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FILE

BEFORE THE
PUBLIC UTILITES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company and Columbus Southern Power Company for Authority to Merge and Related Approvals.	:	Case No. 10-2376-EL-UNC
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.	:	Case No. 11-346-EL-SSO Case No. 11-348-EL-SSO
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority	:	Case No. 11-349-EL-AAM Case No. 11-350-EL-AAM
In the Matter of the Application of Columbus Southern Power Company to Amend its Emergency Curtailment Service Riders	:	Case No. 10-343-EL-ATA
In the Matter of the Application of Ohio Power Company to Amend its Emergency Curtailment Service Riders	:	Case No. 10-344-EL-ATA
In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company	:	Case No. 10-2929-EL-UNC
In the Matter of the Application of Columbus Southern Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Ordered Under Ohio Revised Code 4928.144	:	Case No. 11-4920-EL-RDR
In the Matter of the Application of Ohio Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Ordered Under Ohio Revised Code 4928.144	:	Case No. 11-4921-EL-RDR

OHIO POWER COMPANY'S APPLICATION FOR REHEARING

On December 14, 2011, the Commission issued an Opinion and Order in the above-captioned cases (Opinion and Order), modifying and adopting the September 7, 2011 Stipulation and Recommendation (Stipulation). The Opinion and Order, among other things, adopted a modified Electric Security Plan (ESP) for Ohio Power Company (OPCo) and Columbus Southern Power Company (CSP) and approved the proposed merger of CSP and OPCo. In conformance with the modified Stipulation adopted by the Commission, CSP merged into OPCo effective at the end of 2011. Accordingly, OPCo (also referred to as "AEP Ohio") also represents, and is the successor in interest to, the interests of CSP. On that basis, and pursuant to §4903.10, Ohio Rev. Code, and §4901-1-35 (A), OPCo seeks rehearing of the Opinion and Order as further explained below. Specifically, the Opinion and Order is unlawful and unreasonable in the following respects:

MRO TEST/BASE GENERATION RATES

I. The Opinion and Order's modification on pages 31-32 slashing the agreed base generation rate increases in half, based on a finding the proposed ESP to be more favorable in the aggregate than the expected results that would occur under a market rate offer, is unreasonable and unlawful.

    A. The Commission's reliance upon the quantifiable impacts of price alone in the MRO/ESP comparison is unreasonable and unlawful because it conflicts with the requirement of R.C. 4928.143, that, in addition to pricing, all other terms and conditions of the ESP must be considered in the aggregate.

        1. The Commission erred by giving no credit in the ESP/MRO comparison, in the aggregate, to quantifiable non-price benefits of the ESP.

        2. The Commission gave no meaningful credit in the ESP/MRO comparison, in the aggregate, to other less quantifiable, yet clearly beneficial, aspects of the Stipulation ESP.

    B. The Commission's basis for concluding that the quantifiable price-based advantage of an MRO is $325 million is unreasonable and unlawful because it uses the wrong capacity charge and prematurely attributes cost to the ESP for the Turning Point Solar project.

1. Mr. Fortney's calculation did not incorporate the actual capacity pricing that will be charged to CRES providers. The capacity pricing approved by the Commission leads to a reduction in the MRO price advantage as compared to Mr. Fortney's approach.

2. It was improper to include as a factor increasing the pricing-related cost of the ESP, compared to the MRO, of estimated costs associated with the Turning Point Solar project.

C. The Commission unreasonably and unlawfully reduced the Stipulation ESP base generation rates by half. Any downward adjustment must be limited to the minimum amount necessary to achieve balance, in the aggregate, between the ESP and an alternative MRO. Accordingly, there is no rational basis for, and there is no evidence that supports, arbitrarily reducing the Stipulation ESP's proposed base generation rate increases by half.

    1. When the price and non-price quantifiable benefits of the Stipulation are properly considered in the aggregate, the ESP is demonstrably advantageous compared to an MRO, and there is no basis for any reduction in the Stipulation's SSO base generation rate increases.

    2. Even if the Commission's flawed calculation of the value of the pricing and other terms and conditions of the proposed ESP, in the aggregate, were not erroneous, there is still no basis for reducing the stipulation ESP base generation rate increases by half.

D. The incremental impact of each error is significant

GENERATION RESOURCE RIDER (GRR)

II. The Opinion and Order (on pages 39-40) unlawfully expands the statutory criteria applicable to the Generation Resource Rider (GRR), R.C. 4928.143(B)(2)(b) and (c), by diminishing the GRR's purpose as providing a "lifeline in the event that market-based solutions do not emerge" and by holding that projects will not be approved under the GRR unless generation needs "cannot be met through market-based solutions."

CAPACITY SET-ASIDE MODIFICATIONS

III. The Opinion and Order's modification on page 54 of the RPM-priced capacity set-aside level, to "accommodate governmental aggregation," is unreasonable and against the manifest weight of the record.

   A. The modification to accommodate November 2011 ballot initiatives conflicts with the General Assembly's preference for opt-in aggregation.

   B. There is no basis in the record supporting the decision to keep the set-aside level open through the end of 2012 "to accommodate governmental aggregation."

   C. The Commission unreasonably failed to support the aggregation-related modification as being needed to avoid any violation of an important regulatory principle or policy.

IV. To the extent that the Opinion and Order's governmental aggregation modification can be interpreted (as is advocated by Opposing Parties in connection with the revised Detailed Implementation Plan filed by AEP Ohio) as exposing AEP Ohio to indeterminate financial risk during the term of the ESP, the Commission should reverse and/or clarify the modification to avoid that outcome because the Company would otherwise need to exercise its statutory right to withdraw from the modified ESP and the Stipulation.

CORPORATE SEPARATION/ GENERATION DIVESTITURE

V. The Opinion and Order's modification regarding corporate separation on page 61 is unlawful and unreasonable because it is based on an inconsistent application of the law, discriminatory treatment of AEP Ohio, and violation of state policy provisions to encourage competition.

   A. The Opinion and Order is unreasonable and unlawful because it applies the factors to achieve corporate separation and the divestiture of generation assets under R.C. 4928.17 and O.A.C. 4901:1-37 in an inconsistent manner compared to Commission treatment of the same provisions in other cases.

   B. The Opinion and Order's corporate separation modification violates the state policy to ensure effective competition under R.C. 4928.17, 4928.06 and 4928.02(H).

   C. The Opinion and Order is unreasonable and unlawful to the extent it requires AEP Ohio to divest its generation assets and notify PJM of its intention to enter the PJM auction for years 2015-2016 prior to receiving full approval for corporate separation as contemplated in the Stipulation.

A memorandum in support is attached and sets forth the specific grounds supporting the above-listed errors.

Respectfully Submitted,

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MEMORANDUM IN SUPPORT

ARGUMENT

<u>MRO TEST/BASE GENERATION RATES</u>

I. The Opinion and Order's modification on pages 31-32 slashing the agreed base generation rate increases in half, based on a finding the proposed ESP to be more favorable in the aggregate than the expected results that would occur under a market rate offer, is unreasonable and unlawful.

Section 4928.143(C)(1), Revised Code (R.C.), provides, in relevant part, that:

> the commission by order shall approve or modify and approve an application filed under division (A) of [Section 4928.143] 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.)

As a threshold matter, it is important for the Commission to bear in mind certain key features of the MRO test, as reflected in the statutory language quoted above. First, the MRO test includes pricing and non-pricing terms and conditions – it is not focused on rates alone. Second, the test requires analysis to be done "in the aggregate" and not just for one year or one aspect of the proposed ESP. Third, the test should not be considered as a mechanical or cut-and-dry exercise as the comparison is to the expected results under an MRO, which necessarily cannot be known in advance (due both the unknown future market prices and the yet-to-be-determined blending percentages that would apply).

Ironically, the price test component actually makes it more difficult for a utility with lower existing rates to pass the test (due to the constraining impact of the non-market price blending on the MRO side). A utility with lower existing rates and a lower proposed ESP rate can fail the price test while a utility with higher existing rates and higher proposed ESP rates can pass, using the same market price projection and percentage price blending. This aspect of the MRO price test illustrates that the price test component is anachronistic and shows why it should not be relied upon without also examining the second and third steps of the in-the-aggregate MRO test. To be sure, the statutory MRO test must be followed – but the price test component alone cannot drive final results for the in-the-aggregate test.

In the course of its review of the Stipulation and the ESP that the Signatory Parties recommended be adopted, the Commission improperly found that, pursuant to R.C. 4928.143(C)(1), it was necessary to modify the Stipulation in order to make the proposed ESP "more favorable in the aggregate than the expected results that would occur under [an MRO]." (Opinion and Order at 30.) The Commission relied upon Staff witness Fortney's comparison of the pricing of the proposed ESP to the pricing of an alternative MRO, with one revision, in order to reach its conclusion that modifications had to be made to the Stipulation in order to make the proposed ESP more favorable in the aggregate than an MRO. The Commission found, based on the revised Fortney ESP/MRO price comparison, that the proposed ESP is less favorable than an MRO by approximately $325 million. (*Id.* at 31.) The Commission then determined that the disadvantage of the ESP should be remedied by slashing the ESP's proposed SSO base generation rate increases in half. The Commission concluded that with those modifications to the base generation rate increases, the proposed ESP would be quantitatively better than an MRO by $42,453,616. (*Id.* at 32.) In reaching these findings, the Opinion and Order fails to implement the above-described features of the statutory MRO test and is, consequently, unreasonable and unlawful.

There are three fundamental errors in the Commission's decision making with regard to the ESP/MRO comparison and the modifications it made to the proposed ESP, each of which is summarized here and then discussed in greater detail below.

First, the Commission erred by failing to include the quantifiable non-price benefits that the proposed ESP provides in its calculation of the Stipulation's proposed ESP's value compared to the cost of an MRO. The Opinion and Order explicitly recognizes, at page 31, that non-price quantifiable benefits must be considered in order to meet the statutory "in the aggregate" standard but then inexplicably ignores all non-price quantifiable benefits in the course of arriving at its finding that the proposed ESP is less advantageous than an MRO by $325 million. One non-price quantifiable benefit that the proposed ESP provides, but which the Opinion and Order ignores in its calculation of the purported $325 million MRO advantage, is the reduction in the carrying cost for the Phase-in Recovery Rider (PIRR). The nominal value of the carrying cost reductions is $153 million. (AEP Ohio Ex. 4 at Ex. WAA-6.) Other substantial quantifiable non-price benefits result from the Partnership With Ohio (PWO) and Ohio Growth Fund (OGF) initiatives. Together, the PWO and OGF provide nominally an additional $35 million of value through the proposed ESP. (*Id.*) While the Opinion and Order (at 64) recognized that these proposed ESP provisions provide value and should be considered, it failed to give any credit to them in its calculation that the proposed ESP would provide $325 million less value than an MRO. The aggregate nominal value of just the PIRR and PWO/OGF benefits is $188 million.

A second very significant error results from the Opinion and Order's failure to make all of the necessary pricing-related corrections to Mr. Fortney's ESP/MRO pricing comparison. The Commission's adoption of the Stipulation's pricing for capacity (as modified) has a direct impact on the market prices used to develop MRO pricing. Consequently, the capacity pricing approved by the Opinion and Order has an impact on the ESP/MRO comparison. Specifically, Mr. Fortney's analysis assumed that RPM-prices would apply for all capacity made available to competitive suppliers. It did not consider the impact of $255/MW-Day capacity pricing on non-set aside capacity that the Opinion and Order approved. Accordingly, when the Commission relied upon his calculations in its Opinion and Order, it also failed to take into account the effects of the modified Stipulation capacity pricing on the MRO cost estimates. The impact of the $255/MW-Day capacity pricing for non-RPM set aside capacity on the ESP/MRO comparison is that it produces MRO pricing that is higher than what Mr. Fortney calculated using only RPM pricing for all capacity. The result of using the capacity pricing that the Opinion and Order approved is higher MRO prices than what Mr. Fortney had originally estimated. The consequence of using the correct higher MRO prices in the ESP/MRO comparison is that the pricing disadvantage of the ESP, compared to the MRO alternative, is substantially reduced. The result of this error alone is that Mr. Fortney's, and thus the Opinion and Order's, ESP/MRO pricing comparison overstates the purported price advantage of the MRO by $230 million.

Another error that the Opinion and Order makes, regarding ESP/MRO pricing, is inclusion in the ESP pricing of an amount related to the Turning Point Solar project. Because approval of the project is uncertain and the price is not yet finalized, nor approved by this Commission, including a price value for it improperly inflates ESP pricing in the MRO comparison. The impact on ESP pricing of eliminating the amount that the Opinion and Order erroneously included for the TPS project is approximately $33 million.

Separate and apart from the errors in calculating the relative advantage of the ESP over an MRO, a third fundamental flaw in the Commission's Opinion and Order is that the reduction it made to the ESP's proposed base generation rate increases is not rationally related even to the $325 million differential that the Opinion and Order (incorrectly) calculated. By slashing the base generation rate increases in half, the Commission unjustifiably diminished the value of the ESP by over $42 million too much. (*See* Opinion and Order at 31-32.) Indeed, the Commission itself recognized that reducing the stipulated base generation rate increases by half would over-correct any ESP disadvantage by more than $42 million. Thus, even before any corrections are made for the errors discussed above, the Commission, by its own admission, substantially and arbitrarily overshot the $325 million ESP/MRO differential by over $42 million.

If only the most basic corrections are made, *i.e.*, including the values of the PIRR carrying cost reduction ($153 million in favor of the proposed ESP), crediting the value from the PWO and OGF initiatives ($35 million in favor of the proposed ESP), and incorporating the capacity costs established by the Opinion and Order in the MRO pricing (which results in a change of $230 million in favor of the proposed ESP), the resulting difference in value between the proposed ESP and the MRO becomes a $93 million advantage for the ESP. If the pricing impact of including the TPS project in the GRR is eliminated, as it should be, the advantage of the ESP increases to $126 million. If the Commission further properly accounts for the non-quantifiable (but nonetheless important and substantial) benefits of the Stipulated ESP, then it is an even greater net differential in favor of the ESP.

There is no record basis for concluding that the pricing and non-pricing terms and conditions of the proposed ESP, when considered in the aggregate, are less favorable than the expected results of an MRO. There also is no record basis for reducing the Stipulation's proposed SSO base generation rate increases by any amount, let alone by arbitrarily slashing the increases in half. Consequently, the Commission erred by making any reduction to the stipulated SSO base generation rate increases, because, in the aggregate, the quantifiable benefits of the Stipulation's proposed ESP exceed the value of an MRO alternative. On rehearing, the Commission should correct these errors, reverse its decision to reduce the Stipulation's proposed SSO base generation rate increases, and approve the Stipulation's base generation rate increases agreed to by Staff and the other Signatory Parties.

A. The Commission's reliance upon the quantifiable impacts of price alone in the MRO/ESP comparison is unreasonable and unlawful because it conflicts with the requirement of R.C. 4928.143, that, in addition to pricing, all other terms and conditions of the ESP must be considered in the aggregate.

1. The Commission erred by giving no credit in the ESP/MRO comparison, in the aggregate, to quantifiable non-price benefits of the ESP.

R.C. 4928.143 requires the Commission to approve, or modify and approve, a proposed ESP if it finds that the proposed ESP "including its pricing *and all other terms and conditions* . . . is more favorable *in the aggregate* as compared to the expected results that would otherwise apply" under an MRO. (Emphasis added). Thus, the statutory test requires the Commission, in the course of determining whether a proposed ESP is more favorable than an MRO, to include in the assessment the value of all benefits provided by the proposed ESP – both price and non-price features of the ESP. It does not require that the pricing of the proposed ESP, by itself, be more favorable than the pricing that would result from an MRO. Thus, the statute requires the Commission to consider all benefits provided by the proposed ESP, whether the benefits result from pricing or other terms and conditions of the ESP, before making any modifications to the ESP.

The Commission appears to recognize its obligation to consider benefits of non-price terms and conditions before modifying the proposed ESP, at page 31 of the Opinion and Order, where it states:

> While many Signatory Parties *correctly* point out that the numeric price test is only a factor and should not be the sole consideration pursuant to Section 4928.142 [sic], Revised Code, the fact that there is a gap of over $325 million between the proposed ESP and MRO is significant enough that we believe it is necessary to make modifications to the proposed ESP.

(Emphasis added).

Remarkably, after confirming that other, non-price, benefits of the ESP must be considered before making adjustments to the proposed ESP, the Commission nevertheless did not do that. Indeed, it made adjustments totaling $367 million to the stipulated base generations rate increases, $42 million <u>more</u> than the price-related disadvantage of $325 million, without first giving <u>any</u> consideration to the offsetting value of several very substantial quantifiable non-price benefits that the proposed ESP provides.

For example, the Commission found, at page 58 of its Order, that AEP Ohio's concession, as part of the Stipulation, to reduce the carrying charge on deferred fuel expense recovered through the PIRR from a weighted average carrying cost (WACC) rate to a long-term debt rate provides significant value:

> The Commission agrees with the Signatory Parties that the carrying charge on the deferred fuel expenses accrued was established in the ESP1 proceeding. Thus, the 5.34 percent debt carry[ing] charge represents a significant compromise by the Companies as a part of the Stipulation as a package. . . .

AEP Ohio witness Allen provided unrebutted testimony that the nominal value of this "significant compromise" is $153 million. (AEP Ohio Ex. 4 at Ex. WAA-6.) Yet, the Commission gave no credit for the value of this quantified non-price benefit in its calculation that an MRO had a $325 million advantage over the proposed ESP. The failure to reflect the quantified value of this benefit of the ESP in the comparison of the proposed ESP to an MRO in the aggregate was unreasonable and unlawful.

The Commission also found that AEP Ohio's agreement, pursuant to the Stipulation, to provide annual contributions of $3 million and $5 million to the Partnership With Ohio (PWO) and the Ohio Growth Fund (OGF), respectively, are beneficial to low income, residential customers, and will aid in economic development by enhancing economic stability for AEP Ohio's industrial customers. In order to eliminate any uncertainty regarding whether these benefits would flow to customers, the Opinion and Order modified the contingency, included in the Stipulation, that would have made AEP Ohio's commitment to OGF and PWO conditional upon achieving a ten percent return on equity.

AEP Ohio witness Allen calculated that the nominal value of the PWO and OGF commitments were $13 million and $22 million, respectively, or $35 million in total. (*Id.*) There can be no doubt that the PWO and OGF funding reflects substantial and quantifiable dollar value and should be counted on the ESP side of the ledger for the MRO test. Yet, again, the Commission gave no credit for the value of this quantified non-price benefit in its calculation that the MRO had a $325 million advantage over the proposed ESP. The failure to include the quantified value of these benefits of the ESP in the comparison of the proposed ESP to an MRO in the aggregate was unreasonable and unlawful.

The Commission's failure to include the quantified benefits of the PIRR carrying cost charge reduction and the PWO and OGF initiatives in its assessment of the benefits of the proposed ESP, in the aggregate, violated the requirement of § 4928.143(C)(1), Ohio Rev. Code. This departure from the statutory requirement is particularly conspicuous in light of the Commission's recent decision in the Duke Energy Ohio SSO proceeding. *See* Case Nos. 11-3549-EL-SSO, et seq., Opinion and Order, at 46-47 (Nov. 22, 2011). In the Duke Energy Ohio order, at 47, the Commission found, based on Duke witness Wathen's testimony, that, "on a purely mathematical basis, the net present value of the benefits to customers from Duke's ESP is approximately $62 million greater, including the other benefits associated with the Stipulation, than the total value of the alternative MRO." The Commission order cites to Mr. Wathen's Supplemental Testimony, Duke Ex. 22 at 30-31, in support of the Stipulation and Attachment D to the Stipulation. Review of Mr. Wathen's testimony and Attachment D to the Stipulation confirms that the net present value of the benefits to customers from Duke Energy Ohio's ESP that led to the conclusion of a $62 million dollar advantage included the quantifiable <u>non-price</u> impacts of shareholder-funded economic development and weatherization/fuel fund programs.

The Commission's explicit inclusion of Duke Energy Ohio's quantifiable non-price benefits in its MRO test stands in stark and conflicting contrast to the treatment that the Commission provided to similar quantifiable non-price benefits that AEP Ohio's ESP provides. While the Commission's Opinion and Order in the AEP Ohio ESP proceeding agreed, at pages 58 and 64, that the non-price quantifiable benefits of several provisions of AEP Ohio's Stipulation ESP, including substantially reduced carrying costs for the Phase-In Recovery Rider, and shareholder funded economic development (OGF) and low-income assistance (PWO) programs provided real and substantial benefits, the Commission did not include any of those quantifiable benefits in its comparison, at pages 30-32, of the value of AEP Ohio's Stipulation ESP to the value of an alternative MRO . The impact on the ESP/MRO comparison of omitting these items is significant. The Commission provides no rationale why it accorded this diametrically opposed and financially disparate treatment to AEP Ohio compared to Duke Energy Ohio.

Thus, in a decision issued three weeks prior to its Opinion and Order in this proceeding, the Commission properly gave credit in its ESP/MRO comparison, in the aggregate, to both quantifiable and less readily quantifiable non-price benefits provided by the proposed ESP. *Id.* at 46-47. Its failure to do so in the instant proceeding, in light of the statutory requirement to do so and its clear understanding, reflected in its Duke Energy Ohio Order, that it has an obligation to do so, is inexplicable. Such disparate application of the same statute cannot be justified and is unlawful.

On rehearing, the Commission must correct these errors and properly credit the ESP with providing $188 million ($153 million related to the PIRR carrying cost reduction and $35 million related to the PWO and OGF commitments) of quantifiable non-price benefits.

2. The Commission gave no meaningful credit in the ESP/MRO comparison, in the aggregate, to other less quantifiable, yet clearly beneficial, aspects of the Stipulation ESP.

As demonstrated above, the Stipulation's proposed ESP, including its pricing and all other terms and conditions, is quantifiably more favorable, in the aggregate, when compared to an MRO. Consequently, no reduction of the Stipulation's base generation rate increases was appropriate in order to ensure that the proposed ESP is superior to an MRO on a quantitative basis. But even if there were any doubt about the favorability of the proposed ESP, from a purely quantitative standpoint, it would be necessary for the Commission to recognize and give credit to the many less readily quantifiable yet very significant benefits that the Stipulation's ESP provides. However, the Commission gave no meaningful credit in its comparison of the proposed Stipulation ESP to the MRO alternative. Instead, it essentially ignored those other benefits of the ESP.

There are a number of such benefits that the stipulated ESP provides, compared to what an MRO would provide, and they are significant. For example, for those customers (and marketers and suppliers) that want market-based generation prices sooner, rather than later, the ESP provides an earlier transition to fully market-based prices (about three-and-a half years) than would be possible through an MRO, which requires a significantly longer period for the transition (at least five years). Although not so readily quantifiable as other benefits, AEP Ohio's agreement to eliminate POLR charges that, in large part, are nonbypassable, is a significant benefit to customers. In addition, as a result of the Stipulation, shopping customers who return during the new ESP, who waived POLR charges while away, may return at the SSO price, as opposed to being subject to market-based pricing for their SSO service upon return. AEP Ohio's commitment to pursue a distribution decoupling mechanism and alternative customer-sited generation resources are yet additional benefits not achievable through the MRO alternative. Furthermore, under an MRO, future environmental costs would be explicitly recovered from customers, yet this stipulated ESP has no such cost recovery mechanism. In addition, through the Stipulation's fixed non-fuel generation rates, customers will have known rate certainty over the transition period. AEP Ohio, on the other hand, faces the exposure to the risk of cost increases over this period which will have to be managed. (AEP Ohio Ex. 19, at Revised 29.)

The Opinion and Order recites that many of these less readily quantifiable benefits do provide significant value. Order, at 63-65. However, it assigns no meaningful credit to these ESP benefits at the point where it considers modifying the Stipulation, at significant cost to AEP Ohio. In other words, the Commission gives no practical value to these ESP benefits. That failure conflicts with § 4928.143(C)(1)'s directive to take into consideration, in a meaningful and practical way, the benefits of all terms and conditions of the proposed ESP, whether readily quantifiable or not.

B. The Commission's basis for concluding that the quantifiable price-based advantage of an MRO is $325 million is unreasonable and unlawful because it uses the wrong capacity charge and prematurely attributes cost to the ESP for the Turning Point Solar project.

1. Staff witness Fortney's calculation did not incorporate the actual capacity pricing that will be charged to CRES providers. The capacity pricing approved by the Commission leads to a reduction in the MRO price advantage as compared to Mr. Fortney's approach.

The Opinion and Order (at 31) relies upon Staff witness Fortney's calculation of the value of an MRO alternative as the basis for a pricing comparison of the proposed Stipulation ESP to an MRO. The only adjustment to Mr. Fortney's estimate of the cost of the MRO that the Opinion and Order makes is one correction, recommended by FES, that increases the advantage of the MRO, originally calculated by Mr. Fortney to be $276 million, to $325 million. (*Id.* at 31-32.) However, the Opinion and Order did not address or fix Mr. Fortney's incorrect assumption regarding the capacity pricing input to the MRO's market pricing estimate. Specifically, Mr. Fortney utilized only RPM prices for the capacity element of his market price estimates. Whereas, the Opinion and Order adopted the Stipulation's two-tiered capacity discount as the new charges applicable to capacity made available to CRES providers and their shopping customers. (*Id.* at 51-55.) Accordingly, because the price for capacity is an element of the estimated market price for retail generation supplies, and because the capacity prices that Mr. Fortney's analysis used are, on average, lower than the capacity pricing that will be available during the ESP, the estimated market prices that his analysis utilized are understated. Consequently, the $325 million dollar price advantage that the Order determined, which is based in part upon the understated market prices of Mr. Fortney's ESP/MRO comparison, is overstated. Indeed, because of the fundamental error in how Mr. Fortney calculated MRO prices, using incorrect capacity prices, there is no evidentiary basis to support the Order's finding that an MRO would provide a $325 million pricing advantage compared to the proposed ESP. A conservative estimate, based on the record evidence, of the extent to which that error overstates the Opinion and Order's calculation of the MRO's pricing advantage is approximately $230 million.

Rehearing must be granted to correct this error.

2. It was improper to include as a factor increasing the pricing-related cost of the ESP, compared to the MRO, of estimated costs associated with the Turning Point Solar project.

The Opinion and Order (at 30) determined that it is appropriate to include a cost for the Generation Resource Rider, associated with a revenue requirement for the Turning Point Solar (TPS) project, as a quantifiable price-related cost for the proposed ESP. The Opinion and Order states that it is reasonable to include an estimated charge for the GRR related to the TPS project because AEP Ohio has produced a revenue requirement for the TPS project, and it has claimed the TPS project as a benefit of the proposed ESP. This estimated charge, according to Mr. Fortney, amounts to over $33 million.[1] The Commission erred in including this estimated charge in its calculation of the cost of the proposed ESP, however, because any cost recovery the Commission might subsequently authorize under the GRR in the future is speculative and, therefore, should not be included in the MRO Price Test. Moreover, Mr. Fortney's calculations are stale and inaccurate as the current projected cost of the TPS project is not reflected in the record. Moreover, as noted below in discussing Assignment of Error II, the Opinion and Ordwer's extra-statutory "market failure" test (unless modified on rehearing) further jeopardizes future approval of the TPS project. It was improper for the Commission to include a net cost in the MRO test for the TPS project.

[1] *See* Staff Ex. 4 at Ex. A (the line titled "Generation Resource Rider (GRR) Turning Point," calculates that the charges for the TPS project will roughly equal $7.83 million for 2012, $9.57 million for 2013 ($7.83 million + $1.74 million), and $11.31 million for 2014 ($9.57 million + $1.74 million); summing those values and adding $4.71 million for the first five months of 2015 ($11.31 million x 5/12) yields a total charge over the ESP period of $33.42 million).

The GRR is a placeholder until such time as the Commission approves project-specific costs to be included in the rider. (*See* Opinion and Order at 38-40; AEP Ohio Ex. 5 at 15; AEP Ohio Ex. 4 at 4; Tr. IV at 596-597.) The GRR does not presently account for or represent any charges to AEP Ohio's customers. Rather, in order for AEP Ohio to raise revenue necessary for the TPS project through the GRR, the Commission must approve a charge associated with project-specific costs of the TPS program. (Opinion and Order at 39.) Although the Commission correctly notes that AEP Ohio has produced an estimate of the revenue required for the TPS project, (*see id.* at 30,) that estimate is by no means definite. In fact, some of the underlying projected costs have gone down and will be presented to the Commission in a future filing by AEP Ohio. A future proceeding authorizing the charges could be contested and might not result in a charge comparable to that which the Commission has levied upon AEP Ohio through its ESP/MRO comparison. A charge of more than $33 million for a program that has not been approved or even applied for and that does not presently generate any revenue for AEP Ohio is inappropriate and inequitable.

If the cost included for the GRR <u>were</u> appropriate – which it is not – the Commission erred by failing to credit the corresponding benefits of the TPS program in AEP Ohio's favor in its ESP/MRO comparison. The Commission acknowledged that the Turning Point Solar program may be necessary to comply with state solar renewable energy resource requirements because those resources have not be available in competitive markets in sufficient quantities in Ohio to allow electric distribution utilities to comply with those requirements. (*Id.* at 40.) These benefits equal or outweigh the costs of the TPS program – otherwise the Commission would not approve the project. As such, the TPS project would not represent a net cost, but would represent a net credit in AEP Ohio's favor – if the GRR is considered at all in the MRO Price Test.

Lastly, as AEP Ohio witness Thomas noted, the GRR is a nonbypassable rider that AEP Ohio could collect regardless of whether the SSO is established through an ESP or an MRO (AEP Ohio Ex. 5 at 16; Tr. IV at 554.) The inclusion of the estimated charge as a cost of the ESP is inappropriate on this basis as well. The Commission's error in including a speculative cost of the GRR, unmatched by any corresponding credit, warrants rehearing and correction.

C. The Commission unreasonably and unlawfully reduced the Stipulation ESP base generation rates by half. Any downward adjustment must be limited to the minimum amount necessary to achieve balance, in the aggregate, between the ESP and an alternative MRO. Accordingly, there is no rational basis for, and there is no evidence that supports, arbitrarily reducing the Stipulation ESP's proposed base generation rate increases by half.

1. When the price and non-price quantifiable benefits of the Stipulation are properly considered in the aggregate, the ESP is demonstrably advantageous compared to an MRO, and there is no basis for any reduction in the Stipulation's SSO base generation rate increases.

As explained above, the Commission must correct the errors made in calculating the MRO market prices used in the ESP/MRO price comparison by incorporating into them the capacity prices that the Order confirmed are appropriate. The Commission should also correct the ESP pricing that the Order uses in the ESP/MRO price comparison by removing from the GRR component of the ESP rates the speculative estimates of TPS project rate effects. Moreover, the Commission must factor into the comparison, in the aggregate, of the ESP to the MRO, the quantified benefits of the PIRR carrying cost reduction and the PWO and OGF commitments. When just these obvious and necessary corrections are made, there is no doubt that the Stipulation's proposed ESP, including its pricing and all other terms and conditions is more favorable in the aggregate as compared to the expected results of an MRO.

Once these corrections are made it is also obvious that there is no basis for modifying the Stipulation's proposed ESP by reducing the Stipulation's SSO base generation rate increases by any amount, let alone by half. There is no evidentiary basis in the record for making any downward adjustment to the Stipulation's base generation rate increases.

2. Even if the Commission's flawed calculation of the value of the pricing and other terms and conditions of the proposed ESP, in the aggregate, were not erroneous, there is still no basis for reducing the stipulation ESP base generation rate increases by half.

Even if the errors in calculating the relative advantage of the ESP over an MRO are ignored, and it is assumed for the moment that the proposed ESP does have a $325 million disadvantage, the modification to the proposed ESP that the Opinion and Order makes is not rationally related to that amount of disadvantage. The Opinion and Order acknowledges this error, as a practical matter, when it concedes that reducing the proposed base generation rates by one half would produce ESP rate benefits that exceed the purported $325 million ESP disadvantage by over $42 million. Any modification to a proposed ESP based on a finding that the ESP has a disadvantage compared to the MRO alternative must be calibrated so that it remedies the disadvantage. A (valid) conclusion that there is an ESP disadvantage may support a modification that matches the amount of the disadvantage, but it does not authorize a modification that exceeds the value of the disadvantage by over $42 million. By overshooting the mark set by the ESP's purported

$325 million disadvantage by more that $42 million, the Commission exceeded its authority under § 4928.143(C)(1) to make modifications to the proposed ESP.

D. The incremental impact of each error is significant

The incremental impacts on the SSO base generation rate increases of the errors that the Order made are each very substantial. For example, even if the Order had correctly calculated that the proposed ESP resulted in a $325 million disadvantage, compared to an MRO, reducing the base generation rates by half improperly over corrected that disadvantage by $42,453, 616. Accordingly, as shown in the table below, even assuming that the $325 million disadvantage was correct, the base generation rates approved by the Order must be increased by $.0003/kWh in order to eliminate the $42,453,616 over-correction.

Similarly, if only the $37 million of PWO and OGF benefits were properly included in the ESP/MRO comparison and all other errors were left uncorrected (including the $42,453,616 over-correction), the incremental effect would be that the Order's base generation increases should be increased by $.0003/kWh. The incremental impact that would result from correcting the error of omitting the Stipulation's $153 million PIRR carrying cost benefit would be an increase of $.0010/kWh to the Order's base generation rate increases; from correcting the $230 million error related to capacity pricing used in the MRO prices there would be an increase of $.0016/kWh; and from removing the impact of speculative TPS project costs from ESP prices there would be an increase of $.0003/kWh.

These incremental adjustments are shown in tabular form in the following table:

Line		2012 ($/kWh)	2013 ($/kWh)	2014 ($/kWh)
1	Base Rates – Order Page 32	$0.0227	$0.0233	$0.0241
	Increases Needed to Account For:			
2	Removal of Excess MRO Benefit	$0.0003	$0.0003	$0.0003
3	PWO and OGF Benefit	$0.0003	$0.0003	$0.0003
4	PIRR Carrying Charge Benefit	$0.0010	$0.0010	$0.0010
5	Recognition of Capacity Charge	$0.0016	$0.0016	$0.0016
6	Removal of Turning Point Solar Cost	$0.0003	$0.0003	$0.0003

On rehearing, the Commission should adopt one or more of the adjustments reflected above in lines 2-6 of the table, in order to correct some or all of the MRO test errors made in the Opinion and Order.

GENERATION RESOURCE RIDER (GRR)

II. The Opinion and Order (on pages 39-40) unlawfully expands the statutory criteria applicable to the Generation Resource Rider (GRR), R.C. 4928.143(B)(2)(b) and (c), by diminishing the GRR's purpose as providing a "lifeline in the event that market-based solutions do not emerge" and by holding that projects will not be approved under the GRR unless generation needs "cannot be met through market-based solutions."

Paragraph IV.1.d of the Stipulation provides that AEP shall establish a nonbypassable rider, Generation Resource Rider (GRR), which shall act as a place-holder until such time as the Commission approves any project-specific costs to be included in the GRR. When seeking authorization from the Commission for cost recovery through the GRR, AEP Ohio must demonstrate how the proposed project satisfies all applicable requirements set forth in R.C. 4928.143(B)(2). Subject to resolution of a workable procedural schedule that will not endanger the viability of the project, the issues relating to a nonbypassable charge for the life of the Turning Point solar project will be moved into another docket. The Company agrees during the term of the ESP to only pursue approval of the Turning Point project and the MR 6 shale gas project under the GRR. The Signatory Parties agreed that any nonbypassable surcharge approved by the Commission for inclusion in the GRR shall reflect the net cost of the facility, including fuel and operating and maintenance costs, associated with the facility. While the Commission adopted the GRR as an empty rider as provided in the Stipulation, the additional language set forth in the Opinion and Order substantively and adversely modified the GRR.

In particular, the Opinion and Order states (at 39) that the Commission "will first look to the market to build needed capacity" and characterizes the GRR as a "lifeline in the event that market-based solutions do not emerge for this state's generation needs." The Opinion and Order goes on to state that new projects under the GRR "will only be authorized when generation needs cannot be met through the competitive market." *See also* Opinion and Order at 40 (regarding the "need" determination, AEP Ohio will have to demonstrate that the proposed GRR projects are necessary to meet policy directives and that the policy mandates cannot be met through market-based solutions"). These statements unlawfully alter the controlling statutory language and improperly prejudge future requests under the GRR.

Ironically, the Commission dismissed IEU's and FES's concerns about the GRR as being premature, while the Opinion and Order simultaneously creates this "market failure" test as an advisory pre-judgment of future GRR rider filings. It is completely unnecessary for the Commission to pre-judge future GRR filings, since the Stipulation opponents do not have the ability to appeal and challenge adoption of a zero dollar placeholder GRR; there is no concrete harm to their interests. Rather, the Stipulation opponents have to wait until such time, if any, that a future decision by the Commission authorizes a non-zero rate for inclusion in the GRR. Under Paragraph IV.1.d (page 6) of the Stipulation, all parties (not just the Signatory Parties) reserved their rights to contest or otherwise take positions in the separate future cases that will determine whether to establish a nonbypassable charge and the appropriate level of the charge through the GRR. Specifically, the Stipulation's GRR provision specifies that establishment of the GRR does not constitute precedent for purposes of interpreting and applying R.C. 4928.143(B)(2)(b) and (c), and parties reserve their right to contest or otherwise take positions in the separate future cases that will determine whether to establish a nonbypassable charge and the appropriate level of the charge through the GRR. Thus, it was simply premature and wholly unnecessary for the Commission to add a non-statutory "market failure" test to the list of criteria for approval of a nonbypassable charge for the life of the facility.

More importantly, because the Opinion and Order's "market failure" test has no basis in R.C. 4928.143(B)(2)(b) and (c), the decision unlawfully modifies the controlling statutory standard. The General Assembly explicitly created the option of approving a nonbypassable charge for the life of a generation facility owned or operated by an electric distribution utility; by design, this option is not available to competitive market providers and is not conditioned on any shortcoming or failure in the merchant generation market. AEP Ohio respectfully suggested that the Opinion and Order's preference for a market option as part of a regulated ESP plan is a misnomer and lacks any basis in the controlling statute. Thus, accepting the GRR as part of the modified ESP only to impose extra-statutory conditions, contravenes the purpose and, indeed, emasculates the very purpose and intent of R.C. 4928.143(B)(2)(b) and (c).

As a practical matter, the prospect of imposing a "market failure" test on top of the criteria that are already included in the statute will serve to undermine AEP Ohio successful pursuit of these potentially beneficial projects and prejudges the merits of a future case. As a related matter, the Opinion and Order simultaneously provides additional fodder and encouragement to parties who will already be inclined to oppose the GRR projects. Contrary to the Opinion and Order's stated concern about fulfilling state policy, the non-statutory "market failure" condition created by the Opinion and Order also fails to recognize the purpose and effect of GRR – which itself promotes state policy.

OEG witness Baron testified in support of the GRR, noting the valuable hedging strategy that the GRR can serve for industrial customers:

> Allowing for recovery of the costs of new generation plants dedicated to serving Ohio customers encourages the construction of new plants in Ohio that can: 1) enhance the reliability of the electric system; and 2) provide a cost-based hedge against fluctuations in market prices. In contrast with a reliance on 100% market pricing for energy and capacity, a cost-based hedge would provide customers a blended rate that is mostly market but also part cost of service. While 100% market pricing is currently attractive, in years past that was not the case. Properly designed, a cost-based hedge can be a risk mitigation tool for consumers. Further, such costs would still be subject to Commission review and approval under R.C. 4928.143(B)(2)(b) and (c).

(OEG Ex. 1 at 12-13.) In addition to the testimony of OEG witness Baron supporting use of the GRR as a "cost hedge" against market rates in order to promote rate stability, the testimonies of AEP Ohio witnesses Hamrock and Allen showed that the GRR was necessary and beneficial in pursuing the Ohio shale gas development in connection with

MR 6 and for a large solar development in Ohio in connection with the Turning Point project.

As Staff witness Fortney testified, one of the biggest potential benefits of the Stipulation that should weigh heavily in favor of adopting the Stipulation is related to the GRR:

> I believe that probably the biggest unquantifiable [benefit of the ESP] is the MR6, building a plant that uses natural gas, building a plant that uses exclusively Ohio shale natural gas is a benefit that *is in line with what I understand to be the state policy*, but I do not believe that anyone can possibly quantify the economic benefits of that provision.

Tr. X at 1752 (emphasis added). Thus, the GRR has the potential to advance state policy by providing rate stability and further promote economic development in AEP Ohio's service territory.

While the Opinion and Order generally references state policy in R.C. 4928.02 in the context of saying that AEP Ohio (at page 40) will have to prove that state policies cannot be met through market-based solutions, the reality is that the policies in R.C. 4928.02 contain subtending assumptions and guiding goals which often cannot all simultaneously be satisfied through a single regulatory decision. In any case, AEP Ohio should not be required to file its GRR filings with the deck already stacked against approval. Rather, AEP Ohio should be given a clear slate in the future GRR cases to demonstrate that the proposed projects advance state policies.

Without such a negative presumption being employed at the outset, it is certainly possible that the Commission might end up making a finding (based on evidence of record in the future case that has been admitted after providing due process to all litigants) that a GRR project advances the state policy goal to ensure reasonably priced retail electric service [R.C. 4928.02(A)] by providing a stable "cost-based hedge" against market prices, or the policy goal to facilitate the effectiveness in the global economy [R.C. 4928.02(N)] by creating jobs and tax revenue through a substantial capital investment in Ohio. From the General Assembly's stand point, these policies should at least be on equal footing with the unidentified policy that was contemplated on page 40 of the Opinion and Order.

In order to avoid prejudging future GRR filings and to conform the Opinion and Order's adopted GRR to the controlling statute, R.C. 4928.143(B)(2)(b) and (c), the Commission should eliminate the "market failure" test criteria on rehearing. Absent that correction on rehearing, the Opinion and Order could undermine the projects that Staff viewed as being the potential beneficial and which all Signatory Parties understood would be pursued (but not necessarily approved) under the GRR. That would be particularly unfortunate given that it is completely unnecessary to address the opponent's premature concerns about the GRR.

CAPACITY SET-ASIDE MODIFICATIONS

III. The Opinion and Order's modification on page 54 of the RPM-priced capacity set-aside level, to "accommodate governmental aggregation," is unreasonable and against the manifest weight of the record.

As set forth below in greater detail, there are three major flaws in the Commission's aggregation-related modification of the capacity set-aside.

First, upon review of R.C. Chapter 4928, it is obvious that the General Assembly favors *customer choice, not governmental choice.* In this context, the concern that the Stipulation will unduly burden governmental opt-out aggregation is unwarranted. The unmodified Stipulation fully accommodates customer choice (including opt-in aggregation) and reasonably accommodates governmental choice (including opt-out aggregation). Consequently, there was no legal justification or support for the Commission to go out of its way in the Opinion and Order to specifically protect and preserve opt-out aggregation without due regard to the substantial cost to AEP Ohio and related financial uncertainty cause by the modification. On rehearing, the Commission should eliminate the aggregation-related modification of the Stipulation found on page 54 of the Opinion and Order.

Second, there is no basis in the record supporting the decision to keep the set-aside level open through the end of 2012 "to accommodate governmental aggregation." It was unreasonable and without basis in the evidentiary record to hold the set-aside open until the end of 2012. The concerns addressed in the record only support a brief extension of the deadline for a few weeks or possibly a month or two – not an entire year. Consequently, if the Commission does not eliminate the aggregation-related modification on rehearing, it should at least reduce the extension to a more realistic time period supported by record evidence – ranging from two additional weeks to two additional months from January 1, 2012.

Third, under the three-part test applicable to adoption of the Stipulation, the modifications ordered by the Commission should be justified as being needed in order to avoid the violation of an important regulatory principle or policy. Thus, in making the modification, the Commission should have linked the modification to a particular regulatory practice or principle and narrowly tailored its modification to being only that which was needed to avoid the perceived violation. Because the Commission did not do so and because the Stipulation's set-aside provisions already advance state policy, the aggregation-related modification should be eliminated.

A. The modification to accommodate November 2011 ballot initiatives conflicts with the General Assembly's preference for opt-in aggregation.

As between opt-out and opt-in aggregation, the General Assembly has clearly expressed its skepticism for opt-out aggregation – through a careful and deliberate set of statutory requirements. First, R.C. 4928.20(A) prohibits mercantile customers from being subjected to opt-out aggregation, providing that "aggregation of mercantile customers *shall occur only with the prior, affirmative consent* of each such person owning, occupying, controlling, or using an electric load center proposed to be aggregated." (Emphasis added.) Second, R.C. 4928.20(B) requires that an initiative must be placed on the ballot and passed by a majority of the electors before any opt-out aggregation proposal can be pursued. Third, R.C. 4928.20(D) prohibits any opt-out governmental aggregation plan unless it "in advance clearly discloses" to customers that they "will be enrolled automatically in the aggregation program and will remain so enrolled unless the person affirmatively elects by a state procedure not to be so enrolled." Fourth, R.C. 4928.20(D) requires an opt-out aggregation program to give customers an opportunity to leave the program every three years without paying a switching fee.[2] Fifth, in order to ensure that voters can terminate an opt-out aggregation after problems develop, the General Assembly enacted R.C. 4928.20(E)(2) to make clear that an opt-out aggregation program authorized by a majority of electors is subject to referendum on a

[2] For example, FES witness Banks testified that exit fees could be as much as $150 for leaving the aggregation. (Tr. VII at 1261.)

going-forward basis. Sixth, the preference for customer choice is evident from the creation of the "Do Not Aggregate" list under R.C. 4928.21.

By stark contrast to all of these restrictions and prohibitions that apply to opt-out aggregation, the General Assembly has made it simple and easy to pursue a governmental aggregation that allows customers to choose to participate by opting in. The main requirement is that an ordinance be passed after notice and two public readings, per R.C. 4928.20(C). This deliberate and obvious difference in the structure of R.C. Chapter 4928 shows the General Assembly's preference for opt-in aggregation and its concerns about opt-out programs – a view that is shared by regulators in other states. (Tr. VII at 1275.) The Commission should have made its decision to approve the capacity set-aside provisions without regard to promoting opt-out aggregation at all costs.

Under the unmodified Stipulation, there was a specific residential set-aside for shopping (including aggregation shopping) that occurred during the four month period prior to January 2012. (Signatory Parties Ex. 2 at 5.) Opt-in aggregation has always been available, not only prior to the Stipulation being signed (September 7, 2011), but was also feasible to pursue even if it was initiated after the Stipulation was filed. It would be an easy matter after September 7, 2011 to pass a resolution and sign a contract to implement opt-in aggregation – with weeks or months to spare – in order to lock up the available RPM-priced capacity. If communities followed the favored opt-in approach, there would have been no time crisis for completing aggregation. Even the opt-out aggregation could have been accomplished prior to January 2012 and, in any case, has been available as an option for years (the timeline for opt-out aggregation is separately discussed below).

Instead of acknowledging the potential for opt-in aggregation fostered by the unmodified Stipulation, the aggregation-related modification made in the Opinion and Order focuses on the November 2011 ballot initiative communities – all of which necessarily relate to opt-out aggregation. It is inexplicable why the Opinion and Order was focused on opt-out aggregation when it is the form of aggregation disfavored by the General Assembly. Even FES witness Banks acknowledged that major regulatory concerns have been enforced by the Pennsylvania Commission regarding FES's opt-out aggregation activity. As testified to by FES witness Banks:

> We had several petitioners object to our activity in pursuing opt-out municipal aggregation and the Commission considered those petitions and decided that at that point in time we should not further pursue opt-out municipal aggregation until such time as the Commission would complete its investigation into competitive markets in Pennsylvania....

(Tr. VII at 1275.) AEP Ohio witness Allen also testified that AEP Ohio has seen a number of customers objecting to being switched under opt-out programs – nearly 10,000 complaints so far in 2011. (Tr. XII at 2145.) AEP Ohio is not suggesting that opt-out aggregation needs to be suspended in Ohio as it has been in neighboring Pennsylvania. But there is no reason the Commission needs to implement extreme measures such as modifying the Stipulation, in order to guarantee success for opt-out aggregation – especially in light of the General Assembly's preference for opt-in aggregation, which was fully accommodated by the Stipulation.

Finally in this regard, the often-cited provision in R.C. 4938.20(K) does not help the Commission justify the aggregation-related modification, as that statutory provision only directs the Commission to promote large-scale aggregation in the form of adopting rules. It has no bearing on deciding an adjudicatory case such as the present context. As a related matter, the notion of rules promoting aggregation is not articulated as a state policy like the matters set forth in R.C. 4928.02. Moreover, as referenced above, any goal of promoting aggregation should not be interpreted to apply to opt-out aggregation (as was done by the Commission here), since the General Assembly has articulated its disfavor for that form of aggregation in the same statutory provision. Thus, R.C. 4928.20(K) has no application here. In any case, R.C. 4928.20(K) certainly cannot be read to specifically promote opt-out aggregation as the Opinion and Order's aggregation-related modification does.

B. There is no basis in the record supporting the decision to keep the set-aside level open through the end of 2012 "to accommodate governmental aggregation."

As referenced above, the Opinion and Order (at 54) directed AEP Ohio to adjust the RPM-priced capacity set-aside level to accommodate aggregation load for the November 2011 ballot initiative communities, provided that the process to take service under the resulting aggregation program in completed by December 31, 2012. It was unreasonable and without basis in the evidentiary record to hold the set-aside open until the end of 2012. The concerns addressed in the record only support a brief extension of the deadline for a few weeks or months – not an entire year.

FES argued on brief (at 118) that there was not enough time to complete the process for opt-out aggregation prior to January 1, 2012. Apparently, the Commission gave credence to that unsupported position through the modification adding a full 12-month extension. But rather than tailor a remedy to accommodate the incremental delay that might be given to complete the opt-out aggregation process, the Commission adopted an over-reaching and unreasonable remedy of extending the deadline for a full year. There is no record basis for extending the deadline by a full year.

FES, whose championing of opt-out aggregation appears to be the basis for the Opinion and Order's year-long extension, only advocated for consideration of a 3-4 month process after the election for completing opt-out aggregation. Specifically, in his testimony, FES witness Banks testified (after representing himself a being knowledgeable about the aggregation process) that it only takes 3-4 months after the election to enroll customers in an opt-out aggregation program. (FES Ex. 1 at 33; Tr. VII at 1265.) It is worth noting that FES's advocated time frame exceeds the estimate given by Constellation witness Fein who estimated that it would be a 2-4 month process to enroll customers after passage of the enabling legislation. (Tr. VI at 994-995.) Under Mr. Fein's estimate, the January 1 deadline would only need to be extended as little as two weeks until mid-January. But even accepting FES witness Banks' more generous portrayal of the time needed to complete opt-out aggregation, that estimate would only justify a delay from January 1 of 6-10 weeks – to either mid-February or mid-March 2012. Indeed, relying on this same evidence of record, FES explicitly suggested that customers in communities that adopted November 2011 ballot initiatives for opt-out aggregation could likely join the queue in February or March 2012. (FES Brief at 118.)

In any case, there simply is no record basis for the Opinion and Order's extension of a full year which is an extra 46-50 weeks, or up to 350 days longer than the deadline supported by evidence of record. The Opinion and Order's over-reaching remedy is particularly inappropriate given the resulting financial impact and uncertainty inflicted on AEP Ohio. Consequently, if the Commission does not eliminate the aggregation-related modification on rehearing, it should at least reduce the extension to a more realistic time period supported by record evidence – ranging from two additional weeks to two additional months from January 1, 2012.

C. The Commission unreasonably failed to support the aggregation-related modification as being needed to avoid any violation of an important regulatory principle or policy.

Under the three-part test applicable to adoption of the Stipulation, the modifications ordered by the Commission should be justified as being needed in order to avoid the violation of an important regulatory principle or policy. The Opinion and Order (at 26-27) explicitly recognized that the three-part test governed its consideration of the reasonableness of the proposed Stipulation terms. And this aggregation-related modification was made in the section of the Opinion and Order that applies the test's second prong regarding violation of important regulatory principles or practices. Thus, in making the modification, the Commission should have linked the modification to a particular regulatory practice or principle and narrowly tailored its modification to being only that which was needed to avoid the perceived violation. Because the Commission did not do so and because the Stipulation's set-aside provisions already advance state policy, the aggregation-related modification should be eliminated.

Specifically, by adopting cost-based capacity charges available to all providers that rely on AEP Ohio's capacity in providing competitive retail generation services, the policy of ensuring nondiscriminatory retail rates [R.C. 4928.02(A)] and the policy of avoiding anticompetitive subsidies [R.C. 4928.02(H)] are both advanced. Further, AEP Ohio's agreement to provide all of the generation capacity needed to support up to 100% retail shopping as an alternative to the default standard service offer and its agreement to fully resolve the substantial litigation pending before the FERC and the PUCO regarding capacity charges, also helps fulfill the policy of ensuring the availability of unbundled and comparable retail electric service [R.C. 4928.02(B)]. Perhaps most obvious of all, the policy of ensuring supplier diversity and giving customers effective choices [R.C. 4928.02(C)] is advanced by the Stipulation's two-tiered capacity discount.

The Stipulation's unmodified RPM set aside levels foster considerable potential for the expansion of competitive market-based rates for significant retail loads within AEP Ohio's service territory. As the record evidence demonstrated, the 2012 set aside of 21% of AEP Ohio total retail load is approximately 10,000 GWh, which is roughly equal to the entire 2010 load of Toledo Edison Company. The potential 2013 set aside of 31% of AEP Ohio total retail load is approximately 15,000 GWh, which is roughly equal to the entire 2010 load of Dayton Power & Light Company. And the 2014-2015 set aside of 41% of AEP Ohio total retail load is approximately 20,000 GWh, which is roughly equal to the entire 2010 load of Duke Energy-Ohio. (AEP Ohio Ex. 7 at 12-13.)

As demonstrated, the unmodified RPM-priced capacity set-aside already advances state policy; thus, it cannot be held to violate any important policy or principle. And because the Commission did not make a finding supporting the notion that the unmodified capacity set-aside provisions somehow violated an important regulatory policy or principle, the Opinion and Order's modification was unsupported and unreasonable. Therefore, the aggregation-related modification should be eliminated on rehearing.

IV. To the extent that the Opinion and Order's governmental aggregation modification can be interpreted (as is advocated by Opposing Parties in connection with the revised Detailed Implementation Plan filed by AEP Ohio) as exposing AEP Ohio to indeterminate financial risk during the term of the ESP, the Commission should reverse and/or clarify the modification to avoid that outcome because the Company would otherwise need to exercise its statutory right to withdraw from the modified ESP and the Stipulation.

While AEP Ohio disagrees with the aggregation-related modification of the Stipulation's RPM-priced capacity set-aside provisions, AEP Ohio believes the Opinion and Order was clear in making the modification. In order to implement the Opinion and Order's aggregation-related modification while reserving its right to challenge modification on rehearing, AEP Ohio made a compliance filing on December 29, 2011 to implement the necessary changes through a revised Detailed Implementation Plan (Revised DIP) in association with Appendix C of the Stipulation. AEP Ohio voluntarily filed the Revised DIP in order to help clarify application of the Opinion and Order's modifications affecting the Stipulation's RPM-priced set aside and the Company did so only after soliciting comments from all interested parties. In response to the Revised DIP, the Stipulation opponents filed arguments that advance a variety of different interpretations and ambiguities in connection with the aggregation-related modification.[3] To the extent that any of these alternative interpretations do actually reflect the Commission's intention, AEP Ohio needs to know up front in order to make an informed

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3 Specifically in this regard, on December 30, 2011, IEU filed a motion and request for expedited ruling asking that the Commission direct AEP Ohio to order further modifications to the Revised DIP, based on allegations that it does not conform to the Opinion and Order. Also on December 30, 2011, FES filed objections to the Revised DIP asking that the Commission provide additional clarity on what FES asserted to be the Opinion and Order's intended aggregation-related modification.

decision whether to withdraw from the modified ESP under R.C. 4928.143(C)(2) and under Paragraph VI of the Stipulation.

In its December 30 filing, FES identifies (at 3-4) four aspects of the Revised DIP that it believes are inconsistent with the Opinion and Order. IEU's December 30 filing alleged (at 8-9) three similar and overlapping conflicts. As described below, none of the features of the Revised DIP criticized by FES and IEU actually conflict with the Opinion and Order. AEP Ohio's Revised DIP is based on a straightforward reading and application of the Opinion and Order and the changes advocated by FES and IEU should be rejected as being based on a selective and awkward reading of the decision. In any case, if the Commission did intend some of the alternative interpretations and clarifications advocated by FES and IEU, AEP Ohio would like to get clarification now to make a timely decision as to whether to withdraw from the Stipulation/ESP.

FES's first alleged conflict is that Section 4(a) of the Revised DIP improperly establishes an initial 2012 RPM set aside for residential and industrial customers below 21%, because "industrial and residential customers should receive their full 21% allotment regardless of what happens with the commercial class." IEU's filing does not share this concern of FES and no other party – opposing or supporting the Stipulation – has endorsed FES's interpretation in this regard. The reality is that FES's argument attempts to impose an additional modification of the Stipulation beyond the modification made in the Opinion and Order regarding the *pro rata* allocation.

Paragraph IV.2.b.3 of the Stipulation provides that the initial RPM-priced set aside allocation for each class will be established pursuant to Appendix C. The original DIP filed under the terms of Appendix C provided in Par. 4(a) that if the allotment to any customer class as of September 7, 2011 exceeds 21%, then the allocation to the remaining classes shall be reduced on a pro rata basis such that the total allotment does not exceed 21%. This provision was not modified by the Opinion and Order. Rather, the Opinion and Order (at 55) explicitly modified Paragraph IV.2.b.3's provision that as of January 2012 "any kWhs of RPM-priced capacity that have not been consumed by a customer class will be available for customers in any customer class based on the priority set forth in Appendix C." FES ignores the fact that the Opinion and Order explicitly quoted the above language which only involves the reversion to other classes of unused capacity allotments as of January 2012 – it does not relate to the initial calculation of the classes' set-aside. As the evidentiary record abundantly made clear and discussed, the initial set-aside for the residential and industrial classes was slightly lower than 21% for 2012 because of the pre-existing oversubscription of the commercial class as of September 7, 2011 (the date the Stipulation was executed).

The Opinion and Order's modification (at 55) explicitly changed the January 2012 reversion of capacity set-aside "to ensure that residential customers are not foreclosed from their share of the capacity at RPM rates." The modification did not go back to modify the initial allocation among the classes based on September 7, 2011 data. Expanding the initial set-aside to 21% for residential and industrial classes would exceed the overall limit of 21% -- this would be a material and costly modification that goes beyond anything discussed in the Opinion and Order.

FES's second alleged conflict between the Revised DIP and the Opinion and Order is (at 3) that "the governmental aggregation load should be additive to any pro rata allotment provided to residential or commercial customers." IEU takes a similar position (at 9) that the Revised DIP improperly treats customers served through a governmental aggregation program as first in the queue for the RPM set-aside capacity. In other words, FES and IEU believe that the governmental aggregation load for 2012 must be provided in addition to the 21% level established in the Stipulation for residential and commercial classes and cannot be included as part of the 21%, regardless of what shopping beyond aggregation may occur in those classes and when the shopping occurs. Those positions ignore the language deliberately used by the Commission in modifying the RPM-priced set aside level.

FES is wrong in claiming that the aggregation load cannot be included as part of the 21%, as there is no basis in the Opinion and Order to support the interpretation that the Commission intended to hard-wire the RPM set-aside to be "21% plus all aggregation load" in 2012. Rather, the Commission ordered (at 54) modification of the 2012 set-aside limitation "to accommodate" the load of any community that approved a governmental aggregation program in the November 8, 2011, election, provided that the aggregation programs complete the steps necessary to take service under the program in 2012. Similarly, the Commission (at 54) provided that the RPM set-aside level "shall be adjusted to accommodate such governmental aggregation programs for each subsequent year of the Stipulated ESP, *to the extent, and only, if necessary*." (Emphasis added.) The interpretation submitted by FES and IEU ignores the key qualification that the modification to the set-aside level be made to "accommodate" the actual aggregation load that meets the specified conditions and the set-aside levels be modified "to the extent, and only, if necessary." Thus, the Stipulation's set-aside level should only be expanded to the extent necessary to accommodate the December 31, 2012 completed governmental aggregation load. This concept is already captured in the Revised DIP.

Another conflict alleged by FES (at 4, labeled "d" in its list) is that the Revised DIP improperly limits the set-aside modification to only communities that passed ordinances during the November 2011 election. FES elaborates (at 4) that the Commission broadly modified the set-aside levels to accommodate governmental aggregation and did not provide any rational basis to distinguish between November 2011 ballot communities and others that have already completed the process. IEU (at 9) takes a similar position, arguing that completing the process by December 31, 2012 is the only condition in this regard. Contrary to these claims, the Opinion and Order clearly does tailor its set-aside modification to November 2011 ballot communities. The arguments advanced by FES and IEU plainly constitute rehearing requests seeking modification of the Opinion and Order rather than implementation of the existing decision.

The Opinion and Order explained the modification to the RPM set-aside:

> Although currently shopping customers will not be adversely affected by the capacity set-aside provisions, the Commission is greatly *concerned that governmental aggregations approved by communities across the state in the November 2011 election will be foreclosed from participation* by the September 7, 2011 Stipulation. It is the state policy to ensure the availability of unbundled and comparable retail electric service to all customer classes, including residential customers, and governmental aggregation programs have proven to be the most likely means to get substantial numbers of residential customers to become the customer of a CRES provider. For these reasons, we find it necessary to modify the proposed Stipulation to adjust the RPM set-aside levels *to accommodate the load of any community that approved a governmental aggregation program in the November 8, 2011, election* to ensure that any customer located in a governmental aggregation community will qualify for the RPM set aside, so long as the community or its CRES provider completes the necessary process to take service in the AEP-Ohio service territory by December 31, 2012.

Opinion and Order at 54 (emphasis added).

Thus, the modification made by the Commission was limited to accommodating the load associated with communities that approved a governmental aggregation program in the November 8, 2011 election, not any aggregation that may occur by the end of 2012. That the Commission's modification was limited to the November 2011 election is also unequivocally confirmed elsewhere in the Opinion and Order. *See e.g.,* page 64 (where the Commission indicated it already addressed concerns about shopping caps "by modifying the Stipulation to include governmental aggregation ballots that passed this November."); *id.* at 65 (referencing that the above "modification of the capacity plan allows for all of the communities and municipalities that recently passed governmental aggregation initiatives this November to take advantage of CRES suppliers' offers that may be lower than what AEP-Ohio is offering to its customers.") Moreover, the only concerns about adequate time to complete the opt-out aggregation process that were discussed in the evidentiary record related to the November 2011 ballot initiative communities; other communities that had previously authorized opt-out aggregation would have had plenty of time to complete the process before January 2012. While AEP Ohio legally contests the Opinion and Order's aggregation-related modification as discussed above, it is obvious that the whole point of the Commission's change (and the only purpose with any connection to the evidentiary record) was to give communities who may have relied on RPM availability in pursuing ballot initiatives access to RPM-priced capacity. In any case, any opt-in aggregation could be done at any time under the normal set aside limits and does not require a modification of the Stipulation's set aside limits.

FES's remaining alleged conflict (at 3, labeled "c" in its list) is that the Revised DIP improperly eliminates non-mercantile customer load from the required aggregation accommodation. This overlaps with IEU's argument (at 8-9) that the RPM-priced set-aside should include capacity for mercantile customers served through a governmental aggregation program. The Revised DIP properly limits the qualifying aggregation load to non-mercantile customers, in conjunction with the requirement under Ohio law that opt-out aggregation programs exclude mercantile customers.

As already discussed above, the Opinion and Order's modification of the set-aside levels is focused on communities that adopted November 2011 ballot initiatives. Ballot initiatives are only required for opt-out aggregation initiatives – R.C. 4928.20(B) requires that any proposed opt-out initiative must be placed on the ballot and passed by a majority of the electors before it can be pursued. R.C. 4928.20(A) prohibits mercantile customers from being subjected to opt-out aggregation, providing that "aggregation of mercantile customers *shall occur only with the prior, affirmative consent* of each such person owning, occupying, controlling, or using an electric load center proposed to be aggregated." (Emphasis added.) To the extent that mercantile customers can voluntarily opt in to an existing aggregation program after it is established should not change the nature and intent of the Commission's modification based on a concern for opt-out aggregation customers and the November 2011 ballot initiatives – all of which were necessarily opt-out programs.

As referenced above, the Commission's modification was based in large part on the notion that "governmental aggregation programs have proven to be the most likely means to get substantial numbers of *residential customers* to become the customer of a

CRES provider." (Emphasis added.) This concern for residential customers has nothing to do with subsequent industrial opt-in to an existing program. And the electorate is made up of residential and small commercial customers, not large industrial customers. Large industrial customers were not part of the General Assembly's design for governmental aggregation and were not part of the November 2011 ballot initiatives approved by the communities that the Commission was concerned about. Expanding the Opinion and Order's modification for November 2011 opt-out aggregation programs to include subsequent opt-in decisions by industrial customers is not supported by the existing language in the Opinion and Order and would unnecessarily create a substantial additional financial burden and uncertainty for AEP Ohio.

Thus, the Commission should clarify on rehearing the details of its intended modification to the Stipulation's RPM-priced capacity set-aside so that AEP Ohio can decide whether unacceptable financial uncertainty remains that would cause AEP Ohio to withdraw from the modified ESP and the Stipulation as a whole. This same result could be accomplished by adopting the Revised DIP filed by AEP Ohio on December 29, 2011.

CORPORATE SEPARATION/ GENERATION DIVESTITURE

V. The Opinion and Order's modification regarding corporate separation on page 61 is unlawful and unreasonable because it is based on an inconsistent application of the law, discriminatory treatment of AEP Ohio, and violation of state policy provisions to encourage competition.

The Opinion and Order (at 61) defers ruling on full approval of the Stipulation's corporate separation proposal, even though the Stipulation made it unequivocally clear that the proposal was a fundamental part of the settlement package. AEP Ohio's rehearing argument regarding corporate separation is focused on ensuring equal treatment by the Commission on key statutory matters that will affect the ongoing development of competitive markets for retail electric service in Ohio. In particular, the Opinion and Order treats corporate separation of utility generation assets differently as compared to the Commission's November 22, 2011 decision concerning the Duke Energy Ohio Stipulation (Case Nos. 11-3549-EL-SSO et al.).[4] AEP Ohio's concerns in this regard are particularly poignant given the confusing and potentially adverse impact on generation assets jointly-owned by AEP Ohio and Duke and the contradictory ESP orders dealing with corporate separation and divestiture of these assets. For example, did the Commission actually intend to presently approve the transfer of Duke Energy Ohio's ownership interest in Zimmer generating station at net book value while simultaneously creating a path that could result in withholding approval for AEP Ohio to transfer its interest in the same generating unit for years and possibly requiring the eventual transfer to be based on market valuation? AEP Ohio expects that was not the Commission's intention but that the present circumstances have developed through unintended consequences – which fortunately can be modified and harmonized in a timely manner in this rehearing process.

Thus, the Commission must either modify the order in the Duke Energy Ohio ESP proceeding to conform with the existing decision in this case or modify what it has done here to be consistent with the Duke Energy Ohio case.[5] AEP Ohio recommends the

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4 *See* November 22, 2011 Opinion and Order in Case Nos. 11-3549-EL-SSO, 11-3550-EL-ATA, and 11-3551-EL-UNC (*"Duke ESP Order")*, attached to this Application for Rehearing.

5 AEP Ohio also raises similar issues on rehearing in the Duke Ohio ESP proceeding, Case Nos. 11-3549-EL-SSO, 11-3550-EL-ATA, and 11-3551-EL-UNC, to ensure the Commission is providing consistent application of the rules and statutes in both

latter option and has pursued rehearing here to effectuate that outcome. An equally acceptable outcome is for the Commission to fully approve AEP Ohio's application for structural separation pending in Case No. 11-5333-EL-UNC. If such action is taken in that docket prior to ruling on rehearing in these proceedings, this portion of AEP Ohio's Application for Rehearing could become moot. If neither the current outcome of the Duke Energy Ohio Stipulation or the AEP Ohio Stipulation changes, it may become necessary for AEP Ohio to ask the Supreme Court to review two irreconcilable interpretations of the same statutory provisions.

Of course, if the corporate separation proposal (which is a cornerstone of the Stipulation) is not fully approved, AEP Ohio may also choose to withdraw from the Stipulation and the above-captioned cases will be fully litigated (for years) before the Commission, FERC and the Courts. Generation divestiture is a critical precursor for major components of the plan such as designation of AEP Ohio as an RPM entity in PJM (versus its current FRR status), conducting an auction-based SSO, etc. Thus, unless it is satisfactorily addressed on rehearing, this modification has the distinct potential to unravel the entire settlement and cause all of the involved cases to be fully litigated.

A. The Opinion and Order is unreasonable and unlawful because it applies the factors to achieve corporate separation and the divestiture of generation assets under R.C. 4928.17 and O.A.C. 4901:1-37 in an inconsistent manner compared to Commission treatment of the same provisions in other cases.

The actions of the Commission and the legal foundation of the Opinion and Order in these proceedings related to divestiture of generation assets and corporate separation is contradictory to the Commission's application of the same provisions in the recent

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proceedings. AEP Ohio urges the Commission to coordinate its decision the AEP Ohio and Duke Ohio proceedings to ensure consistency.

approval of Duke Energy Ohio's Stipulation making the Opinion and Order in this case unlawful and unreasonable.

The relevant corporate separation statue, R.C. 4929.17, and administrative rules, O.A.C. Chapter 4901:1-37, are presently being applied inconsistently to the Duke Energy Ohio and AEP Ohio stipulations recently modified by the Commission. Both stipulations contain provisions which clarify that by adopting the respective stipulation the Commission is (1) giving final Commission approval to transfer title of all generation assets out of the Electric Distribution Utility (EDU); (2) approving full legal separation and the related corporate separation plan; and (3) providing a waiver of certain subsections of Rule 4901:1-37-09, O.A.C, regarding the transfer of generation assets. In each instance, despite the fact that Duke Energy Ohio and AEP Ohio provide similar record support for each element, the Commission approves Duke Energy Ohio's provision (*Duke ESP Order* at p. 32) but, inconsistently defers the same issues for AEP Ohio to be determined at a later date in a different proceeding (Opinion and Order at 60-61).[6] The following are two examples that illustrate how the Commission applied the same rules to similar provisions in these stipulations but arrived at conflicting– unreasonable and unlawful – results that merit rehearing.

A critical underpinning for both stipulations is to transfer the generation assets out of the EDU at net book value. To that end, both Duke Energy Ohio and AEP Ohio

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6 Duke and AEP Ohio both provide testimony summarizing the effect of stipulation and provide a list of the generation assets. In the *Duke 2011 ESP Order* see Charles Whitlock Direct (attachment CRW 1-2 is a list of generation assets indicating Duke's percentage of ownership in each) and Julie Janson Supplemental Direct at page 7, which provides a brief overview of the transfer. See AEP Ohio Ex. 7 at Exhibit PJN-1 (which also contains an internal reference to Exhibit WAA-1 from the testimony of William A. Allen, AEP Ohio Ex. 4). Both Exhibit PJN-1 and Exhibit WAA-1 were also included in AEP's Application in Case No. 11-5333-EL-UNC.

sought a waiver of rule 4901:1-37-09 (C)(4), O.A.C.[7] In the Duke Energy Ohio decision, the Commission waives the rule and provides final approval for Duke Energy Ohio to transfer its generation assets at net book value. For AEP Ohio, however, the Commission defers not only the substantive approval but also AEP Ohio's identical waiver request for decision in a different proceeding (Case No. 11-5333-EL-UNC); Staff's initial comments in that proceeding opine that AEP Ohio should provide a market study of the generating assets and pro-forma financial information, apparently contemplating that full Commission approval of AEP Ohio's generation divestiture would not be complete until after FERC proceedings for Generation Pool amendment or termination – which could be months or even over a year away.

There is no basis for this conflicting treatment when reviewing whether these stipulations are in the public interest. It is either in the public interest to permit the transfer of the generation assets at net book value or it is not. To decide one way for Duke Energy Ohio and another for AEP Ohio is unreasonable and unlawful and leads to illogical and irreconcilably conflicting results. For example, Duke Energy Ohio and AEP Ohio share ownership in generation units at Wm. H. Zimmer Generating Station, Conesville Generating Station, W.C. Beckjord Generation Station, and J.M Stuart Generating Station. The Commission cannot intend for Duke Energy Ohio's ownership interest to be transferred at net book value but require AEP Ohio to submit a market study and potentially be ordered to transfer its ownership interest in those same assets at fair market value. To AEP Ohio's knowledge, it is unprecedented for the Commission to

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7 Rule 4901:1-37-09 (C)(4), O.A.C., requires that an electric utility "state the fair market value and book value of all property to be transferred from the electric utility, and state how the fair market value was determined."

even require such a market analysis in the first place. That would be a particularly ironic (and unfair) result given that AEP Ohio will be the last of the three large EDUs to receive approval from the Commission for structural separation.

A related problem is that the Commission is inconsistently applying the administrative rules which, by definition, are supposed to be general and uniform in application. *See e.g.*, R.C. 119.01(C). Duke Energy Ohio is clearly not required to conduct a market valuation study, since the Commission summarily waived Rules 4901:1-37-09(B) through (D), OAC which rules the Commission explicitly acknowledged "set forth the filing requirements and the procedures to be followed for an application requesting approval of the sale or transfer of generating assets." (*Duke ESP Order* at 46.) In doing so, the Commission found that the outcome sought by Duke Energy Ohio provides "the necessary safeguards to ensure that the statutory mandates pertaining to Duke Energy Ohio's sale of generation assets and corporate separation are adhered to and the policy of the state is carried out." (*Id.*) These are the same rules being enforced against AEP Ohio, even though a waiver was requested and supported by the Signatory Parties to the AEP Ohio Stipulation. The Commission should ensure its decisions are consistent and correct this unequal treatment by permitting AEP Ohio to transfer its generation assets at net book value and grant AEP Ohio's similar waiver request. The fact is that there are no material differences in the underlying facts between Duke Energy Ohio and AEP Ohio's agreements that justifies a completely different outcome when applying the same rules to the same situation at the same time.

The Commission also inconsistently applied the important matter of granting final approval for the transfers. Both the Duke Energy Ohio Stipulation and the AEP Ohio

Stipulation contain provisions which make it clear that adoption by the Commission provides final approval regarding the transfer of generation assets – neither party will need to come back to the Commission for additional subsequent approval. Duke Energy Ohio and AEP Ohio provide similar detail regarding the transfer of their generation assets.[8] In the Duke Energy Ohio docket the Staff finds the level of detail to be sufficient,[9] and the Commission grants "final approval for the transfer of generation assets" (*Duke ESP Order* at 32) without the need for additional proceedings and information. In fact, for Duke Energy Ohio, it appears as if the Commission concluded that the public interest is satisfied by reviewing the terms and conditions *after* the assets are transferred.[10]

But with AEP Ohio, reviewing a similar provision and supporting information, the Commission concludes that it "needs additional time to determine and understand the terms and conditions relating to the sale/or transfer of generation assets from EDU to

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8 *See supra* footnote 7.

9 *See Duke 2011 ESP* Testimony of Tamara Turkenton testimony in support of stipulation at page 7.

10 Section VIII.A of the Duke stipulation states, "Staff, or an independent auditor at Commission discretion and with costs to be recovered through Rider SCR, shall audit the terms and conditions of the transfer to ensure compliance with R.C. 4928.17 and 4901:1-37 corporate separation rules." Aside from the list of generation assets attached to Duke Ex. 24 (Whitlock), the terms and conditions are not specified in the application, stipulation, or the opinion and order adopting the stipulation. At hearing, Examiner Stenman asked Duke witness Whitlock, "Assuming that the stipulation is approved and not modified, are there any elements of Duke's transfer of its legacy generation assets or its corporate separation that would be subject to any further Commission review?" Mr. Whitlock replied, "I think the stipulation serves as final approval for the transfer of the assets. There is a provision in the stipulation for an audit to make sure that we basically transferred the assets in a manner that's consistent with the stipulation. . . ." (Tr. Vol. I at 51.)

AEP subsidiary." (Opinion and Order at 60.) Staff states in its initial comments in Case No. 11-5333-EL-UNC that, unlike Duke Energy Ohio, AEP Ohio needs to (a) provide additional details regarding the asset transfer, (b) provide supporting rationale as to why a waiver of the fair market value rule is necessary, (c) provide evidence reflecting the net book value of the generating assets, (d) provide a market study of the generating assets, (e) collaborate with Staff in FERC proceedings related to corporate separation and power pool dissolution or amendments, and (f) provide pro-forma financial information and other related information to Staff as they are developed. Even more troubling, unlike Duke Energy Ohio where the Commission provided final approval in its opinion and order adopting the stipulation and determined it to be in the public interest for Staff or an independent auditor to merely confirm that the transfer occurred in a manner consistent with the stipulation and the relevant Commission rules, Staff envisions "several state level proceedings" for AEP Ohio to achieve the same result.[11]

In sum, it is unreasonable and unlawful for the Commission to apply the same rules to these stipulation provisions and arrive at two completely different results. If it is in the public interest to provide final approval for the transfer of Duke Energy Ohio's generation assets based on the information provided, then it is in the public interest for AEP Ohio to do the same in some instances on the very same assets. To the extent any party argues that there are differences between the two cases that would somehow justify differing treatment by the Commission, AEP Ohio has already made clear in its December 29, 2011 reply comments in Case No. 11-5333-EL-UNC (at 11) that, to the extent not already incorporated in AEP Ohio's corporate separation plan or not already

[11] Staff initial comments at page 8 in Case No. 11-5333-EL-UNC.

required by law, AEP Ohio does not object to the Commission's imposition of comparable conditions to those set forth in the Duke Stipulation (a copy of those conditions was set forth in the attachment to AEP Ohio's reply comments). Thus, there are no differences in the outcome of the two cases being advocated by AEP Ohio and the Commission should render comparable and nondiscriminatory results in the two cases.

B. The Opinion and Order's corporate separation modification violates the state policy to ensure effective competition under R.C. 4928.17, 4928.06 and 4928.02(H).

As a threshold matter, R.C. 4928.17 – the controlling statute regarding corporate separation matters – requires the Commission to ensure that an approved corporate separation plan does not extend an undue advantage or preference in the provision of competitive electric services. *See* R.C. 4928.17(A)(3). Granting Duke Energy Ohio's affiliate full and final approval for generation divestiture up front and waiving the filing and process rules, while simultaneously deferring approval of AEP Ohio's GenCo, and possibly subjecting these assets to market valuation studies and protracted litigation, serves to extend Duke Energy Ohio an undue preference and advantage in violation of this statute. The better approach is to grant AEP Ohio the same relief afforded to Duke Energy Ohio. Full approval of AEP Ohio's structural corporate separation proposal is particularly appropriate given that functional separation has occurred for more than a decade and R.C. 4928.17(C) permits functional separation "for an interim period" and otherwise mandates structural separation.

The Commission's inconsistent application of its corporate separation efforts concerning utility generation assets also violates the state policy provision of R.C. 4928.02. The Commission's decision to treat the corporate separation of the two utilities differently results in a competitive disadvantage in violation of the state policy provisions of R.C. 4928.02. Specifically, R.C. 4928.02(H) instructs the Commission to ensure effective competition in the provision of retail electric service. More specifically the policy provisions require the avoidance of subsidies between competitive and noncompetitive interests.

An inconsistent application of the corporate separation provisions and rules is anticompetitive and provides one entity subsidies and a competitive advantage in violation of R.C. 4928.02. If Duke Energy Ohio is able transfer assets as outlined by the Commission in the Opinion in the *Duke ESP Order* at the net book value and AEP Ohio is subject to greater scrutiny and different valuations levels, then Duke Energy Ohio is receiving an unfair benefit or subsidy from the truncated process between its entities and avoiding the different costs associated with complying with O.A.C. 4901:1-37-09(C)(4), and potentially the transfer of assets at fair market value. Nowhere is the direct difference more obvious than in the jointly owned utility assets. If Duke Energy Ohio is able to transfer those assets at the net book value but AEP Ohio is required to incur a greater cost, over a greater period of time and transfer the same assets under a different methodology, then Duke Energy Ohio and its new competitive generation company are receiving an advantage or subsidy not provided other entities like those involved in the AEP Ohio corporate separation.

Similarly, the General Assembly enacted R.C. 4928.06 entitled "Commission to ensure competitive retail electric service" - originally as part of SB 3 and retained by SB 221. The enactment of this provision provides multiple directives to the Commission concerning retail choice and placed a duty on the Commission to address and resolve any decline or loss of effective competition. Among other things, the Commission is to consider specific factors in determining whether effective competition exists:

> (1) The number and size of alternative providers of that service;
> (2) The extent to which the service is available from alternative suppliers in the relevant market;
> (3) The ability of alternative suppliers to make functionally equivalent or substitute services readily available at competitive prices, terms, and conditions;
> (4) Other indicators of market power, which may include market share, growth in market share, ease of entry, and the affiliation of suppliers of services.

The unequal competitive playing field created by the disparate treatment of Duke Energy Ohio's new GenCo affiliate versus AEP Ohio's new GenCo affiliate cannot survive scrutiny under these factors and operates to stifle the development of a competitive retail electric generation market.

With both Duke Energy Ohio and AEP Ohio, the Commission is reviewing the stipulations to determine if the relevant provisions are in the public interest. It is unreasonable and unlawful for the Commission to apply the same rules to each stipulation and determine based on similar record support that (a) final approval to transfer title of all generation assets out of the EDU, (b) approval of full legal separation and related corporate separation plan, and (c) waiver of relevant rules so that the assets can be transferred at net book value without a hearing is in the public interest for Duke Energy Ohio but not in the public interest for AEP Ohio. For the forgoing reasons, the Commission should grant rehearing on these items and treat AEP Ohio in the same manner it did Duke Energy Ohio.

C. The Opinion and Order is unreasonable and unlawful to the extent it requires AEP Ohio to divest its generation assets and notify PJM of its intention to enter the PJM auction for years 2015-2016 prior to receiving full approval for corporate separation as contemplated in the Stipulation.

The Opinion and Order (at 61) "directs [AEP Ohio] to notify PJM that it intends to enter PJM's auction process for the delivery year 2015-2016, as the Stipulation indicates." Because the directive includes the phrase "as the Stipulation indicates," it is possible the Commission did not intend to prematurely direct AEP Ohio to make its RPM election prior to receiving full approval of corporate separation. But this aspect of the Opinion and Order is unreasonable and unlawful to the extent it orders AEP Ohio to divest its competitive generation assets from its noncompetitive electric distribution utility to its separate competitive retail generation subsidiary and notify PJM of intentions to enter the 20115-2016 auction prior to receiving full approval for corporate separation as provided for in the Stipulation. If the Commission intends to withhold approval of an appropriate corporate separation yet at the same time direct compliance with requirements that were premised on that structure, then it is unreasonable to require these actions without recognizing the possibility that the separation will not be approved and the divestiture will not occur. Because corporate separation is such a critical component of the settlement package, it is simply unacceptable to move forward with the irrevocable RPM election without clear approval from this Commission of corporate separation.[12] In recognition of the timing of the PJM election (the election being in March 2012 and the coordination work starting in January), Paragraph IV.1.q of the Stipulation explicitly tied

[12] Upon making the RPM election with PJM, AEP Ohio would be obligated to remain an RPM entity for five years starting with the 2015-2016 planning year.

AEP Ohio's agreement to make the RPM election to full approval of corporate separation. Accordingly, the Commission needs to clarify on rehearing that AEP Ohio is not bound to make the RPM election unless and until the Commission grants full approval of structural separation.

CONCLUSION

For the foregoing reasons, the Commission should grant the foregoing application for rehearing submitted by Ohio Power Company.

Respectfully Submitted,

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BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of Application of Duke Energy Ohio, Inc. for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications, and Tariffs for Generation Service.	)	Case No. 11-3549-EL-SSO
In the Matter of Application of Duke Energy Ohio, Inc. for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20.	)	Case No. 11-3550-EL-ATA
In the Matter of Application of Duke Energy Ohio, Inc. for Authority to Amend its Corporate Separation Plan.	)	Case No. 11-3551-EL-UNC

OPINION AND ORDER

The Public Utilities Commission of Ohio, considering the above-entitled applications, the testimony, the applicable law, the proposed stipulation, and other evidence of record, and being otherwise fully advised, hereby issues its opinion and order.

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Kegler Brown Hill & Ritter, LPA, by Andrew Sonderman and Margeaux Kimbough, Capital Square, Suite 1800, 65 East State Street, Columbus, Ohio 43215, on behalf of Duke Energy Retail Sales, LLC.

Chester, Wilcox & Saxbe, LLP, by John W. Bentine, 65 East State Street, Suite 1000, Columbus, Ohio 43215, on behalf of American Municipal Power, Inc.

Vincent Parisi and Matthew White, 6100 Emerald Parkway, Dublin, Ohio 43016, on behalf of Interstate Gas Supply, Inc.

Williams, Allwein, and Moser, LLC, by Christopher Allwein, 1373 Grandview Avenue, Suite 212, Columbus, Ohio 43212, on behalf of the Natural Resources Defense Council.

Vorys, Sater, Seymour & Pease, LLP, by M. Howard Petricoff and Lija Kaleps-Clark, 52 East Gay Street, Columbus, Ohio 43216, and Eimer, Stahl, Kelvorn & Solberg LLP, by Scott C. Solberg, David M. Stahl, and Arin C. Aragona, 224 South Michigan Avenue, Suite 1100, Chicago, Illinois 60604, on behalf of Exelon Generation Company, LLC.

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

McDonald Hopkins, by Matthew R. Cox, 41 South High Street, Suite 3550, Columbus, Ohio 43215, on behalf of Council of Smaller Enterprises.

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

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

OPINION:

I. HISTORY OF THE PROCEEDINGS

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

On June 20, 2011, as supplemented on June 28, 2011, Duke filed an application for a standard service offer (SSO) pursuant to Section 4928.141, Revised Code. This application is for an electric security plan (ESP) in accordance with Section 4928.143, Revised Code.

By entry issued June 21, 2011, the attorney examiner established the procedural schedule in these cases. On June 30, 2011, a technical conference was held regarding Duke's application. By entry issued July 22, 2011, four local public hearings were scheduled in these matters for August 30, 2011, and September 8 and 9, 2011. Duke submitted proofs of publication for the hearings (Duke Ex. 3). In total, at the four local public hearings, 34 witnesses testified.

The following entities were granted intervention by entry dated July 22, 2011: Industrial Energy Users-Ohio (IEU); The Ohio Energy Group (OEG); Ohio Partners for Affordable Energy (OPAE); The Kroger Company (Kroger); Ohio Environmental Council (OEC); FirstEnergy Solutions Corp. (FES); The Greater Cincinnati Health Council (GCHC); Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc. (Constellation); Ohio Consumers' Counsel (OCC); Duke Energy Retail Sales, LLC (DERS); Dominion Retail, Inc. (Dominion); Wal-Mart Stores East, LP and Sam's East, Inc. (Wal-Mart); Ohio Manufacturers' Association (OMA); Retail Energy Supply Association (RESA); Columbus Southern Power and Ohio Power Company (AEP Ohio); AEP Retail Energy Partners LLC (AEP Retail); city of Cincinnati (Cincinnati); Eagle Energy, LLC (Eagle); People Working Cooperatively, Inc. (PWC); Council of Smaller Enterprises (COSE); Cincinnati Bell Inc. (Cincinnati Bell); Environmental Law & Policy Center (ELPC); EnerNOC, Inc. (EnerNOC); Vectren Retail, LLC d/b/a Vectren Source (Vectren); PJM Power Providers Group (PJM PPG); Direct Energy Services, LLC and Direct Energy Business, LLC (Direct Energy); Miami University and The University of Cincinnati

(Miami/UC); The COMPETE Coalition (COMPETE); American Municipal Power, Inc. (AMP); Natural Resources Defense Council (NRDC); Interstate Gas Supply, Inc. (IGS); and Exelon Generation Company, LLC (Exelon). By entries issued July 22, 2011, and September 8, 2011, the motions for admission *pro hac vice* filed on behalf of Scott C. Solberg, David M. Stahl, Arin C. Aragona, William L. Massey, and Rick D. Chamberlain were granted.

The evidentiary hearing was initially scheduled to commence on September 20, 2011. However, by entry issued August 26, 2011, the attorney examiner granted, in part, a motion filed by some of the parties; thus, the procedural schedule in these cases was extended and the evidentiary hearing was rescheduled to October 20, 2011. Subsequently, by entry issued October 5, 2011, at the request of the parties, the evidentiary hearing was rescheduled to November 3, 2011.

On October 24, 2011, a stipulation and recommendation (stipulation) was filed in these cases, purporting to resolve all of the issues in these cases (Jt. Ex. 1). The stipulation contained the agreement of Staff and all of the parties in these cases, with the exception of AEP Ohio and Dominion, which signed stating that they take no position on the stipulation and Eagle, which did not sign the stipulation.

The evidentiary hearing commenced on November 3, 2011. At the hearing, Duke presented four witnesses supporting the stipulation, and Staff, OPAE, Constellation, RESA, and Kroger each provided testimony by a witness in support of the stipulation. No testimony was presented in opposition to the stipulation.

At the hearing held in these matters, the attorney examiner granted Duke's motion for protective treatment of certain information presented on the record in these dockets on June 20 and 28, 2011, and admitted into the record Duke Exs. 2A, 6A, 10A, 10A.1, 18A. In accordance with that ruling, Duke was directed to file late-filed exhibits in this docket, which contain the portions of the documents filed under seal on June 20 and 28, 2011, for which protective treatment was denied. On November 9, 2011, Duke filed Late-filed Duke Exs. 2.1, 6.1, 10.1, 10.2, and 18.1 in the open record, as directed by the attorney examiner at the hearing. In accordance with the attorney examiner's ruling at the hearing, the unredacted versions of the documents filed on June 20 and 28, 2011, which have been admitted into the record as Duke Exs. 2A, 6A, 10A, 10A.1, 18A, should be afforded protective treatment. Rule 4901-1-24(F), Ohio Administrative Code (O.A.C.), provides that, unless otherwise ordered, protective orders issued pursuant to Rule 4901-1-24(D), O.A.C., automatically expire after 18 months. Therefore, confidential treatment shall be afforded for a period ending 18 months from the date of this order or until May 22, 2013. Until that date, the docketing division should maintain, under seal, the information filed confidentially. Any party wishing to extend the protective order, must file an appropriate motion at least 45 days in advance of the expiration date. If no such motion to extend confidential treatment is filed, the Commission may release this information without prior notice to Duke.

On November 16, 2011, Duke filed a motion to revise Section IV.A of the stipulation stating that through an inadvertent error the name Duke was inserted in this provision, rather than PJM. In order to correct this error, Duke requests that its revision to Section IV.A of the stipulation be marked as Jt. Ex. 1.1, and that the exhibit be admitted into record. The Commission finds that Duke's motion to revise Section IV.A of the stipulation is reasonable and should be granted; therefore, Jt. Ex. 1.1 should be admitted into record.

II. DISCUSSION

A. Applicable Law

Chapter 4928, Revised Code, provides a roadmap of regulation in which specific provisions were put forth to advance state policies of ensuring access to adequate, safe, reliable, and reasonably priced electric service in the context of significant economic and environmental challenges. In reviewing Duke's application for an ESP, the Commission is aware of the challenges facing Ohioans and the electric power industry and will be guided by the policies established by the General Assembly in Section 4928.02, Revised Code, which provide that it is the policy of the state to, *inter alia*:

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

(2) ensure the availability of unbundled and comparable retail electric service;

(3) ensure diversity of electric supplies and suppliers, and the development of distributed and small generation facilities;

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

(5) encourage cost-effective and efficient access to information regarding the operation of the transmission and distribution systems in order to promote both effective customer choice and the development of performance standards and targets for service quality;

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

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

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

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

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

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

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

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

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

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

Section 4928.14, Revised Code, provides that, beginning on January 1, 2009, electric utilities must provide customers with an SSO, consisting of either a market rate offer (MRO) or an ESP. The SSO is to serve as the electric utility's default SSO. Section 4928.143, Revised Code, sets out the requirements for an ESP. Section 4928.143(C)(1), Revised Code, provides that the Commission is required to determine whether the ESP, including its pricing and all other terms and conditions, including deferrals and future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code.

In accordance with Sections 4928.06 and 4928.141, Revised Code, the Commission promulgated rules, which are contained in Chapter 4901:1-35, O.A.C., for the purpose of considering SSO filings made by electric utilities in conformance with Chapter 4928, Revised Code.

B. Summary of Application

Along with its application filed in these cases on June 20, 2011, Duke provided supporting testimony from 17 witnesses, as well as supporting exhibits (Duke Exs. 2, 4-20, 2A, 6A, 10A, 10A.1, 16.1, 18A; Duke Late-filed Exs. 2.1, 6.1, 10.1, 10.2, 18.1).

According to Duke, the ESP set forth in the application would allow for both competition in the supply of energy and assurance of the availability of capacity. Duke proposed to supply generation service through a bifurcated structure, with capacity being supplied by the company to all customers and the energy being procured via competitive auctions to serve the customers that choose to purchase energy from Duke. In accordance with the application, Duke would provide capacity over a nine-year, five-month period, by establishing an unavoidable capacity charge, that would be adjusted annually, which would allow the company to recover the costs of supplying capacity and a reasonable rate of return. Furthermore, Duke proposed to sell the energy that is produced by its legacy generating assets, sharing most of the net proceeds of the energy and ancillary service sales with its customers; thus, lowering the universal capacity charge. Duke offered that 76 percent of the net profits from the sale of energy and ancillary service would be allocated to customers pursuant to the application. An additional portion, approximately 10 percent of the remaining net proceeds from the sale of energy and ancillary services, would support economic development in Duke's service territory. (Duke Ex. 1 at 1-2, 8, 10-12.)

Under the application, because the energy from the legacy generating assets would be sold to the market and a portion of the net profits would be returned to Duke's customers, the energy would not be available to the company's SSO load. Therefore, to supply energy to the SSO load, Duke proposed to hold periodic auctions through a competitive bid process (CPB) to obtain the lowest cost energy from competitive wholesale suppliers. Duke stated that retail competitors would continue to be able to compete for customers on the energy portion of the service. Duke proposed the CBP entail a descending-price clock auction with the first auction conducted on December 1, 2011, for delivery on January 1, 2012. In 2012, and for the remainder of the ESP, Duke proposed to conduct two auctions per year. Because the Commission has the authority to terminate the ESP, Duke's auction schedule incorporated transition periods at the end of the fourth and eighth years of the plan, at which time the supply contracts would terminate, so that there would not be any existing obligations that prevent termination of the ESP. The application provided that the auction product would be an hourly, load-following, full-requirements tranche of the company's SSO load for energy, where a tranche is equal to 1.00 percent of Duke's total SSO load obligation for energy or a slice of the system of Duke's hourly SSO load for energy. The products included in the CBP plan included unbundled energy, ancillary service, and market-based firm transmission services. As explained in the application, Duke retained CRA International, d/b/a Charles River Associates (CRA), to design, administer, and oversee at least the first CBP. (Duke Ex. 1 at 2, 8, 12-15.)

C. Summary of Stipulation

As stated previously, a stipulation signed by Staff and all of the parties in these cases, with the exception of AEP Ohio and Dominion, which signed stating that they take no position on the stipulation, and Eagle, which did not sign the stipulation, was filed in these cases on October 24, 2011, as revised on November 16, 2011, and it has been entered into the record as Jt. Ex. 1 and 1.1. The stipulation, as revised, was intended by the signatory parties to resolve all issues in these proceedings. The following is a summary of the provisions agreed to by the stipulating parties and is not intended to replace or supersede the stipulation:

(1) Term of the ESP

(a) Duke's ESP will be for a three-year, five-month period, January 1, 2012 through May 31, 2015. Duke shall file its next application, pursuant to Section 4928.141, Revised Code, for an SSO no later than June 1, 2014. This subsequent application shall make provision for SSO supply procurements via a descending-clock format CBP. The parties waive any rights they may have to contest the use of such a CBP for the purpose of establishing Duke's next SSO. A collaborative meeting will be held prior to March 31, 2014, to discuss lessons learned and potential improvements to the bid process, including, but not limited to, the need, if any, to address changes to the rules regarding switching between SSO and CRES providers, for consideration in Duke's next SSO. Through the CBP to be included in its next SSO application, Duke will seek to procure, on a slice-of-system basis, the aggregate wholesale full requirements SSO supply, which includes energy and capacity, market-based transmission service, and market-based transmission ancillary services requirements, for the period of its next SSO. Market-based transmission services include those PJM charges and credits assigned to CRES providers and those identified on the sample PJM invoice as being assigned to wholesale suppliers. Said process shall be conducted by an independent bid manager and consistent with the bid documents submitted as a part of Duke's application, as modified in the stipulation and the attachments to the stipulation. The parties shall expressly support the use, by Duke, of such a CBP for purposes of acquiring all of the supply needed to serve its SSO load under the next SSO. The parties reserve all other rights that they may have to support, contest, or recommend modification of Duke's next SSO. Duke reserves all rights to withdraw its next SSO application.

(b) In the event the Commission rejects Duke's next SSO application or substantially modifies it such that Duke withdraws the application, the parties acknowledge and agree that the auction-based pricing and cost-recovery provisions of the SSO structure under which Duke is operating as of May 31, 2015, shall persist until such time as a subsequent SSO is approved and not withdrawn, as provided for in Section 4928.143(C)(2)(a), Revised Code. Any such withdrawal by Duke shall be filed within 30 days following the issuance of the Commission's final order. Specifically, for the term commencing June 1, 2015, unless a new SSO is approved by the Commission and not withdrawn by Duke, prior to April 1, 2015, Duke will procure, through a descending-clock, auction-based SSO procurement process substantially similar to the auctions conducted under the ESP described herein, a full-requirements, load-following product for a term that is not less than quarterly or more than annually until a new SSO is approved and not withdrawn, with retail generation rates being determined based on the results of those auction-based SSO load procurements. The parties agree and recommend that the Commission determine the term for the procurement process upon the filing of any Duke withdrawal of its next SSO application. For purposes of this paragraph, the parties also agree that, for so long as Duke is a fixed resource requirements (FRR) entity under PJM, it will provide capacity at the final zonal capacity price (FZCP) in the unconstrained regional transmission organization (RTO) region. For the period during which Duke participates in PJM's reliability pricing model (RPM) and base residual auction (BRA), the capacity price is the FCZP for the Duke Energy Ohio and Kentucky (DEOK) load zone region, and capacity shall be provided pursuant to the PJM RPM process. The Commission's oversight of said procurement process shall be consistent with the oversight afforded it in the ESP discussed herein. For purposes of this paragraph, a full-requirements load-following product shall include energy and capacity delivered to the DEOK load zone, as well as market-based transmission service, and market-based transmission ancillary service, plus the reasonable costs to procure.

(2) SSO Supply

(a) Duke agrees to procure all of its energy, capacity, market-based transmission service, and market-based transmission ancillary services requirements for its SSO load, for the duration of the ESP, through the CBP outlined in the application and testimony filed in these proceedings, except as modified in the stipulation. The auction schedule shall proceed consistent with attachment A to the stipulation, which provides that the first auction will take place in December 2011, and will include 100 tranches.

(b) Duke shall supply capacity to PJM, which, in turn, will charge for capacity to all wholesale supply auction winners for the applicable time periods of Duke's ESP with the charge for said capacity determined by the PJM RTO, which is the FZCP in the unconstrained RTO region.

(c) Duke will implement it retail capacity rider (Rider RC) and retail energy rider (Rider RE) to recover the costs associated with serving its SSO load, with the aggregate sum of the revenues under Riders RC and RE equal to the auction clearing prices, as converted into retail rates. Rider RC shall recover the cost of capacity and Rider RE shall recover all remaining auction costs, including energy, market-based transmission service, and market-based transmission ancillary services. Riders RC and RE are unconditionally avoidable by all non-SSO customers. Riders RC and RE will be put into effect through updated rates for each of the PJM planning years for which all tranches for the delivery period have been approved by the Commission.

(d) Duke shall implement its conditionally avoidable supplier cost reconciliation rider (Rider SCR) to recover any difference between the payments made to suppliers for SSO service and the amount of revenue collected from Riders RC and RE. Rider SCR will also be used to recover all prudently incurred costs associated with conducting the auctions for SSO service and any costs resulting from supplier default. Rider SCR will be filed quarterly in this docket and will be subject to annual audits by the Commission. The monthly accumulated balance of over- or under-recovery will accrue a carrying charge equal to Duke's overall cost of long-term debt, as approved in its most recent distribution rate case. Rider SCR shall be avoidable by shopping customers during the time that they purchase retail electric generation service from a CRES provider, as long as the balance of said Rider is less than 10 percent of Duke's overall actual SSO revenue (*i.e.*, all revenue collected for SSO service under Rider RE, Rider RC, the reconciliation rider (Rider RECON), and the alternative energy resource requirement rider (Rider AER-R)) for the most recent quarter for which data is available at the time of the filing. If the balance of Rider SCR becomes equal to or greater than 10 percent of Duke's overall actual SSO revenue, Duke shall apply to the Commission for confirmation that Duke should modify Rider SCR such that it becomes unavoidable (whether the balance in the rider results from over- or under-recovery). Rider SCR will again become avoidable for shopping customers if the balance of Rider SCR falls below 10 percent of Duke's overall actual SSO revenue.

(e) Upon Commission approval of the bids, Duke shall determine the rates for Riders RE and RC by converting the clearing prices from each auction into retail rates pursuant to the methodology contained in attachment B to the stipulation. The conversion of the auction prices into Riders RC and RE will include applicable losses.

(f) Affiliates and subsidiaries of Duke shall be permitted to participate and compete in the SSO auctions on the same fair and nondiscriminatory manner as all other participants. Duke shall not give any competitive advantage to an affiliate or subsidiary participating in the SSO auctions. Notwithstanding the above, Duke agrees that, for the period during which its electric service stability charge rider (Rider ESSC) is in place, and irrespective of ownership of its generation assets, it shall not participate in the SSO auctions. Generation assets include all generation assets currently, directly owned by Duke, whether operating or retired, but shall not include any generation assets currently owned by an affiliate or subsidiary of Duke. Rather, during said period and irrespective of ownership, Duke shall cause the energy from all of its generation assets to be sold into the day-ahead or real-time PJM energy markets, or on a forward basis through a bilateral arrangement. Any forward bilateral sales must be done at a liquid trading hub (*i.e.*, Western Hub, AD-Hub, Cinergy Hub) at the then-current market wholesale equivalent price. Intercontinental-Exchange (ICE) or a similar publicly available document shall be used as a form of measure of the then-current market wholesale equivalent pricing. Staff, or, at the Commission's discretion, an independent auditor, shall semi-annually audit Duke's records to ensure compliance with this provision. The cost of any such audits shall be recovered through Rider SCR.

(g) There shall be load caps applicable to each auction conducted during the term of the ESP, with no one supplier being able to bid upon or be awarded more than 80 percent of the tranches in any one auction.

(h) The bidding process described in Duke's application, as modified in the stipulation, shall be conducted by an independent bidding manager, CRA, except as provided in the stipulation. The Commission may also retain a consultant who may monitor the bidding process, and the costs of such consultant shall be recovered under Rider SCR.

(i) Within the first 30 days following Commission approval of the results of each auction, Staff may notify Duke of its desire to evaluate the use of an independent auction manager other than CRA. Within 30 days of such notification, Duke and Staff shall jointly: (1) confirm whether CRA will continue to serve as the independent auction manager; or (2) identify a new independent auction manager; or (3) identify a process to determine the new auction manager. In order to avoid disruption to the auction schedule, the substitution of the independent auction manager shall occur no sooner than six months after confirmation of such a substitution. If Staff does not provide notice, as set forth above, CRA shall continue to serve as the auction manager until such time as a substitution is confirmed. In no event shall the substitution of the independent auction manager delay or otherwise alter the bidding schedule as delineated in attachment A to the stipulation or result in a modification of the CBP or bidding documents detailed in Duke's application, and as modified by the stipulation, except to revise the identification of, and contact information for, the auction manager. Any costs associated with the substitution of independent auction managers shall be recovered through Rider SCR.

(j) The Commission may reject the results of any auction, by means of an order filed within 48 hours of the conclusion of each such auction, based upon a report from the independent auction manager or the Commission's consultant that the auction violates a specific CBP rule in such a manner so as to invalidate the auction or if the Commission determines that one or more of the following criteria were not met:

(i) The bidding process was over-subscribed based upon bidder indicative offers submitted as part of the Part 2 Application, such that the amount of the supply bid upon was greater than the amount of the load bid out;

(ii) There were four or more bidders; or,

(iii) Consistent with the load cap, no bidder won more than 80 percent of the tranches in any one auction.

Duke witness Lee explains that the parties agreed to changes to the CBP plan that was proposed by Duke in its initial application, with those changes being reflected in attachments A, C, F, and G of the stipulation. Mr. Lee states that attachment A to the stipulation is the schedule for Duke's auctions to be conducted for the term of the ESP and he points out that the document reflects the change in timing of the auctions due to the shorter term of the ESP, from what was originally proposed in the application. As set forth in attachment A, the first auction would include 100 tranches and take place in December 2011. Mr. Lee also explains that attachment C of the stipulation reflects the revised bidding rules for the auctions to be conducted during the term of the ESP[1] and he points out that the rules are similar to those used as part of the FirstEnergy distribution utilities' competitive procurement for its SSO. However, Mr. Lee notes that the differences in the final document are designed to provide enhancements from what was proposed, including certain relaxed credit terms for auction participants and the provision of additional information in advance of the auction. In addition, the witness states that the stipulation also reflects changes to the Master SSO Supply Agreement. (Duke Ex. 23 at 2-4; Jt. Ex. 1 at Att. A.)

With respect to the timing of the auction, Mr. Lee offers that the auction can be conducted for delivery commencing January 1, 2012. Although Mr. Lee acknowledges that the schedule will be compressed, he explains that preparations for the auction will be occurring prior to a Commission decision on the stipulation, so that auction participants will not be unduly burdened in preparing for the auction and the December 14, 2011, auction date will not be jeopardized. (Duke Ex. 23 at 4-5, Att. RJL Supp-1.)

Duke witness Wathen explains that the SSO price paid by nonshopping customers will be determined primarily by the price that results from the procurement of energy and capacity via the CBP, which will yield bundled prices for energy and capacity on a $/megawatt-(MW) hour basis. The resulting average rate for the bundled capacity and energy product will be decoupled so that the prices for capacity and energy can ultimately be shown separately on customers' bills as Rider RC or Rider RE. According to the witness, decoupling the capacity and energy components of the CBP auction results is simple due to the use of the PJM market price for capacity. Mr. Wathen further explains that Duke will file an application to propose a decoupling mechanism related to its energy efficiency program. Given opposition by some of the parties, Duke was unable to accomplish the objective of decoupling its distribution revenue from energy sales as part of the current cases. (Duke Ex. 22 at 4-5, 24-26.)

As explained by Mr. Wathen, Rider SCR is a means of truing up the costs of procuring SSO supply and revenue collected from customers for SSO service. According to Mr. Wathen, Rider SCR provides a means of making Duke's customers, Duke, and SSO suppliers whole for the energy and capacity procured to meet the SSO load obligation and includes: a reconciliation of the difference between revenue collected from SSO customers and the payments Duke will make to SSO suppliers for the power they actually deliver; the cost of consultants hired by Duke or Staff, if charged to Duke to administer the auction; and any other costs directly associated with the procurement process. Mr. Wathen submits that the need to reconcile the difference between revenue collected from SSO customers and the payments Duke makes to its SSO suppliers results from the

1 Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively referred to herein as FirstEnergy).

combination of differences in rate design among the classes and the fact that switching is not uniform across all rate classes. (Duke Ex. 22 at 13-17.)

With respect to Rider ESSC, Duke witness Wathen avers that Rider ESSC is necessary because Duke is required to supply capacity for Duke's entire footprint until at least the 2015/2016 PJM planning year. Duke will satisfy its obligation, in part, with its generation assets. Moreover, Duke has agreed that its generation assets will only participate in the wholesale PJM day-ahead and real-time energy markets for the first three calendar years of the ESP. According to Mr. Wathen, Rider ESSC is a means of providing economic stability and certainty during the term of the ESP, while recognizing the value of Duke's commitment of its capacity and the separation of the generation assets. (Duke Ex. 22 at 18-19.)

Duke's load factor adjustment rider (Rider LFA) is a mechanism that only applies to nonresidential, demand-metered, rates, and is an unavoidable demand charge for all billed kilowatts (kW) of demand and a corresponding unavoidable energy credit for all kW hours (kWhs) of usage designed to stabilize retailed prices by enhancing some of the benefits associated with high-load factor customers under current rates. Mr. Wathen explains that the intent of Rider LFA is to recognize that customers that maintain a higher than average load factor are generally more efficient users of electricity, in that their pattern of consumption is not as volatile as a low load factor, higher energy user. High-load factor customers are typically more sensitive to volumetric energy charges as well, which suggests that a rider such as Rider LFA will serve to mitigate the impact on energy intensive industries. Rider LFA will have no impact on residential and other nondemand metered classes. (Duke Ex. 22 at 19-20.)

Rider AER-R will, according to Duke witness Wathen, recover Duke's costs to comply with Ohio's AER requirements, will be implemented through quarterly filings, will include true-up provisions, and will be subject to annual audits (Duke Ex. 22 at 21). Ms. Janson explains that, because Rider AER-R will not expire until May 31, 2015, under the terms of the ESP, Duke will be able to recover all of the reasonably and prudently incurred costs associated with Ohio's AER requirements. Moreover, the stipulation provides for the further development of Duke's existing residential SREC program. (Duke Ex. 21 at 15.)

Mr. Wathen explains that Rider RECON, as agreed to in the stipulation, is a true-up of Duke's current price-to-compare fuel and purchased power rider (Rider PTC-FPP) and Rider PTC-SRT (system reliability tracker), both of which will expire on the effective date of the ESP. Because it cannot be determined whether there will be a zero balance in these riders when they expire, the purpose of Rider RECON is to recover the collective balance of any over- or under-recovery in both of these riders. Once the balances in Riders PTC-

FPP and PTC-SRT are resolved, Rider RECON will expire. (Duke Ex. 22 at 21; Duke Ex. 1 at 24.)

Rider UE-GEN is a mechanism to recover the cost of bad debt associated with generation service. Mr. Wathen explains that Duke will modify its purchase of accounts receivable (PAR) program to reduce the discount rate suppliers pay for this service to zero percent, with the PAR program working like it does in its current form. Rider UE-GEN will be initially set at zero. Duke will file its initial application to set Rider UE-GEN rates in conjunction with its filing for Rider EU-ED in May 2012. (Duke Ex. 22 at 22-23.)

(3) Transmission Services

Transmission services shall be provided consistent with the May 25, 2011, opinion and order issued by the Commission in *In the Matter of the Application of Duke Energy Ohio, Inc. for Approval of the Establishment of Rider BTR and Associated Tariff Approval*, Case Nos. 11-2641-EL-RDR, *et al.*, except that PJM Schedule 1 (Scheduling, System Control, and Dispatch) shall not be included in Duke's base transmission rate rider (Rider BTR) and will be billed directly to wholesale auction winners and CRES providers by PJM.

(4) Capacity for Shopping Customers

Duke shall supply capacity resources to PJM, which, in turn, will charge for capacity resources to all CRES providers in its service territory for the term of the ESP, with the exception of those CRES providers that have opted out of Duke's FRR plan, for the period during which they opted out. During the term of the ESP, PJM shall charge CRES providers for capacity as determined by the PJM RTO, which is the FZCP in the unconstrained RTO region, for the applicable time periods of its ESP. When computing the capacity allocations for PJM, Duke shall use an allocation formula in common use in PJM.

(5) Future Capacity Supply

Duke will provide its generating unit commitment information to PJM as soon as reasonably possible, but no later than February 1, 2012. Provided that Duke does not withdraw this ESP prior to February 29, 2012, it will terminate its election of an FRR plan and provide written notice by March 2, 2012, to the PJM Office of Interconnection of its intent to participate in the RPM and the BRA for the 2015/2016 planning year. If Duke is required to make a filing with the Federal Energy Regulatory Commission (FERC) to terminate its FRR status for the 2015/2016 planning year, the parties agree not to intervene in said proceeding for the purpose of contesting, opposing, or otherwise objecting to the termination of the election; nor shall the parties seek to delay the proceeding. Nothing herein prohibits the parties from intervening in such proceeding for the purpose of supporting the filing. In the event Duke is precluded from terminating its FRR plan for the 2015/2016 planning year and, in addition, the Commission permits full legal corporate separation, Duke will provide notice to PJM no later than March 2013, that it intends to participate in the RPM and BRA for the 2016/2017 planning year. Further, in the event Duke is precluded from terminating its FRR plan for the 2015/2016 planning year, it shall supply capacity to PJM, which, in turn, shall charge all wholesale auction winners, generation suppliers for the percentage of income payment plan (PIPP) contract load, and CRES providers for capacity as determined by the PJM RTO, which is the FZCP in the unconstrained RTO region.

(6) Renewable Energy Credits

(a) Duke will implement Rider AER-R, as proposed in its application, to recover the costs incurred in complying with the requirements of Section 4928.64, *et seq.*, Revised Code. Rider AER-R shall not expire upon the termination of the ESP on May 31, 2015, but instead shall continue in order to enable recovery of all reasonable and prudently incurred costs for the acquisition of renewable energy credits (RECs), including brokerage fees, REC tracking participation expenses, gains and losses realized from the sale of RECs, and carrying costs at the long-term cost of debt, as approved in

Duke's most recent distribution rate case. Rider AER-R shall remain avoidable for customers taking generation service from a CRES provider. Rider AER-R will be filed quarterly and will include true-up provisions, with annual audits conducted by Staff, or an independent auditor at the discretion of the Commission, in a manner similar to that employed with respect to Duke's current Rider PTC-FPP.

(b) Within 60 days of the issuance of a final order adopting the stipulation, Duke will engage in collaborative discussions with interested parties to prepare an application to revise certain elements of the current Section 4928.64, Revised Code, residential solar REC (SREC) purchase program. With the common goal of expanding customer participation in the program, Duke will work with the signatory parties to identify mutually agreeable modifications aimed at enhancing clarity, transparency, and certainty of contractual terms. These changes may include, but may not be limited to, features such as the assignment of a known SREC price over the length of the contract, an up-front rebate with certain output standards, or another mutually agreed solution as yet to be developed. If the parties are unable, within 60 days of the start of the collaborative process, to agree on changes to Duke's existing SREC tariff, Duke shall file a letter at the Commission indicating that the parties could not reach agreement. In such event, the other parties retain the right to petition the Commission to make changes to Duke's existing SREC tariff. The Commission will become the final arbiter in the event of such a dispute.

(c) Within 60 days of the Commission's issuance of a final order adopting the stipulation, Duke will initiate collaborative work in consultation with the OEC, ELPC, and other interested signatory parties on an evaluation and report on combined heat and power.

(7) Ohio Policy

(a) For calendar years 2012, 2013, and 2014, of the ESP, Duke shall recover annually, via an unavoidable generation charge, Rider ESSC, an amount intended to provide stability and certainty regarding Duke's provision of retail electric service as an FRR entity while continuing to operate under an ESP.[2] Duke shall be permitted to implement a Rider ESSC rate to collect $110 million per year for a period of three years commencing January 1, 2012, with the collection to be trued up annually and the total equal to $330 million, allocated in accordance with attachment B to the stipulation. The revenue collected under Rider ESSC shall stay with Duke and shall not be transferred to any subsidiary or affiliate.

(b) For calendar year 2012, Duke commits to a $1 million contribution to support economic development efforts in its service territory. For each of the two remaining calendar years of the ESP, Duke agrees to provide $1 million annually, to support economic development efforts, provided Duke's return on equity (ROE), as determined in its then most recent annual significantly excessive earnings test (SEET) review, exceeds 10 percent for the prior calendar year. Said funds will be provided from Duke Energy Corporation (DEC) shareholders and Duke shall have sole discretion to direct the use and allocation of the funding, which shall be available to customers in Duke's service territory on a competitively neutral basis and without regard to their status as a shopping or nonshopping customer.

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2 OCC, FES, and OMA support the stipulation. However, OCC, FES, and OMA take no position regarding Section VII.A. of the stipulation, or do not support or oppose the paragraph, so that support for the stipulation by OCC, FES, and OMA may not be used as precedent in any other proceeding. (Jt. Ex.1 at 16.)

(c) For calendar year 2012, Duke commits to a $100,000 contribution to OMA to support economic development and energy efficiency initiatives among its members within Duke's service territory. For each of the remaining two calendar years of the ESP, Duke agrees to provide $100,000 annually, to support economic development and energy efficiency efforts, provided Duke's ROE, as determined in its then most recent annual SEET review, exceeds 10 percent for the prior calendar year. Said funds will be provided from DEC shareholders and shall be available to OMA members in Duke's service territory on a competitively neutral basis and without regard to their status as a shopping or nonshopping customer.

(d) For the term of this ESP, while PIPP customers will remain retail generation customers of Duke, their metered, retail load and usage will be supplied by FES at a five percent discount off the applicable residential price to compare, excluding Rider AER-R. Duke will enter into a wholesale bilateral contract with FES at such pricing for the full-requirements supply including capacity, energy, market-based transmission services, and market-based transmission ancillary services for the term of the ESP, with power flow under such wholesale contract commencing January 1, 2012. While Duke is an FRR entity, it will continue to supply the capacity at the FZCP for the unconstrained RTO region. Duke will continue to supply RECs associated with the PIPP load, as required under the AER requirements of the Commission, with cost recovery through Rider AER-R. Under the bilateral contract, FES will supply power to Duke at wholesale in an amount sufficient to meet the requirements of all PIPP customers taking service under Duke's tariffs and riders for generation service. For purposes of this section, a PIPP customer shall be defined as any customer who is a PIPP customer as of January 1, 2012, and any customer who, thereafter, is enrolled in the PIPP program during the period of this ESP. Within five days of the filing of this stipulation, Duke will enter into the bilateral agreement with FES, as referred to herein, with performance obligations thereunder expressly conditioned upon Duke's acceptance of the Commission's order approving or modifying and approving the stipulation.[3]

(e) For calendar year 2012, Duke commits to a $1 million contribution for low-income weatherization efforts in its service territory, to be administered by PWC. For each of the two remaining calendar years of the ESP, Duke agrees to provide $1 million annually to support low-income weatherization, provided Duke's ROE, as determined in its then most recent annual SEET review, exceeds 10 percent for the prior calendar year. Said funds will be provided from DEC shareholders and shall be available to customers in Duke's service territory on a competitively neutral basis and without regard to their status as a shopping or nonshopping customer.

(f) Duke and PWC will jointly undertake a pilot energy efficiency project. This pilot will utilize Duke funds provided to PWC for low-income weatherization. PWC will use Duke dollars to leverage additional energy efficiency funds from nonutility public and private sources for both electric and gas energy efficiency for low-income households. The leveraged energy efficiency funds will provide funding for low-income weatherization services that will yield energy efficiency that is enhanced by additional improvements in the home and funded by other sources. It is anticipated that the enhanced energy efficiency services will yield better results as measured by the total resource cost test. Duke

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3 RESA, Constellation, Exelon, Direct Energy, IGS, Vectren, Wal-Mart, PJM PPG, and AEP Retail support the stipulation but do not endorse Section VII, Paragraph D, of the stipulation (Jt. Ex. 1 at 18).

and PWC will provide the results of the pilot energy efficiency project to the energy efficiency collaborative and will jointly file such results with the Commission and seek the Commission's approval of inclusion of the enhanced energy efficiency attributes in Duke's portfolio of programs for energy efficiency. The project shall be available to customers in Duke's service territory on a competitively neutral basis and without regard to their status as a shopping or nonshopping customer.

(g) For calendar year 2012, Duke commits to a $350,000 fuel fund contribution to benefit electric consumers in its service territory who are at or below 200 percent of poverty level. The fund will be managed in conjunction with the Ohio Department of Development in a manner consistent with the operation of the fuel fund provided by Duke during the current ESP. Assistance will be provided through the agencies in the Duke service territory that provide assistance under the Emergency Home Energy Assistance Program in the Duke service territory. For each of the two remaining calendar years of the ESP, Duke agrees to provide $350,000 in continued support of the fuel fund, provided Duke's ROE, as determined in its then most recent annual SEET review, exceeds 10 percent for the prior calendar year. Said funds will be provided from DEC shareholders and shall be available to customers in Duke's service territory on a competitively neutral basis and without regard to their status as a shopping or nonshopping customer.

(h) For calendar year 2012, Duke commits to a $325,000 contribution for low-income weatherization efforts in its service territory in Adams, Brown, Butler, Clermont, Clinton, Highland, Montgomery, and Warren Counties. The contribution shall be made to OPAE, which shall receive an administrative fee of $25,000. The funds shall be available until expended for the benefit of the appropriate agencies within Duke's service territory. Duke and OPAE shall agree to the amount of distribution to each agency, program parameters, and reporting requirements. The program parameters shall be substantially similar to the programs currently managed by OPAE for AEP, The Dayton Power & Light Company, and FirstEnergy. For each of the two remaining calendar years of the ESP, Duke agrees to provide $325,000 annually to support low-income weatherization programs of OPAE member organizations, provided Duke's ROE, as determined in its then most recent annual SEET review, exceeds 10 percent for the prior calendar year. Said funds will be provided from DEC shareholders and shall be available to customers in Duke's service territory on a competitively neutral basis and without regard to their status as a shopping or non-shopping customer. The Duke Energy Community Partnership shall review the results of the program and make recommendations regarding continuation of the program as a part of Duke's DSM portfolio.

(i) Duke will continue to provide existing distribution reserve capacity at no charge for existing load for GCHC member hospitals for the term of this ESP. Duke agrees to consider similar reasonable arrangements for new hospital construction and/or expansion up to 4,000 kilovolt ampere during the term of this ESP, provided the requesting hospital(s) and Duke can reach agreement on appropriate compensation to Duke if it is necessary to upgrade facilities for the purpose of a secondary distribution service and/or reserve capacity. Duke agrees to meet with any requesting GCHC member hospitals to discuss Duke's electric distribution system serving the member hospital, including, but not limited to, any system enhancements planned and the age and performance of the system. Also, for the term of the ESP, Duke will work with GCHC member hospitals to understand and evaluate service quality concerns, particularly with regard to secondary feeders for reliability purposes, and to enhance communication between members and Duke to facilitate better understanding of overall service quality. Duke and GCHC will hold meetings upon request to discuss, at least annually, any service quality or reliability concerns. Within 90 days of the approval of this stipulation, Duke will meet with GCHC to identify ways to leverage and better utilize Duke's nonresidential custom and prescriptive energy efficiency programs to benefit GCHC member hospitals.

For the term of the ESP, Duke agrees to continue to compensate GCHC member hospitals that participate in PowerShare agreements consistent with the terms of the PowerShare program and any subsequent program approved by the Commission.

(j) For the term of the ESP, the parties agree to establish, on a revenue-neutral basis among all demand-metered customer classes, an unavoidable demand charge and unavoidable energy credit designed to stabilize electric service by enhancing some of the benefits associated with high-load factor customers under current rates. For customers served under rates for service at secondary distribution voltage (DS), service at primary distribution voltage (DP), and service at transmission voltage (TS), there will be an unavoidable demand charge of $8/kW per month and a unavoidable energy credit of $0.020961/kWh to produce net revenues of $0 for Rates DS, DP, and TS as a group. The energy credit referred to in this paragraph is to be trued up quarterly to maintain net revenue neutrality.

(k) UC operates a Commission-certified renewable energy generation facility at its main campus in Cincinnati which is not directly metered by Duke. For the term of this ESP, UC will establish its main campus demand usage for rate purposes, including for Rider ESSC and the load factor adjustment, by using the five coincident peak (CP) demand determinate established by PJM for purposes of assessing capacity costs. Until PJM establishes an actual demand determinate for the PJM 2012/2013 planning year, which is anticipated to occur in October 2011, Duke shall use 12,475 kW, which is the five CP demand factor for UC for the 2011/2012 PJM planning year. The commodity billing determinates for both Rider ESSC and the load factor adjustment shall be the kWh received by UC at its side of the substation.

(l) COSE and Duke will work with small and mid-sized businesses in the Duke service territory to educate such entities with respect to services provided by both Duke and COSE related to energy efficiency during the term of this ESP. To the extent such customers can provide energy savings as a result of implementing energy efficiency measures, Duke will compensate COSE through its Commission-approved energy efficiency programs for services performed on behalf of the businesses that they work with, at a rate to be determined in the future and similar to the compensation rate paid to other vendors, provided the savings contribute to Duke's mandated energy efficiency requirements. COSE will participate in Duke's energy efficiency collaborative and provide its views and input with respect to the design of energy efficiency products and programs for small- and mid-sized businesses.

(m) In the aggregate, the ESP, as agreed to in the stipulation, is better than the results that would be expected under an MRO and is consistent with and advances state policy, as set forth in Section 4928.02, Revised Code, as it:

(i) Is quantitatively better than the results expected under the MRO, as provided in attachment D to the stipulation;

(ii) Allows customers to benefit from a fully competitive market as soon as practicable;

(iii) Encourages and supports the development of competitive retail markets in Ohio;

(iv) Results in stability and certainty with respect to retail electric service;

(v) Provides for a stable electric distribution utility;

(vi) Encourages the development of renewable resources in Ohio;

(vii) Supports economic development;

(viii) Provides low-income assistance;

(ix) Ensures PIPP customers a discount from the SSO;

(x) Continues and expands the ability of retail electric consumers served by Duke to choose from among CRES providers on a competitive basis;

(xi) Expands wholesale competition;

(xii) Mandates divestiture of Duke's generation assets;

(xiii) Constitutes a state regulatory structural change, within the meaning of Section 1.81 and Section C.3 of Schedule 8.1 of the PJM Reliability Assurance Agreement (RAA); and

(xiv) Allows Duke to terminate its FRR plan due to such state regulatory structural change, subject to any necessary governmental approvals, by providing notice of termination pursuant to Section C.3 of Schedule 8.1 of the PJM RAA at least two months prior to the May 2012 PJM Base Residual Auction.[4]

According to Duke witness Janson, the ESP reflects financial commitments by Duke for economic development and serving low-income customers. PIPP customers will be precluded from participating in customer choice; however, they will be afforded the benefit of a discounted price for generation service, via the agreement between Duke and FES to supply PIPP customers at a five percent reduction. (Duke Ex. 21 at 6-7.) The Commission notes that, if a customer is no longer a PIPP customer, they will be eligible to participate in customer choice.

(8) Generating Assets

(a) Duke will transfer title, at net book value, to all of its generation assets out of Duke. Such transfer shall occur on or before December 31, 2014, and Duke commits to using its best commercial efforts to complete the transfer as soon as practicable upon its acceptance of a Commission order approving the stipulation and upon receipt of necessary regulatory approvals. Staff, or an independent auditor, at the Commission's discretion and with costs thereof to be recovered through Rider SCR, shall audit the terms and conditions of the transfer of the generation assets to ensure compliance with the stipulation and shall also audit Duke's compliance with Section

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4 OCC supports the stipulation. However, OCC takes no position regarding Section VII.M. of the stipulation, or does not support or oppose that paragraph, so that OCC's support for the stipulation may not be used as precedent in any other proceeding. (Jt. Ex. 1 at 25.)

4928.17, Revised Code, and Rule 4901:1-37, O.A.C., to ensure that no subsidiary or affiliate of Duke that owns competitive generation assets has any competitive advantage due to its affiliation with Duke. The parties support Duke's request for a waiver of the Commission's rule requirements, as set forth in Rule 4901:1-37-09(B) through (D), O.A.C., relating to the sale or transfer of generating assets. Approval of the stipulation shall constitute the Commission's consent required by paragraphs (A) and (E) of that rule, and that no hearing is required under paragraphs (D) and (E) of that rule. Staff shall be provided with access to books and records in compliance with paragraph (F) of that rule.

(b) Approval of this stipulation will serve as the Commission's approval of full legal corporate separation, as contemplated by Section 4928.17(A), Revised Code, such that the transmission and distribution assets of Duke will continue to be held by the distribution utility and all of Duke's generation assets shall be transferred to an affiliate. Full legal corporate separation will be implemented as soon as reasonably possible after necessary regulatory approvals are obtained. Following the transfer of the generation assets, Duke shall not, without prior Commission approval, provide or loan funds to, provide any parental guarantee or other security for any financing for, and/or assume any liability or responsibility for any obligation of subsidiaries or affiliates that own generating assets; provided, however, that contractual obligations arising before the signing of the stipulation shall be permitted, but only to the extent that assuming or transferring such obligations is prohibited by the terms of the contract or it is commercially infeasible for Duke to transfer such obligation to its subsidiary or affiliate, and provided further that, on and after the signing of this stipulation, Duke shall ensure that all new contractual obligations have a successor-in-interest clause that transfers all Duke responsibilities and obligations under such contracts and relieves Duke from any performance or liability under the contracts upon the transfer of the generation assets to its subsidiaries. This does not restrict Duke's ability to receive and pass through to the subsidiary(ies) that own the generation assets equity contributions from its parent that are in support of the generation assets, nor does it restrict Duke's ability to receive dividends from the subsidiary(ies) that own the generation assets and pass through such dividend(s) to its parent. Generation-related costs associated with implementing corporate separation shall not be recoverable from customers. Any subsidiary of Duke to which generation assets are transferred shall not use or rely upon the rating(s) from credit rating agency(ies) for Duke if such subsidiary currently does not maintain separate rating(s) from the credit rating agency(ies), then upon transfer of any of the generation assets, it shall either seek to establish such rating(s) or shall tie its credit rating to DEC as soon as practicable, but no later than six months following such transfer.

(c) The parties expressly agree that full legal corporate separation is in the public interest and, as such, they will not intervene in the FERC proceeding to transfer Duke's generation assets in order to contest, challenge, or in any way oppose the transfer. Parties are not precluded from intervening in said FERC proceeding for purposes other than those prohibited by this paragraph.[5]

Duke witness Whitlock explains that Duke's generating assets have been functionally separated from Duke, the regulated distribution utility, but that, since 2001, the energy and capacity of these plants have been dedicated to serving Duke's retail electric customers. Mr. Whitlock states that the objective of transferring the generation assets to an affiliate or subsidiary is to allow Duke to fully embrace competitive markets

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[5] OMA supports the stipulation. However, OMA takes no position regarding Section VIII.C of the stipulation, or does not support or oppose that paragraph, so that OMA's support for the stipulation may not be used as precedent in any other proceeding. (Jt. Ex. 1 at 28.)

and bring the benefits of competition in both wholesale and retail markets to Duke's customers. According to Mr. Whitlock, the transfer of the generation assets will begin immediately after the approval of this order, which serves as final approval for the transfer of the generation assets, but could potentially take as long as one year, as the transfer also requires FERC approval. (Duke Ex. 24 at 4-8; Tr. at 51.)

(9) Miscellaneous

(a) Duke shall implement Rider RECON as proposed in Duke's application. Rider RECON shall terminate no later than two quarters after the filing of a final entry in the docket initiated by the Commission for purposes of conducting its final audit of Rider PTC-FPP.

(b) Effective January 1, 2012, Duke shall implement Rider UE-GEN applicable to all retail jurisdictional customers including those taking generation service from a CRES provider, except for those customer accounts designated by CRES providers as not part of Duke's PAR program. Rider UE-GEN shall be avoidable by dual-billed customer accounts and customer accounts designated by CRES providers as not part of the PAR program, but shall be unavoidable by all other retail customers, including SSO customers and customer accounts designated by CRES providers as part of the PAR program. Accordingly, uncollectible expenses generated by customer accounts of CRES providers that utilize dual billing and customer accounts of CRES providers that utilize consolidated billing but are not designated as part of the PAR program are excluded from Rider UE-GEN and, instead, remain the liability of said CRES provider. Rider UE-GEN will initially be set at zero in these proceedings. Duke's initial application to establish a rate for Rider UE-GEN shall be filed in conjunction with Duke's Rider UE-ED filing. Thereafter, Duke will file annual applications to adjust Rider UE-GEN in conjunction with and governed by the same review process applicable to adjustments to Rider

UE-ED as provided in *In the Matter of the Application of Duke Energy, Inc. for an Increase in Electric Rates*, Case Nos. 08-709-EL-AIR, et al. As with Rider UE-ED, Duke shall not accrue carrying charges on the monthly unrecovered uncollectible expense balances for which recovery is sought through Rider UE-GEN. Rider UE-GEN shall be in form set forth in attachment E to the stipulation.

(c) After the effective date of Rider UE-GEN, Duke shall purchase the customer accounts receivable of CRES providers that designate accounts to participate in the PAR program at no discount and shall pay such CRES providers for such receivables no later than twentieth day of the month after the month in which the billing occurs. Duke's Supplier Tariff shall be amended as shown in attachment E to the stipulation to memorialize this change to the PAR Program. Duke agrees to amend any existing PAR agreements with CRES providers participating in the PAR program to make them consistent with the stipulation.

(d) Duke agrees to modify its Certified Supplier Tariff and its Electric Tariff, and to make any other tariff modifications that are necessary to eliminate the prohibition against customers enrolling in the PAR program where such customers have outstanding arrears of more than $50 or 30 days.

(e) CRES providers may designate which of their customer accounts will be billed using a dual-billing method, which of their customer accounts will be billed using consolidated billing but with no purchase of receivables by Duke, and which of their customer accounts will be billed using consolidated billing with purchase of receivables. Duke will accommodate different methods of billing and collections by a CRES provider, so long as alternative methods of billing and collection are distinguished as subaccounts to PJM. The responsibility for, and PJM costs related to, creating a PJM subaccount shall be that of the CRES provider.

(f) Duke withdraws its proposed profit sharing mechanism rider and Advance Southwest Ohio Fund, as well as the funding for same.

(g) Duke withdraws its distribution reliability rider as proposed in these proceedings. Within 45 days of the execution of the stipulation, Duke shall file, in a separate proceeding, for Commission approval of a distribution revenue decoupling mechanism that will adjust rates between rate cases to effectively remove Duke's through-put incentive, with all parties retaining their rights to due process in such proceeding. The decoupling mechanism to be filed through such application shall not be applicable to Rates TS, DS, and DP. Nothing in this stipulation is intended, or shall be interpreted, to signify parties' agreement with such application. Further, nothing in this stipulation shall affect Duke's existing SmartGrid recovery mechanism, which shall continue under the distribution reliability infrastructure modernization rider.

(h) Duke shall conduct collaborative meetings, on or before November 15, 2011, with all interested wholesale suppliers, retail suppliers, and transmission owners to confirm the charges from PJM that shall be paid by Duke and the charges from PJM that shall be paid by CRES providers.

(i) Duke shall be permitted to amend its certified supplier tariff, as proposed in its application, as modified in this stipulation.

(j) Duke agrees to withdraw from these proceedings the proposed amendment to Section XIV.C of its Third Amended Corporate Separation Plan (CSP) that, if approved, would enable Duke to provide special customer services. Duke expressly reserves the right to seek revision of its CSP to incorporate this proposal to provide special customer services in a subsequent proceeding. Except as modified in the stipulation, Duke shall be permitted to adopt its Third Amended CSP, as proposed in its application. The Third Amended CSP will be amended to identify additional affiliates and parties to agreements following the anticipated merger of DEC and Progress Energy, Inc., and the parties agree not to oppose such amendment. Within 90 days after the effective date of full legal corporate separation, Duke agrees to file for approval of a fourth amended CSP that will address any issues with the full legal corporate separation.

(k) The parties agree that the SEET, as provided for under Section 4928.143(F), Revised Code, shall be administered to Duke with an ROE threshold of 15 percent for the term of this ESP. The methodology for applying the SEET is outlined in attachment H to the stipulation.

(l) During the term of this ESP, transmission voltage customers, whether shopping or nonshopping, with loads in excess of 10 MW at a single site shall have the option to annually nominate any part of their load as being subject to interruption through Duke. Any such nomination shall have an effective date no earlier than June 1, 2012. For any customer electing to nominate load subject to interruption through Duke, such load: (1) must be registered with PJM and abide by all of PJM's requirements for the demand response (DR) program chosen by the customer, by March 1 of the upcoming PJM planning year; (2) must not have been previously sold or committed to PJM or another party as a DR resource for the same planning year; and, (3) will have Duke serve as its curtailment service provider. The customer acknowledges that Duke may use such interruptible load in Duke's FRR plan and any capacity resource revenues associated with this DR resource will be credited to the economic competitiveness fund (Rider DR-ECF). The interruptible credit for load subject to interruption will be one half of the PJM net cost of new entry (CONE) on a $/MW-day basis for the planning year in which the interruptible load is nominated (net CONE equals 2011/2012 = $160.76, 2012/2013 = $276.09, 2013/2014 = $317.95, 2014/2015 = $342.23 per MW-day). The maximum amount of interruptible load under this program shall be 250 MW in the DEOK zone. The amount of this interruptible credit shall be recoverable by Duke through Rider DR-ECF. Duke shall file a separate application to amend Rider DR-ECF.

(m) Duke will work with interested CRES providers and Staff to jointly develop a secure, web-based system that will provide electronic access to key customer usage and account data that can be accessed via a secure, supplier website that presents the following data and information in a format that can be automatically retrieved, by the CRES provider authorized by the customer, subject to appropriate limitations reflecting legally mandated customer privacy issues, including compliance with protections addressed in the O.A.C. and specifically including, but not limited to, Rules 4901:1-10-24 and 29, O.A.C.. The following data and information, in a format that can be automatically retrieved, will be the subject of the web-based system: account numbers; meter numbers; names; service address, including zip codes; billing address, including zip codes; email address; meter reading cycle dates; meter types; indicator if customer has an interval meter; rate code indicator; load profile group indicators, peak load contribution (PLC) and network service peak load (NSPL) values (capacity and transmission obligations); 24 months of consumption data (in kWh) by billing period; 24 months of demand data (in kW); 24 months of interval data; indicator if

SSO customer; and, identifier as to whether customer is participating in the budget billing plan.

Duke shall use commercially reasonable efforts to add to the existing web system the load profile group indicators and the customer service addresses by March 1, 2012, but shall complete such additions no later than June 1, 2012. Duke shall make a commercially reasonable effort to add the other items by June 1, 2013, but agrees to complete the additional data items no later than June 1, 2014, and will work with Staff and interested CRES providers to stage the implementation of various portions of this website, as possible. Additionally, Duke shall add an indicator to the preenrollment list, noting whether a customer is an SSO customer or is shopping, by no later than June 1, 2012.

Duke shall recover the actual costs to develop said web-based system, recovery not to exceed $500,000, on an unavoidable basis. Duke shall be permitted to create a regulatory asset for purposes of recording said costs for future recovery through electric distribution rates. The carrying charge on said regulatory asset shall not exceed Duke's long-term cost of debt from the then most recent distribution rate case.

In addition, the following types of data would be provided via electronic data interchange (EDI) transactions: 867 historical usage (HU) and historical interval (HI); 867 monthly usage and monthly interval data; NSPL and PLC in 867HUs, 867HIs, and 814 accepted enrollment responses; and meter read cycle and load profile segment information to be in 867HUs no later than 12/31/12, as agreed to in the Ohio EDI Working Group - Change Control #82 (current rate code already included in 867HUs).

Duke shall confirm that accounts requested together in the same EDI envelope come back together, unless there would be an unnecessary delay for a particular subset of accounts. Duke shall make available, upon request, a quarterly updated sync list to CRES providers on a confidential basis showing the accounts that are enrolled with the CRES provider. The list would contain information such as service start date, bill method, NSPL values, and PLC values. Duke confirms that validation, error detection, and editing (VEE) rules and processes are now in place and will continue to be applied to raw meter read data before Duke transmits such usage data to the CRES providers via EDI.

Effective January 1, 2012, Duke shall increase the required interval meter threshold size requirement from 100kW to 200kW and will make such tariff changes as are necessary to accomplish this result.

Duke agrees to conduct a collaborative process to discuss the deployment of an electric vehicle (EV) ecosystem that works in tandem with a competitive retail market, including, but not limited to, customer education and additional billing system functionality to support various EV deployment programs and charging platforms. All interested persons shall be encouraged to participate in the EV collaborative process. The first such EV collaborative meeting shall occur in the first quarter of 2012 and continue to be held periodically, but not less often than three times a year for the first two years thereafter. At the conclusion of the EV collaborative process, the participants in the EV collaborative shall prepare a report to the Commission discussing the progress of the collaborative and any recommended regulatory or legislative changes to facilitate the development of an EV ecosystem.

Duke shall host annual meetings or conference calls with registered CRES providers to discuss supplier coordination issues affecting CRES providers, including but not limited to CRES consolidated billing.

(n) All energy efficiency programs and rebates shall be made available at the same terms and conditions to customers, regardless of whether they purchase generation service from a CRES provider or Duke. Duke shall maintain its policy to make SmartGrid meters and data available to all customers on a competitively neutral basis and without regard to their status as a shopping or nonshopping customer.

(o) Duke shall provide, from shareholder funds, a one-time economic development/energy efficiency grant of $50,000 for IEU to be distributed among its members.

(p) For the term of this ESP, Duke will maintain its existing procedures contained in its tariff (*e.g.*, bulking of meters, power factor adjustments, demand ratchets) for metering and calculating billing determinants that are used in the calculation of retail bills.

(q) For the term of this ESP, Duke will continue the retail real-time pricing rate (Rate RTP), Sheet No. 90. Current customer base line and billing demand history values will continue for each customer taking service under RTP as of October 18, 2011, subject to the terms of Rate RTP, as modified to be consistent with this stipulation.

(r) Duke will reduce its switching fee, as set forth in rate certified supplier, Sheet No. 52.2, of its Certified Supplier Tariff, from $7.00 to $5.00. Duke will make bill-ready billing functional and available as soon as commercially and reasonably practicable, but in no event later than September

30, 2013. In addition, Sheet 52.2 of the Certified Supplier Tariff shall be modified to reduce the per-bill charges for consolidated, bill-ready billing to 50 percent of the existing rate. Duke agrees to continue its current practice of not imposing a per-bill charge for rate-ready consolidated billing services.

(s) Retail customers in Duke's territory are permitted to participate in PJM DR programs including through aggregators of retail customers or curtailment service provider and the following conditions apply:

(i) Duke retail customer DR capacity may be utilized to satisfy either FRR or non-FRR capacity obligations (such as DR that clears in a PJM RPM auction);

(ii) Any customer that is already receiving an incentive payment through a reasonable arrangement, including but not limited to energy efficiency/peak demand reduction, economic development arrangements, unique arrangements, and other special tariff schedules that offer service discounts from the applicable tariff rates and would currently or would like to participate in PJM programs must agree to commit to the electric distribution utility the peak DR attributes that have cleared in the PJM market in a manner consistent with applicable statutes and rules at no cost to the utility for the duration of the arrangement. This provision shall not be interpreted as modifying the express specific terms of any agreement; and

(iii) Duke may issue a request for proposal (RFP) to meet its peak demand reduction mandates under the statute.

The "Summary of Riders Impacted by the ESP," attached as attachment I to the stipulation, provides an accurate recitation of Duke's riders for electric distribution, transmission, and generation service, effective January 1, 2012. Rider RTC (regulatory transition charge) and Rider DRI (distribution reliability investment) expired for all customers on December 31, 2010.

III. CONSIDERATION OF THE STIPULATION

Rule 4901-1-30, O.A.C, authorizes parties to Commission proceedings to enter into a stipulation. Although not binding on the Commission, the terms of such an agreement are accorded substantial weight. See *Consumers' Counsel v. Pub. Util. Comm.* (1992), 64 Ohio St.3d 123, 125, *citing Akron v. Pub. Util. Comm.* (1978), 55 Ohio St.2d 155. The standard of review for considering the reasonableness of a stipulation has been discussed in a number of prior Commission proceedings. See, e.g., *Cincinnati Gas & Electric Co.*, Case No. 91-410-EL-AIR (April 14, 1994); *Western Reserve Telephone Co.*, Case No. 93-230-TP-ALT (March 30, 1004); *Ohio Edison Co.*, Case No. 91-698-EL-FOR, *et al.* (December 30, 1993); *Cleveland Electric Illum. Co.*, Case No. 88-170-EL-AIR (January 30, 1989); *Restatement of Accounts and Records (Zimmer Plant)*, Case No. 84-1187-EL-UNC (November 26, 1985). The ultimate issue for our consideration is whether the agreement, which embodies considerable time and effort by the signatory parties, is reasonable and should be adopted. In considering the reasonableness of a stipulation, the Commission has used the following criteria:

(1) Is the settlement a product of serious bargaining among capable, knowledgeable parties?

(2) Does the settlement, as a package, benefit ratepayers and the public interest?

(3) Does the settlement package violate any important regulatory principle or practice?

The Ohio Supreme Court has endorsed the Commission's analysis using these criteria to resolve issues in a manner economical to ratepayers and public utilities. *Indus. Energy Consumers of Ohio Power Co. v. Pub. Util. Comm.* (1994), 68 Ohio St.3d 559 (*citing Consumers' Counsel, supra,* at 126.) The court stated in that case that the Commission may place substantial weight on the terms of a stipulation, even though the stipulation does not bind the Commission. (*Id.*)

A. Is the settlement a product of serious bargaining among capable knowledgeable parties?

Duke witness Janson testified that the signatory parties represent a broad range of interests, regularly participate in rate proceedings before the Commission, are very knowledgeable in regulatory matters, and were represented by experienced, competent counsel. Moreover, Ms. Janson opines that all of the issues raised by the signatory parties in negotiations were thoroughly reviewed and addressed and all parties had an opportunity to express their opinions on each issue during negotiations that occurred over a period of three months and involved almost daily meetings in the weeks leading up to the filing of the stipulation. Further, parties were represented by counsel and had the additional benefit of subject matter experts. (Duke Ex. 21 at 8-9.) OPAE witness Rinebolt asserts that, in addition to numerous discussions with all parties, numerous bilateral discussions between Duke and individual parties occurred prior to reaching the stipulation (OPAE Ex. 1 at 3). Kroger witness Higgins opines that the stipulation is the product of serious bargaining, which resulted in a comprehensive and fair compromise among diverse parties with competing interests (Kroger Ex. 1 at 4).

Upon review of the stipulation, the Commission observes that, based upon the wide-range of issues addressed and resolved in the stipulation, which affect a very diverse and experienced group of parties that signed the stipulation, it is evident that the parties expended a great deal of time and effort to resolve the issues in these proceedings. The signatory parties represent interests including the company, municipalities, competitive suppliers, industrial consumers, commercial consumers, advocates for low- and moderate-income customers, environmental advocates, and Staff. Further, we note that the signatory parties routinely participate in complex Commission proceedings and that counsel for the signatory parties have extensive experience practicing before the Commission in utility matters. Accordingly, the Commission finds that the stipulation meets the first prong of the test and appears to be the product of serious bargaining among capable, knowledgeable parties.

B. Does the settlement, as a package, benefit ratepayers and the public interest?

Ms. Janson asserts that the stipulation benefits consumers and the public because it provides significant benefits across all customer groups and for other interested stakeholders, while advancing and remaining consistent with state policy (Duke Ex. 21 at 10). Mr. Higgins opines that the stipulation results in fair and reasonably priced rates for customers (Kroger Ex. 1 at 4). Mr. Rinebolt explains that the stipulation allocates funding from shareholders to meet pressing social and economic needs within Duke's service territory. Further, Mr. Rinebolt avers that the stipulation utilizes market forces to establish the price of the SSO, which will benefit consumers compared with the alternative. (OPAE Ex 1 at 4.) Constellation and RESA witness David Fein believes that the stipulation will encourage competition in Duke's territory, which will benefit all consumers (RESA Ex. 1 at 9; Constellation Ex. 1. at 6).

Staff witness Turkenton explains some of the benefits customers will see under the proposed ESP, including increased development of competition in Duke's service territory, a discount for PIPP customers, and incentives to support economic development and energy efficiency initiatives. Moreover, Ms. Turkenton explains that the Duke auction process is similar to the one that has been successfully utilized in the FirstEnergy service territory to fulfill market-based SSO obligations. (Staff Ex. 1 at 3-7.)

As noted by the witnesses supporting the stipulation, it appears that, as a whole, the provisions of the stipulation provide benefits to all stakeholders. Not only does the stipulation, when compared to the initial application filed in these cases, provide a more straightforward approach for Duke's provision of SSO service, but the three-year, five-month term of the ESP set forth in the stipulation is more judicious. The stipulation provides safeguards and promotes an appropriate level of review during the term of the ESP, including audits and true-ups of Duke's riders, as well as audits of Duke's energy sales, transfer of generation assets, and Duke's compliance with Section 4928.17, Revised Code, and Rule 4901:1-37, O.A.C., to ensure that no subsidiary or affiliate of Duke that owns competitive generation assets has any competitive advantage due to its affiliation with Duke. Furthermore, the Commission finds that the stipulation promotes collaborative discussions amongst stakeholders for topics including, the CBP, the residential SREC purchase program, combined heat and power, a pilot energy efficiency project, energy efficiency products and programs for small- and mid-sized businesses, confirmation of the charges from PJM, and the deployment of an EV ecosystem that works in tandem with a competitive retail market.

Moreover, the Commission acknowledges that the stipulation contains provisions which promote economic development and energy efficiency as evidenced by Duke's commitment to provide support to industrial and commercial enterprises throughout the company's service territory. Duke's support for low-income ratepayers is also demonstrated in the stipulation through Duke's commitment to low-income, weatherization programs and the discounts for PIPP customers.

Accordingly, based upon the evidence on the record in these proceedings, the Commission finds that the stipulation, as a package, benefits ratepayers and promotes the public interest.

C. <u>Does the settlement package violate any important regulatory principle or practice?</u>

Staff witness Turkenton explains that the stipulation does not violate any important regulatory principle, but instead furthers the policy of the state to provide reasonably priced and reliable electric service and gives customers effective choices that ensure diversity of electric supply and suppliers. Moreover, Ms. Turkenton opines that, under an ESP framework, flexible regulatory treatment is achieved that could not be achieved under an MRO structure. (Staff Ex. 1 at 7-8.) Duke witness Janson further avers that the stipulation complies with all relevant and important principles and practices, and furthers those through the advancement of the competitive market in Duke's service territory in Ohio, by embracing a full competitive auction SSO and full legal separation of Duke's generating assets from its distribution utility (Duke Ex. 21 at 9-10). Kroger witness Higgins asserts that the stipulation is consistent with Ohio's regulatory principles and practices, and is consistent with Ohio law. Moreover, Mr. Higgins states that the stipulation promotes an orderly transition to market-based pricing and encourages competition by giving customers choices with respect to their electricity suppliers. (Kroger Ex. 1 at 5.)

Section 4928.02, Revised Code, establishes 14 state policy objectives the Commission must take into consideration when reviewing the proposed stipulation. When contemplating these objectives, the Commission understands that it is our responsibility to weigh the facts presented in these cases and, ultimately, ensure that consumers are provided adequate, safe, reliable, nondiscriminatory, reasonably-priced services, while also balancing the need to promote competitive options, where appropriate. Among these policy objectives is encouraging innovation and market access for demand-side retail electric service, Section 4928.02(D), Revised Code. We find that the stipulation provision at IX.H, which directs Duke to file an application for a distribution revenue decoupling mechanism that will adjust rates between rate cases to effectively remove Duke's throughput incentive, supports this goal. However, because, under this ESP, Duke will continue to recover fixed distribution costs lost as a result of energy efficiency through a rider, which is currently known as the Distribution Rider - Save-A-Watt, the Commission clarifies that the application for a distribution revenue decoupling mechanism must incorporate a proposal to adjust this rider mechanism, as well. With this clarification, the Commission concludes that, in considering the stipulation and the record in these cases, the policy objectives set forth in Section 4928.02, Revised Code, will be advanced by the provisions contained in the agreement submitted for our consideration by the stipulating parties. Accordingly, based upon the evidence of record in these proceedings, the Commission finds that the stipulation does not violate any important regulatory principles or practices.

D. Generating Assets and Corporate Separation, Section 4928.17, Revised Code

The stipulation provides that the Commission's approval of the stipulation will constitute approval of Duke's Third Amended CSP and full legal corporate separation, as contemplated by Section 4928.17(A), Revised Code, such that the transmission and distribution assets of Duke will continue to be held by the distribution utility and all of Duke's generation assets will be transferred to an affiliate (Jt. Ex. 1 at 26).

Section 4928.17, Revised Code, provides that an electric utility that, either directly or through an affiliate, engages in the business of supplying a noncompetitive retail electric service and a CRES or a product or service other than retail electric service must operate under a CSP. Pursuant to the statute, the CSP must be consistent with the policy of the state set forth in Section 4928.02, Revised Code, and achieve all of the following:

(1) provide, at minimum, for the provision of the CRES or the nonelectric product or service through a fully-separated affiliate of the utility, and include separate accounting requirements, the code of conduct, and such other measures as are necessary to effectuate the state policy;

(2) satisfy the public interest in preventing unfair competitive advantage and preventing the abuse of market power; and

(3) be sufficient to ensure that the utility will not extend any undue preference or advantage to any affiliate, division, or part of its own business engaged in the business of supplying the CRES or nonelectric product or service, without compensation based upon fully-loaded embedded costs charged to the affiliate; and ensure that any such affiliate, division, or part will not receive undue preference or advantage from any affiliate, division, or part of the business engaged in business of supplying the noncompetitive retail electric service. No such utility, affiliate, division, or part shall extend such undue preference.

Chapter 4901:1-37, O.A.C., sets forth the requirements pertaining to corporate separation for electric utilities. Specifically, this chapter is applicable to the activities of the utility and its transactions or other arrangements with its affiliates, any shared services of the utility with any affiliates, and the sale or transfer of generating assets.

Pursuant to the stipulation, the parties support Duke's request for waiver of the requirements set forth in Rule 4901:1-37-09(B) through (D), O.A.C., relating to the sale or transfer of generating assets (Jt. Ex. 1 at 26). Specifically, the provisions in Rule 4901:1-37-

09(B) through (D), O.A.C., set forth the filing requirements and the procedures to be followed for an application requesting approval of the sale or transfer of generating assets.

Upon review of the stipulation, the Commission believes that the provisions contained therein provide the necessary safeguards to ensure that the statutory mandates pertaining to Duke's sale of generation assets and corporate separation are adhered to and the policy of the state is carried out. Therefore, we conclude that, to the extent necessary, Rule 4901:1-37-09(B) through (D), O.A.C., should be waived and Duke should be authorized to transfer title to all of its generation assets out of Duke, in accordance with the provisions of the stipulation. Furthermore, we conclude that Duke's full legal corporate separation and Third Amended CSP, as provided in the stipulation, are in compliance with Section 4928.17, Revised Code, and the rules contained in Chapter 4901:1-37, O.A.C., and should be approved.

E. Is the proposed ESP more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code?

The Commission must also consider the applicable statutory test for approval of an ESP. Section 4928.143(C)(1), Revised Code, provides that the Commission should approve, or modify and approve, an application for an ESP if it finds that the ESP, 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 an MRO pursuant to Section 4928.142, Revised Code.

Staff witness Turkenton believes that the ESP provides a better framework than an MRO. According to Ms. Turkenton, the ESP should be judged as a comprehensive plan that promotes fully competitive markets, promotes energy efficiency, provides rate certainty and stability, promotes economic development by making specific tangible commitments to vital industrial and commercial enterprises, and supports low-income ratepayers. (Staff Ex. 1 at 8.)

In support of the ESP, Duke witness Janson explains that, under the ESP, Duke residential SSO customers will see an approximate 11 percent reduction from their current rates. In addition, customers will realize financial benefits that are not contemplated under MRO provisions, including: $1 million to support economic development efforts in Duke's service territory in 2012; $1.35 million for low-income weatherization programs; and $350,000 for a fuel fund administered by OPAE. These programs may be renewed for 2013 and 2014. (Duke Ex. 21 at 10-11.)

Duke witness Wathen points out that the ESP will result in lower overall costs for retail ratepayers than what customers would experience in an MRO, independent of any other benefits of the ESP. Specifically, Mr. Wathen explains that, on a purely mathematical basis, the net present value of the benefits to customers from Duke's ESP is approximately $62 million greater, including the other benefits associated with the stipulation, than the total value of the alternative MRO. Accordingly, Mr. Wathen concludes that these figures contribute significantly to the conclusion that the ESP is better in the aggregate that an MRO. (Duke Ex. 22 at 30-31; Jt. Ex. 1 at Att. D.)

In addition to the mathematical benefits, Mr. Wathen explains that there are other benefits to the ESP. Specifically, Mr. Wathen explains that Duke is currently working to provide customers with more dynamic pricing options; however, customers have not taken advantage of these options due to Duke's high SSO price. With the implementation of the new ESP, Mr. Wathen opines that more Duke customers will take advantage of Duke's dynamic pricing options because there will not be such a large disincentive to take generation from Duke. (Duke Ex. 22 at 32-33.)

Duke witness Janson also explains that the ESP provides for a stable distribution utility. Specifically, she states that Rider ESSC is intended to ensure the availability of adequate, reliable, and reasonably priced electricity supply and rate stability and certainty in respect to retail electric service. Rider ESSC further is intended to protect Duke's financial integrity and ensure that the overall revenue under the ESP is adequate for Duke in its provision of an SSO. (Duke Ex. 21 at 14.)

Furthermore, Ms. Janson believes that, under the ESP, Duke will ensure that competitive markets will be realized (Duke Ex. 21 at 12-13). Likewise, Constellation witness Fein submits that the stipulation increases competition in the market place on both the wholesale level for procuring SSO energy and at the retail level by allowing for greater customer shopping, which will keep costs as low as possible and produce benefits including advancements in reliability, conservation, renewable energy development, and the ability of customers to purchase green power. Moreover, Mr. Fein explains that the ESP provides a superior platform to promote DR and energy efficiency, because consumers will pay actual market prices and have incentives to reduce or defer consumption during times when production costs are high. (Constellation Ex. 1 at 6-7; RESA Ex. 1 at 4-5.)

Having considered the evidence presented in these proceedings, the Commission agrees that the ESP, including its pricing and all other terms and conditions, is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code.

IV. CONCLUSION

Initially, the Commission notes that attachment A to the stipulation provides a timeline for conducting the auctions pursuant to the proposed CBP. The initial auction, to take place in December 2011, will be for multiple products of 17-month, 29-month and 41-month duration, with each product for approximately one-third of the SSO supply. This arrangement allows for staggered expiration of contracts so that, in any given future year, only a portion of the load will be subject to renewal at market conditions at the time. The auctions planned for 2012 would be held to acquire product to replace the 17-month product expiring at the end of May 2013, and the auctions planned for 2013 would be held to acquire product to replace the 29-month product expiring at the end of May 2014. Given the record evidence of significant shopping levels in Duke's service territory, the Commission is concerned that the remaining level of SSO load in years 2012 and 2013 may not be sufficiently large to justify holding multiple descending-clock auctions each year, pursuant to the planned schedule. Conducting these auctions is time consuming and costly, for both the company and the auction participants. The Commission would like to determine if there are more cost-effective methods to procure the necessary supply, while assuring broad bidder participation and procurement of the supply at minimal cost. Alternatives could include, among other things, combining the planned multiple auctions into single annual auctions, or conducting the solicitations pursuant to an RFP. At this time, we believe it would be helpful to obtain additional information about this issue; therefore, the auction manager and the Commission's consultant are hereby directed to file reports in these dockets setting forth their evaluations and recommendations on this issue. These reports shall be filed no later than January 20, 2012. Interested parties may file comments on the reports by January 27, 2012, and reply comments by February 3, 2012. This expedited timeframe will allow the Commission to consider the information provided and issue a timely decision well in advance of the planned May 2012, auction.

Upon consideration of the record, we find that the stipulation satisfies the three-prong criteria employed by the Commission for consideration as to the reasonableness of a stipulation. We further find that, to the extent necessary, Rule 4901:1-37-09(B) through (D), O.A.C., should be waived and Duke should be authorized to transfer title to all of its generation assets out of Duke, in accordance with the provisions of the stipulation. Furthermore, the stipulation's proposed full legal corporate separation of Duke's generation assets, in conformance with Duke's Third Amended CSP, are in compliance with Section 4928.17, Revised Code, and the rules contained in Chapter 4901:1-37, O.A.C., and should be approved. Finally, we find that the ESP, as proposed in the stipulation, is more favorable in the aggregate than an MRO. Accordingly, having made these determinations, the Commission concludes that the stipulation, as revised, should be adopted and approved.

FINDINGS OF FACT AND CONCLUSIONS OF LAW:

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

(2) On June 20, 2011, as supplemented on June 28, 2011, Duke filed an application for an SSO in accordance with Section 4928.141, Revised Code.

(3) On June 30, 2011, a technical conference was held in these proceedings.

(4) In total, at the four local public hearings that were held in these cases on August 30, 2011, and September 8 and 9, 2011, 34 witnesses testified.

(5) The following entities were granted intervention: IEU; OEG; OPAE; Kroger; OEC; FES; GCHC; Constellation; OCC; DERS; Dominion; Wal-Mart; OMA; RESA; AEP Ohio; AEP Retail; Cincinnati; Eagle; PWC; COSE; Cincinnati Bell; ELPC; EnerNOC; Vectren; PJM PPG; Direct Energy; Miami/CU; COMPETE; AMP; NRDC; IGS; and Exelon.

(6) On October 24, 2011, a stipulation was filed in these cases. The stipulation contained the agreement of Staff and all of the parties in these cases, with the exception of: AEP Ohio and Dominion, which signed stating that they take no position on the stipulation; and Eagle, which did not sign the stipulation.

(7) The evidentiary hearing in these proceedings was held on November 3, 2011.

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

(9) Duke's November 16, 2011, motion to revise Section IV.A of the stipulation should be granted and Jt. Ex. 1.1 should be admitted into the record.

(10) In accordance with the attorney examiner's ruling at the hearing, Duke Exs. 2A, 6A, 10A, 10A.1, 18A, should be granted protective treatment for a period of 18 months.

(11) Duke's application was filed pursuant to Section 4928.143, Revised Code, which authorizes the electric utilities to file an ESP as their SSO.

(12) The Commission finds that the stipulation meets the three criteria for adoption of stipulations, is reasonable, and should be adopted.

(13) Rule 4901:1-37-09(B) through (D), O.A.C., should be waived and Duke should be authorized to transfer title to all of its generation assets out of Duke, as provided in the stipulation.

(14) Duke's full legal separation and Third Amended CSP are in compliance with Section 4928.17, Revised Code, and Chapter 4901:1-37, O.A.C., and should be approved.

(15) The proposed ESP, including its pricing and all other terms and conditions is more favorable in the aggregate as compared to the expected results that would otherwise apply under Section 4928.142, Revised Code.

(16) The auction manager and the Commission's consultant shall file reports setting forth their evaluations and recommendations regarding methods to procure the necessary supply by January 20, 2012. Comments and reply comments on the reports are due by January 27, 2012, and February 3, 2012, respectively.

(17) The stipulation, as revised, is reasonable and should be approved and adopted.

ORDER:

It is, therefore,

ORDERED, That Duke's motion to amend Section IV.A of the stipulation be granted and Jt. Ex. 1.1 be admitted into the record. It is, further,

ORDERED, That Duke Exs. 2A, 6A, 10A, 10A.1, 18A, be granted protective treatment. The docketing division shall maintain these documents under seal for a period of 18 months from the date of this order, or until May 22, 2013. It is, further, ORDERED, That Rule 4901:1-37-09(B) through (D), O.A.C., be waived and Duke be authorized to transfer title to all of its generation assets out of Duke, as provided in the stipulation. It is, further,

ORDERED, That Duke's full legal separation and Third Amended CSP be approved. It is, further,

ORDERED, That the auction manager and the Commission's consultant file reports setting forth their evaluations and recommendations regarding methods to procure the necessary supply, as discussed herein, by January 20, 2012. Comments and reply comments on the reports are due by January 27, 2012, and February 3, 2012, respectively. It is, further,

ORDERED, That the stipulation filed in these proceedings, as revised, be approved and adopted. It is, further,

ORDERED, That Duke take all necessary steps to carry out the terms of the stipulation and this order. It is, further,

ORDERED, That Duke is authorized to file four complete copies of its tariffs in final form consistent with this opinion and order. DEO shall file one copy in these dockets and one copy in its TRF docket (or may make such filing electronically as directed in Case No. 06-900-AU-WVR). The remaining two copies shall be designated for distribution to the Rates and Tariffs, Energy and Water Division of the Commission's Utilities Department. It is, further,

ORDERED, The effective date of the new rates shall be a date not earlier than the date upon which four complete, printed copies of the final tariff page is filed with the Commission. It is, further,

ORDERED, That Duke shall notify all affected customers via bill message, bill insert, or separate mailing within 30 days of the effective date of the revised tariffs. A copy of this customer notice shall be submitted to the Commission's Service Monitoring and Enforcement Department, Reliability, and Service Analysis Division at least 10 days prior to its distribution to customers. It is, further,

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

THE PUBLIC UTILITIES COMMISSION OF OHIO

Todd A. Snitchler, Chairman

Paul A. Centolella

Steven D. Lesser

Andre T. Porter

Cheryl L. Roberto

CMTP/KLS/vrm

Entered in the Journal

NOV 22 2011

Betty McCauley
Secretary

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of Application of Duke Energy Ohio, Inc. for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications, and Tariffs for Generation Service.	)	Case No. 11-3549-EL-SSO
In the Matter of Application of Duke Energy Ohio, Inc. for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20.	)	Case No. 11-3550-EL-ATA
In the Matter of Application of Duke Energy Ohio, Inc. for Authority to Amend its Corporate Separation Plan.	)	Case No. 11-3551-EL-UNC

CONCURRING OPINION OF COMMISSIONER CHERYL L. ROBERTO

I join my colleagues in approving the stipulation entered in these matters. It represents a thoughtful pathway to reliance upon electric retail competition, this State's goal as espoused in S.B. 3 adopted in 1999. The parties have clearly endeavored to structure a balanced route to this ultimate destination. Since 2008, with the adoption of S.B. 221, this Commission has been granted additional tools to ease the transition from a vertically integrated regulated electricity industry to reliance upon retail competition. Over the past three years, we have utilized those tools to create a hybrid regulatory structure – something between regulation and not-quite market. Because I am concerned that lingering too long between the two regulatory structures can only harvest the worst of both worlds for Ohio's residential, commercial and industrial customers, I join in accepting a stipulation that moves Ohio inexorably to reliance upon retail competition.

I write separately to give voice to my apprehension that a truly competitive retail market in electricity, with our current technology, is an illusion. Fundamentally, I agree that load-following and peaking generation has reached the stage that competition is possible and that competition in this realm can thrive. Markets for demand response and energy efficiency bolster the competition in meeting these generation needs. Thus, I am fully supportive of competition to meet generation needs for load-following and peaking.

However, I see no real economic potential, with our current technology, that base-load generation will be built in a competitive environment prior to the market experiencing damaging and painful shortages. Investment in base-load generation is tremendously capital intensive and cannot reasonably be achieved in modular fashion (with the exception of plant efficiency investments which can provide additional generation in an incremental fashion within incumbent generation facilities). It requires a huge commitment in capital that in a competitive environment is simply too risky without a benefit to cost ratio that can only be achieved when shortages exist. At that point, the time that it will take to plan, site, finance and build generation will only add to upward price pressures and economic damage to customers. Without the ability of competitors to enter freely the market for base-load generation, a truly competitive retail electric market cannot exist. In fact, with the current Reliability Pricing Model (RPM), incumbent generators reap RPM payments to prop up existing generation while those same RPM markets are insufficient in predictability or term to support investment by new entrants.

The current relatively low electricity rates offered in recent auctions for retail service represent one of the few silver linings in the storm clouds of our country's current sluggish economy. These rates are projected to rise, as the forward price curves submitted without contradiction in this matter do. In fact, even inside the window of this Electric Security Plan, the market is projected to be significantly higher than a price that would result from a regulated environment. When the economy recovers, electricity prices will rise and customers will be fully reliant on the market to meet generation needs.

Because, however, as a Commission, it is our responsibility to implement the regulatory structure prescribed by statute, I join my colleagues in adopting this stipulation which is designed to accomplish the given goal of relying upon retail electric competition to meet the comprehensive needs of Ohio's residents and commercial and industrial enterprises - despite my misgivings that reliance on retail electricity competition may not be in the public interest.

Cheryl L. Roberto

Cheryl L. Roberto

Entered in the Journal

NOV 22 2011

Betty McCauley

Betty McCauley
Secretary

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of the foregoing Ohio Power Company's Application for Rehearing has been served upon the below-named counsel and Attorney Examiners by U.S. Mail and by electronic mail to all Parties this 13th day of January, 2012.

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