BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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

REPLY COMMENTS BY THE OHIO CONSUMER AND ENVIRONMENTAL ADVOCATES

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REPLY COMMENTS
BY THE
OHIO CONSUMER AND ENVIRONMENTAL ADVOCATES

I. INTRODUCTION

A. Preliminaries

The Ohio Consumer and Environmental Advocates (collectively "OCEA")[1] jointly submit these reply comments to comments filed by other parties[2] addressing rules proposed in an Entry dated July 2, 2008. It should be noted that the following organizations are limiting their comments to issues that relate to the advanced energy portions of the rulemaking: Sierra Club Ohio Chapter, Greater Ohio and Environment Ohio. OCEA requests that the Public Utilities Commission of Ohio ("PUCO" or

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[1]OCEA includes the Office of the Ohio Consumers' Counsel, NOPEC, Ohio Partners for Affordable Energy, Ohio Interfaith Power and Light, Appalachian People's Action Coalition, Communities United for Action, Citizen Power, AARP, Northwest Ohio Aggregation Coalition, Edgemont Neighborhood Coalition of Dayton, and Ohio Farmers Union, and as to the Energy Efficiency comments only, Sierra Club Ohio Chapter, Midwest Energy Efficiency Alliance and Environment Ohio.

[2] OCEA responds to comments filed by Dayton Power & Light Company ("DP&L"); Duke Energy Ohio ("Duke"); Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company (collectively "FirstEnergy" or "FE"); Columbus Southern Power Company and Ohio Power Company (together "AEP"); Industrial Energy Users-Ohio ("IEU"); The Alliance for Real Energy Options ("AREO"); The City of Cincinnati ("Cincinnati") American Municipal Power-Ohio, Inc. ("AMP-Ohio"); Ormet Primary Aluminum Corporation ("Ormet"); Nucor Steel Marion, Inc ("Nucor"); Ohio Energy Group, The Chemistry Technology Council, the Ohio Cast Metals Association, The Ohio Aggregates and Industrial Minerals Association and the Ohio Manufacturers' Association (collectively "OEG"); The Council of Small Enterprises ("COSE"); and the Ohio Farm Bureau Federation ("OFBF").

"Commission") adopt the revisions proposed by OCEA and not adopt the revisions of other parties that represent narrower self-interests than the public interests that are represented by the broad coalition this is OCEA.

This pleading also addresses comments filed in response to the six questions posed by the Commission in its Entry.[3] OCEA requests that the Commission consider the responses provided to the questions in the PUCO's deliberations on the proposed rules, including the proposed changes to the rules that we have included to implement our responses to the Commission's questions.

Finally, the rules fail to address the requisite comparison between the Electric Security Plan rate and a Market Rate Option required by S.B. 221 (i.e. R.C. 4928.143(C)). This issue should be addressed so that there are consistent rules for making these comparisons and evaluating the results.

B. The Commission's Questions

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

The vast number of respondents said yes.[4] Duke and IEU are the only parties that disagreed but Duke did agree that the Commission should remain flexible with regard to CBP methodologies.[5] Other parties, such as AREO, did not answer the question regarding alternative products and instead suggested a collaborative stakeholder process

[3] Entry at 3-4, ¶ (7) (July 2, 2008).

[4] AEP Comments at 22; Nucor Comments at 21; Ormet Comments at 4; DP&L Comments at 16; FE Comments at 2; AEP Comments at 22; OCEA Comments at 2; Cincinnati at 2.

[5] Duke Comments at 2-3.

to discuss methodology.[6] Several respondents recommended an Integrated Portfolio Management strategy that would determine the products used to meet energy needs based upon a least-cost approach.[7] This approach would provide the greatest long-term benefit to all parties and should be adopted. Given the significant increases in rates that are being requested coupled with rising fuel costs, it is imperative that Ohio adopt a smart strategy that relies on least-cost planning. Only an Integrated Portfolio Management approach will accomplish this objective.

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

The respondents had different interpretations of "the value of lost load." Duke and FirstEnergy seemed to interpret it to mean that customers should be compensated for periods when a customer experiences an outage.[8] AEP and OEG seemed to interpret it as a means of justifying increased expenditures for the distribution system.[9] DP&L, Cincinnati and OCEA interpreted it more as a reference to assisting utilities that have lost load.[10] Many parties did not discuss it. In any case, the Commission must clarify what it meant by "the value of lost load" if the Commission would like more focused responses.

If the Commission intended it to mean that customers should be compensated for the loss of service during an outage, OCEA believes that the Commission should consider "the value of lost load" in R.C. 4928.143(B)(2)(h) proceedings. If the Commission

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[6] AREO Comments at 9-10.

[7] Ormet Comments at 4; OEG Comments at 12; and OCEA Comments at 3-6.

[8] Duke Comments at 4; FE Comments at 3.

[9] AEP Comments at 22; OEG Comments at 12.

[10] OCEA Comments at 6-7 and DP&L at 16.

intended it to mean assisting utilities who have lost load, the Commission should also consider the "lost load" suffered by customers through outages and offset its consideration of the "lost load" of utilities by the "lost load" of customers.

Ultimately, utilities should never be able to recover through any special rate increase mechanisms anything but clearly distinguishable fixed distribution costs. Operations and maintenance expenditures and other variable costs should be recovered through measured usage and not the customer charge. Certainly, the Commission should never allow the recovery of distribution costs until the Commission has clearly distinguished those costs from generation costs.

3. Should the Commission, by rule, invite a utility to identify in an ESP specific long-term objectives together with milestones and metrics for measuring progress? If so, are there specific topics that should be addressed?

The utilities objected to the long-term planning.[11] Most other parties believe that long term planning could be beneficial. OEG perceives that the new filings are too complicated and the mandates too broad to allow for ongoing measurements. But OCEA continues to believe that the utilities should establish milestones through a public process for distribution service that includes specific performance standards and predetermined penalties. Utilities should also have to meet milestones for new construction and for identifying least cost alternatives.

4. How should the rules define the baseline level of customer energy consumption from which reductions are measured?

There appears to be some confusion in the various responses to this question. Some responses appear to conflate what an individual manufacturing baseline should be, with the macro utility baseline which is that baseline against which the mandated energy

[11] DP&L Comments at 16; FE Comments at 4; Duke Comments at 4; AEP Comments at 23.

savings levels are to be measured. The former is the question being asked the latter is specified in Sections 4928.66(A)(2)(a), 4928.66(A)(2)(b) and 4928.66(A)(2)(c) of the Revised Code. For example, Duke and OEG support a 3 year average of consumption in response to the baseline question.[12] This suggestion corresponds with the provisions of S.B. 221 and should be adopted regarding the macro utility baseline but omits other important considerations such as those posited by OCEA.[13] The 3-year average is much too simplistic of an approach to determine a manufacturer's baseline at a micro level.

The OEG suggestion that the baseline be designed to avoid gaming, "known and measurable changes" is suggested as a controlling term.[14] FirstEnergy recommended that "there be no individual customer baseline methodology used to estimate consumption reductions."[15] Nucor Steel concurs and proposed that the determination should be left to each utility with customer input and review by the Commission. This general proposition is well advised; it implicitly recognizes the challenges inherent in thousands of separate monitoring and verification procedures. DP&L's suggestion that individual verification not be required and their perception that engineering estimates should be sufficient is not acceptable. Engineering estimates have historically overstated savings and should be used with caution. Only measures with long verification track records are appropriate for engineering estimates. And again, OCEA would point the Commission to international energy efficiency verification protocols such as IPMVP. Over-reliance on anything other than individual verification would probably overstate savings and invite gaming.

[12] The Duke Comments, at 6 and OEG Comments at 13.

[13] OCEA Comments at 11-14.

[14] OEG Comments at 13.

[15] FE Comments at 4.

DP&L recommended that mercantile customers that contribute energy efficiency credits to utilities to meet their targets so that they can avoid the energy efficiency surcharge, must provide savings equal to or better than the required statutory savings for the year.[16] This rule is necessary to prevent huge losses to the surcharge by mercantile customers who save minimal amounts of use as DP&L warned. Shifting the bulk of responsibility for savings and financial responsibility to residential and small commercial customers will not result in a just and reasonable outcome.

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

OCEA said special arrangements should be used minimally and only under an ESP. All other parties said no. OCEA continues to believe that special arrangements must be kept to a minimum. Residential customers are facing dramatic increases in not just their energy bills but also in most essential needs. Residential customers should not have to subsidize large customers who do not bring a clear and continuing benefit to them and their communities. Many of the interested parties providing comments, including utilities, are concerned that special arrangements will not be awarded to just those customers who benefit the communities and that no one will be responsible for ensuring that those customers awarded benefits will follow through on their commitments. Additionally, the Commission should make public the customers who are awarded the special arrangements, the level of discount provided them and the benefits the customer has promised to give to the community as recommended by many parties filing comments.

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[16] DP&L Comments at 18.

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

Two of the utilities were not in favor of a cap on the level of incentives for special arrangements.[17] Both of them perceived the cap as creating an impediment to economic development programs. DP&L and AEP prefer the guidance of a cap.[18] Ormet, Nucor and IEU perceived that a cap is not necessary and suggested that incentive levels should be set on a case-by-case basis.[19] OEG preferred the cap on individual customers but not statewide.[20] Cincinnati, AREO and OCEA preferred a cap.[21]

COSE recommended that the special arrangement incentives should be tied to the user class.[22] COSE seemed to suggest that the industrial class be one class and that the commercial and residential customers be another class. COSE appeared to be suggesting that only the industrial class contribute to industrial incentives and only the commercial and residential class pay the discount for smaller customers. COSE also recommended that the longer the incentive, the more reporting the beneficiary should be required to prove that it is benefiting the class paying the incentive.

OCEA continues to believe that the award of special arrangements to customers should be few and far between. The Commission should be held accountable for awarding these contracts and ensuring that commitments made by the customers do not fall by the wayside. The Commission can best maintain accountability by making it

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[17] Duke Comments at 7; FE Comments at 5.

[18] DP&L Comments at 18; AEP Comments at 23.

[19] Ormet Comments at 6; Nucor Comments at 22; IEU Comments at 21.

[20] OEG Comments at 14.

[21] OCEA Comments at 15; AREO Comments at 15.

[22] COSE Comments at 5.

public knowledge which of the customers receive the special arrangements, the discounts those customers will receive and the commitments those customers have made to the communities and the State in exchange for the discounts.

II. ELECTRIC UTILITY STANDARD SERVICE OFFER – CHAPTER 4901:1-35

FirstEnergy stated that "the Commission's rules must closely reflect the express language of the statute and may not vary from or go beyond the Ohio legislature's intent as delineated in the words used in Am. Sub. S.B. 221."[23] The other utilities had similar comments. But the statute expressly defers to the Commission most of the substantive decisions.[24] The Commission can not meet the directives of the statute without providing clear directions to the electric utilities on what they need to do in order to provide competitive market-rate offers or electric security plans that are more favorable in the aggregate. The electric utilities continue to benefit from monopoly franchises and the Commission must provide sufficient direction and monitoring of monopoly distribution services—including generation—that are the source of utility revenues.

The utilities' retain significant market power in generation sales. The Commission cannot defer to the utilities to create just and reasonable rates. The Commission cannot meet its obligations under Am. Sub. S.B. 221 if it does not create rules and processes that will ensure that the utilities charge reasonable rates and provide adequate service.

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[23] FE Comments at 1-2.

[24] Am. Sub. S.B. 221 requires the Commission to establish rules for R.C. 4928.141, R.C. 4928.142, R.C. 4928.143 and many other sections.

A. Definitions – 4901:1-35-01 (Rule 1)

FirstEnergy argues that the definition "Electric security plan" under Rule 1(E) should be revised to state "means an electric utility plan for the supply and pricing of electric generation service INCLUDING OTHER MATTERS THAT MAY BE PROPOSED BY THE ELECTRIC UTILITY pursuant to R.C. 4928.143 of the Revised Code." While R.C. 4928.143 permits utilities to propose certain specific generation items and other distribution items in their electric security plan, it does not allow the utilities to collect revenues for anything it chooses. Therefore the Commission should not adopt FirstEnergy's proposed language. Rather, the Commission should simply revise the definition of "Electric security plan" to state:

> Means an electric utility plan for the supply and pricing of electric ~~generation~~ service AS PROVIDED FOR UNDER ~~pursuant to~~ R.C. 4928.143.

B. Purpose and Scope – 4901:1-35-02 (Rule 2)

AREO recommended that Rule 2(A) be expanded to include in the purpose of the rules the following statement:

> The purpose of this chapter is to establish rules for the form and process under which an electric utility shall file an application for an SSO THAT DOES NOT IMPAIR GOVERNMENTAL AGGREGATION OR A RETAIL CUSTOMER'S ABILITY TO PURCHASE GENERATION FOR A COMPETITIVELY PRICED RETAIL ELECTRIC SUPPLIER and the commission's review of that application.

This suggested revision reflects the state policies under R.C. 4928.02(B) and (C) and should be adopted, with a minor clarification:

> The purpose of this chapter is to establish rules for the form and process under which an electric utility shall file an application for an SSO THAT DOES NOT IMPAIR GOVERNMENTAL AGGREGATION CUSTOMER'S OR A RETAIL CUSTOMER'S ABILITY TO PURCHASE GENERATION FOR A

COMPETITIVE**LY PRICED** RETAIL ELECTRIC **OFFER** ~~SUPPLIER~~ and the commission's review of that application.

C. Filing and Contents of Application – 4901:1-35-03 (Rule 3)

The substance of the applications filed by an electric utility is critical to evaluating compliance with the statute and producing the least-cost outcome for customers. Am. Sub. S.B. 221 provides an electric distribution utility with wide latitude in the structure of its filing. However, the nature of the filing is circumscribed both substantively and procedurally. The statute requires an electric utility to demonstrate compliance with state policy goals. It also creates an affirmative obligation to provide the evidence necessary to evaluate all aspects of the application—the electric utility has the burden of proof. FirstEnergy correctly notes that the application should include direct testimony, with provision made for reply and supplemental testimony.[25]

The comments of AEP indicate the company has the view that an electric utility may file a MRO or an ESP as initial plans prior to the effective date of the Rules.[26] FE shares that view. This reading of the statute is incorrect. As noted in R.C. 4928.141(A), "…the utility's first standard service offer application at a minimum shall include a filing under section 4928.143 of the Revised Code" though it "may apply simultaneously under both sections [4928.142 or 4928.143]". Proposed R.C. 4928:1-35-03(C) correctly notes that the ESP and MRO are to be filed as a single application and should not be modified.

Many of the comments of the electric utilities focused on the timeline for consideration of applications, the need to "conform" to the final regulations, and the requirement to refile when the application cannot be revised to comply with the rules.

[25] FE Initial Comments at 6-7.

[26] AEP Initial Comments at 2.

The general thrust of these comments is that the Commission must act within the 150 days from filing, creating tremendous pressure on consumer advocates to effectively ensure that the standard service offers ("SSO") comply with the law. The beginning of the SSO journey begins, and the countdown begins when an application is properly filed and supported and complies with the statute and the rules authorized by statute.

The General Assembly did not mandate an arbitrary deadline for consideration as argued by the utilities. R.C. 4928.142(B)(3) provides that if the Commission finds that the utility's MRO does not meet the requirements of a market rate offer:

> The commission shall direct the electric distribution utility regarding how any deficiency may be remedied in a timely manner to the commission satisfaction; otherwise, the electric distribution utility shall withdraw the application.

Therefore, the Commission has direct authority to not approve a market rate option, and authority to require that the utility withdraw an application that is "not within substantive compliance with this rule" and refile the application.

The same is true for an ESP. R.C. 4928.143(A) provides:

> For the purpose of complying with section 4928.141 of the Revised Code …[t]he utility may file that application prior to the effective date of any rules the commission may adopt for the purposes of this section, and, as the commission determines necessary, the utility immediately shall conform its filings to those rules upon their taking effect.

To better reflect these requirements, OCEA recommends the following addition to proposed rule 4901:1-35(C):

> * * First applications that are filed with the commission prior to the effective date of this rule and THAT DO NOT MEET ALL OF THE REQUIREMENTS OF THE RULE MAY BE SUPPLEMENTED TO MEET ALL THE REQUIREMENTS. HOWEVER, FIRST APPLICATIONS THAT ARE FILED WITH THE COMMISSION PRIOR TO THE EFFECTIVE DATE OF

> THIS RULE AND that are determined by the commission to be not in substantive compliance with this rule, shall be refiled at the direction of the commission.

The statute also contemplates what will happen should the SSO application not be approved. R.C. 4928.141(B) states:

> Notwithstanding the foregoing provision, the rate plan of an electric distribution utility shall continue for the purpose of the utility's compliance with this division until a standard service offer is first authorized under section 4928.142 or 4928.143 of the Revised Code.

The utilities, other than DP&L, are determined to force a land rush approach to establishing customer rates. AEP contends that the 150 days must start with the filing of the plan, not with conformance to the rule requirements. Duke argues that the Commission should be required to make a decision on whether the application conforms within 60 days and electric utilities should be required to amend or refile an application to bring it into compliance with the rules within 30 days.

FE argues that the statute prohibits any rules that would delay a decision beyond 150 days. It also argues that a decision on whether a utility meets the criteria in R.C. 4928.143 for an MRO must be made in 90 days from the date of filing. FirstEnergy's position can be summed up as requiring a 150 day ruling and the Commission cannot require re-filing of either a MRO or ESP.

There is a need to recognize that FE does not 'own' generation, so there is a greater imperative to dealing with its application. Nonetheless, the utilities have chosen to ignore the requirements of the statutes that the 150 day limit applies at the point where an application complies with the statute. Such a limited reading of the statute would severely handicap the ability of customer advocates such as the members of OCEA from having the opportunity to make the arguments so that the reasoned outcome envisioned by the General Assembly occurs.

If the utilities want self-imposed deadlines for modifying their proposals to comply with rules or to withdraw and refile a proposal they certainly may do so but there is no statutory support for rules in that regard. The authority of the Commission to require conformance with the rules and require re-filing of an application if it is not responsive to statutory requirements is clearly grounded in statute. If a utility chooses to voluntarily file an MRO as a part of the initial SSO application which must include an ESP, R.C. 4928.142(B)(3) dictates that the "utility shall not initiate its competitive bid until at least one hundred fifty days after the filing of those applications."[27] The ninety day timeframe requires a decision on whether the "electric distribution utility and its market-rate offer meet all of the foregoing requirements," as dictated by the subsections of R.C. 4928.142(B). NOPEC is correct in pointing out that this should be included in the rules. OCEA recommends the following sentence be added to proposal rule 4901:1-35-03(C):

> <u>THE MRO COMPETITIVE BID PROCESS ("CBP") SHALL NOT TAKE PLACE UNTIL A MINIMUM OF NINETY DAYS AFTER THE ESP COMPONENT OF THE INITIAL APPLICATION IS APPROVED.</u>

NUCOR made a reasonable suggestion, urging that approved SSO rates not be implemented until ninety days after approval of the application.[28] OCEA agrees that ninety days would provide customers with an opportunity to shop once the final outcome, whether an ESP or an MRO, is known. To do otherwise would frustrate the intent of the

[27] Northeast Ohio Public Energy Council ("NOPEC") at 9.

[28] NUCOR Comments at 3-4.

General Assembly to promote competitive markets. Under the statute, electric utilities are granted time to prepare for the bid. Customers should likewise have the opportunity to prepare for the implementation of the outcome of a CBP or the ESP. It also will be important to ensure that the CBP or the ESP is correctly reflected in tariffs. The applications may result in fundamental changes in how rates are established – e.g., if bidding by customer class occurs – that will require some thought prior to translation into tariffs.

To reflect both these well-reasoned additions, OCEA recommends the following sentences be added at the end of proposal rule 4901:1-35-03(C):

> The MRO competitive bid process ("CBP") shall not take place until a minimum of ninety days after the ESP component of the initial application is approved. The commission shall determine when the SSO rates take effect, but in no case will SSO rates take effect earlier than ninety days after the rates have been approved.

NUCOR also recommended a new subsection (E) that requires the SSO application to demonstrate the transition from existing rates as of July 1, 2008 to the new SSO. NUCOR also supports the position of OCEA that the applications demonstrate compliance with state policy. OCEA appreciates the potential difficulties of complying with these rules but nonetheless recommends that the requirement be retained, including the suggestion of the OEG, that the formulas be included, and that the electric utility be permitted to ask to waive this particular requirement when compliance is not possible.[29]

There are no other comments on proposed section 4901:1-35-03. OCEA stands behind its initial comments requesting additional detail in the applications; the need to conform initial applications with the rules; the need to show compliance with state policy

[29] OEG Comments at 2.

as enunciated in R.C. 4928.02; the requirement that a corporate separation plan prohibit the shifting of earnings from the electric distribution utility to other affiliates of the holding company; and, the requirement for a ten-year procurement plan for SSO consisting of a long-term portfolio management and resource procurement plan designed to produce the least-cost outcome for customers.

D. Requirements for Market-Rate Offers—Appendix A

Generally, FirstEnergy and AEP complained that the Staff did not use the exact words of the statute, arguing that to not do so was going beyond the latitude that was provided in the legislation.[30] The utilities are wrong. The General Assembly granted the Commission authority to establish rules for the competitive bid in R.C. 4928.141(B) and R.C. 4928.142(A)(2). The General Assembly would not have authorized the Commission to establish rules if it intended the rules to be exactly the same as the legislation. Rather, the General Assembly delegated to the Commission the establishment of rules consistent with the intent of the legislation that fleshed out the concepts set forth in the statute and gave specificity to general directions. As noted by the Ohio Supreme Court:

> The power of an administrative agency to administer a program necessarily requires the formulation of policy and the making of reasonable rules to fill any gap left, implicitly or explicitly, by the legislature.[31]

R.C. 4928.142(B)(2) requires that in order to provide a market based offer a utility must demonstrate:

[30] FE Comments at 16; AEP Comments at 12.

[31] *Northwestern Ohio Bldg. & Constr. Trades Council v. Conrad*, 92 Ohio St. 3d 282 (2001).

> Any such regional transmission organization [an RTO approved by the FERC] has a market-monitor function and the ability to take actions to identify and mitigate market power or the electric distribution utility's market conduct; or a similar market monitoring function exists with commensurate ability to identify and monitor market condition and mitigate conduct associated with the exercise of market power.

In response to that, the Staff proposed Appendix A Section (A)(2):

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

FirstEnergy argued that the Staff's language "ability to identify any potential for a market participant to exercise market power" goes beyond its latitude in rulemaking and even conflicts with the legislative language.[32] FirstEnergy is wrong.

The Staff proposed rule interprets the phrase "the ability to take actions to identify and mitigate market power or the electric distribution utility's market conduct." The Staff's proposed rule describes those actions it believes are necessary for an RTO to identify and mitigate market power." The Staff perceives that an RTO does not have that ability unless it can identify "any potential for a market participant to exercise market power." Staff is not the only party to grasp this key concept.

[32] FE Comments at 16.

Market power and its abuses are frequently not identified until after the fact, when a market has failed. This was the case in California when the traders of the major companies manipulated the market, causing extreme, unnecessary rate hikes, bankrupt electric utilities and outages that led to the state of California having to purchase electricity under very uneconomic terms, and years of litigation between the states and FERC. It was only after one of the power suppliers filed bankruptcy and the documents and tapes of the power supplier became available to the public that the extent of the manipulation became evident to public officials. Public utilities, such as the public utility districts in the northwest, battled to the Supreme Court to force restitution to their customers. Ohio can learn from these realities and work to prevent the abuses of oligopolies.

Because market power and market power abuses can be hidden through confidentiality and proprietary laws, a market monitor cannot effectively identify market abuses and market power unless it is on the alert, aware of where and when it can occur. Competition and employee incentive programs will always put pressure on companies and their employees to take advantage of market power whenever possible. A market monitor is simply not able to "mitigate market power" as required under R.C. 4928.142(B)(2) and R.C. 4928.06 (C) if it is unable "to prevent or preclude the exercise of market power by any market participant" as required under the proposed Appendix A, Section A(2).

FirstEnergy also complained that the Staff does not have the latitude to define market mitigation as involving each of the markets it identifies: energy, capacity, and ancillary service or bilateral markets. Instead, FirstEnergy stated that the market monitor must only be able to have the "ability to take actions to identify and mitigate market power."[33] However, if the monopoly control of markets identified by the Staff does not involve each or any of the markets the Staff identifies, which are common electric generation markets, FirstEnergy failed to explain in which market the market monitor can mitigate market power. Once again, FirstEnergy's insistence that the rules language must "be limited to the precise wording of Am. Sub. S.B. 221" does not make sense.

Duke argued that Section (A)(2) be revised to remove the requirement that the market monitor has the ability to identify the potential for a market participant to exercise market power in any markets that are "necessary for a winning bidder to fulfill the contractual obligations resulting from the CBP." Duke did not explain why it thought that phrase should be removed.[34] In any case, the phrase should not be removed because if any market that bidders must use has failed due to market power, the Commission cannot expect a valid competitive bid. If the market monitor is unable to mitigate market power in any of the required markets for the bid, the CBP will not produce competitive or reasonable prices. Accordingly, Duke's suggestion should not be incorporated into the rule.

Section A(2), Appendix A regarding the market monitor should be amended to ensure the market monitor has all the information necessary to mitigate the conduct of market participants as contemplated by the proposed rule:

> The electric utility shall establish ~~one~~ ALL of the following. FIRST, that its RTO retains an independent market monitor that has the DEMONSTRATED ability to identify THE ~~any~~ potential for a market participant to exercise market power in ~~any~~ energy, capacity, and/or ancillary service markets necessary for a winning

[33] FE Comments at 16.

[34] Duke Comments at 20-21.

> bidder to fulfill the BIDDER'S contractual obligations resulting from the CBP (INCLUDING ACCESS TO THE CONTRACTS BETWEEN THE WINNING BIDDER AND THE COMPANIES THAT WILL SUPPLY THE WINNING BIDDER), whether such market is administered by the RTO or whether it is a bilateral market necessary for a winning bidder to fulfill the contractual obligations resulting from the CBP ~~by virtue of access to the RTO and the market participant's data and personnel,~~, and that THE INDEPENDENT MARKET MONITOR has the authority to mitigate the conduct of the market participants so as to prevent or preclude the exercise of market power by any market participant. ~~or~~ SECOND, if no such market monitor exists, ~~the electric utility shall demonstrate~~ thAT an equivalent function exists ~~which~~ THAT can monitor, identify, and HAS THE DEMONSTRATED ABILITY TO mitigate conduct associated with the exercise of market power.

R.C. 4928.142(B)(3) states:

> A published source of information is available publicly or through subscription that identifies pricing information for traded electricity on-and off-peak energy products that are contracts for delivery beginning at least two years from the date of the publication and is updated on a regular basis.

FirstEnergy and AEP argued that the Staff's proposed Appendix A Section (A)(3), which is intended to implement that section is inconsistent because Staff's rule does not precisely mirror the law.[35] Once again, the utilities are denying that the rules have any purpose. FirstEnergy and AEP claimed that it was unreasonable for the Staff to require that the source of published information be "independent and reliable." While it is true that the legislation did not specifically state that the information must be independent and reliable, the utilities cannot possibly argue that the General Assembly purposefully left that "legal standard" out because they expect bidders and other interested parties to rely on unreliable, biased information. Because the Staff knows, more so than the General Assembly, that some published information, has been biased

[35] FE Comments at 17; AEP Comments at 12.

and unreliable, the Staff again complied with the Supreme Court's directive to "fill any gap left, implicitly or explicitly, by the legislature."[36] Again, it is absurd for the utilities to claim that the General Assembly does not care if the information published is unreliable and biased.

FirstEnergy and AEP also claimed that R.C. 4928.142(B) did not necessarily intend the published information to be "relevant to the electric utility's electricity market" and argued that the Staff's incorporation of that provision in the rule to be beyond its latitude.[37] If the General Assembly did require that published information be available it is doubtful that it expected that the available published information would not be relevant to the regional electricity markets. There is no purpose for the published information if it is not relevant. For those reasons, the Staff's proposed rules should not be revised.

Duke argued that Section A(3) of Appendix A should be revised to allow its own electric pricing information stand in for the "published source of information" required under R.C. 4928.142(B)(3) as a prerequisite to a MRO. The Commission should not allow a utility that has so much interest in the MRO, such as Duke, to provide the source of pricing information. The published source of information should be "independent and reliable" as the Staff proposed in its Rule; otherwise the information is useless.

Additionally, Duke deleted the phrase "to fulfill the contractual obligations resulting from the CBP is publicly available" without explaining the reason.[38] Duke states that it revised the rule to allow all bid participants to have access to public pricing

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[36] *Northwestern Ohio Bldg. & Constr. Trades Council v. Conrad*, 92 Ohio St. 3d 282 (2001).

[37] FE Comments at 18; AEP at 12.

[38] Duke Comments at 22.

data. But the rule as written does allow all bid participants to have access to public pricing information:

> The electric utility shall demonstrate that an independent and reliable source of electricity pricing information for any product or service necessary for a winning bidder to fulfill the contractual obligations resulting from the CBP **is publicly available** (emphasis added).

The Commission should not adopt Duke's recommended changes.

AREO recommended adding additional language to Section B that specifies exactly what the CBP is. But the additional language does not provide the flexibility permitted under the CBP.[39] For example, the CBP does not necessarily have to include transmission, ancillary services or RTO costs. If a CBP can obtain a lower overall rate for the customer by allowing the utility to provide some of the transmission, ancillary services or RTO costs, a different CBP should be permitted. On the other hand, the clarifications provided in the additional language does provide some consistency that would simplify the process and would allow competitive retail electric suppliers a clear bid target against which they can compete.[40]

Perhaps the best means of allowing for maximum flexibility to provide the lowest rate possible under the CBP and yet to ensure that bids are comparable is for the Staff to require that every cost component included in an MRO be identified and priced separately under all bids. If the utility would like to provide any of the cost components, the utility would have to price certain cost components ahead of time and would allow the utility to include a risk component in their price.

[39] AREO Comments, Exhibit B at 2.

[40] AREO Comments at 17.

AREO also recommended that more details be included in the description of the CBP plan under (B)(1), which would better flesh out the process.

AREO requested that the Commission require very specific and extensive credit for potential wholesale bidders of the CBP.[41] These requirements should not be excessive so as to discourage smaller but reasonably reliable potential bidders. Before the Commission adopts these or any other credit requirements they should check with other Commissions, such as the New Jersey Service Commission, who have extensive experience with how credit requirements have affected bids or how they have not been sufficiently strict to prevent defaults with insufficient collateral.

Staff's Appendix A Section (B)(2)provides that each CBP plan should include:

> Pro forma financial projections on the effect of the CBP plan's implementation upon generation, transmission, and distribution of the electric utility or its affiliate for the duration of the CBP plan.

FirstEnergy complained that it should not be required to provide financial projections on the effect of its CBP plan to affiliates because R.C. 4928.143(F) does not permit the Commission to consider earnings of affiliates in determining whether the utility has excess earnings.[42] FirstEnergy's analogy is not appropriate.

Under 4928.18(B) the Commission has the authority to:

> Examine books, accounts, or other records kept by an electric utility or its affiliates as may relate to the businesses for which corporate separation is required under section 4928.17 of the R.C. and may investigate such utility or affiliate operations as may relate to those businesses and investigate the interrelationship of those operations.

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[41] AREO Comments, Exhibit B at 3-4.

[42] AREO Comments, Exhibit B at 3-4.

Nothing in R.C. 4928.142 or 4928.143 undermines the Commission's 4928.18(B) authority. R.C. 4928.143 (F) simply does not extend that authority in quantifying earnings for purposes of determining whether the utility is acquiring excess earnings. For all other purposes, the Commission retains the right to investigate the interrelationship of the utility and its affiliates, as long as the utility is sharing resources and transacting with its affiliates. Accordingly, the Staff's rule should not be revised.

AEP argued that Section (B)(2) should not include the submission of pro forma financial projections of the competitive bidding process plan's implementation upon transmission and distribution operations or rates because the CBP is intended to establish generation rates only.[43] However, while the CBP is intended to only affect generation rates, it may also affect transmission and distribution operations based upon where or how generation is obtained or what sort of energy supplies the CBP will provide. Accordingly, the provision should remain as it has been proposed.

AEP complained that Section (B)(10) requires the utility to make a comparison between the projected adjusted generation service pricing under the CBP to the projected generation service pricing under its proposed electric security plan.[44] AEP argued that "there is no allowance for testing a proposed MRO by comparing it to a proposed ESP." But R.C. 4928.143(C)(1) essentially states that the Commission must not approve an MRO if it finds that in the first application the ESP "is more favorable in the aggregate as compared to the expected results that would otherwise apply under section 4928.142." That law also states that the utility has the burden of proof. Therefore the comparison

[43] AEP Comments at 13.

[44] AEP Comments at 13.

required by Section (B)(10) is quite relevant to at least the first application made by the utilities and should remain in the rules.

Ormet suggested that the blending provisions of the MRO as discussed under B(10) of Appendix A should require, to the extent that utility assets are incorporated into the blended rates, that the least cost utility owned resources should be assigned to this rate.[45] This is appropriate and should be incorporated into Section (B)(10) of Appendix A accordingly:

> * * *The proposed blending shall show the generation service price(s), WHICH IF INCLUDING GENERATION OWNED BY THE UTILITY MUST BE BASED UPON THE LEAST COST GENERATION THE UTILITY OWNS, that will be blended with the CBP determined rates, and any descriptions,* * *

Again, under Section (B)(14), FirstEnergy and Duke do not want to be held to the state policies delineated under R.C. 4928.02(A) through (N). The utilities argued that they conflict with one another so they are impossible to achieve with respect to MRO applications.[46] Duke argued in this section that R.C. 4928.02(H) prohibits subsidies and therefore conflicts with R.C. 4928.02(J), which allows for subsidies to environmental technologies.[47] But there is no conflict between the two policies because R.C. 4928.02(H) prohibits "anticompetitive subsidies" and subsidizing environmental technologies is not anticompetitive.

Every MRO application can achieve each of the state policies (A) through (N) to one degree or another and it is necessary in order to meet the General Assembly's

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[45] Ormet Comments at 3.

[46] FE Comments at 20; Duke Comments at 24.

[47] Duke Comments at 24.

directives. MRO applications being "generally consistent" is not sufficient. FirstEnergy and Duke should be required to show how its MRO application promotes each of the state policies (A) through (N) and the Staff's proposed rule should not be revised. FirstEnergy's and Duke's recommendations are contrary to Am. Sub. S.B. 221 and should be rejected.

IEU recommended that Appendix A address the fact that bidders can include in their bids transmission service, ancillary or other RTO costs under Rule 4901:1-36-04.[48] Because bidders can include those items in their bids, something in the rules must ensure that customers do not pay for them twice, once through the bid and once through charges to the utility. In order to ensure that customers do not pay for them twice, the Commission should adopt an additional sentence under Section B(8) of Appendix A that states:

> THE DESCRIPTION SHALL PROVIDE AN EXPLANATION AS TO HOW BIDS THAT INCLUDE TRANSMISSION, ANCILLARY SERVICES OR OTHER RTO RELATED COSTS WILL BE EVALUATED IN RELATION TO THOSE BIDS THAT DO NOT.

E. Requirements for Electric Security Plans—Appendix B

1. General Requirements

As part of the filing for an ESP, the Staff proposes in Section (B) that the utilities should be required to include:

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

AEP requested that this provision be eliminated because the law only permits a prospective review of excessive earnings for a proposed ESP that exceeds three years and

[48] IEU Comments at 10.

should be required by only those ESPs that exceed three years.[49] Without conceding that AEP's interpretation of the law is correct on this point, OCEA asserts that the Commission must determine if the proposed ESP is "more favorable in the aggregate" than expected results of the MRO. This comparison can only be made if utilities and ultimately regulators can project the effect of the ESP for the duration of the ESP. Further, because the utility has the burden of proof in ESP proceedings, it should be required to provide its projections. Accordingly AEP's recommendation should not be adopted.

The Staff's proposal that each rate plan under R.C. 4928.141 must achieve each of the state policies articulated under R.C. 4928.02 (A) through (N) complements Am. Sub. S.B. 221 perfectly and should be adopted despite FirstEnergy's, AEP's and Duke's repeated arguments to the contrary.[50] In this section FirstEnergy claimed that it is impossible to encourage the development and interconnection of distributed and small generators and to ensure against anti-competitive subsidies at the same time.[51] Apparently, FirstEnergy believes that the interconnection of distributed and small generators creates a subsidy although it did not provide any explanation as to how that is nor provided any data to back that claim up. If small generators have the option to buy-through in the market as opposed to paying a standby charge, there is no subsidy because the utility will have no obligation to have capacity available.

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[49] AEP Comments at 14.

[50] FE Comments at 21; Duke Comments at 25; AEP Comments at 14.

[51] FE Comments at 21.

Even if hypothetically encouraging that kind of interconnection does create subsidies, that subsidy would help competition rather than threaten it because subsidies to small generators are more likely to disperse market power rather than subsidies to large players like FirstEnergy Services. Accordingly, FirstEnergy should be required to show how it is encouraging interconnection of small generators at the same time as it is proving that the distribution rates paid to FirstEnergy are not subsidizing its competitive affiliates who can threaten competition. FirstEnergy's argument about the state policies 4928.02(A) through (N) as being unachievable through a 4928.141 plan should be rejected. It is not for FirstEnergy to decide which laws it will comply with. Noncompliance with state policy is not an option.

AEP argued that "the Commission should strictly adhere to the governing statute and avoid adding substantive conditions already considered and rejected by the General Assembly." [52] The General Assembly did not reject that standard. Rather they provided the Commission with an ambiguous standard "more favorable in the aggregate" and provided the Commission with policies under R.C. 4928.02 (A) through (N). The Staff simply relied upon the policies to define favorable, which appropriately reflects the intent of the General Assembly.

Duke claimed that a just and reasonable standard is sufficient but it is not. The General Assembly established a very specific set of policies that the utilities should be required to meet in their plans in order to provide a just and reasonable outcome under Ohio law. The utilities recommendations to the contrary should not be adopted.

[52] AEP Comments at 14.

DP&L argued that Appendix B should be revised to release the utilities' obligations to address governmental aggregation.[53] In its comments, DP&L raises two issues relating to the encouragement of governmental aggregation in Am. Sub. S.B. 221. Neither of these issues have merit.

DP&L's first argued "the State's encouragement of government aggregation undermines the objective of providing and maintaining certainty for utilities (and customers) during the ESP period" and "creates a risk environment for Ohio utilities unique to the industry." These assertions by DPL are misplaced and without merit for several reasons.

One, OCEA notes that the General Assembly and the Governor are responsible for setting state policy in relation to the structure of electric markets. They have determined it to be in the best interests of consumers to not only continue governmental aggregation as it exists in Ohio but to actively seek its promotion. Therefore, attempting to undermine that objective through the rule-making process is inappropriate.

Two, DP&L's concern over governmental aggregation exposing utilities to unnecessary risk is belied by the very definition of an ESP. An ESP should provide generation costs below market prices. If an ESP generation price is properly set and is below market price, the risk of a governmental aggregation taking large numbers of customers out of SSO generation service is unlikely. Even if governmental aggregation transitions customers from SSO supply, the utility would have the opportunity to sell the excess electricity at market rates, which should be higher than the ESP price offered in the SSO. Accordingly, governmental aggregation provides little financial risk to utilities.

[53] DP&L Comments at 4.

Three, it appears that the legislature anticipated that governmental aggregation could provide an additional check on a utility's SSO pricing structure to ensure that consumers obtain the lowest generation costs possible. DP&L's opposition to governmental aggregation appears designed to remove that effective check on its forward SSO pricing and inhibit future competition.

DP&L's second suggestion is that the rules "should require that the government aggregator obtain customer authorization either through a ballot process or otherwise, before the aggregator can place the future market price risk on customers." Governmental aggregators, like NOAC and NOPEC, have already secured voter permission to operate opt-out programs. Nothing in Am. Sub. S.B. 221 requires the redundancy of another "ballot process." Moreover, the opt-out process itself, and the Staff proposed requirement to inform consumers of the governmental aggregator's election not to receive stand-by service, provide each citizen the information necessary to decide whether to remain with SSO generation supply or go with the governmental aggregation.

For these reasons, the Commission should not amend Appendix B as proposed by DP&L.

2. Specific Information

FirstEnergy and AEP argued that utilities should not be required to "offset" costs of fuel or costs of emission allowances by the gains of the sale of ratepayer funded fuel and emission allowances under Section (A)(2) because R.C. 4928.143(B)(2)(a) does not require it.[54] These utilities demonstrate through this argument their utter lack of a sense

[54] FirstEnergy Comments at 21; AEP Comments at 15.

of fairness to ratepayers and reveals the necessity of the Commission's supervision over pricing. As fuel costs rise and customers are increasingly challenged when it comes to paying their bills, there is a moral imperative that utilities act as good corporate citizens and do the right thing.

Additionally, the utilities' argument that R.C. 4928.143(B)(2)(a) does not permit credits or offsets fails to recognize that any costs permitted under this provision must be found to be prudently incurred. Commission practice under the EFC cases has held that costs of fuel and purchased power that are recovered from EFC customers are not prudently incurred if they are not offset by credits and revenue the utility gains through fuel and purchased power.[55] Accordingly, the Staff's proposed rule is necessary to prevent the utility from collecting imprudent costs from its customers.

AEP commented that because the fuel cost recovery is an automatic recovery mechanism, it should allow for the pass through of any amounts the utilities claim they spent. [56] This is absurd in light of the fact that the utilities must prove that the amounts they spent are prudent and that the EFC rule that traditionally required credits and offsets from fuel costs was also referred to as an automatic recovery mechanism. Precedent has value and should be adapted to current realities.

FirstEnergy again argued that under Section (A)(5) it should not be required to provide "any and all documents prepared by the electric utility for the application."

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[55] See *In re Duke Energy Ohio, Inc,* 07-723-EL-UNC, Finding and Order (June 27, 2007); *In re Ohio Power Company,* Case Nos. 98-101-EL-EFC and 98-102-EL-EFC, Opinion and Order (May 26, 1999).

[56] AEP Comments at 15.

FirstEnergy comparison of the ESP filing requirements to the base rate case filing requirements[57] is not valid.

The statutory requirements as set forth under R.C. 4909.18 et. al. are explicit and the Commission's experience with base rate case filings is extensive. The statutory requirements as set forth under R.C. 4928.143 are broad. Because the ESP process is new, all relevant data is needed in order to understand the nature of the requests. Given that the utilities have filed plans that call for unprecedented massive increases, which if adopted will create significant burdens on customers, it is imperative that the Staff and intervenors have the opportunity to review the underlying workpapers. Otherwise, the parties are left to assume that there is no clear basis and that the increases requested were pulled from thin air. For these reasons, the filing requirements should be extensive so that the Commission has an opportunity to see how the utilities formulate the proposals they make and so that the Commission, Staff and intervenors can gain experience with the filings.

Duke suggested that the Commission add a paragraph 5 to Section (B) so that utilities can impose unavoidable surcharges not only on new construction but also on existing assets.[58] The suggestion is contrary to R.C. 4928.143(B)(2)(b) and (c), which allows the surcharge for only new construction and environmental expenditure of generation resources "provided the cost is incurred or the expenditure occurs on or after January 1, 2009." Accordingly, the Commission should reject Duke's suggestion. Moreover, allowing non-bypassable charges associated with existing generation would have an anti-competitive impact and would be contrary to State policy.

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[57] FE Comments at 22.

[58] Duke Comments at 26.

IEU recommended that (B)(4) be clarified to reflect that recovery of the actual costs of a generation facility is limited to only those that are used and useful and those whose capacity and energy are dedicated to Ohio.[59] This clarification in the rule is helpful. And OCEA fully concurs.

IEU also suggested that (B)(1), which states that an integrated resource plan is necessary to demonstrate that the proposed facility is needed to serve Ohio, should identify the information needed to obtain approval of an integrated resource plan. Unquestionably this will be needed before an application can be made under this provision. The Commission can meet this need by adopting rules similar to those already adopted but repealed under S.B. 3 and incorporating them into these rules.

Contrary to FirstEnergy's and AEP's complaints,[60] Section (C)(1)'s "listing of all components of the ESP which would have the effect of preventing, limiting, inhibiting, or incentivizing customer shopping for retail electric generation service" is an important exercise for both the utilities and the Commission in understanding competition. Oddly, FirstEnergy perceives that this provision is contrary to the R.C. 4928.143(C)(1) requirement that the ESP be approved if it is "more favorable in the aggregate than the market rate offer." [61] Apparently, FirstEnergy perceives that "more favorable" relates only to rates rather than to other considerations, such as the medium and long-term impact of expanded energy efficiency programs and a large renewable energy portfolio, both of which contribute to price stability over time.

[59] IEU Comments at 11.

[60] FirstEnergy Comments at 22; AEP Comments at 15-16.

[61] FE Comments at 22.

The Staff proposed Section (D) rules requires utilities asking for automatic increases under R.C. 4928. 143(B)(2)(f) to provide a means of verifying the reasonableness of the charge. AEP complained that this should not be necessary because the increases are meant to be automatic. However, the Commission must determine whether the ESP plan is "more favorable in the aggregate" and the Commission cannot determine if a plan is "more favorable" if it does not determine whether the automatic increases expected under the plan will be prudent and reasonable. Moreover, the utility has the burden of proof in the ESP proceeding and therefore cannot show that the ESP is favorable if it does not show that automatic increases are reasonable. The provision should remain in the rules.

OEG recommended that section (F) in Specific Filing Requirements of Appendix B clarify that all transmission–related costs that a utility attempts to recover through the ESP should be "net of transmission revenues."[62] Such an addition is helpful and should be adopted.

FirstEnergy appears to perceive that the Commission is requesting it to file with its ESP all the specifics listed under (G) (1) through (5) for any "infrastructure maintenance plan" it may propose in the future, rather than any it will propose in its ESP filing.[63] In order to clarify the rule it should read:

> While a number of mechanisms may be combined within a plan, for each specific mechanism or program PROPOSED IN THE ESP, the electric utility must provide a narrative explanation and information to allow appropriate evaluation of the proposal.

[62] OEG Comments at 6.

[63] FE Comments at 23.

With that clarification, it should be clear to utilities that for each infrastructure maintenance plan proposed in each ESP, the specifics listed under (G)(1) through (5) should be included.

AEP claimed that the Staff's rule includes a "laundry list" of filing requirements for each alternative regulation mechanism relating to distribution service that is proposed in the ESP plan and argued that many of the filing requirements might not be applicable to certain mechanisms.[64] However, because the Commission must determine if a plan is "more favorable in the aggregate" the Commission must review all benefits and all costs associated with each of the mechanisms in order to determine if the plan is "more favorable than the aggregate." Accordingly, all the requirements under (G) will be necessary for the appropriate review and should not be limited to only certain mechanisms.

OEG recommended that all breakdowns of capital costs and operating and maintenance expenses as required Under (G)(3) should be reported as "net of any related savings."[65] This language should ensure that only costs that do not benefit the utility would be recovered and should be adopted.

The Staff's proposed infrastructure maintenance plan requirements (G)(1) through (5) are a good start and should be retained. If the Commission finds that other items are necessary or that some of the items listed are not, the Commission can revise the rule after it gains experience with it.

AEP argues that the Commission should not require cost-benefits analysis of programs that are required. Such cost-benefit analysis should be required to assist the

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[64] AEP Comments at 17.

[65] OEG Comments at 6.

Commission in determining whether the programs are appropriately designed and will result in net benefits to customers who must pay for these investments.

3. Additional Required Information

FirstEnergy's, DP&L's, Duke's and AEP's complaints that Section (A) requires utilities to provide information "functionalized as to distribution, transmission and generation activities" [66] for the purpose of determining whether utilities have excessive earnings is misplaced. The rule should require that the information must be provided, not to determine which of the activities are earning excessively, but to compare the utilities relative risk to other publicly traded companies as is required under R.C. 4928.143(E) and (F). Although Duke[67] claims that the functionalized amounts are not publicly available for other publicly traded companies, that does not mean that such functionalized amounts will not assist the Commission in making comparisons to similarly situated companies that provide only one of the functions, such as generation companies and fully divested distribution companies. Accordingly, the functionalized requirements of the rule should be retained.

OEG requested that the Commission provide more specificity as to what kind of income statement information and balance sheet information must be filed by the utility under (A)(1) and (2).[68] OEG pointed out that the Commission cannot meet its requirements to conduct earnings reviews without at least as much detail as is provided in a FERC Form 1. OEG also noted that providing that information would not be

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[66] FE Comments at 24; DP&L Comments at 6; Duke Comments at 27; AEP Comments at 18.

[67] Duke Comments at 28-29.

[68] OEG Comments at 6.

burdensome and appropriately recommended additional language, which should be adopted.

FirstEnergy suggested that the Commission also remove the requirement under Section (B) that it provide specific testimony and analysis demonstrating the return on equity that was earned during the same period by publicly traded companies. FirstEnergy stated that it is up to the utility to determine what evidence it will need to provide to meet its burden of proof.[69] But the Commission will be the entity who determines whether the burden is met. Setting out the evidentiary requirements ensures that the necessary information is before the Commission. Put another way, it is appropriate for the Commission to warn utilities before such filings that they will not be able to meet the burden of proof without testimony and analysis. For that reason, the provisions should not be removed.

F. Service of Application – 4901:1-35-04 (Rule 4)

FirstEnergy complained that the use of the adjective "proposed" to describe filings in Rule 4(A) is inappropriate because the rule as written would require utilities to provide notice of proposed filings rather than just actual filings. OCEA agrees and suggests that the Rule 4(A) be revised to require:

> Concurrent with the filing of a standard service offer (SSO) application and the filing of any waiver requests, the electric utility shall provide notice of its proposed ~~filing~~ APPLICATION to each party in its most recent SSO or, if this is its first SSO filing, then its last rate plan proceeding.

[69] FE Comments at 25.

FirstEnergy argued that requiring a utility to provide paper copies of their applications without cost is unnecessary, wasteful and burdensome.[70] Rather than being required to provide paper copies of their application, FirstEnergy requested that the rule clarify that utility need only provide electronic copies. Utilities should be required to provide copies of their rate applications to anyone who will be required to pay their rates. Some individuals do not have computer expertise and some do not have access to computers. Publicly available computers at the libraries are busy and sometimes difficult to access. For those reasons, if an individual who will be required to pay the rates under the application tells the utility that he or she does not know how or cannot access the application in an electronic version, the utility should be required to provide a paper copy or at least a summary of the application that includes all the components of the application, the associated rates of the components or the means whereby the rate components will be calculated. It should also include any tariff changes that would be made based upon the application. Accordingly, Rule 4(B) should be revised to state:

> The electric utility shall provide electronic copies of the application upon request, without cost and within a reasonable period of time. IF A CUSTOMER OF AN ELECTRIC UTILITY REQUESTS FOR A COPY OF THE APPLICATION AND THE CUSTOMER TELLS THE ELECTRIC UTILITY THAT HE OR SHE CANNOT ACCESS AN ELECTRONIC COPY OF THE APPLICATION, THE ELECTRIC UTILITY SHALL PROVIDE A PAPER SUMMARY OF THE APPLICATION THAT INCLUDES A DESCRIPTION OF ALL THE COMPONENTS OF THE APPLICATION, THE CHARGES ASSOCIATED WITH EACH COMPONENT AND ALL TARIFF CHANGES PROPOSED IN THE APPLICATION. IF AFTER THE SUMMARY, THE CUSTOMER CONTINUES TO REQUEST THE APPLICATION, THE ELECTRIC UTILITY MUST PROVIDE A PAPER COPY OF THE APPLICATION.

[70] FE Comments at 10.

G. Hearings 4901:1-35-06 (Rule 6)

FirstEnergy and AEP insisted that Am. Sub. S.B. 221 was quite specific as to the standard of review for either MRO or ESP applications.[71] FirstEnergy, Duke and AEP claimed to believe that the General Assembly did not provide discretion to the Commission that would allow the Commission to adopt Rule 6(A), which establishes the standard of review as "just and reasonable" and "achieve the policy of the state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code."[72] Rather they argued that the Commission can only repeat the standards in the law. The utilities are wrong.

The standard of review as to whether the Commission should adopt an ESP under R.C. 4928.143(C) states:

> Subject to division (D) of this section, the commission by order shall approve or modify and approve an application filed under division (A) of this section if it finds that the electric security plan so approved, including its pricing **and all other terms and conditions**, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code (emphasis added).

FirstEnergy and AEP quoted the phrase "is more favorable in the aggregate as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code." FirstEnergy's characterized that standard as specific. AEP implied that the standard is specific.[73] Again, the utilities are wrong.

[71] FE Comments at 11; AEP Comments at 5.

[72] FE Comments at 11; Duke Comments at 9-10; AEP Comments at 5.

[73] AEP Comments at 6-7.

The descriptive phrase "more favorable in the aggregate" is not specific. "More favorable" must be defined and the only guidance the General Assembly gave to define that term is the state policies under R.C. 4928.02(A) through (N). More favorable in the aggregate means meeting those policies in the least-cost manner. As the pertinent part of the statute clearly states above, the determination of "more favorable" includes "all other terms and conditions." The Staff's proposed rule was a logical and even necessary, given the statutes. The "just and reasonable" standard included in Rule 6(A) is also logical because it is the standard included in the first policy identified by Am. Sub. S.B. 221 under R.C. 4928.02:

> Ensure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service.

FirstEnergy also incorrectly stated that the standard of review for an MRO application is simply whether it meets requirements under 4928.142(A)(1) and (C)(1). First, because part of the requirements under R.C. 4928.142(C) is that the market-rate offer meets "all of the foregoing requirements" the market-rate offer filing must meet requirements established through Commission rules under R.C. 4928.142(A)(2). Also, because all utilities must make an ESP filing initially under R.C. 4928.141(A), the Commission must compare the ESP to any MRO application made in the first applications. Therefore, an MRO application that meets the requirements of 4928.142(A) and (C) must also, in the aggregate, be just as favorable or more favorable than an ESP that conforms to the requirements of R.C. 4928.143 and the rules established by the Commission under R.C. 4928.143(C). And because of that necessary comparison, the

Staff's adoption of the state policies under R.C. 4928.02 as a definition of what favorable means appropriately applies.

FirstEnergy also complained that the state policies under R.C. 4928.02(A) through (N) are conflicting and that electric utilities should not be required to "achieve" those goals as required under Rule 6(A). Instead FirstEnergy would prefer that utilities only need to meet a standard that the plans are "generally consistent with" the goals of R.C. 4928.02.

The goals under R.C. 4928.02(A) through (N) are not conflicting. The goals promote reasonable prices, competitive markets, customer choice, diverse supplies to meet customer needs, quality distribution and transmission service, nondiscriminatory use of the distribution and transmission systems, flexible regulatory treatment, the avoidance of anti-competitive subsidies, customer protection and protection of at risk populations, distributed generation, education of small business owners on energy efficiency, facilitating the state's competitiveness in the global economy, and incentives for technologies that adapt successfully to environmental compliance. While any of those policies taken to an extreme can undermine other policies, an ESP or MRO should achieve each of those goals. To state that a plan is "generally consistent" with those goals is not sufficient direction. Each utility should propose a well-balanced plan that includes at least one or more than one meaningful program that is intended to achieve each of those goals in a well-balanced manner. Therefore, the rule should not be revised.

FirstEnergy also complained about the first sentence in Rule 6(A), which provides that the Commission will set an application for hearing after the application conforms to the commission rules. FirstEnergy insisted that if the utility files an application early enough the Commission must set an application for an SSO for hearing before the rules are established.[74] FirstEnergy argues that because the Commission must decide upon an ESP application within 150 days after it is filed under R.C. 4928.143(C)(1) and an MRO application within 90 days after it is filed under R.C. 4928.142(B)(3), the Commission does not have the discretion to wait to hold a hearing on an application until after its rules for such hearings are established. FirstEnergy's interpretation is nonsensical.

Under R.C. 4928.141(B) the Commission has been authorized to "adopt rules regarding filings under those sections [R.C. 4928.142 and 4928.143]." If the General Assembly had intended the Commission to proceed to hearing before it completed the rules, the General Assembly would not have directed the Commission to adopt rules for the proceedings. Moreover, R.C. 4928.142(B) and R.C. 4928.143(A) allows the utility to file before the effective date of the rules but in both cases, a utility is required to "immediately" conform their "filing" to the rules when the rules are completed. If the General Assembly had intended the Commission to take a filing to hearing before the rules are finalized, the General Assembly would not have stated that the utility is required to "immediately" conform its "plan" to the final rules.

Moreover, if a utility files an application under R.C. 4928.142 before the Commission completes the rulemaking process under R.C. 4928.142(A)(2), the Commission could simply reject the application within the 90 days as not meeting "the foregoing requirements," and explain to the applicant that they need to comply with the rules when established to be in compliance with the law.

The Commission must either modify and approve or approve an application under R.C. 4928.143, within 150 days of the filing. As long as the Commission adopts the rules

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[74] FE Comments at 12.

within those 150 days, the Commission can modify the plan based upon the rules it completes under R.C. 4928.143(A) by issuing an order under that division stating it approves the filing but modifies it based on the rules it adopted. For the reasons stated above, the Commission should not revise Rule 6(A) as the utilities have suggested and should require the filing of an application that conforms to the Commission rules before the Commission sets the application for hearing.

OEG and Nucor recommended that the hearing that addresses a standard service offer should allow for reasonable discovery and the submission of intervenor testimony and suggested additional language for Rule 6(A).[75] This language is necessary to ensure due process.

H. Discoverable Agreements—4901:1-35-07 (Rule 7)

Duke argues that as long as the utility does not know that its affiliate has a contract with a party to the proceeding, a consumer, an electric service company or political subdivision it should not be required to provide such an agreement to other parties in the proceeding.[76] This suggestion is ridiculous, especially when the utility, its affiliates and its parent company share so many employees, including legal counsel. It would be impossible for the utility to prove that it did not know that its affiliate has a contract with a party to the proceeding.

Any electric utility providing a standard service offer in an electric proceeding should be required to know if its affiliates have a contract with a party to the proceeding. That knowledge is necessary especially if part of the agreement between the affiliate and the party to the proceeding has an affect on what the party does within the proceeding. If

[75] OEG Comments at 2; Nucor Comments at 7.

[76] Duke Comments at 11.

electric utilities and their affiliates undermine regulatory plans as Duke suggests in this rule revision, electric utilities should not be permitted to have any affiliates.

Nucor requested that agreements between the utility and another utility or supplier of generation and agreements between the utility's affiliates and another utility or supplier of generation should also be discoverable.[77] Granting this request is reasonable and important because utilities and their affiliates could use other suppliers as go betweens to allow transactions that would otherwise not be permitted. Such allegations have been made before the Commission and the evidence indicated that such arrangements are possible and would be very difficult to prove.[78] For this reason, the Commission should incorporate Nucor's suggested revision. To do less would be inconsistent with the extensive legislative discussions on transparency.

I. Competitive bidding process requirements and use of independent third party—4901:1-35-08 (Rule 8)

It is not surprising that the theme of the comments submitted by the utilities, namely Duke, AEP, and FirstEnergy, emphasize the need for flexibility with respect to the implementation of any Competitive Bidding Process (CBP). Their comments are designed to provide the utilities more discretion and control of the CBP with less regulatory oversight. In general, the OCEA opposes any changes to the proposed rule that would diminish the Commission's oversight and ability to implement the CBP. This is particularly true when reviewing compliance with the least-cost portfolio management approach OCEA recommends. The statute does not mandate full requirements bid for the entire load or for tranches. Relying on such approaches has resulted in increases in

[77] Nucor Comments at 7.

[78] *Dominion East Ohio*, 03-219-EL-EFC, Trial Transcript.

generation supply prices and high profits for the owners of those generating resources in other states. Ohio should learn from the errors committed in the other laboratories of democracy. Just because a state and the consultants involved in the process chose a particular approach to the auction or request for proposal ("RFP") coupled with a simplistic product is no reason to assume that there are not better options such as the integrated portfolio approach recommended by OCEA.

Generation, efficiency, and demand response all represent multi-year investments in the elements of electric service. Annual bidding for full requirements power does not represent accurately the investments necessary to provide that service. If the products and the revenues earned with those products do not match up with the nature of utility financing, then there will be little investment in new generation and existing plants will retain their oligopoly status. The bidding process should be used to correct the flaws in the current iteration of wholesale electricity markets.

While OCEA agrees that some degree of discretion should be permitted under the regulations, the nature of that flexibility may differ from what is proposed by the utilities. The Commission and the utilities may well put forward different approaches to a CBP depending on the type of contract or other portfolio service that is approved as part of a proposed MRO or ESP. However, once the specific contract or product that is to be acquired is approved as part of the overall MRO or ESP portfolio, the implementation of the CBP to obtain that product or contract should be highly supervised by the Commission.

The utility comments fail to reflect the central proposition of OCEA's initial comments, namely that the products and services that need to be acquired to provide

Standard Service, whether implemented by means of an MRO or ESP, will vary according to the procurement plan approved by the Commission and implemented by the electric distribution utility. OCEA opposes the notion that there will be a single CBP approved to purchase the entire Standard Service Offer or that the same type of contract should be relied upon for this Service even if purchased at different times. Therefore, the regulations must contemplate that a variety of appropriate CBP approaches could be proposed and relied upon to purchase different contract types and resource acquisitions for the entire portfolio.

Duke suggested that the independent third party should not design the competitive bidding process and Duke wants flexibility in the design of the bid.[79] But R.C. 4928.142(A)(1)(a-c) does not permit such flexibility. OCEA is particularly concerned about the comments filed by Duke, which appear to suggest that an individual customer could choose a CRES provider directly from the winners at the bid price.[80] This is a strange suggestion. A bidder should not sell to an individual customer for the same price as the winning bid because the administrative costs of providing to an individual customer as opposed to a tranche are so much higher. Accordingly, the independent third party should design a standard competitive bid that assures that the bidding process avoids anti-competitive and discriminatory rates.

Any CBP operated by the utility to provide Standard Service to its customers will be conducted for the purpose of serving a particular customer class, a slice of the utility's load obligation, or perhaps a region. It is not at all clear how any individual customer would be able to interact with a winning bidder for this type of acquisition since an

[79] Duke Comments at 13.

[80] Duke Comments at 14.

individual customer's load, load shape, and generation supply needs would naturally vary from that bid specifications for a larger or homogenous group of customers.

Any changes to the regulations designed to permit such a specicious suggestion should be rejected. Specifically, Duke's proposal that the design of the bid should be the responsibility of the utility and not the third party administrator should be rejected. Duke has sufficient bias with regard to the outcome of the bid and its competitive standing so that Duke's concerns should be no more influential than any other generation providers to the design of the competitive bid. The independent third party should be responsible to the Commission, which should prevent such outcomes as allowing a bidder to undercut competition by selling below cost as a CRES provider.

Additionally, Duke's approach fails to contemplate that the product or service that is being acquired will be approved as part of the MRO or ESP proposal by the utility. The design of the bid specifications should be prepared by a qualified third party administrator as part of the requirements in administering the bid process. Any third party administrator retained to conduct the bid process should be able to design the detailed bid specifications based on the approved portfolio and obtain the necessary information from the utility to properly reflect the approved plan.

FirstEnergy expressed concerns about the Commission making changes to the CBP after the plan is approved.[81] OCEA suggests that any such changes should be publicly noticed by the Commission and due process rights provided to all affected parties. OCEA agrees that last minute changes by the Commission would not be appropriate in most cases and should be avoided. FirstEnergy expressed concerns that parties to the hearing will complain that their due process rights have been offended and

[81] FirstEnergy Comments at 13.

will challenge the validity of the process. Of particular concern should be modifications or additions made by the independent third party to the CBP after the hearing.

Under Rule 8(A), the competitive bidding process must be filed as part of its MRO. However, the rule is somewhat unclear as to the role of the independent third party during the MRO hearing. In Appendix A (B)(12) the rule requires the utility to include in its plan:

> Funding for a consultant[82] that may be selected by the commission to assess and report to the commission on the design of the solicitation, the oversight of the bidding process, the clarity of the product definition, the fairness, openness, and transparency of the solicitation and bidding process, the market factors that could affect the solicitation, and other relevant criteria as directed by the commission.

Neither the Appendix nor Rule 8 seems to have a role for the independent third party during the hearing on the MRO. But to avoid problems of post-hearing modifications or additions to the CBP process, perhaps the Commission should engage the third party consultant to offer testimony at the hearing on the CBP process so that there can be no due process complaints after the hearing is completed. In that way, the Commission and the Staff, along with interested parties will have an opportunity to address their concerns regarding the CBP process and make recommendations to the independent third party about the CBP. Accordingly Rule 8(A) should be revised to state:

> The electric utility shall use an independent third party SELECTED BY THE COMMISSION to design an open, fair and transparent bid solicitation, to administer the bidding process; and to oversee the entire procedure to assure that the CBP complies with the CBP plan. THE INDEPENDENT THIRD PARTY SHALL PRESENT THE DESIGN OF THE COMPETITIVE BID SOLICITATION IN TESTIMONY DURING THE MRO

[82] If the Commission intends this “consultant” to be the same person as the independent third party proposed in Rule 8(A), the Commission should change the term “consultant” above to “independent third party” in Appendix A to clarify that they are the same.

> HEARING AND WILL BE SUBJECT TO CROSS-EXAMINATION. THE DESIGN OF THE COMPETITIVE BID SOLICITATION SHALL BE A SUBJECT ADDRESSED BY THE COMMISSION IN ITS DECISION REGARDING THE MRO APPLICATION. The independent third party shall be accountable to the commission for all design, process, and oversight decisions BEYOND THOSE ALREADY DETERMINED THROUGH THE HEARING PROCESS. Any ~~modifications or~~ additions to the CBP made by the independent third party shall be FILED WITH THE COMMISSION ~~submitted to staff prior to implementation~~ . NO ADDITIONS WILL BE MADE TO THE CBP THAT WILL SUBSTANTIALLY CHANGE THE CBP PROCESS ALREADY APPROVED BY THE COMMISSION. WITH REGARD TO SUCH ADDITIONS, the independent third party ~~shall~~ MAY PROPOSE TO incorporate into the solicitation, THE INDEPENDENT THIRD PARTY WILL ADJUST THE ADDITIONS WITH such measures as the Commission or its staff may prescribe, and shall incorporate into the bidding process any direction the Commission may provide THAT WILL NOT SUBSTANTIALLY CHANGE THE CBP PROCESS ALREADY APPROVED BY THE COMMISSION.

IEU suggested that Rule 8(A) should include a process whereby the Staff or the Commission will make public any prescription of particular CBP measures it communicates to the independent third party.[83] This kind of a formal process would increase trust and transparency in the process and may be instrumental in attracting more bidders and should be incorporated accordingly:

> ANY MEASURES THE STAFF OR THE COMMISSION PRESCRIBE TO THE INDEPENDENT THIRD PARTY TO BE INCORPORATED INTO THE BIDDING PROCESS SHALL BE IDENTIFIED IN THE COMMISSION'S ORDER APPROVING THE MRO OR SHALL BE IDENTIFIED IN A SUBSEQUENT ENTRY.

Nucor recommended that two changes be made to Rule 8(B): that the independent third party's report be made available to interested parties and that the independent third party report on whether he or she observed any market manipulation or anticompetitive

[83] IEU Comments at 8.

behavior during the CBP.[84] Both changes would increase trust and ultimately effectiveness in the process and therefore should be adopted.

FirstEnergy does not want the independent third party to discuss in its report "any aspects of the process that *could have* adversely affected the outcome" (emphasis added) as required under this proposed rule. Rather, FirstEnergy argued that the rule should require the independent third party to address only those aspects of the process that did *in fact* have an adverse affect on the outcome of the bid.[85]

It is highly unlikely that the third party will have the capacity or resources to make a factual determination that the bid process was in fact adversely impacted by events or market power, the details of which are likely to not be easily detected in the time frames contemplated by the rule. The rule should not be changed so that intervenors can make the full range of comments and observations that he or she has observed or has concerns about. Moreover, such a suggestion places a burden of proof on the independent third party that is not appropriate. It is near impossible to prove "what might have been but for".

The competitive bid process is a relatively new method of purchasing generation supplies in Ohio and it is not always possible to know *for a fact* every aspect of a process that did have an effect on the outcome. For those reasons, it is important to have the independent third party discuss "any aspects of the process that could have adversely affected the outcome." Such discussion will aid the Commission in reviewing future competitive bid processes and are likely to lead to progressively better outcomes. For that reason, Rule 8(B)(1) should not be revised.

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[84] Nucor Comments at 9.

[85] FE Comments at 13.

The Staff proposed rule 8(B)(7) requires the independent third party to include in its report after the bidding process:

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

FirstEnergy prefers that the Commission not see the retail rate until after the Commission approves the winning bids.[86]

Although FirstEnergy may consider the calculation of the retail rate to be mechanical, the retail rate calculation will likely involve some assumptions and judgment calls so utilities should be required to file testimony on it in the MRO proceeding. All interested parties should have an opportunity to review it and cross-examine a witnesses regarding the process. In the past, utilities have sought to use legacy cost-of-service studies to establish rates. Additionally the method of calculating the retail rates should also be carefully checked. The independent third party should also have an opportunity to comment on it in testimony. Finally, the independent third party should formalize its approval of the retail rate and the method of calculating the retail rate in the report to the Commission. Therefore, Rule 8(B)(7) should not be revised as FirstEnergy suggested.

The rule is somewhat unclear about how the retail rate shall be set but OEG made some logical recommendations in its comments.[87] OEG suggested that first, the utility provide a description of its proposed methodology for converting the winning bids into retail rates in its CBP plan. This should be supported with testimony and should be subject to cross examination. Second, if the Commission approves the CBP plan, the

[86] FE Comments at 14.

[87] OEG Comments at 3.

independent third party uses the Commission-approved methodology to convert the winning bids into retail rates. Third, the Commission should select the least-cost bids and sets the retail rates in an issued decision.

J. ESP Rule and Purchased Power Adjustments—Rule 4901:1-35-09 (Rule 9)

AEP and IEU both suggested that Rule 9(B) clarify a time period by which the Staff will have to raise issues concerning the quarterly adjustment filing before the quarterly adjustment becomes effective. AEP suggested that the quarterly adjustment be filed at least 21 days before it is to be effective.[88] IEU suggested 30 days.[89] The Staff and other interested parties should have at least 30 days to review the quarterly filing and customers should have time to prepare themselves for changes in the rates. In addition interested parties should have the opportunity to file comments before that 30 day period, in case an interested party notices something wrong or has a concern. In fact, more than 30 days would be beneficial so that interested parties have the time to review the filing and file comments.

AREO requested that an additional paragraph be attached to Rule 9 as Rule 9(E) that paragraph reads:

> NO CHARGE OR ADJUSTMENT RIDER FOR FUEL OR PURCHASED POWER SHALL BE ASSESSED AGAINST A CUSTOMER WHO RECEIVES ELECTRIC GENERATION FROM A COMPETITIVE RETAIL ELECTRIC SUPPLIER OR A GOVERNMENTAL AGGREGATION PROGRAM. IF A FUEL OR PURCHASED POWER CHARGE IS DEFERRED SO THAT STANDARD SERVICE CUSTOMERS RECEIVE THE VALUE OF THE FUEL OR PURCHASED POWER BUT THE COST FOR SUCH FUEL OR PURCHASED POWER IS COLLECTED AT A SUBSEQUENT TIME, CUSTOMERS WHO

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[88] AEP Comments at 9.

[89] IEU Comments at 8.

> RECEIVE ELECTRIC GENERATION DURING THE PERIOD OF THE DEFERRAL WILL GET A CREDIT AGAINST THEIR ELECTRIC UTILITY CHARGES IN THE AMOUNT PER KWH OF THE FUEL AND PURCHASED POWER DEFERRAL PER KWH. WHEN THE DEFERRAL OF THE FUEL AND PURCHASED POWER AMOUNTS ARE COLLECTED THEY MAY BE ASSESSED AGAINST ALL CUSTOMERS INCLUDING THOSE TAKING ELECTRIC GENERATION FROM COMPETITIVE RETAIL ELECTRIC GENERATION FROM COMPETITIVE RETAIL ELECTRIC SUPPLIERS AND GOVERNMENTAL AGGREGATION PROGRAMS.

If understood correctly, this recommended addition is a practical solution to a complicated problem. But the rule should be further clarified to state:

> NO CHARGE OR ADJUSTMENT RIDER FOR FUEL OR PURCHASED POWER SHALL BE ASSESSED AGAINST A CUSTOMER WHO RECEIVES ELECTRIC GENERATION FROM A COMPETITIVE RETAIL ELECTRIC SUPPLIER OR A GOVERNMENTAL AGGREGATION PROGRAM. IF A FUEL OR PURCHASED POWER CHARGE IS DEFERRED SO THAT STANDARD SERVICE CUSTOMERS RECEIVE THE VALUE OF THE FUEL OR PURCHASED POWER BUT THE COST FOR SUCH FUEL OR PURCHASED POWER IS COLLECTED AT A SUBSEQUENT TIME, CUSTOMERS WHO RECEIVE ELECTRIC GENERATION **FROM A COMPETITIVE RETAIL ELECTRIC SUPPLIER OR GOVERNMENTAL AGGREGATION PROGRAM** DURING THE PERIOD OF THE DEFERRAL WILL GET A CREDIT AGAINST THEIR ELECTRIC UTILITY CHARGES IN THE AMOUNT PER KWH OF THE FUEL AND PURCHASED POWER DEFERRAL PER KWH. WHEN THE DEFERRAL OF THE FUEL AND PURCHASED POWER AMOUNTS ARE COLLECTED THEY MAY BE ASSESSED AGAINST ALL CUSTOMERS INCLUDING THOSE TAKING ELECTRIC GENERATION FROM COMPETITIVE RETAIL ELECTRIC GENERATION FROM COMPETITIVE RETAIL ELECTRIC SUPPLIERS AND GOVERNMENTAL AGGREGATION PROGRAMS.

K. Annual Review of the ESP (Excessive Earnings Review)— Rule 4901:1-35-10 (Rule 10)

Nucor suggested language that will better ensure that the utility does not earn amounts significantly in excess of comparable companies.[90] Nucor recommends that with the earnings filing the utility be required to show "that the ESP produced just and reasonable rates and will continue to do so." Because that language is consistent with R.C. 4928.02(A), the Commission should incorporate it into Rule 10(A).

FirstEnergy and AEP complained that the Staff did not actually use the adjective "significant" in front of the term "excessive earnings" to conform to the statutory language in its Rule 10(A).[91] Rules are intended to flesh out or provide specificity to general terms provided by the statute. For this reason, the Staff should provide more specificity in the rule to clarify what "significantly in excess" means. Essentially the term significant means "having or expressing a meaning."[92] Accordingly, the excess needs to be beyond chance or needs to be meaningful. The best way to test whether an excess is beyond chance or is meaningful is to test it for more than one year. The Commission should revise its rule to specify what period of time it will look at earnings to determine if they are in excess. Rule 10(A) is not the best provision to use for this purpose. Rather it would be preferable that Rule 10(C) include more specificity as to what "significantly in excess means."

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[90] Nucor Comments at 10.

[91] FE Comments at 15; AEP Comments at 9.

[92] New World Dictionary, Second College Addition (1978) at 1325.

Nucor suggested language that will better ensure that the utility does not earn amounts significantly in excess of comparable companies.[93] Nucor recommends that with the earnings filing the utility be required to show "that the ESP produced just and reasonable rates and will continue to do so." Because that language is consistent with R.C. 4928.02(A), the Commission should incorporate it into Rule 10(A).

OEG accurately stated that the rules cannot meet due process requirements unless a hearing is provided upon the finding that reasonable grounds exist to indicate that a utility did earn significant excess earnings.[94] Accordingly Rule 10(C) should state:

> Based upon the above filings, if the commission finds that there are reasonable grounds that such adjustments, in the aggregate, may have resulted in ~~significant excess earnings for the electric utility,~~ THE ELECTRIC UTILITY EARNING MORE THAN COMPARABLE COMPANIES DURING THE PREVIOUS TWO YEARS, the Commission SHALL~~may~~ set the matter for hearing. IN ANY SUCH HEARING INTERVENORS SHALL HAVE REASONABLE DISCOVERY RIGHTS AND THE ABILITY TO FILE TESTIMONY. IF IT IS DETERMINED AFTER HEARING THAT EXCESS EARNINGS DURING THE ANNUAL PERIOD DID OCCUR, THEN THE EXCESS WILL BE RETURNED TO CONSUMERS BY PROSPECTIVE ADJUSTMENTS DETERMINED BY THE COMMISSION.

Nucor suggested that parties be given an opportunity to issue discovery in the utility's annual ESP review filing under Rule 10(B).[95] This suggestion is sensible, given interested parties right to file comments in those cases and Nucor's suggested language should be adopted.

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[93] Nucor Comments at 10.

[94] OEG Comments at 3-4.

[95] Nucor Comments at 10.

DP&L read R.C 4928.143(E) to limit the earnings tests to utilities with ESP plans longer than three years to only prospective tests that occur every four years. [96] But R.C. 4928.143(F) does not state that annual retrospective earnings tests will not apply to utilities with ESP plans longer than three years if they include adjustments. Accordingly, DP&L's requested revisions to Rule 10 should not be granted.

IEU recommended that Rule 10 should provide for a hearing that will allow for the test of the prudence of purchases made, the opportunity for interested parties to participate, and a reconciliation adjustment to credit customers with imprudently incurred costs that have been recovered.[97] The Commission must provide for that opportunity to meet the requirements of R.C. 4928.143(B)(2)(a).

OEG also pointed out that if the utility must file their excess earnings filing on April 1, and parties only have 30 days to comment, parties would not have the benefit of the most recent FERC Form 1, filed at the end of April, for their comments.[98] OEG suggested a 60 day comment period instead of the 30 day comment period, which the Commission should adopt for the reason given by OEG.

L. Competitive Bidding Process Ongoing Review and Reporting Requirements—4909:1-35-11 (Rule 11)

Duke argued unreasonably that the Commission revise Staff's proposed Rule 11(B)(1) to require offsetting benefits accrued to the utility be "listed separately and be used to **increase** the cost levels requested for recovery.[99] There is no justification that

[96] DP&L Comments at 2.

[97] IEU Comments at 9.

[98] OEG at 4.

[99] Duke Comments at 16.

benefits that accrue to the utility through customer funded resources should increase the recovery a utility get from customers. For this reason, Duke's suggested revision should not be adopted.

OEG noted that Rule 11(B), which allows for the prospective review of how proposed adjustments for costs for fuel, purchased power, portfolio requirements and environmental compliance will affect the utilities return on common equity, does not include a provision that the adjustments must be reduced if the return on common equity will be excessive.[100] Such a provision is required under R.C. 4928.142(D)(4) and OEG's suggested language should be adopted to meet that requirement.

Duke and AEP complained that Rule 11(C)(4) requires utilities to provide certain information in its annual CBP report:

> This information should be provided for generation, transmission and distribution for the electric utility and its affiliates as well as functionalized as to distribution, transmission, and generation activities.[101]

Duke argued that its financial records do not contain the level of detail sufficient to enable it to functionalize various activities.[102] None of the other utilities seem to have a similar problem so it appears that it would not be a difficult problem to overcome.

Additionally, Duke complained that functionalization is directly at odds with the statute. But the statute requires the Commission to compare its earnings to that made by "other publicly traded companies." Each of these functions involves different levels and kinds of risk and it is necessary for the Commission to have the functionalized

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[100] OEG Comments at 8.

[101] Duke Comments at 20; AEP Comments 10.

[102] Duke Comments at 18.

information for comparisons. Duke argues that because the functionalized information is not publicly available the Commission will not be able to use the functionalized information. This assessment is incorrect because there are many companies that engage in only one of the functionalized activities and such companies can provide an appropriate comparison.

AEP argued that 11(C)(4) should be removed because R.C. 4928.142 allows only for prospective earnings reviews and does not allow retrospective earnings reviews.[103] But the Commission cannot conduct a prospective earnings review that involves a comparison of the utilities earnings to comparable businesses if it does not have any idea as to what the utilities are currently earning.

AEP also complained that the requirement under 11(C)(4) should be removed because the utility does not have an obligation to show that it meets the earnings test.[104] Under R.C. 4928.142(D)(4) the General Assembly required:

> The burden of proof for demonstrating that significantly excessive earnings will not occur shall be on the electric distribution company.

Therefore, the utilities must show that they will not have excessive earnings in the future, which is a much more complicated showing than showing that they are not currently making excessive earnings. For that reason, an important and necessary step in making that projection is showing that they do not have excessive earnings currently. The Commission cannot possibly meet its obligations under R.C. 4928.142(D)(4) if it does

[103] AEP Comments at 11.

[104] AEP Comments at 11.

not have the information required under Rule 11(C)(4) and the Commission should not change it or remove it as suggested by the utilities.

OEG asked that the Commission incorporate language that will require the utility to return any excess earned as reflected in the annual report to the customers.[105] Such a provision would provide equity and should be adopted.

DP&L complained that Rule 11(C)(5) allows utilities to file for relief of an emergency situation only at the time of its annual status report. DP&L claimed that waiting for the annual report may not be practical for granting appropriate relief.[106] DP&L did not explain what situations could arise that would require such immediate relief. In any case, under the CBP plans, customers must wait for the annual review to obtain relief from any excess earnings the utilities may be collecting and the utilities that have an opportunity to choose or not choose a CBP plan, should also have to wait for the annual review for any relief that could be deemed necessary.

IEU requested that the Commission incorporate in Rule 11(C)(5) a requirement that the utility has the burden of proof to show that it needs relief due to an emergency situation to reflect R.C. 4928.142(D)(4).[107] Incorporating that language in the rule would be helpful for future reference.

Duke argued nonsensically that the Commission should not adopt the Staff's Rule 11(C)(8) requirement that utilities report in their annual CBP report whether the RTOs market monitoring function has mitigation authority over competitive whole electric

[105] OEG at 5.

[106] DP&L Comments at 4.

[107] IEU Comments at 9.

service market transactions.[108] The purpose of the report is to determine whether the wholesale market is being protected by a market monitor, because if it is, the Commission can expect competitive bids. If the market monitor is not protecting the wholesale market the Commission cannot expect competitive bids.

Duke complained that the Commission has no right to even use the market monitoring function over wholesale markets as a sign whether or not it can expect competitive bids.[109] This is contrary to the direction given by the General Assembly under R.C. 4928.142(B)(2) that a CBP not be permitted if the market monitor is not able to mitigate market power or the electric distribution company's market conduct. For this reason, the Commission should not adopt Duke's revision.

AEP argued that Rule11(C)(8) should be eliminated because it serves no purpose after the MRO is first approved.[110] This requirement will be necessary for the Commission to meet its obligations under R.C. 4928.142(E). The Commission is obliged to alter prospectively the proportions of the blended price "to mitigate any effect of an abrupt or significant change in the electric distribution utility's standard service offer price." In order to make a reasonable judgment when fulfilling this duty, the Commission must have information regarding how the markets are functioning and should be prepared to act quickly if they are failing due to a lack of effective market monitoring. Additionally, the Commission should be prepared to return to the legislature

[108] Duke Comments at 20.

[109] Duke Comments at 20.

[110] AEP Comments at 12.

for a change in the law if markets are failing and rates are not "reasonably priced" as intended by the General Assembly.

Nucor requested that the Commission add language to Rule 11(D)(5) that explicitly states that interested parties can review the report, can conduct discovery on the annual report and can request a hearing on the CBP based upon the report and discovery responses.[111] This would provide due process rights to the customers who must pay the CBP rates and the Commission should grant the request.

III. TRANSMISSION COST RECOVERY – CHAPTER 4901:1-36

Whenever customers are required to pay for costs for receiving electric service the costs must be determined in an open, fair, and transparent manner. This is also true for transmission costs. Even though transmission costs are determined through a FERC approval process the electric utility is still responsible for selecting the lowest cost options[112] and making every effort to assure that transmission costs are as low as possible. These efforts of electric utilities may take the form of participating in the RTO stakeholder process or litigating at FERC for example, the most advantageous allocation for Ohioans of transmission costs (postage stamp vs. license plate). In addition, portions of RTO rates are collected to support the formation of other product markets which may not be relevant to serving Ohio customers. Ohioans should only pay RTO costs that deliver value to them in the form of services necessary for the SSO. Utilities may have to pay more costs than they can pass through to SSO customers.

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[111] Nucor Comments at 11.

[112] *Pike County Light and Power Company-Electric Div. v. Pennsylvania Public*, 77 Pa.Cmwlth. 268, 465 A.2d 735, Pa.Cmwlth. (September 22, 1983).

Before the PUCO, transmission costs must be subject to scrutiny by those who will pay the costs. In the case of residential consumers this means that all interested parties must have access to the same information as staff in order to evaluate the costs, be allowed to conduct discovery, and if the cost issues cannot be reconciled between all parties and the electric utility, evidentiary hearings should be held before the PUCO. Findings of fact and conclusions of law by the PUCO will permit appellate evaluation of the material factors relied upon by the PUCO to charge customers these costs.

OCEA proposed revisions to the transmission cost recovery rules to incorporate this open and transparent process that is designed to satisfy the due process requirements of imposing costs upon customers.

OCEA agrees with Duke that in evaluating transmission costs, the PUCO should be able to hire consultants to assist in the analysis. The revision proposed by Duke to OAC 4901:136-03(C) that such costs of consultants must be paid by the utilities and recovered through the transmission rider is redundant -- although OCEA agrees with the concept.

The rules as proposed by the PUCO deny parties the right to evaluate the request to recover transmission costs, a hearing when recovery is disputed, and basic other rights when costs are assessed against customers -- such as discovery. The electric utilities did not address these issues in any meaningful way, which itself should suggest they are satisfied with rules that eliminate due process rights and rely on the PUCO to determine proper recovery on its own. While the PUCO may be knowledgeable in such matters, OCC and other parties such as OPAE participate in the RTO stakeholder proceedings and in litigation before FERC regarding such issues and can offer valuable insight into the appropriate recovery of transmission costs. In previous transmission cost recovery proceedings OCC has successfully challenged recovery of certain transmission cost by electric utilities. Consumers should not be denied this protective oversight in the future.

IV. CORPORATE SEPARATION – CHAPTER 4901:1-37

The promulgation of correct corporate separation rules is imperative if a competitive electric market is to develop in Ohio. The Corporate Separation rules, as proposed do not accomplish this. The PUCO must ensure that competitors can efficiently and effectively participate in the Ohio markets. If the PUCO does not accomplish this result, it is unlikely that competitors will focus on developing Ohio markets given the significant resources that will need to be expended to establish functioning markets in Ohio.

The assurance of a level playing field for competitors must take into account the competitive advantages electric utilities have historically enjoyed in Ohio. The PUCO's proposed rules accomplish none of these goals and, in fact, OCEA believes the draft rules represent a barrier to competition in Ohio. For example, under proposed rule 4901:1-37-04(A)(1), there is no valid reason to limit the application of structural safeguards to affiliates and utilities that operate within the utilities' service territory. FirstEnergy and Duke, for example, are well known beyond their own service territories. Trading upon the goodwill of the electric utility and failure to appropriately allocate expenses can be just as damaging to customers in another utilities' service territory as it is in its own. Using fully allocated costs, as OCEA pointed out in its Comments, may not be the true measure of the benefit to affiliates of sharing costs with the electric utility. Competitors may not, and usually do not, have affiliates that can share the costs of employees and other resources. This places competitors in an immediate disadvantage – a disadvantage that hurts customers and Ohio markets.

It follows that the records of electric utilities and their affiliates must be open to inspection and evaluation. As proposed the rules appear to limit such evaluation to evaluation by PUCO staff.

OCEA disagrees with DP&L that the corporate separation rules language must be reconciled with other rules. There are reasons various elements of the rules are applicable to specific issues such as corporate separation. For example, the rules for special arrangements are promulgated under specific statutory authority that permits the rate discrimination banned by the corporate separation rules.

OCEA strongly disagrees with the proposed rule and Duke comments regarding an electric utility's compliance with the CAM requirements, SEC, and other reporting requirements establishing a rebuttable presumption of compliance with all corporate separation rules. The utility is in the best position to know what its various filing requirements are and demonstrate that they have been satisfied.

Finally, regarding 4901:1-37-05, OCEA disagrees with Duke that complaints should be made to legal counsel or customer service representatives. The complaints contemplated by the proposed rules pertain to corporate separation issues. To have complaints handled by an employee of the utility is completely inconsistent with all accepted corporate governance practices. The reporting and processing of such complaints is a "check" on management practices and such complaints must be made to the Board of Directors. As is recognized in independent audit, internal audit, ethics, and in RTO market monitoring it simply does not work to have management be the "check" for management. This is and remains the responsibility of the Board of Directors.

V. SPECIAL ARRANGEMENTS – CHAPTER 4901:1-38

A. Definitions – 4901:1-38-01 (Rule 1)

FirstEnergy commented in this section that the Commission should treat delta revenues differently than it has in the past, especially for utilities that do not own their generation.

FirstEnergy argued that all delta revenues should be fully recovered from customers on a current basis.[113] FirstEnergy pointed out that the benefit of special arrangements no longer exists because utilities are no longer building large baseload power stations. FirstEnergy also complained that stand-alone utilities no longer have the financial wherewithal to contribute to delta revenues.[114] To the extent that FirstEnergy garners a steady flow of revenues, relatively risk free, from these customers as a distribution company, FirstEnergy benefits. It also benefits to the extent that its affiliate provides some or all of the generation services to FE customers. Finally, as good corporate citizens, whose first and foremost goal should be to serve its customers, FE should contribute to the community.

FirstEnergy should no more be permitted to avoid delta revenues than customers can. Accordingly, special arrangements should not be permitted unless utilities, whether stand-alone or not pay 50% of all delta revenues.

[113] FE Comments at 26-27.

[114] FE Comments at 26-27.

IEU asked that the Commission delete the definition of "energy efficiency production facility" and references to energy efficiency in Chapter 38 altogether based upon its arguments in Rule 4, below. This request is inappropriate as discussed in the Rule 4 section below and the Commission should not grant the request.

Nucor recommended revising the definition of "Nonfirm electric service" to also include customers who are interrupted for emergency/reliability purposes.[115] The Commission should not make this change. The change would make the term "nonfirm electric service" meaningless because all electric service is curtailed or interrupted on an emergency/reliability basis.

B. Purpose and Scope—4901:1-38-02 (Rule 2)

DP&L argued that energy efficiency programs should not be treated as special arrangements because they are too different from economic development arrangements.[116] Although, the energy efficiency programs should not be taken out of this rule, they are different from economic development arrangements in that they are cost justified because they are cheaper than procuring an energy supply for the demand they replace. Moreover, these programs do not produce delta revenues that need to be subsidized by other customers.

C. Economic Development Schedule—4901:1-38-03 (Rule 3)

DP&L complained that Rule 3 does not define "non-retail purposes" and suggested a definition. However, DP&L did not provide a justification or explanation as

[115] Nucor Comments at 14.

[116] DP&L Comments at 11.

to why the definition is needed or why its definition is appropriate.[117] The Commission should not adopt the definition without better justification.

DP&L suggested modifications to Rule 3(A)(2)(d), which clarifies the kinds of projects that will be eligible for an economic development schedule.[118] These clarifications are appropriate, important and should be adopted:

> The project must have A NEW OR ADDITIONAL fixed asset investment in land, Building, machinery/equipment, and infrastructure AT A SINGLE LOCATION of at least five hundred thousand dollars.

OEG complained about the criteria required for existing customers to obtain an economic development schedule for the retention of existing customers under Rule 3(d) and (e).[119] Rule 3(d) requires that an applicant show that at least 10% of its operational costs are electric costs. OEG believes this requirement is unreasonable and should be removed from the rule.

The 10% rule under Rule 3(d) must be retained to prevent every large customer from threatening to leave the state if they do not get a subsidy on their electric service. The 10% rule is reasonable because a customer will not leave based upon electricity prices unless a large portion of their costs are electricity. Moreover, it is logical to impose this test only on existing customers because the Commission must give customers who are not currently located within the state or are start ups or customers who are investing money in an expansion, a greater incentive than existing customers for economic development purposes. Customers who must move into the state or expand in

[117] DP&L at 11-12.

[118] DP&L at 12.

[119] OEG Comments at 8.

the state are far less likely to chose to move or expand (all else being equal) than are existing customers likely to move out of Ohio.

OEG argued that the 10% test discriminates against existing customers who must pay the subsidy for customers who are new.[120] But the expanded provisions in Rule 3(A) provide existing customers an opportunity to avoid the 10% rule by expanding their operations and qualifying for a discounted rate. Existing customers who are willing to increase the number of employees and make additional investments in Ohio should be rewarded, but they should not be rewarded if they do not provide additional benefits to Ohio and the customers who must pay some portion of the cost.

OEG perceives that the 10% test can be eliminated because Rule 3(B)(2)(e) has an additional test requiring the price of electricity "major factor" in its decision to cease, reduce, or relocate its facilities to an out-of-state site. OEG is incorrect. The proposed "major factor" test is ambiguous and relies solely on the customer's word. Such a subjective test cannot be the only test relied upon to determine whether existing customers should receive subsidies paid for, in part, by other customers.

OEG also suggested that new or expanding customers under Rule 3(A) be subject to a "major factor" test as is existing customers.[121] This suggestion is reasonable. Even though the test is somewhat subjective, requiring potential or expanding customers to describe how the electric rates affect their decisions to expand or to move to Ohio would provide the Commission and other parties information to evaluate both the application

[120] OEG Comments at 7.

[121] OEG Comments at 8.

and give insight as to how economic development programs can best work and bring the most benefits to Ohio for the discount dollar.

Nucor argued that customers who simply increase investment by $500,000 should be eligible for an economic development incentive without having to employ twenty-five new employees are required under the Staff's proposed rule. [122]

IEU argued that the Commission should delete all of the Staff's eligibility requirements because they are inconsistent with flexibility.[123] IEU suggested that the Commission should replace eligibility requirements with allowing each EDU to propose standardized schedules. Through this process the Commission can determine whether it is necessary for the Commission to standardize among utilities. IEU also requested that the rules state that any standardized schedule should not limit the utilities or customer's opportunity to obtain approval for any reasonable arrangement.[124]

A public authority, such as the Commission should take the role of establishing eligibility requirements and standardizing schedules that require small customers to subsidize the rates of larger customers than should a private entity such as a utility. This recommendation is contrary to the purpose of Am. Sub. S.B. 221, as described by Governor Strickland as an "Energy, Jobs and Progress" initiative.[125] Investments in land and assets provide a much less certain benefit to Ohio. While it could lead to increased activity in the community—it also may not. It depends if the customer is buying

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[122] Nucor Comments at 14.

[123] IEU Comments at 14.

[124] IEU Comments at 15.

[125] http://governor.ohio.gov/

everything for that increased investment from Ohio. For that reason, both the employment and investment requirements under Rule 3(A)(2)(b)-(d) should be met to obtain the new or expanding incentive.

Nucor also suggested that customers not be required to remain in business for at least twice the term of the incentives to receive an incentive as required under Rule 3(A)(2)(h). Rather, Nucor states that applicants should only be required to "use commercially reasonable efforts to maintain its operations."[126] The standard recommended by Nucor is too vague to keep customers accountable for the commitment they are supposedly making in exchange for a subsidy. As such, it would allow customers to forum shop each year for the best deal they can get from each state on utility and tax rates. Employing citizens of Ohio for such a limited period and then laying them off brings little if any economic stability to Ohio and accordingly, the Commission should not revise the Staff's proposed rule to limit the commitment to remain in business for at least twice the term of the incentives.

AEP commented that the Ohio Department of Development, the Commission or some other agency in the state of Ohio should "identify and screen potential candidates or projects that should be deemed worthy of the classification as economic development for which other utility customers benefit from and should help pay."[127] AEP expressed concern that the "filtering" criteria in (B)(2) is too ambiguous and may not sufficiently limit the number and size of companies receiving economic development subsidies.[128]

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[126] Nucor Comments at 16.

[127] AEP Comments at 20.

[128] AEP Comments at 20.

The Commission should take heed to this concern. Consumers who must subsidize economic development programs are already strapped with energy bills and their earnings have not kept up with inflation, particularly if they are unemployed or an ex-factory working that is working three jobs and still not making what they made in the factory. Some entity, preferably a public authority that is accountable to the public, must prevent subsidies to large customers who are not providing the employment or investment benefits as a result of economic development subsidies.

Additionally AEP expresses concerns that utilities will not be able to ensure that the commitments made by the customers receiving economic development subsidies are met.[129] AREO also expresses concerns regarding the economic development program and concerns that the related employment and investment commitments will not be enforced.[130] Again, the Commission should not ignore these concerns. Energy costs are simply too high for all sizes of customers to allow these subsidies to flow to customers who are not meeting employment and investment commitments.

Without some kind of tabulation of the ongoing price tag of these subsidies, the cost could be enormous. For example, according to OEG, the cost of the subsidy of recently approved special arrangement with Solaris [sic] is a staggering $52 million over ten years. With the utilities having no obligation to contribute, it is conceivable that there could be a proliferation of these special arrangements—as has occurred in the past—at a high cost to the consumers. The commission needs to be mindful of the tipping point for customers—at what point the total subsidy gets too high for a customer to pay his/her bill and therefore is subject to disconnection. Perhaps the special arrangements should be

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[129] AEP Comments at 21.

[130] AREO Comments at 15.

treated as a line item on customers' bills in the same way PIPP is so that they can see the amount of the subsidy to the businesses.

Additionally, the economic development schedules should not vary, as requested by IEU.[131] Nor should they be filed under seal. Economic development schedules should be easy for the customers who must subsidize the special rates to access and to understand. Special arrangements between customers and the utilities are not private matters due to the subsidy inherent in them. Therefore, all customers who obtain these discounts should be public knowledge, the discount they receive should be publicly available and the commitments the customers offer in exchange for the discounts should public knowledge in order to keep these customers accountable.

D. Energy Efficiency Schedule—4901:1-38-04 (Rule 4)

FirstEnergy and IEU take a far more expansive view of the potential for mercantile customer exemptions from efficiency targets in comments on proposed 4901:1-38-04 than Sub. Am. S.B. 221 allows. First Energy and IEU offer differing advice to the Commission regarding the proposed energy efficiency schedule. The two sets of comments fail to recognize the clear discretion Sub. Am. S.B. 221 confers on the PUCO to craft the mercantile customer exemption to energy efficiency related charges or the broad latitude offered under the draft rules in the provisions for Economic Development Schedules and Unique Arrangements. FirstEnergy stated:

> R.C. 4928.66(C) does not limit the time period for the applicability of energy efficiency programs involving mercantile customers, and expressly provides that "existing" demand response, peak reduction and energy efficiency programs are to be counted.[132]

[131] IEU Comments at 15.

[132] FirstEnergy Comments at 4.

Similarly, IEU stated:

> S.B. 221 contemplates a much broader scope for customer-sited programs by mercantile customers than the proposed rules offer. Perhaps this scope will be appropriately respected in the proposed rules that will be issued under Sections 4928.64, 4928.65, and 4928.66, Revised Code.[133]

These comments fail to appreciate the express grant of discretion that S.B. 221 under R.C. 4928.64 confers upon the PUCO in this area:

> As used in section 4928.64 and 4928.65 of the Revised Code, "alternative energy resource" means an advanced energy resources or renewable energy resource, as defined in section 4928.01 of the Revised Code that has a placed-in service date of January 1, 1998, or after; or a mercantile customer-sited advance energy resource or renewable energy resourced, **whether new or existing, that the mercantile customer commits for integration into the electric distribution utility's demand-response, energy efficiency, or peak demand reduction programs** as provided under division (B)(2)(b) of section 4928.66 of the Revised Code (emphasis added).

The Companies seem also to confuse the language in S.B. 221 regarding recovery of cost for efficiency and demand programs with special arrangements based on energy efficiency investments. The physics of theses two different types of programs are such that demand-response measures, which pre-exist can produce benefits to the utility which may or may not result in savings to customers or delta revenues, while efficiency programs which pre-exist do not change the status quo, and therefore don't provide any change in resource allocation.

S.B. 221 does contain language allowing, but not requiring, the Commission to create an opportunity for some customer sited efficiency improvements to count towards the utility efficiency mandates under R.C. 4928.66. R.C. 4928.66 (A)(2)(c) states that the PUCO *may* exempt mercantile customers from the charges associated with the standard,

[133] IEU Comments at 16.

but does not require the exemptions. This discretion creates several implications. First, if the Commission determines that this exemption is simply unworkable, then the PUCO has the discretion to ignore it. Second, because the Commission has discretion in applying this provision, it may modify the implementation of the provision to ensure real savings occur. The applicable language is clear:

> Any mechanism designed to recover the cost of energy efficiency and peak demand reduction programs under divisions (A)(1)(a) and (b) of this section may exempt mercantile customers that commit their demand-response or other customer-sited capabilities, whether existing or new, for integration into the electric distribution utility's demand-response, energy efficiency, or peak demand reduction programs, if the commission determines that that exemption reasonably encourages such customers to commit those capabilities to those programs.[134]

Again, it is important to emphasis here that the provision of S.B. 221 which forms the basis of this proposed rule is *discretionary* for the PUCO; the Commission *may* exempt mercantile customers from the charges associated with the standard, but the PUCO *must* require utilities to meet the annual savings benchmarks of the standard. Note also that the language states that if the Commission grants the opt-out, it must find that the exemption reasonably encourages the customers to commit those capabilities to the programs. This implies the need for new endeavors that would be dedicated for the purpose of these programs. ORC 4928.66 (A)(1)(a) contains no discretionary language:

> Beginning in 2009, an electric distribution utility shall implement energy efficiency programs that achieve energy savings equivalent to at least three-tenths of one per cent of the total, annual average, and normalized kilowatt-hour sales of the electric distribution utility during the preceding three calendar years to customers in this state. The savings requirement, using such a three-year average, shall increase to an additional five-tenths of one per cent in 2010, seven-tenths of one per cent in 2011, eight-tenths of one

[134] ORC Sec. 4928.66 (A)(2)(c).

> per cent in 2012, nine-tenths of one per cent in 2013, one per cent from 2014 to 2018, and two per cent each year thereafter, achieving a cumulative, annual energy savings in excess of twenty-two per cent by the end of 2025.

A clear distinction exists between these two sections. ORC Sec. 4928.66 (A)(2)(c) confers on the PUCO considerable discretion to allow mercantile customers to avoid efficiency related charges, and allows the PUCO to permit existing efficiency improvements with utility programs. However, the non-discretionary section, ORC 4928.66 (A)(1)(a) requires utilities to meet the mandated savings benchmarks. Again, the PUCO *may* exempt mercantile customers from the charges associated with the standard, but the PUCO *must* require utilities to meet the annual savings benchmarks of the standard.

By their very nature, *existing* efficiency improvements cannot create future savings, and since the PUCO has discretion with regard to one section, and no discretion is associated with regard to the other section, the PUCO must resolve the distinction by barring existing improvements from qualification towards benchmark achievement. Efficiency improvements, existing prior to the effective date of the standard, cannot in any circumstance contribute to future annual savings benchmarks. Enhancements to those improvements may qualify, but the standard should be analogous to the approach recommended for economic development contracts; there must be an increase in efficiency or employment.

Additionally, IEU and Nucor Steel proposed that the one thousand KW limit on customer load in the two forms of Energy Efficiency Schedules is too low.[135] The proposed rules allow Economic Development Schedules and Unique Arrangements, and

[135] IEU Comments at 16-17; Nucor Comments at 18.

provide two avenues to establishment of a Unique Arrangement. We are unclear about the administrative purpose of the distinctions between these four types of Special Arrangements, but do not see any barrier to any reasonable arrangements between utilities and all customers. The proposed language for Unique Arrangements seems to be globally inclusive and may result in extensive subsidies.

Nucor requested that the Commission make similar changes to Rule 4(A) that it did in Rule 3(A). [136] For the same reasons, discussed under the Rule 3 section, the Commission should not grant Nucor's request to allow a customers to benefit from energy efficiency programs with either employing 25 persons or investing $500,000 in assets. The Commission should require applicants for the discount to meet both in order to meet the intent of the law. Additionally, applicants for discounts should be required to commit to maintaining operations for at least twice the term of the incentives.

DP&L's recommendations on energy efficiency special arrangements and the energy efficiency schedules are largely supported, however DP&L's recommendations on penalties for non-achievement of energy efficiency targets do not properly recognize the role of EDU's in monitoring the savings of those private actors offering efficiency savings for EDU targets.

DP&L's suggestion that energy efficiency and special arrangements are different regulatory animals, and should be dealt with in separate rule packages, is well advised.[137] Energy efficiency self-directed programs have a place in these rules, but will be better addressed when the rules regarding energy efficiency standards are developed.

[136] Nucor Comments at 19.

[137] DP&L Comments at 11.

Additionally, DP&L's observation that if a mercantile customer is to provide qualifying energy efficiency to a utility, then the mercantile customer must have proved savings equal to or greater than the required statutory savings, is consistent with S.B. 221.[138] If mercantile customers wish to avoid charges associated with efficiency targets, those mercantile customers must achieve savings on the order of the applicable benchmarks. Since efficiency resource acquisition is parallel to, but not identical to the provision of efficiency benefits to individual customers. The ordinary ratepayer has no specific need to require each individual customer seeking any sort of special arrangement to achieve a specific efficiency target. At the same time, it is the electric utility's responsibility to identify within a proposed special arrangement any delta revenues that might result and the verification program which will ensure the Commission and the public that such recovery is justified.

DP&L also requests more guidance from the PUCO regarding monitoring and verification in the context of self-directed savings achievement.[139] This too makes sense, in coming rule sets it is expected that the PUCO will expand guidance in this area, and we suggest a uniform monitoring and verification procedure, like the International Performance Measurement and Verification Protocol (IPMVP).

However, DP&L's suggestion that EDU's should not be penalized if customer-sited efficiency providers do not achieve promised savings is not consistent with S.B. 221.[140] Utilities are responsible for meeting targets. Mercantile customers can provide a

[138] DP&L Comments at 18.

[139] DP&L Comments at 11.

[140] DP&L Comments at 13.

component of this compliance, but it remains the responsibility of the utility to meet the target. As the utility contracts for energy efficiency savings with the mercantile customer, the utility may impose contractual penalties upon the mercantile customer for failure to provide promised savings – this is a contractual issue, not a regulatory one. The utility must be placed in the position of ensuring the mercantile customer that makes a commitment meets that commitment. This provides a necessary system of checks and balances that ensure compliance without unnecessary regulatory meddling.

IEU requested the Commission to delete this entire Rule 4 because the eligibility requirements are inconsistent with the law.[141] This request has no basis and should be denied.

E. Reporting Requirements—4901:1-38-06 (Rule 6)

DP&L and FirstEnergy argued that it should not have to meet the reporting requirements under Rule 6(E). DP&L and FirstEnergy believe that the Commission is using the utilities as a conduit to ensure that the customer is complying with the economic development arrangement requirements because the Commission does not have jurisdiction over the customer.[142]

DP&L complained that this puts it in an awkward position for ensuring that the customer provides correct information and meets the deadline.[143] The Commission should require the utilities to obtain these reports because utilities have many similar requirements regarding arrangements between themselves and customers such as disconnection of customers etc. under Ohio Adm. Code 4901:1-10 and have always dealt

[141] IEU at 16-17.

[142] DP&L Comments at 14; FE Comments at 32.

[143] DP&L Comments at 14.

with them. Moreover, before an electric utility can pass costs on to other customers, it needs to verify that the pass through is justified. But DP&L makes a good point that it may not be able to ensure that the correct information is provided and that the customers are meeting the deadlines. Accordingly, the Commission should add a provision (C):

> IF A CUSTOMER IS UNABLE TO DEMONSTRATE ON-GOING COMPLIANCE WITH THE SCHEDULE OR UNIQUE ARRANGEMENT OR IF THE CUSTOMER DOES NOT MEET THE REPORTING DEADLINES SET FORTH IN THIS RULE, THE CUSTOMER SHALL NOT RECEIVE THE DISCOUNT IT AUTHORIZED UNDER THIS RULE.

Other techniques can be used to ensure compliance. If a discount is coordinated with other economic development programs, the utility can request that the Ohio Department of Development or other funder to certify compliance with the agreement. To assist the utilities in determining whether a customer is complying with the terms and conditions of its special arrangement, the utilities should post annual notices in local newspapers that the customer is receiving electric service discounts and to retain those discounts the customer must meet certain ongoing employment and investment obligations. The notice should state the employment and investment obligations of the customer and should encourage any individual who believes that the customer is not meeting the commitments, to call the utility at a specified phone number. To implement this provision the Commission should add an additional provision (D):

> A UTILITY THAT HAS SPECIAL ARRANGEMENTS WITH CUSTOMERS UNDER WHICH THE CUSTOMER HAS ONGOING EMPLOYMENT AND INVESTMENT OBLIGATIONS SHALL POST AN ANNUAL NOTICE IN A PAPER THAT IS LOCAL TO THE CUSTOMER'S EMPLOYMENT AND INVESTMENT OBLIGATIONS FOR EACH SUCH CUSTOMER. THE NOTICE SHALL STATE THAT THE CUSTOMER IS RECEIVING A SPECIAL ELECTRICITY RATE IN EXCHANGE FOR COMMITTING TO

> EMPLOY A CERTAIN NUMBER OF INDIVIDUALS AND FOR MAKING A CERTAIN AMOUNT OF LOCAL INVESTMENT. THE NOTICE SHALL STATE THE NUMBER OF EMPLOYEES THE CUSTOMER IS REQUIRED TO MAINTAIN AND THE AMOUNT OF INVESTMENT THE CUSTOMER IS REQUIRED TO MAKE. THE UTILITY SHOULD ALSO CONSULT WITH OTHER ORGANIZATIONS PROVIDING ECONOMIC DEVELOPMENT SUPPORT TO THE CUSTOMER TO ENSURE EMPLOYMENT AND INVESTMENT OBLIGATIONS ARE BEING MET.

F. Level of Incentives—Rule 4901:1-38-07 (Rule 7)

IEU also argued that the Commission should not set the level of incentives that economic development programs can provide and asked that the Commission delete Rule 7(D).[144] IEU complained that limiting the level of incentive permitted to the economic development customers and will "chill the creativity that Ohio must dispatch to accomplish its economic development and retention goals." IEU also recommended that the Commission allow customers to obtain more than one incentive.[145]Again, public authorities should not defer to private actors to set up subsidies for certain customers by other customers. The level of incentive should reflect the benefit the customer can show that it is providing customers. Private parties should not measure that benefit nor should they set incentives based upon their opinion of the benefit. Public parties must be accountable to the customers for this very public program.

The Commission should not complicate the economic development program by allowing customers to obtain more than one subsidy. The program should be clear, simple and easily understood by the customers who must subsidize the discounts.

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[144] IEU Comments at 17.

[145] IEU Comments at 17.

Allowing customers to receive more than one subsidy would make it harder for customers to understand and to track.

Nucor expressed concerns about the protection of proprietary or confidential information that may be posted on the Commission's website in relation to special arrangements under Rule 7(C), which is reasonable.[146] But neither the discount a customers receives under a special arrangement nor the associated commitments made by the customers should be considered proprietary or confidential. Such programs are paid for by the public and the exchanges being made on behalf of the public should be publicly available.

G. Revenue Recovery—Rule 4901:1-38-08 (Rule 8)

Duke recommended that the Commission add an additional paragraph (5) to this rule that provides for the full recovery of the delta revenue through other customers. This is not authorized under Sub. Am. S.B. 221. It is not Commission practice and should not be adopted. Utilities should be required to absorb at least 50% of the delta revenues because utilities benefit from economic development.

In addition, the Commission should be free, and should have a preference for, allocating the delta revenues to the customer class under which the company receiving the benefit is served. The justification for spreading the cost to residential and small business customers has long been that these customers benefit from the investment. While that may be true to some extent, the business suppliers of the company also benefit. For example, a company making automotive interiors benefits when the assembly plant it supplies receives a special contract. In fact, the benefit is more directly

[146] Nucor at 19.

felt by the supplying companies than by the residential customers—unless they happen to be one of the lucky persons to get a job out of the investment.

OEG urged the Commission to allow economic development contracts that result in a cost savings to the utility shareholders and ratepayers, such as interruptible contracts that reduce demand at system peaks.[147] Essentially OEG states that ratepayers will always benefit from when shareholders also benefit via the automatic recovery mechanisms or through the annual excessive earnings provision.[148] OEG's claim is highly speculative and would be very difficult for the Commission to ensure. It also presumes that efficient operation of the system will benefit ratepayers, which may not be true if an ESP is based on a revenue target. Moreover, OEG fails to adequately quantify how money taken out of the pockets of a struggling family for the benefit of an investor, benefits that struggling family. OEG's recommendation should be rejected.

Ormet insisted that the Commission should not provide for the hearing under Rule 8(A) simply on the basis that the utility may not have sufficient interest in the economic development schedule.[149] Ormet's recommendation should not be adopted because it would be contrary to the due process rights of customers who must pay the resulting subsidy. If the Commission sets an economic development schedule for hearing, the customer would be able to intervene to defend the schedule.

H. Failure to Comply—4901:1-38-09 (Rule 9)

DP&L requested that Rule 9(C) be revised to clarify that utilities need not refund customers for the discounts that DP&L fails to recovery from a non-compliant

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[147] OEG Comments at 10.

[148] OEG Comments at 11.

[149] Ormet Comments at 3.

customer.[150] Utilities should have the incentive to collect from defaulting customers. The utilities will not have an incentive if they are not required to reimburse customers the uncollected amounts. If the utility believes that a business is not likely to comply with the provisions of a contract, then it should not enter into the contract. Other customers are not parties to the contract and have no ability to enforce it; they only pay for it. For that reason, Rule 9(C) should not be revised as suggested by DP&L.

FirstEnergy complained that the use of the term “substantially” in front of the word complies in Rule 9(A) should be removed because it creates ambiguity.[151] Public authorities should be held accountable for ensuring that customers receiving discounts actually comply with the special arrangement. A public agency should be more concise about what compliance means and how the utility will be able to collect incentives from non-complying customers.

VI. CONCLUSION

OCEA appreciates the opportunity to reply to comments filed in response to the rules proposed in an Entry dated July 2, 2008. OCEA requests that the Commission carefully consider these comments and the comments of other interested parties in an effort to best implement the provisions contained in S.B. 221.

[150] DP&L Comments at 15.

[151] FE Comments at 34.

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