determines it is in the best interest of Duke and its customers to modify and approve the proposed ESP, Kroger recommends the Commission: reject Duke's proposed allocation methodology for Rider DCI; adopt Staff's proposal for Rider LFA; reject Duke's reservation of the right to terminate the ESP one year early; and reject the PSR. To the extent the Commission adopts these proposals, Kroger would then agree that the ESP would be more favorable in the aggregate than an MRO. (Kroger Br. at 17.)

Duke asserts the intervenors' arguments are without merit. Specifically, Duke disagrees with OCC's assertion that the Ohio Supreme Court requires a strictly quantitative analysis of the MRO test. Duke advocates the Commission should follow its past precedent and perform a thorough analysis of the proposed ESP in the aggregate considering both quantitative and qualitative factors. In addition, while agreeing the state policies set forth in the statute are a guide to be considered by the Commission, Duke disputes OCC's insistence that each element of the proposal must be consistent with state policies, averring such consistency is not part of the MRO test. (Duke Reply Br. at 76-78.)

In response to the arguments that the comparison must include the PSR, Duke points out that the opposition's position is based on the PSR being quantifiable. However, Duke states the impact of the PSR is entirely based on future events outside of Duke's control and, in response to discovery, Duke projected future cost or benefit based on numerous assumptions about future events. Duke states forecasts are not the same as estimates, and the Commission has previously recognized there is a limit as to how speculative quantification can be and still be included in the MRO test. *AEP ESP 2 Case*, Opinion and Order (Dec. 14, 2011) at 31. Duke states that, in the instant cases, it intentionally excluded the PSR from consideration in the test, because the forecasts were too speculative to rely on. Therefore, Duke maintains the impact of the PSR is inappropriate for inclusion in the quantitative aspect of the MRO test. Duke also states the

Commission has previously found that qualitative benefits have significant value and can outweigh even quantitative detriments. Therefore, even if the Commission were to conclude that the forecasted financial impact of the PSR must be considered, the Commission could and still should find that qualitative benefits exceed any costs, making the ESP more favorable in the aggregate. *See AEP ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 75-77. With regard to OCC's argument that the cost of Rider DCI should have been included in the MRO, Duke states the Commission has clarified in other cases that the cost of Rider DCI should not be included in a comparison of the ESP and MRO, as recovery under such a rider would be a wash when compared to the recovery available under traditional rate cases if Duke was operating under an MRO. *See Ohio Edison ESP Case*, Opinion and Order (July 18, 2012). (Duke Reply Br. at 79, 81-82.)

Pursuant to R.C. 4928.143(C)(1), the Commission must determine whether the proposed ESP, as modified, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under R.C. 4928.142. The Ohio Supreme Court has determined that R.C. 4928.143(C)(1) does not bind the Commission to a strict price comparison, but rather instructs the Commission to consider pricing, as well as all other terms and conditions. *Columbus S. Power Co.*, 128 Ohio St.3d 402, 2011-Ohio-958, 945 N.E.2d 501. Therefore, we must ensure that the modified ESP as a total package is considered, including both a quantitative and qualitative analysis. Upon consideration of the modified ESP, in its entirety, we find that the ESP is, in fact, more favorable in the aggregate than the expected results under R.C. 4928.142.

Initially, the Commission finds that the modified ESP is more favorable quantitatively than an MRO. Under the ESP, the rates to be charged customers will be established through a fully auction-based process; therefore, it will be equivalent to the results that would be obtained under R.C. 4928.142. We would note that, in light of our determination to set the PSR at zero, it is not necessary to attempt to quantify the impact of the PSR in this ESP versus MRO analysis. Regarding Rider DCI, and other approved distribution-related riders, we find that the revenue requirements associated with the recovery of incremental distribution investments should be considered to be the same whether recovered through the ESP or through a distribution rate case conducted in conjunction with an MRO. We agree that Rider DCI, specifically, provides an economic and efficient process for Duke to make investments in its distribution system; thus, improving the system's safety and reliability. Moreover, the Commission finds the modification to the rate designs to better reflect what the competitive market provides for customers. However, under an MRO, the generation rates charged to customers would be market rates and there would be no ability to phase-out the current rate design, which could result in substantial rate impacts for customers. (Staff Ex. 2 at 3-4.) Therefore, the

Commission finds that, quantitatively, the modified ESP is better in the aggregate than an MRO.

The evidence in the record reflects that there are additional benefits that make the ESP, as modified by the Commission, more favorable in the aggregate than the expected results under R.C. 4928.142. The Commission notes that many of the provisions of the modified ESP advance the state policy enumerated in R.C. 4928.02, as discussed above. The modified ESP also continues to enable Duke to move more quickly to market rate pricing than would be expected under an MRO. In fact, under this ESP, Duke will implement fully market-based prices beginning on June 1, 2015. The Commission continues to believe that the more rapid implementation of market-based rates possible under an ESP is a qualitative benefit that is consistent with R.C. 4928.02. Additionally, the Commission's approval of the distribution-related riders should enable Duke to hold base distribution rates constant over the ESP period, while making significant investments in distribution infrastructure and improving service reliability.

IV. CONCLUSION

Upon consideration of the ESP application filed by Duke, the Commission finds that the ESP, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, as modified by this Opinion and Order, is more favorable in the aggregate as compared to the expected results that would otherwise apply under R.C. 4928.142. Therefore, the Commission finds that the proposed ESP should be approved, with the modifications set forth in this Opinion and Order. As modified herein, the ESP provides rate stability for customers and revenue certainty for Duke. To the extent that intervenors have proposed modifications to Duke's ESP that have not been addressed by this Opinion and Order, the Commission concludes that the requests for such modifications should be denied.

Duke is directed to file revised tariffs consistent with this Opinion and Order, to be effective with the first billing cycle in June 2015.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

(1) Duke is a public utility as defined in R.C. 4905.02 and an electric utility as defined in R.C. 4928.01(A)(11) and, as such, is subject to the jurisdiction of this Commission.

(2) On May 29, 2014, Duke filed an application for an SSO in accordance with R.C. 4928.141. The application is for an ESP in accordance with R.C. 4928.143.

(3) On June 12, 2014, a technical conference was held in these proceedings.

(4) In total, at the four local public hearings that were held in these cases on September 8, 9, 10, and 18, 2014, 27 witnesses testified.

(5) The following entities were granted intervention: IEU, OEG, OPAE, Kroger, OEC, FES, GCHC, Exelon, OCC, Wal-Mart, OMA, RESA, AEP, Cincinnati, PWC, ELPC, EnerNOC, Direct Energy, Miami/UC, NRDC, IGS, EPO, DP&L, Sierra, and ODSA.

(6) The evidentiary hearing in these proceedings was held on October 22, 2014, through November 12, 2014, with the rebuttal on November 20, 2014.

(7) Proofs of publication of the hearings were submitted on the record.

(8) Briefs and reply briefs were filed on December 15, 2014, and December 29, 2014, respectively.

(9) In accordance with the attorney examiner's ruling at the hearing and the rulings herein, the following documents should be granted protective treatment for a period of 24 months: Duke Exs. 16A-17A, 21A; OCC Exs. 4A-5A, 7A-8A, 10A-27A, 29A-31A, 39A, 41A, 43A-44A; OEG Ex. 1A; IGS Exs. 4A, 7A-8A, 12A; Sierra Ex. 4A; OMA Exs. 3A-8A; Transcripts III, V-VII, IX-XII, and XV; and the briefs filed by IGS, Sierra, and OCC.

(10) The proposed ESP, as modified pursuant to this Opinion and Order, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under R.C. 4928.142.

ORDER:

It is, therefore,

ORDERED, That Duke's application is approved, subject to the modifications set forth in this Opinion and Order. It is, further, ORDERED, That the Commission declines to rule on the merits of the parties' arguments regarding OCC's October 27, 2014 interlocutory appeal; however, the information shall remain under seal. It is, further,

ORDERED, That, in accordance with our ruling herein, Duke conduct a review and provide IGS and Sierra with the revised redacted versions of their briefs by April 15, 2015, and, upon receipt of the revised redacted versions of their briefs, IGS and Sierra file the revised redacted versions in these dockets by April 20, 2015. It is, further,

ORDERED, That, in accordance with the above, the briefs filed by IGS, Sierra, and OCC be afforded protective treatment, to the extent set forth herein, and the attorney examiner's rulings with regard to the motions for protective order for portions of the exhibits and transcripts are affirmed. These documents will be subject to this protective order for 24 months from the date of this Opinion and Order, or until April 3, 2017. It is, further,

ORDERED, That OCC's requests that the Commission reverse the attorney examiner's rulings regarding disclosure of the OVEC entities and rebuttal testimony are denied. It is, further,

ORDERED, That Duke file a status report regarding the transfer or divestiture of the OVEC asset, in these dockets, by June 30 of each year of the ESP, with the first such filing to occur by June 30, 2015. It is, further,

ORDERED, That, consistent with this Opinion and Order, Duke file proposed tariffs, subject to review and approval by the Commission. It is, further,

ORDERED, That nothing in this Opinion and Order shall be binding upon the Commission in any future proceeding or investigation involving the justness or reasonableness of any rate, charge, rule, or regulation. It is, further, ORDERED, That a copy of this Opinion and Order be served upon each party of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Thomas W. Johnson, Chairman

Steven D. Lesser

Lynn Slaby

M. Beth Trombold

Asim Z. Haque

CMTP/NW/vrm

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Barcy F. McNeal

Barcy F. McNeal
Secretary