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BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets	)	**Case No. 08-917-EL-SSO**
In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan and an Amendment to its Corporate Separation Plan	)	**Case No. 08-918-EL-SSO**

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S REPLY BRIEF

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Filed: January 14, 2009

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I. INTRODUCTION

Sec. 4928.143 (C) (1), Ohio Rev. Code, provides that the Commission "shall approve or modify and approve an [ESP] ... 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 [an MRO]."

In consideration of that statutory directive, the Staff's brief makes the following declaration: **"As a general principle, the Commission Staff believes that the Companies' proposed ESP is more favorable than would be expected**

under an MRO proposal." (Staff's Br. p. 2, emphasis added). If the Commission accepts its Staff's impartial analysis, Staff's conclusion and this statutory provision resolve this proceeding.

Besides Staff's conclusion that the Companies' proposed ESP is more favorable than what would be expected under an MRO proposal, a conclusion supported by Mr. Baker's analysis comparing the proposed ESP to the MRO alternative (Companies' Ex. 2A, pp. 3-18; Companies' Ex. 2B, Exhibit JCB-2), the only other witness to present an ESP/MRO comparison was OCC's witness Smith. As will be discussed later in this brief, Ms. Smith was unable to explain her analysis with any degree of confidence.

Unfortunately, the Staff and Intervenors seem to believe that the Commission has the authority, and should exercise that authority, to improve upon an ESP so that it is even **more** favorable when compared to the expected results of an MRO than the proposed ESP is.[1] These positions by Staff and Intervenors take on many different appearances, but they all come back to one consistent, and statutorily impermissible theme. As Staff puts it, "modifications to the Companies' proposal are necessary to make it reasonable." (Staff's Br. p. 2). Of course, what is "reasonable" is not always easily determinable. Mr. Baker testified that other AEP system operating companies have had recent rate activity where the range of requested rate increase was 20 percent to

[1] The Intervenors' briefs were filed by Industrial Energy Users-Ohio (IEU); Appalachian People's Action Coalition and Ohio Partners for Affordable Energy (OPAE/APAC); Ohio Energy Group (OEG); Ohio Hospital Association (OHA); Ohio Manufacturers' Association (OMA); Kroger Co. (Kroger); Wal-Mart Stores East, LP, Sam's East, Inc. and Macy's Inc. (Commercial Group); Ohio Association of School Business Officials, Ohio School Boards Association and Buckeye Association of School Administrators (Schools); Integrys Energy Services, Inc. (Integrys); Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc. (Constellation); and Ohio Consumers' Counsel and Sierra Club Ohio Chapter (OCEA).

34 percent. (Companies' Ex. 2, p. 21). Also, Appalachian Power Company's Virginia rates were recently increased by 42 percent, without deferral. (Tr. XI, p. 237).

All of the other arguments about the favorability of the ESP compared to an MRO are related to Staff's notion that the Commission is free to make the proposed ESP even more favorable. That notion is wrong. SB 221 was enacted as a response to the impending implementation of full market rates under SB 3 for all but one of Ohio's electric distribution utilities whose Rate Stabilization Plans (RSP) expired at the end of 2008. Instead of full market rates, the General Assembly created a legislative structure that offered two choices to the utilities: pursue an MRO, which for the Companies would phase-in market rates over a period of years, or pursue an ESP. The content of an ESP was left open by the General Assembly's listing of certain provisions that could be included in the ESP, but making clear that the content was "without limitation" to the list it included in SB 221. Unlike the pre-SB 3 cost-of-service rate making structure, SB 221 gives considerable latitude to the utility in setting rates.

Understandably, the General Assembly authorized the Commission to review a proposed ESP. The extent of that review was to determine if the proposal was more favorable in the aggregate than the expected results of an MRO. If the Commission were to determine that the ESP did not pass the ESP/MRO comparison, SB 221 does not require the Commission to reject the proposed ESP. Instead, the Commission is authorized to modify the proposed ESP in such a fashion that the modified ESP would pass the ESP/MRO comparison standard. To be balanced, SB 221 does not impose such a modified ESP on the utility. Instead, the utility may withdraw its ESP application, "thereby terminating it, and may file a new standard service offer ..."which can be either another ESP or an MRO. (Sec. 4928.143 (C) (2) (a), Ohio Rev. Code),

Giving the Commission the authority to modify a proposed ESP is an appropriate "check and balance" on the latitude given the utility to structure its own ESP. The authority to modify, however, is misconstrued by the Staff and Intervenors. Their briefs are based on the improper assumption that the Commission is free to refashion an ESP to fit the parties', or perhaps the Commission's vision of the ESP they would have created if it were up to them.

The Commission's authority to modify a proposed ESP is triggered only if the ESP is not more favorable than the expected results of an MRO. The Commission is not authorized to make the ESP even better for customers in relation to the MRO than the utility's ESP already is. Were that the case there would be no need for the electric utility to submit an ESP application. The Commission simply would initiate a proceeding to set the ESP of its liking.

Prior to replying to various parties' arguments concerning the issues in this proceeding, it is appropriate to address a variety of related themes that run through the Intervenors' briefs, and to some extent the Staff's brief. These themes reflect the perception that SB 221 has reverted Ohio's electric utilities back to a pre-SB 3 form of rate regulation. The Intervenors contend that an ESP must be based on specific costs and that those costs must be proven to be prudently incurred. They argue that this cost-of-service concept supersedes the statutory "more favorable in the aggregate" standard set out in Sec. 4928.143 (C) (1), Ohio Rev. Code, for approving an ESP.

Examples of these views are found in IEU's Br. p. 8 ("SB 221's grant of authority to the Commission for the purpose of enabling cost adjustment mechanisms does so for ***prudently incurred*** costs...." (emphasis in original) and p. 19 ("The Commission's ability to look at costs and changes in cost is a function of its larger responsibility based on the objectives of Chapter 4928, Ohio Rev. Code."); Kroger's Br. p. 24 ("Before AEP is permitted to increase rates, AEP should be required to show that its *overall* cost of supplying electricity to customers has increased." (emphasis in original)); OEG's Br. p. 2 ("This means that to gain Commission approval the Companies have the burden of proving that its ESP plan ... 2) contains only costs that are '*prudently incurred.*' " emphasis in original).[2] OEG also contends that the Commission's order in the FirstEnergy companies' ESP case rejected the view that the ESP must be viewed in the aggregate of its parts, rather than judged on a component-by-component basis. (OEG Br. p. 4). The "Applicable Law" portion of that order on which OEG relies makes no such statement.[3] OCEA's Br. p.16, (The "Companies have not justified the various costs associated with the proposed ESP. As a result, customers bear a significant risk that they will be overpaying for the Companies' electric service, with no opportunity for the overcharge to be refunded."). OCC and the Sierra Club are of course aware that the General Assembly included the unique Significantly Excessive Earnings Test (SEET) in Sec. 4928.132 (F), Ohio Rev. Code. The SEET provides for possible refunds to

[2] As seen from footnotes 11-25, 28, 30, 33, 37-40, 43, 45-47, 69, 70, 72, 74-82, 84 in OEG's Brief, OEG's arguments place heavy reliance on Mr. Kollen's analysis. His analysis is based on the mistaken understanding that SB 221 requires that the "financial components" or "quantitative factors" of an ESP are "required to be cost based." (Tr. VII, pp. 172-173). It is Mr. Kollen's misunderstanding that "the generation function is essentially being reregulated on a cost basis...." (*Id.* at 181).

[3] *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to Sec. 4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan,* Case No. 08-935-EL-SSO, Opinion and Order, pp. 8-10.

customers. OCC and Sierra Club appear to be quarreling with the statutory standard for triggering such a refund, just as they quarrel with the General Assembly's decision that an ESP would not be judged on traditional cost-of-service principles.[4]

A. Significance of State Policies

In an equally unsupported argument, OEG and OPAE/APAC focus on the state policies found in Sec. 4928.02, Ohio Rev. Code, OEG reaches far beyond the boundaries of interpretational differences when it contends that in the Commission's *FirstEnergy* order "the Commission determined that the policy mandates **must be met** in order for the Commission to approve any ESP rate plan filed under Chapter 4928." (OEG Br. p. 1, emphasis added). The brief filed by OPAE/APAC relying on the same *FirstEnergy* order, makes a similar argument at page 3 of their brief – an ESP "must comply with state policy as well as be 'more favorable in the aggregate'....".[5] What the Commission held in the *FirstEnergy* case is that the policy objectives are important, must be kept in mind, and should be considered and used as a guide in implementing Sec. 4928.143, Ohio Rev. Code. This is a far cry from saying that all the policy objectives "must be met", or must be complied with, in order to approve an ESP.

The Commission's position concerning the significance of the state policies in Sec. 4928.02, Ohio Rev. Code, is sensible and is consistent with the inherent distinction between policies and mandatory statutes. The Companies' ESPs advance the general

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[4] Their view is consistent with the testimony of OCC's witness Smith that a change to the current SSO rate "is not appropriate unless there were some demonstration that there were cost increases that required such an increase." (Tr. VI, p 95; see also Tr. VI, p. 102)

[5] OPAE/APAC's assertion that an ESP must comply with state policies is particularly troublesome given their claim that all ratepayers are "at risk" and should be protected. This claim takes the policy stated in Sec. 4928.02 (L), Ohio Rev. Code, far beyond what the General Assembly ever could have intended.

directives of the various state policies and they are worthy of approval, without modification, by the Commission.

The Intervenors also raise concerns regarding the impact of the proposed ESPs during difficult economic conditions.[6] The core of these arguments is that the Commission should ignore the statutory standard for approving an ESP and instead should set rates in accordance with current economic conditions. The Companies are keenly aware of the currently difficult economic conditions and their proposal for FAC deferrals helps address those conditions. They believe, however, that their rates must be set in accordance with applicable statutes. Further, the Companies are confident that neither the Staff nor the Intervenors would suggest that the Commission should authorize an ESP that in the aggregate is not more favorable than an MRO simply because the economy was booming and customers were able to pay rates that would exceed MRO rates.

Not surprisingly, this is not the first time that public service commissions have been asked to reduce rates below those permissible under applicable law. Even in times as difficult as the Great Depression such requests have been resisted. A frank discussion of such requests is found in *City of Detroit v. Detroit Edison Company*, Case No. D-1722, P.U.R. 1933 E, p. 193 (*City of Detroit*).

In that case, the Michigan Public Utilities Commission considered the argument "that the general decline in commodity prices should be accompanied by an equal reduction in utility rates ...."[7] The Commission's response was to the point.

[6] See, for instance, Kroger Br. pp. 13, 24; OMA Br. pp. 3, 16-17; OEG Br. p. 30.

[7] *City of Detroit* p. 199.

> It cannot be denied that [the argument] has a reasonable sound and that to a superficial observer it seems unanswerable. One who has little time for study of these problems cannot be blamed for accepting such an argument as the major reason why rates should be arbitrarily reduced. No such excuse can be given for public officers [counsel for the City of Detroit]. They have the same opportunity as the Commission to discover the facts and it is as much their duty as it is ours to determine the soundness and the truth of such matter. Their earnest advocacy of false and unsound argument before this Commission can and does undeniably lead the public generally to an acceptance of such arguments.

Commissioner Waples' concurring opinion relied upon an analysis published in 1933 in Nash on Public Utility Structures. The analysis was titled "A Critical Present Problem."

> Regulation at the present time is confronted with a problem which is an outstanding test of its consistent equity. Since the beginning of 1930 there has been a marked reduction in cost of commodities and construction, in cost of living, and, at times, in rates for money. These reductions have led to a nation-wide agitation for similar reductions in utility rates, particularly those applicable to domestic electric service. It is alleged that during the widespread unemployment and economic distress prevailing since 1930, electric power companies have maintained their income without material diminution and that the public interest demands the assumption by these companies of a fair share of the prevailing economic burdens.
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> The consistent downward trend of electric rates even in years when other prices reached exceptionally high levels, was largely due to regulation which restricted utility rates to the cost of service regardless of the prosperity and profits enjoyed by other industries. Such profits permitted the accumulation of reserves sufficient to sustain these industries in succeeding periods of depression when current profits were scant or entirely lacking. The restriction of utility income during periods of prosperity is based on a

> policy of regulation looking to stability and sustained credit. It is a necessary part of this policy that utility income should, as far as possible, be maintained during periods of depression.
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> [T]he wisdom of this established regulatory policy has not been seriously questioned, and it follows that the present demands for rate reductions should be met with the frank statement that utilities which have been denied the advantages that other industries enjoy in prosperity should not be called upon to share in the burdens of depression.[8]

The Alabama Commission made a similar Depression Era ruling, focusing on the utility's obligation to serve in hard times.

> There is another important difference between utilities and private business. In hard times like the present, the private business ceases to borrow money, immediately curtails expenses by cutting down production or refusing to buy, unless the price is satisfactory, and, if necessary, closes up shop and awaits more prosperous times. The public utility because of its obligation to continue to serve and to render adequate service, is greatly limited as to the extent to which it can go in making any such economies.

(*Smith v. Birmingham Gas Co.*, 1932 B Pur 241, 246-47 (1932))

In addition to their arguments concerning the economy, the Staff and Intervenor both take a very simplifying approach to many of the issues raised in the ESP, rather than deal with the deferral process provided by the General Assembly. Instead, they would have the Commission put off ruling on important ESP issues until some later date.

The Staff and many Intervenors propose that the Significantly Excessive Earnings Test (SEET) be the subject of a Commission workshop. (Staff Br. p. 27; OCEA Br. p. 110; OMA Br. p. 13; and Commercial Group Br. p. 9). The premise for resolving this issue in a workshop is that there should be a single test applicable to all Ohio electric

[8] *City of Detroit* pp. 213-215.

utilities that are subject to the SEET. The support for their argument is the Commission's order in the *FirstEnergy* case.

As will be discussed later in this brief, the practicability of constructing a SEET that would be suitable for all electric distribution utilities is at best questionable. Further, knowing how the SEET will be applied is critically important now, when a decision by the Companies to accept a modified ESP likely will need to be made and/or a decision by parties of whether to appeal a Commission order approving or modifying and approving the ESP would need to be made.

A similar situation applies to the suggestion that resolving the distribution-related issues in the ESP should be postponed until some future distribution rate case. (IEU Br. p. 25; OHA Br. p. 17; Staff Br. p. 8; and OMA Br. p. 6). These parties' preference for postponing the resolution of these issues is puzzling. A Commission non-decision leaves the Companies and the Intervenors uncertain regarding what the full rate increase is that will result from these issues. Once again, the parties would be lacking the full information needed to determine whether to accept the Commission's ESP order.

The Companies are aware that the Commission's order in the *FirstEnergy* case put off distribution-related issues for consideration in the context of those companies' pending distribution rate case that was fully litigated and awaiting decision.[9] To the extent such a decision was appropriate, it must be noted that the Commission's agenda for its January 14, 2009 meeting reflects that it is about to rule on that case. Therefore, the postponement was of a short duration, and a Commission ruling on those issues would have been timely enough for parties in the *FirstEnergy* case to consider as they

[9] Case No. 07-551-EL-AIR, et al.

determined what course of action to take concerning that ESP order.[10] Moreover, the opportunity for addressing individual distribution issues in an ESP was included in SB 221 as one of the factors that would make an ESP more attractive to the utility than an MRO. The Commission should not negate the availability of that factor by postponing decisions on distribution issues.

Postponing the resolution of important issues that are part of the Companies' ESPs is inappropriate. The parties have litigated the SEET and distribution issues and the Commission has a complete record on which to make decisions. Putting off decisions for another time is administratively inefficient and will deny the Companies their right to have these issues resolved as part of their ESPs.

B. Disclaimer

The Companies attempted in good faith to address in their Initial Brief all of the significant issues that were presented through written testimony and also anticipated and addressed many issues developed through cross examination. In order to promote efficiency, the Companies have avoided unnecessarily repeating arguments from their Initial Brief within this Reply Brief and, in many instances, rely on the arguments already presented. Accordingly, where an issue is not again addressed or further addressed in this Reply Brief, the Companies rest on their prior arguments set forth in their Initial Brief and the Companies' decision to not address any issues should not be interpreted as a concession to or agreement with any arguments made in the Initial Briefs of other parties.

[10] The Companies are aware that the FirstEnergy Companies have terminated their ESP application.

II. GENERATION RATE PROPOSALS

A. Fuel Adjustment Clause

1. The Companies' Right to Establish a FAC

At pages 9-10 of its brief, Kroger argues that the Companies should not be permitted to establish a FAC until they demonstrate that their "net" generation costs have increased. Kroger's position appears to be that no generation price increases may be permitted until the Companies conduct a traditional cost-of-service rate case for their generation function. IEU also contends that the Companies' proposed FAC should not be approved unless they pass a generation function-wide cost-of-service test or earnings test. (IEU Br. pp. 12-15). Sec. 4928.143, Ohio Rev. Code, and particularly paragraph (B)(2)(a) of that section, requires no such tests either to establish a FAC or to implement other adjustments to the non-FAC base generation rate.

2. FAC Costs

a. Off-System Sales Margins

Kroger argues, at pages 11-12 of its brief, that FAC costs must be offset by a credit for Off System Sales (OSS) margins, concluding that "customers should receive a *full* credit for [OSS] margins" (emphasis in original) made directly to the FAC charge. Kroger cites the use of OSS margins in other jurisdictions to offset revenue requirements of other AEP operating companies as support for doing so in Ohio for OPCo and CSP. This is not a legitimate basis for making such an adjustment. First, neither Sec. 4928.143(B)(2)(a), Ohio Rev. Code, nor any provision of SB 221, requires that an Ohio electric distribution utility (EDU) offset FAC charges with OSS margins. Kroger's argument ignores, or is an effort to rewrite, Sec. 4928.143, Ohio Rev. Code, and the rest of SB 221.

Second, it is not pertinent that electric utilities in other states might have regulatory regimes that provide for a sharing of OSS margins. The statutory schemes of those states are not Ohio's and the Ohio Legislature did not adopt any such requirement in SB 221.[11] Again, attempting to import practices from other states that are the result of different laws and regulations that apply in those states simply ignores, or is an effort to rewrite, Ohio law.

OEG, at page 10 of its brief, and OCC and Sierra Club, at pages 57-59 of their brief, make the same argument as Kroger, and their arguments are misguided for the same reasons as Kroger's. An additional flaw in OEG's argument is that it assumes that SSO generation rates are regulated on a cost-of-service basis. Although the FAC rate is cost-based, the remaining base (non-FAC) component of the SSO generation rate is not regulated on a cost-of-service basis.

b. AEP Pool Capacity Equalization Receipts

OEG contends, at page 11 of its brief, that monthly AEP Pool capacity receipts that OPCo receives should be used as an offset to OPCo's FAC costs. OEG argues that

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[11] For example, §56-249 (D)(1), Va. Code, specifically authorizes (and limits) the manner in which OSS revenues may be used to offset retail revenue requirements in Virginia. That provision provides, in pertinent part:

> Energy revenues associated with off-system sales of power shall be credited against fuel factor expenses in an amount equal to the total incremental fuel factor costs incurred in the production and delivery of such sales. In addition, 75 percent of the total annual margins from off-system sales shall be credited against fuel factor expenses; however, the Commission, upon application and after notice and opportunity for hearing, may require that a smaller percentage of such margins be so credited if it finds by clear and convincing evidence that such requirement is in the public interest.

this is appropriate because CSP is including Pool capacity payments that it makes to other companies as a FAC cost. OCC and Sierra Club make a similar argument at pages 59-60 of their brief. The primary error in this argument is that Sec. 4928.143(B)(2)(a), Ohio Rev. Code, specifically allows the EDU to include purchased power capacity costs in a FAC, which includes CSP's capacity equalization payments; but it does not require the EDU to include revenues related to sales of power, which would include OPCO's capacity equalization receipts, as an offset to costs included in a FAC.

Second, to the extent that the criticism by OEG and other Intervenors is that the statute provides an unbalanced result by including capacity payments but not capacity receipts in the FAC, the record does not support that assessment either. On the contrary, CSP's customers have benefited from the manner in which CSP has included Pool capacity payments in the calculation of its FAC. As Companies Ex. 7, at Exhibit PJN-1, line 25, shows, the Companies are including $114.8 million of capacity payments by CSP in the calculation of its base period FAC. The result is to reduce the base non-FAC SSO by that same amount. In contrast, CSP's estimated Pool capacity payments for 2009 are only $33.8 million. (*Id.*, at Exhibit PJN-2, line 38). Consequently, the Companies' approach benefits CSP customers' rates by $80 million. The Intervenors also fail to recognize that OPCo has excluded from the FAC those costs that are billed to other members of the pool, through the use of the allocation factors developed on Companies' Exhibit 7, at Exhibit PJN-6. In addition, they ignore that the 71% Pool Allocation factor Mr. Nelson applied to OPCo's environmental carrying cost removes tens of millions of dollars of additional costs from OPCo customers' responsibility. (*Id.* at Exhibit PJN-8). Moreover, there are many other expense items related to OPCo's capacity receipts, besides those reflected in the FAC or environmental carrying costs, none of which the Intervenors take into account. The net result is the Companies have properly designed the FAC and the environmental carrying charge calculation to give recognition to recoveries of costs from other AEP power pool members.

In addition, it should be recognized that OPCo's base generation rates, when unbundled pursuant to SB 3, reflected the impact of capacity equalization receipts from OPCo's last base rate case conducted under Ohio's cost-of-service ratemaking that preceded SB 3 (and SB 221).

c. Inclusion in the FAC of Capacity (Non-Energy Related) Costs

Commercial Group argues, at pages 4-5 of its brief, that AEP Ohio's proposed FAC is contrary to SB 221, because the FAC will allow non-energy (capacity) related costs to be recovered through the FAC. Commercial Group asserts that this will result in anti-competitive subsidies, and that such costs should be recovered in non-FAC charges. OMA, at page 5 of its brief, concurs in Commercial Group's argument, and contends that the FAC is a mechanism for recovering variable costs alone.

These criticisms appear to be an objection to recovering capacity costs of purchased power through the FAC. Sec. 4928.143(B)(2)(a), Ohio Rev. Code, does not restrict recovery of costs through a FAC only to costs that are purely variable or energy-related. Rather, it specifically allows for the "[a]utomatic recovery of... the cost of purchased power supplied under the offer, including the cost of energy **and capacity**...." (Emphasis added). In addition, the several cost components that the Companies have included in their FAC are included in a single adjustment provision as a matter of convenience and efficiency. The Companies could have crafted their FAC by presenting it in several subparts, one for traditional EFC-type costs, another for the cost of purchased power (including capacity costs), and so forth. However, the end result would be precisely the same as what the Companies' proposal accomplishes.

Staff confirms, at page 2 of its brief, that "the costs that the Companies seek to recover are appropriate for inclusion in the FAC, and that recovering them in a single rate makes sense." Also notable is that OPAE/APAC likewise confirms, at page 9 of its brief, that "[t]he costs AEP proposes to recover through the FAC are consistent with statutory provisions."

3. Other Costs Included in the FAC

a. Renewable Energy Purchased Power Cost

Companies' witness Nelson explained that, as part of the FAC proposal, costs of renewable energy purchases and renewable energy credits (RECs) would be passed through the FAC mechanism for convenience. (Companies' Ex. 7, p. 14). Specifically, Mr. Nelson indicated that purchased power would be included within Account 555 and that REC purchases would be included within Account 557. (*Id.* at 6-7). Although the Companies proposed to administer renewable energy purchase costs through the FAC for convenience, the ability to recover those costs does not necessarily arise from Sec. 4928.143(B)(2)(a), Ohio Rev. Code. Sec. 4928.64(E), Ohio Rev. Code, specifically contemplates a bypassable charge for recovery of the cost of compliance with the section.

On brief, Staff recommends that the Commission reiterate in its order that renewable costs would only be recovered through the bypassable FAC and not deferred for future recovery through a non-bypassable rider. (Staff Br. p. 5.) Similarly, OPAE/APAC argues that the Companies' proposal to administer recovery of renewable energy costs through the FAC mechanism is inconsistent with the requirement in Sec. 4928.64(E), Ohio Rev. Code, that such charges be bypassable. In response to Staff Data Request 12-1b, the Companies indicated their intention to keep all of the renewable energy costs within the FAC and Mr. Siegfried stated that this approach would appear to address his concern. (Staff Ex. 4, pp. 6-7). As referenced above, the Staff's recommended clarification is the Companies' intention and proposal, so it does not object to having the Commission's order so indicate.

Regarding the recovery of renewable energy costs through the FAC mechanism, Staff also indicated a potential concern about potential dilution of the 3 percent threshold for excusal found in Sec. 4928.64(C)(3), Ohio Rev. Code. (Staff Br. p. 5.) This potential concern should not materialize as a problem because the Companies' accounting and financial records will clearly segregate the costs associated with renewable energy. Although the renewable energy costs will be administered through the FAC for convenience, the separate records associated with renewable energy costs will be auditable and will easily facilitate any calculations needed regarding the 3 percent threshold provision.

b. Purchased Power on a Slice-of-System Basis

The Companies' proposal to purchase 5 percent, 10 percent and 15 percent of their loads in 2009, 2010 and 2011, respectively, was discussed at pages 37-40 of their Initial Brief. In summary, these purchases are intended to address the Companies' service to Ormet and to customers in the Ohio certified territory previously served by Monongahela Power Company (Mon Power) and to encourage further economic development in the Companies' certified territories. The purchases also will serve to continue a transition to market-based rates. Unanticipated support for this final purpose came from OCC witness Ms. Smith:

> Making rulings that will prevent moving toward competitive markets due to fear of current rate increases is basically an undesirable result. (Tr. VII, p. 157).

Nonetheless, OCC and Sierra Club oppose the Companies' proposal, in part because "the costs of such purchased power are not least-cost." (OCEA Br. p. 54). OCC and Sierra Club also argue that these purchases will result in the Companies selling existing power, that will be made available by the purchase, to other members of the AEP Interconnection Agreement.[12] This argument incorrectly assumes that if CSP and/or OPCo have more capacity the other members of the Agreement can acquire more power and energy from them. There are at least two faults in such thinking. First, Sec. 4.1 of the Interconnection Agreement gives a member the right to receive power and energy from the members' electric power sources "to meet its specific load obligation." Further, the purchases proposed by the Companies would not meet the guidelines for being Member Primary Capacity under the Interconnection Agreement. Sec. 5.7.1 provides that purchases of capacity normally need to be for at least five years to be included as a capacity source.

In another argument related to the Interconnection Agreement, OPAE/APAC argue that pursuant to the Interconnection Agreement CSP and OPCo should acquire the equivalent of the 5 percent, 10 percent and 15 percent purchases from other members of the Interconnection Agreement. As OPAE/APAC note in their brief, Mr. Baker testified that the Interconnection Agreement does not provide for that kind of a purchase arrangement. (OPAE/APAC Br. p. 10). APAC's counsel did not follow up with Mr.

[12] Administrative notice of the Agreement was taken. (Tr. XI, p. 136).

Baker concerning that testimony. Instead, APAC and OPAE now argue that Mr. Baker did not identify any barrier in the Interconnection Agreement and, they contend Mr. Baker's testimony represents nothing more than an internal policy.

The problem with the arguments made by these Intervenors is that the FERC-approved Interconnection Agreement provides for transactions between the members based on capacity equalization (these purchases will not be considered as primary capacity) and for energy sales that result from dispatch. The Interconnection Agreement only provides for this type of transaction with non-AEP companies.

Kroger (at page 13 of its brief) and OCC and Sierra Club (at page 56 of their brief) argue that the proposed power purchases will inappropriately support the Companies' ability to make additional OSS. The fact is that these purchases, to the extent they would result in greater OSS, would restore the Companies to the level of OSS capability at which they would have been if their service territories had not been extended by the return of Ormet and the transfer of the Mon Power service territory. That is the primary reasoning behind these power purchases. The Staff understands this and supports the concept of power purchases.[13]

OEG contends that these purchases will benefit other AEP system companies because of the allocation of OSS margins under the AEP Interconnection Agreement. (OEG Br. p. 9). To the extent other AEP system companies would benefit in that manner they too would be placed in the position they would have been but for the Ormet load and the load of customers in the former Mon Power service territory being served by the Companies.

[13] Constellation supports the Companies' power purchase proposal as well.

A few final points need to be mentioned about this subject. First, OEG presents some figures that cannot be recreated and appear to be well overstated. OEG contends that the power purchases would represent 77 percent of CSP's FAC costs and 76 percent of OPCo's FAC costs. (OEG Br. p. 8) These numbers cannot be substantiated. Even the chart on page 4 of OEG's brief is of no help. For instance, focusing on the CSP columns, the total power purchases shown on line 2 of $600 million is 77 percent of the line 1 (FAC) figure for 2011. However, it makes no sense to compare a three-year total number to a one-year number. Moreover, the line 1 numbers already include the purchase power values on line 2. Therefore, the chart double counts the purchased power costs (about $1.3 billion). Correcting for this one mistake reduces the alleged $5.823 billion rate increase request by nearly 25 percent.

The other point is that Kroger complains that the purchased power proposal "exposes customers to increasingly volatile market rates...." (Kroger Br. p.13). Kroger's view of the market over the next three years being "increasingly volatile" supports the Companies' opinion that it would be a mistake to use market rates in this proceeding based solely on five days in October 2008. (See pages 44-45 and 133-135 of the Companies' Initial Brief). Nonetheless, the Companies believe that whether the market price of power over the three-year ESP period will remain volatile or trend upward or downward, these purchases represent fair treatment of the Companies for the impact on the Companies of assuming the load of Ormet and of customers in the former Mon Power service territory. This proposal is reasonable and should be approved.

4. Establishing the Baseline FAC Component of the Current SSO Rate

OPAE/APAC objects, at pages 11-12 of its brief, to the Companies' proposed baseline FAC rates. OPAE/APAC apparently believes, incorrectly, that the Companies have proposed using rates in effect as of 1999 for their baseline FAC rates. OPAE/APAC recommends, instead, that actual 2008 fuel costs should be used for the baseline and that, because "at present, fuel costs are down . . . ," this will reduce the baseline and could result in further downward adjustments in the future. (*Id.* at 12).

OPAE/APAC misunderstands the Companies' proposal, and its recommendation is not sensible. First, as Mr. Nelson explained, the purpose of identifying the baseline FAC component of the current SSO is to establish the non-FAC (or base) SSO in current rates. (Companies' Ex. 7B, p. 2). Consequently, OPAE/APAC's recommendation to adjust the baseline FAC rate retrospectively to reflect fuel cost decreases (or increases) would simply raise (or lower) the non-FAC generation component of the current SSO based on the vagaries of volatile fuel cost changes. Indeed, the irony of OPAE/APAC's recommendation is that, if they are correct regarding the movement of fuel costs, it would end up increasing the non-FAC generation rate. Second, as explained in Companies' witness Nelson's testimony (Companies' Ex. 7, pp. 8-11) and in their Initial Brief, at pages 20-24, the Companies identified the FAC components of their current rates by starting with the 1999 rate levels, and then conservatively adjusting those rate levels for subsequent rate changes. They do not use 1999 rates as their baseline FAC rates. Third, the Companies' proposal is to recover through the FAC their actual fuel costs, as Sec. 4928.143(B)(2)(a), Ohio Rev. Code, allows, starting in 2009. While they must forecast what those actual costs will be, ultimately through the FAC reconciliation process they will recover just their actual costs. Accordingly, if fuel costs decline, the lower costs will automatically flow through to customers.

OPAE/APAC's belief that fuel cost reductions (or increases) would, or should, somehow be used in a retrospective fashion to change the baseline FAC rate is incorrect. In any event, even if such retrospective changes to the baseline rates were made, there would be no impact on the FAC rates that the Companies would collect from customers. The obvious flaws in OPAE/APAC's recommendation confirm the appropriateness of Mr. Nelson's method of determining the FAC (and, thus, the non-FAC) rates in the Companies' current SSOs.

OCC and the Sierra Club mistakenly believe that the purpose of identifying the baseline FAC rate is to determine the amount of fuel costs being incurred to provide the current generation standard service offer (SSO). (OCEA Br. p. 49). That is not the purpose. The objective is to identify the FAC rate component of the current generation SSO so as to also identify the base (non-FAC) rate component of the SSO. Accordingly, OCC's and the Sierra Club's view that the baseline FAC rate component would be understated (or overstated) based on whether the baseline rate ends up matching a particular measure of fuel costs, such as 2008 fuel costs (OCEA Br. p. 50), is likewise mistaken.

The flaw in OCC's and the Sierra Club's approach is illustrated by their statement, at page 50 of their brief, that if "the Companies' 2008 baseline [FAC] rate will have understated 2008 fuel costs . . . [the] understated baseline rate for the FAC may be corrected through the future truing-up of FAC costs . . . ." There is no purpose in "truing up" the baseline FAC rate because the FAC will recover the actual FAC costs incurred in 2009, and thereafter, whatever they are.

The flaw in their proposal to use actual 2008 fuel costs as the measure of the baseline FAC rate is further illustrated by that proposal's basic infeasibility and inappropriateness. First, even if there were record evidence available to construct a quantitative measure of actual 2008 fuel costs, from a qualitative perspective, Companies' witness Nelson explained that the volatility of fuel costs in 2008 and the extraordinary nature of significant fuel procurement activities in 2008 would make use of such costs unrepresentative, absent significant adjustments. (Companies' Ex. 7B, pp. 2-3; Tr. XIV, pp. 74-75). Second, there is no basis in the record for calculating what actual 2008 fuel costs are, which is not surprising in light of the fact that the Application was filed on July 31, 2008, and the hearing was completed before the end of the year.[14]

The Staff's proposal to use actual 2007 costs, escalated by 3 percent for CSP and 7 percent for OPCo, does bypass the practical infeasibility of OCC's recommendation. However, as explained in the Companies' Initial Brief, at pages 23-24, the Staff's method does not avoid being subjective and arbitrary, which results from using a measure of current costs to identify the baseline FAC rate component and, ultimately, the non-FAC rate component of the Companies' SSOs. Nor is that flaw excused because, in the Staff's assessment, its method would not have harmed the Companies from an earnings standpoint if it had been applied to them in 2007 and might not harm them if applied in 2008. Such a rationale effectively applies an earnings test during the Companies' RSP,

[14] Notwithstanding their suggestion, at page 52 of the OCEA brief, that there is a basis for using nine months of actual and three months of estimated data, in fact, there is no such information available in the record.

when none was applicable, and it also applies such a test prospectively, at the outset of their ESP, when none is permitted by SB 221.

5. Operation of the FAC Mechanism

a. Review of the Prudence of FAC Costs

OPAE/APAC argues, at page 9 of its brief, that the Companies must demonstrate in this case that their procurement of fuel and purchased power costs are prudent, and that prudency includes a least-cost criterion. OPAE/APAC's arguments are without merit. First, while Sec. 4928.143(B)(2)(a), Ohio Rev. Code, does require that costs recovered through a FAC must be prudently incurred, it is not necessary for that review to be completed at the time the FAC mechanism is being established as part of the ESP. Rather, as Staff witness Strom explained, the periodic reviews will occur in accordance with the Commission's rule that implements the FAC process:

> A review of the appropriateness of FAC costs, and the prudence of decisions made relative to the components of the FAC, should be conducted annually. I would expect the audit activities associated with these reviews to begin shortly before the end of each calendar year, and be conducted with an audit report to be filed by early March. The auditor selection process, and the procedural schedule for conducting the audit and hearing related activities, should be established by the Commission.

(Staff Ex. 8, p. 4). Mr. Strom's understanding tracks new Rule 4901:1-35-09, Ohio Admin. Code. *See also* OCC's Ex. 11, pp. 29-41, (in which OCC's witness Medine provides an overview of the Companies' fuel procurement practices, and recognizes, e.g. at p. 37, that those practices will be scrutinized in the context of the Companies' annual FAC audit filings).

Second, there is no basis in the statute or otherwise for grafting a least-cost criterion onto the FAC prudency review. Reasonableness is the appropriate standard for the cost-based FAC, and flexibility must be maintained.

Third, in any event, OPAE/APAC's contention that the record does not demonstrate the prudence of the Companies' procurement of fuel and purchased power is baseless. The record does support the conclusion that the Companies' customers have benefited from the Companies' low-cost fuel procurement practices. For example, the information the Companies submitted in their October 16, 2008, filing regarding their fuel procurement practices (OCC Ex. 4, pp. 1-6) positively supports the conclusion that their practices are prudent.[15] In addition it must be recognized that the Companies have not had an automatic recovery mechanism for their fuel costs for nearly 10 years. They have been bearing the risk for recovery of those costs, and have had every incentive to manage their procurement of fuel prudently. Moreover, it is important to keep in mind that a public utility's conduct is presumed to be prudent.[16] Although there is no requirement to review the Companies' fuel procurement strategy and practices in this proceeding, there is no evidence in the record that rebuts the presumption that their

[15] At page 9 of its Brief, OPAE/APAC claims that "AEP Witness Baker admits that AEP has the ability to manage procurement effectively, but apparently has chosen not to apply that expertise to minimize costs for Ohio customers" and cites Mr. Baker's cross examination by Mr. Rinebolt at Tr. XIV, pp. 267-268, to support this claim. Mr. Baker's testimony at Tr. XIV, pp. 267-268, had nothing to do with fuel procurement, and certainly did not support a conclusion that the Companies' fuel procurement practices are not prudent. Rather, the testimony by Mr. Baker that OPAE/APAC cites simply explained that AEP manages its generation portfolio on a daily basis.

[16] In 1986, the Commission stated that an assessment of the prudence of utility decisions should be conducted under the following guidelines: (1) There should exist a presumption that the decisions of utilities are prudent; (2) The standard of reasonableness under the circumstances should be used; (3) Hindsight should not be used in determining prudence, although consideration of the outcome may legitimately be used to overcome the presumption of prudence; and (4) Prudence should be determined in a retrospective, factual inquiry. *In the Matter of the Regulation of the Purchased Gas Adjustment Clause Contained Within the Rate Schedules of Syracuse Home Utilities Company, Inc. and Related Matters*, Case No. 86-12-GA-GCR, Order at 10 (December 30, 1986). The Ohio Supreme Court adopted this test in *City of Cincinnati v. Pub. Util. Comm.*, 67 Ohio St. 3d 523 (Nov. 3, 1993).

strategy and practices are prudent, and in addition there is ample evidence that supports the prudence of their strategy and practices. Consequently, the presumption, coupled with the record, confirms the prudence of the Companies' fuel procurement strategy and practices.

b. Audit Issues in Future Periodic FAC proceedings

OCC and the Sierra Club, at pages 67-68 of their brief, urge the Commission to adopt the various recommendations of Ms. Medine regarding the Companies' fuel procurement practices and procedures. Ms. Medine's recommendations are more properly addressed in the FAC audit proceedings for the Companies' fuel practices and procedures. Even the testimony that Ms. Medine provided on this point, and that they quote in their brief, at page 67, supports that conclusion. The relevant portion of her testimony states that "to the extent that [my] recommendations address issues **and you're addressing the prudence of these fuel costs**, I think they can't be delayed." (Tr. VI, p. 264 (emphasis added)).

OCC has recognized that the ESP proceeding is not the time or place to review the prudence of the EDU's fuel costs:

> [T]he General Assembly did not contemplate [in SB 221] that ESP proceedings would review the prudence of costs incurred before the ESP was submitted. Rather, the ESP proceeding will address the plan [the FAC] that an electric distribution utility ("EDU") proposes that may allow the EDU to collect fuel costs from customers.
>
> *In Re Ohio Edison Co., et al.*, PUCO Case No. 08-124, et al., OCC's Memorandum Contra, at 3 (June 9, 2008).

The Commission is not addressing, in this proceeding, the prudence of fuel costs that will be incurred in 2009 and thereafter. That prudence review will occur in the future audit proceedings. That will be an appropriate time, as even Ms. Medine appears to concede, to take up the recommendations regarding fuel procurement practices that she makes on behalf of OCC.

c. EFC-Based Criticisms

IEU, at pages 9-13 of its brief, raises several objections to the Companies' FAC proposal. The theme of those objections is that the Companies' proposed FAC does not fit within the contours of, and they have not committed to meeting the requirements specified by, the prior Electric Fuel Component and related Commission rule (which fell by the wayside with the passage of SB 3 and which SB 221 did not reinstate). For example, the paragraph in IEU's brief following its criticism that there is not "a fully fleshed out FAC tariff" makes clear that this criticism is really a complaint that the proposed FAC includes costs in addition to "[those] which were historically subject to recovery through the Electric Fuel Component (EFC) rate." (IEU Br. p. 10). Similarly, IEU's criticism that "the Companies' proposed FAC is fundamentally unbalanced" because it automatically adjusts rates to recover a range of costs while not submitting their generating units' operation to the Commission's regulation (IEU Br. pp. 10-11) is also just a complaint that the FAC is not regulated in the same manner as the EFC was. IEU's objection that the proposed FAC includes capacity-related costs, such as capacity costs of purchased power, is based on the argument that the prior EFC rules did not provide for recovery of such costs. (IEU Br. pp. 11-12). These criticisms are objections to SB 221's provision that governs the FAC, Sec. 4928.143(B)(2)(a), Ohio Rev. Code, and the Commission's rule which will implement that Sec., Rule 4901:1-35-09, Ohio Admin. Code. The Companies' proposed FAC and related tariffs are within the parameters of, and the Companies are committed to complying with the requirements of, the statute and rule. The statute and rule permit inclusion of costs, including capacity-related costs, that the prior EFC statute and rule did not include. IEU's EFC-based objections to the Companies' establishment of a FAC are meritless.

OCC and Sierra Club also attempt to engraft the requirements of the prior EFC statute and rule onto the FAC. (OCEA Br. p. 48). Their arguments, which OCC presented to the Commission in the course of the comment cycle for the ESP rulemaking, Case No. 08-777-EL-ORD, and which the Commission did not adopt in that proceeding, should be rejected for the same reasons provided above in response to IEU's criticisms.

6. The FAC After the ESP

IEU also objects to the proposed FAC because it may continue in operation past the three-year term of the ESP. IEU characterizes this as "a mysterious facet of the Companies' proposed ESPs . . . ." (IEU Br. p. 13). This will be a characteristic of any ESP that includes a FAC and has a term less than perpetuity. Because no ESP will have a term that long, every EDU that has a FAC and an approved ESP will address this issue by the end of their existing ESP's term. It is not mysterious. As Companies' witness Roush explained, the FAC will continue on, after the term of the proposed ESP, either in connection with a subsequent ESP or as part of an MRO. (Tr. IX, pp. 143-146).

B. Capital Carrying Costs On Incremental 2001-2008 Environmental Investments

Intervenors make several objections that question whether the Companies may increase their base non-FAC generation rates to recover the capital carrying costs on their incremental 2001-2008 environmental investments. They also have criticized the levelized carrying cost rate that the Companies use to quantify those costs. Included among their criticisms of the levelized carrying cost rate are objections to the manner in which it recovers depreciation expense, certain overhead expenses, and the weighted average cost of capital. As explained below, none of the objections or criticisms has merit.

1. Carrying Cost Recovery

Sec. 4928.143(B)(2), Ohio Rev. Code, provides that an ESP may provide for or include **without limitation**, any of the provisions identified in paragraphs (a) through (i) of that subdivision. In short, while the list of provisions may be illustrative, it is not exhaustive. The Companies' primary source of statutory authority for their proposed recovery of the 2009-2011 capital carrying costs associated with their incremental 2001-2008 environmental investments is the "without limitation" language of Sec. 4928.143(B)(2), Ohio Rev. Code. (*See* Tr. XIV, p. 115, where Companies' witness Nelson confirmed that, "[t]he particular provision that we are filing under [for recovery of carrying costs of incremental environmental investments,] it's section 4928.143(B)(2)").[17]

OEG, OCC, and the Sierra Club claim that the Companies' proposal to recover carrying costs on their incremental 2001-2008 environmental investments would violate Sec. 4928.143(B)(2)(b), Ohio Rev. Code, which allows the EDU to recover the costs of "an environmental expenditure for any electric generating facility of the [EDU], provided the cost incurred or the expenditure occurs on or after January 1, 2009." They believe

[17] Mr. Nelson did explain that Sec. 4928.143(B)(2)(a), Ohio Rev. Code, specifically authorizes recovery through the FAC of environmental emission allowances, at Tr. V, p. 12. OCC apparently believes that Mr. Nelson was stating that the Companies are relying on paragraph (B)(2)(a) to recover their carrying costs on incremental environmental investments. OCC is mistaken. Again, the primary authority for recovery of those carryings costs is the "without limitation" language of subdivision (B)(2).

that the Companies' proposal would result in the retroactive recovery of environmental costs (OEG Br. p. 13) or retroactive ratemaking (OCC Br. pp. 68-70), apparently because the investments were made before January 1, 2009. [18] There are at least two flaws in these arguments. First, as explained above, the Companies' primary source of authority for their provision for carrying costs on incremental 2001-2008 environmental investments is the "without limitation" language of Sec. 4928.143(B)(2), Ohio Rev. Code, not subparagraph (B)(2)(b). The "without limitation" language of that statute contraindicates the interpretation OEG, OCC, and Sierra Club give to it. Their interpretation is as startling as the testimony of OCC witness Smith, who believed that "without limitation" meant that only the items listed in subparagraphs (B) (2) (a) – (i) could be included in an ESP. (Tr. VI, p. 139).

Second, subparagraph (B)(2)(b) does not prohibit the recovery of carrying costs on environmental investments, as long as those carrying costs are incurred on or after January 1, 2009. While the investments involved in this aspect of the Companies' ESP were made prior to January 1, 2009, "the carrying cost itself is the carrying cost [the Companies are] going to incur in 2009." (Tr. XIV, p. 93, 114 (Nelson)).[19]

IEU also argues, at pp. 20-21 of its brief, that the Companies' proposal does not comply with subparagraph (B)(2)(b). IEU's argument is that, under subparagraph

[18] OCC and the Sierra Club also conjecture, at p. 69 of their brief, that the Companies are relying upon the FAC provision, paragraph (B)(2)(a) of Sec. 4928.143, Ohio Rev. Code, as the statutory authority for recovering the environmental carrying costs, and then argue that paragraph (B)(2)(a) does not authorize recovery of such costs. The Companies are not relying on that provision. As a result, their argument is not on point.

[19] Mistaking the difference between investments, on the one hand, and carrying costs on investments, on the *other* hand, or possibly in an effort to avoid the difference, OCC and the Sierra Club, at page 22 of their brief, mischaracterize the Companies' proposal as a "rate increase for the 2001-2008 carrying costs related to environmental investments," and then argue that recovery of such costs through an ESP is not permitted by paragraph (B)(2)(b). As noted above, the carrying costs that the Companies seek to recover will be incurred during 2009-2011. The Companies are not requesting recovery of carrying costs incurred in 2001-2008.

(B)(2)(b), the Companies must show, with respect to the proposed environmental capital carrying charges, that "the benefits derived for any purpose for which the surcharge is established are reserved and made available to those that bear the surcharge." IEU believes that the Companies have not met this standard. IEU's argument is baseless. First, neither the language that IEU quotes nor the test that it would create is part of subparagraph (B)(2)(b). Second, subparagraph (B)(2)(b) is not the primary basis for the Companies' proposed recovery of the carrying costs. The "without limitation" provision of paragraph (B)(2) is the primary basis. Third, Companies' witness Nelson explained that the carrying charges will recover the ongoing costs of investments in environmental facilities and equipment that are necessary to keep the Companies' low-cost coal-fired generation units running. Their customers will benefit because the operating costs of these units remain well below the cost of securing the power on the market, and the Companies are passing the lower-cost power through the FAC. (Companies' Ex. 7B, p. 7). Thus, the consumers who pay the carrying charges do obtain benefits from the investments that the carrying charges help to support. In addition, a Pool Capacity Allocation Factor was applied for OPCo and Jurisdictional Allocation Factors were applied for both Companies in order to assure that the Companies' retail customers are responsible for no more than an appropriate portion of the carrying costs. (Companies' Ex. 7, pp. 18-19 and Exhibit PJN-8). Consequently, the Companies' proposed carrying charges would satisfy IEU's test in any event.

Kroger and OEG argue that the Companies should be denied recovery of carrying costs on their incremental 2001-2008 environmental investments because they have not demonstrated that those carrying costs have resulted in a net under-recovery of the

Companies' costs of providing generation service. In particular, they claim that the Companies have not taken into account the offsetting effects of accumulated depreciation for the environmental investments in their carrying cost calculations. (Kroger Br. pp. 1-15; and OEG Br. p. 14).

The fundamental error of these criticisms is that SB 221 does not authorize, let alone require, a traditional cost-of-service test, using rate base/rate of return methods, to establish SSO generation rates for an ESP under Sec. 4928.143, Ohio Rev. Code. Nor does SB 221 apply such a test to the total generation rates in order to determine whether an EDU may include in its ESP an adjustment provision, such as the Companies' provision to recover carrying costs for the incremental 2001-2008 environmental investments, that Sec. 4928.143, Ohio Rev. Code, otherwise permits.

With regard to the specific concern that the Companies have overstated carrying costs because they have ignored accumulated depreciation for the underlying investments, that criticism misunderstands the Companies' proposed carrying charge.

Mr. Nelson explained that the carrying cost rate that he developed is a levelized rate over the life of the property. (Companies' Ex. 7, p. 19). He showed in detail the manner in which the levelized carrying cost rate is calculated at Exhibit PJN-10 of Companies' Ex. 7. The levelized nature of the calculation is clearly shown by the depreciation component of the charge. Exhibit PJN-10 shows that for 25-year life property, which is an approximation that coincides with estimates of generation unit remaining lives for the Ohio generating fleet (Companies' Ex. 7, p. 19), and thus is appropriate for the environmental facilities and equipment in question here, the depreciation rate included in the levelized carrying charge is 2.23 percent (*Id.*, at Exhibit PJN-10).

Mr. Nelson contrasted the results of using the levelized carrying charge to what a traditional rate base/rate of return calculation, using accumulated depreciation as an offset to the rate base, would produce.

> [I]f you did a rate base type calculation you would have different components. You would have depreciation expenses. You'd have your other expenses associated with that investment plus the return component.
>
> Generally what would happen is . . . you'd start pretty high when the plant initially went in, and then over time that would be fully depreciated over its life. So what I've done is used a levelized carrying cost that accounts for that, and in a sense it's a conservative approach because this equipment is relatively new so it wouldn't have been depreciated very much...
>
> If you did a traditional rate base calculation . . . you'd probably end up with a somewhat higher cost than the $84 million I've calculated, for example, for Ohio Power Company.

(Tr. V, pp. 55-56).

Accordingly, if the Companies had done what OEG and Kroger advocate and used a traditional rate making approach relying on an original cost rate base offset by accumulated depreciation, the result probably would be higher than the result from using the levelized carrying charge. That makes sense because the traditional rate base approach tends to load the capital costs of the investments at the front end of the useful lives of the related assets.

Kroger's witness Mr. Higgins conceded that, if Mr. Nelson used a levelized approach that "took account of accumulated depreciation in a way that lined up with what otherwise would occur under traditional rate making for these assets . . . with respect to the treatment of depreciation, that then would resolve a concern on these lines." (Tr. VII, pp. 22-23). Mr. Nelson's levelized approach toward accounting for depreciation did not just "line up" with what otherwise would occur under traditional rate making, it provides a better result for customers. Because Mr. Higgins' concern was satisfied, the criticism that Kroger and OEG make based on that concern has no basis.

OPAE/APAC claim that the Companies' proposal for recovering carrying costs on the incremental 2001-2008 environmental investments should be rejected because, in their view, the Companies have already been compensated for these costs. In particular, they assert that these costs were factored into the Companies' electric transition plan (ETP) cases and, thus, the generation rates from those cases (which were unbundled and capped at their 2000 levels during 2001-2005) were adequate to compensate the Companies for those costs. They also contend that the rate increases in the Companies' RSP cases (during 2006-2008) provided recovery for those costs. In addition, they assert that until the Companies show their earnings are inadequate to pay for the costs of the environmental investments, their carrying cost recovery proposal should be denied. (OPAE/APAC Br. pp. 5-6). These arguments are all baseless. First, the Companies' investments in environmental compliance projects during 2001-2008 were not "factored" into the rates that were unbundled in 2000, and then capped for the next five years, as part of the ETP proceedings. Rather, the rates were unbundled and capped before any of the investments were made in 2001-2008.

Second, the rate increases authorized in the RSP (and RSP 4 percent) cases did not provide recovery for the 2009-2011 carrying costs that the Companies have requested in this proceeding related to the incremental 2001-2008 investments. The investments for which carrying cost recovery is being proposed are in addition, i.e., "incremental," to those identified in the earlier cases. Mr. Nelson described in detail the amount of the 2001-2008 environmental investments that were identified in the RSP and RSP 4 percent cases (Companies' Ex. 7, at Exhibit PJN-12); the total amount of environmental investments made during the 2001-2008 period (*Id.*, at Exhibit PJN-9); and the difference between those two amounts (the incremental investments) and the carrying costs on that incremental amount that the Companies will incur during 2009-2011. (*Id.*, at Exhibit PJN-8).[20]

Third, as explained in the Companies' Initial Brief, at page 34, and above in response to Kroger's and OEG's similar argument, no provision of SB 221 conditions recovery of incremental capital carrying costs on the Companies passing an earnings or cost-of-service test. OPAE/APAC's arguments should be rejected.

2. Levelized Carrying Cost Rate

OCC and the Sierra Club raise various objections to the Companies' proposed levelized carrying cost rates for incremental 2001-2008 environmental investments, several of which relate to the weighted average capital cost (WACC) component of the carrying charges (OCEA Br. pp. 71-74). IEU also criticizes the proposed WACC in several respects. (IEU Br. p. 21).

OCC's and Sierra Club's first objection to the levelized carrying cost rates is that the Companies provided no explanation of or support for the Property Taxes and General Administrative Expenses component of the carrying cost rates. They also object that the carrying charges "are simply too high and would be significantly burdensome" on

[20] Companies' witness Nelson's Exhibit PJN-13 to his Direct Testimony, Companies' Ex. 7, illustrated that the RSP and RSP 4% cases' rate increases have not provided recovery of the carrying costs on the incremental environmental investments.

customers. These objections are also baseless. Companies' witness Nelson provided the calculation and components of the levelized carrying cost rates, which he detailed for each Company at Exhibit PJN-10 to Companies' Ex. 7. There is no basis in the record to contradict either the accuracy or reasonableness of the Property Taxes and General Administrative Expenses components that Mr. Nelson used for each Company. Notably, none of OCC's expert witnesses found anything remarkable about these components, and OCC's counsel had no questions of Mr. Nelson during cross-examination regarding the values he used for these components. (Sierra Club's counsel did not appear at the hearing). Similarly, OCC provides no evidence either through its own witnesses or through cross-examination, to support the conclusory statement that the carrying cost rates overall are "simply too high." On the other hand, Staff witness Cahaan testified that he "examined the carrying cost rates . . . and found them to be reasonable." (Staff Ex. 10, p.7).

IEU and OCC and the Sierra Club criticize the WACC components of the levelized carrying cost rates, claiming that they don't reflect debt available to finance environmental plant and equipment, such as pollution control bonds. This criticism is simply not correct. There is no debate that there is long-term debt specifically available to finance pollution control facilities. However, there is no record support for the notion that the Companies do not take advantage of pollution control bond financing when it is available and to the extent that it makes financial sense to use it. Mr. Baker explained that pollution control bonds can only be used for certain parts of a facility, so equity (and other long-term debt) are still needed in order to cover the financing for the remaining parts. (Tr. XI, p. 218). Moreover, Mr. Baker explained that floating rates for pollution control bonds, today, are "actually higher than the debt rate that is embedded in the [WACC]." (Tr. XI, p. 218). Mr. Nelson provided the embedded cost of long-term debt used in the calculation of the Companies' WACC rates at Exhibit PJN-11 to Companies' Ex. 7. There is no basis for the contention that the Companies' proposed carrying cost rates do not properly reflect pollution control bond financing.

OCC and Sierra Club also recommend that the Companies should use a short-term debt rate, rather than a WACC rate, as the return component of their levelized carrying cost rates for the incremental environmental investments. This is a bad idea. First, it conflicts with OCC's own argument that long-term pollution control bonds should be used. Second, as Mr. Baker observed, floating rate debt currently is more costly than the long-term fixed rate debt that is reflected in the Companies' WACC rates. So, use of short-term debt, which also is floating rate, could lead to higher WACC rates than what the Companies have proposed. Third, environmental control facilities and equipment have 25-year useful lives and have required, so far, $3 billion of capital since the start of 2001. It is not possible to maintain a reasonable debt-to-equity ratio and to finance such massive amounts of investment with long-term debt alone, let alone with short-term debt. (Companies' Ex. 7B, p. 7). Long-lived assets should be financed by long-term debt and equity.

IEU's next criticism of the Companies' WACC rates is that the appropriate debt-to-equity capitalization ratio to use for each Company's WACC is 60/40, rather than the 50/50 ratio that Mr. Nelson used in Companies' Ex. 7, at Exhibit PJN-11. IEU is mistaken, for the reasons the Companies gave in their Initial Brief, at pages 31-32. The proper capitalization ratio for use in the computation of each Company's WACC rate is 50 percent equity and 50 percent debt, as Mr. Nelson recommends.

OEG, IEU, and OCC and the Sierra Club claim that the Companies' proposed WACC rates for the carrying charges should be adjusted to reflect the tax expense benefit of the IRC § 199 deduction. (OEG Br. p. 14; IEU Br. p. 2; OCEA Br. pp. 74-75). The primary flaw in the Intervenors' argument is that the § 199 deduction is not a reduction to the statutory tax rate used in the WACC, and the FERC and FASB have confirmed this point. The Companies addressed the substance of this argument in detail in their Initial Brief, at pages 35-37.

However, both OEG and OCC and Sierra Club have presented an inaccurate picture of the Commission's treatment of the § 199 deduction issue in the *FirstEnergy* case, which requires correction. OEG, referring to page 19 of the December 19, 2008 Opinion and Order in that case, states "the Commission confirmed its position on the Sec. 199 deduction." (OEG Br. p. 14). OCC and the Sierra Club, relying on the same portion of the *FirstEnergy* order, argue that: "In the *First Energy* (sic) case, the Commission relied on its treatment of the Section 199 tax deduction in the [AEP] Companies' RSP case and 'agree[d] that applicable Section 199 deductions should be taken into consideration. The Commission should follow these precedents and order a similar offset in this proceeding." (OCEA Br. p. 75).

The reliance placed on the Commission's *FirstEnergy* order concerning the § 199 deduction is misplaced for two reasons. First, the Commission did not make a § 199 deduction offset in that case. What the Commission said was that "the modifications [to the proposed ESP] set forth in this order adequately account for the possibility of any applicable Section 199 tax deduction." (Opinion and Order, p. 19). Therefore, despite the not-so-subtle suggestions by OEG, OCC and Sierra Club to the contrary, the Commission did not order any adjustment to reflect the § 199 deduction. Second, the Commission's consideration of the § 199 tax deduction in the *FirstEnergy* case arose in the context of the taxes built into the costs of generation being purchased by the FirstEnergy operating companies. The issue did not involve the revenue requirement tax gross-up for determining the proper carrying charge rate.

C. Phase-In And FAC Deferrals

1. Appropriateness of a Phase-In

Many of the Intervenors, including the representatives of the Companies' residential customers have expressed a preference not to be responsible for deferrals and the associated carrying charges. For example, OCC and the Sierra Club argue that a phase-in and deferral of costs would, itself, destabilize customer prices and, so, should not be permitted. (OCEA Br. pp. 87-89). Similarly, Constellation and the Schools contend that the Companies have not demonstrated that a phase-in of ESP rate increases and deferral of FAC costs is needed to stabilize prices or rates. (Constellation Br. p. 8; Schools Br. p. 3). Constellation and the Schools also argue that the recovery of deferrals through non-bypassable charges resulting from the phase-in would conflict with state policies against collection of generation costs through non-bypassable distribution fees and that encourage diversity of energy supplies and suppliers (Constellation Br. pp. 10-11; Schools Br. pp. 5-6).

IEU, on the other hand, agrees that Sec. 4928.144, Ohio Rev. Code, allows a phase-in mechanism and, that if the Commission authorizes the Companies to increase their rates and charges, they would support the use of a phase-in to ensure rate or price stability. (IEU Br. pp. 27-29). However, IEU also believes that Sec. 4928.144, Ohio Rev. Code, does not allow the non-bypassable charge to extend beyond the term of the ESP. (*Id.*). Staff recommends on brief that if the Commission determines that a phase-in is needed, it should be limited to phasing in the first year increase, and that the phase-in "be levelized over the three year ESP period." (Staff Br. pp. 21-22). However, Staff witness Cahaan conceded on cross-examination that the Staff's position against deferrals has weakened, and the argument for deferrals has become stronger. (Tr. XII, pp. 260-261).

The Companies proposed a phase-in of their ESP rate increases, and the resulting deferral of a portion of FAC costs that must accompany the phase-in, as a means of moderating the total rate impacts associated with the Companies currently having no fuel cost recovery mechanism in a period of escalating fuel prices and not having earned any return on over $1 billion of environmental investments. (Companies' Ex. 7, at Exhibit PJN-8). The Companies' assessment is that the stabilizing effects on customer prices of their proposal, compared to the impacts without the phase-in and deferral, are clear. Accordingly, IEU has got it right on this point, and Constellation, the Schools, and OCC and the Sierra Club are misguided.

In any event, Intervenor arguments that the Commission does not have the statutory authority to moderate the impact of the rate increases through the Companies' phase-in and deferral proposal are wrong. Specifically, criticisms that the phase-in and deferral contradicts State policies against collecting generation costs through distribution rates and in support of diversity of electricity supplies and suppliers are incorrect. First, Sec. 4928.144, Ohio Rev. Code, specifically permits a phase-in, deferral of the costs (and carrying costs) that result from the phase-in, and recovery of those costs through non-bypassable charges. The general policy objectives of Sec. 4928.01(D) and (H), Ohio Rev. Code, do not override the specific authority that Sec. 4928.144, Ohio Rev. Code, provides. Second, the non-bypassable charge that Sec. 4928.144, Ohio Rev. Code, authorizes can be, indeed will be, a non-bypassable generation charge, not a distribution charge.

With regard to IEU's contention that the non-bypassable charges authorized by Sec. 4928.144, Ohio Rev. Code, to recover the phase-in cost deferrals (and carrying costs) may not extend past the term of the ESP, the statutory language does not contain that restriction. On the contrary, Sec. 4928.144, Ohio Rev. Code, broadly authorizes "any" just and reasonable phase-in of ESP rates or prices necessary to ensure rate or price stability for consumers, and it requires the Commission to authorize the collection of the related cost deferrals and carrying costs through non-bypassable surcharges. It does not require that the non-bypassable surcharges must begin or end before the expiration of the ESP's term.

The Companies' proposed phase-in, cost deferrals (including carrying costs), and recovery of the deferrals, is a tool for the Commission's use to moderate rate impacts on consumers. It will be up to the Commission to decide whether, or to what extent, such a tool is necessary to ensure rate or price stability for consumers. While the Companies believe that their phase-in/deferral proposal, which includes setting up a regulatory asset with carrying costs based on a WACC to be recovered through a non-bypassable charge, is appropriate, they will accept a Commission order that approves the ESPs as proposed, but for the phase-in/deferral proposal.

2. The Appropriate Carrying Cost Rate for FAC Deferrals

OCC and the Sierra Club have two primary criticisms of the carrying cost rate that the Companies have proposed for FAC cost deferrals that result from the phase-in. First, they argue, at pp. 63-64 of their brief, that carrying charges on deferrals should be calculated on a net-of-tax basis, in the manner that Commercial Group witness Gorman recommended. The Companies explained the lack of merit for this recommendation, at page 56 of their Initial Brief. It improperly injects rate base rate making methods into a generation pricing proceeding that is not governed by cost-of-service methods. Notably, the Staff is not proposing this inappropriate net-of-tax approach. In addition, Commercial Group did not advance Mr. Gorman's net-of-tax idea in its post-hearing brief. The Commission should not adopt this proposal.

Second, OCC and the Sierra Club contend that carrying costs for FAC deferrals should be based on the cost of short-term debt, and should exclude equity. (OCEA Br. pp. 64-66 and 92-93). The rationale that OCC and Sierra Club offer to support their claim that the Companies can use short-term debt to finance FAC deferrals over a 3 – 10 year period is that in 2009 AEP plans to use a combination of cash flow from operations and new issues of long-term debt and equity to fund its capital expenditures. They apparently believe that, to the extent that AEP generates cash flow from its operations, that is a source of capital for the Companies to use to finance FAC deferrals, and the cost of that capital is the rate for short-term debt. (OCEA Br. pp. 64-65). There is no basis in the record for or in logic for OCC's and Sierra Club's belief. First of all, cash flow from operations represents a return of capital (through recovery of depreciation and amortization expenses) and on capital (through earnings). If the business is to continue, let alone grow, those funds must be reinvested in the types of long-term assets that enabled the Companies to provide the services that produced the cash flow in the first place. There is no basis for the belief that the Companies will produce any "spare" cash flow in 2009, let alone enough to finance the Companies' proposed long-term FAC deferrals. In that regard, it must be recognized that the information that OCC and the Sierra Club rely upon to construct their rationale applied to AEP as a whole, not to the Companies specifically. Second, even if the Companies could use cash flow from operations as a source of funds for financing the proposed FAC deferrals over 10 years, the cost of doing so would not be the short-term debt rate. It would still be the WACC rate that represents the Companies' cost to finance long-term assets such as the proposed FAC deferrals.[21]

OCC and the Sierra Club assert, at page 65 of their brief that "[OCC's witness] Smith supports short-term debt cost, not long-term debt cost" related to the FAC deferrals. This is a striking mischaracterization of the record. As support for this statement on brief, they cite Tr. VI at pp. 157-158. The cross-examination of Ms. Smith at these pages reflects a very different picture than the one that OCC (and the Sierra Club) draw on brief:

> Q. At page 35, lines 1 and 2, and actually this carries over from the bottom of 34, you say: 'If deferrals are approved

[21] At page 73 of its brief, OCEA contends that short-term cost of debt also should be used "for deferrals of environmental costs." This is yet another example of OCEA either fundamentally misunderstanding the issue, intentionally mischaracterizing the record, or both. The Companies are not seeking deferral of environmental costs. They are seeking recovery of carrying costs related to environmental investments as those costs are incurred in 2009-2011. Moreover, advocating that capital carrying costs for environmental investments with 25-year lives should be based on short-term debt rates is without any merit.

by the commission, the carrying costs should be set at the **long term** cost of debt.' (emphasis added).

A. Yes.

Q. And are you talking about the current long-term cost of debt as opposed to embedded?

A. I have not considered that question. Perhaps one of the OCC's other witnesses may have addressed that.

Q. I'm not sure if they do, but could I ask you to consider that question now.

A. I would it appears to me that this would be these deferrals would be a new cost which would need to be financed a new and, therefore, the current cost of debt would be appropriate.

Q. As opposed to the embedded cost.

A. It would be new debt.

Q. Okay. And you recommend long-term debt instead of short-term; is that correct?

A. Well, the carrying charges are going to extend over a total period of ten years.

Q. Right.

A. So from that standpoint long-term debt does make sense."

The only conclusions that can be drawn from this exchange is that Ms. Smith thought that carrying charges should be based on the cost of long-term debt since the carrying charges on the deferrals were going to be accrued over a ten-year period.[22] Further, the cost of long-term debt should be based on the current cost of such debt, not

[22] Constellation read and heard the same testimony from Ms. Smith as the Companies did. At page 8 of its brief, Constellation relies on Ms. Smith's Direct Testimony, OCC Ex. 10, p. 35, to support its argument that the carrying cost for FAC deferrals should be set at the cost of long-term debt, and should exclude equity. While the Companies disagree with Constellation's position that equity should be excluded, they appreciate that Constellation does not mischaracterize the record in the course of advocating its position.

the embedded cost. Nowhere does Ms. Smith indicate how she would calculate carrying charges to be accrued over a three-year period.

OCEA also argues that:

> carrying charges on short-term deferrals should be based on the actual short-term cost debt. This is consistent with practices used by other Ohio electric distribution utilities (fn 257) and consistent with recent rulings by the Commission that have limited carrying charges on riders and deferrals to the interest rate of debt only (fn 258)." (OCEA Br. p. 65).

OCEA cites to two Commission dockets, both involving the Companies -- their recent Transmission Cost Recovery Rider proceeding [23] and their proceeding to address accounting procedures for storm-related service restoration costs.[24] OCEA argues that "[c]onsistent with the Commission precedent, the Companies should only be permitted carrying costs on short-term deferrals based on their actual short-term debt." (OCEA Br. p. 66).

What OCEA fails to mention is that the carrying charge rates approved by the Commission in both of those cases were 5.73 percent for CSP and 5.71 percent for OPCo.[25] As can be seen from Exhibit PJN 11 of Companies' Ex. 7, these are the debt rates used by the Companies in calculating their Weighted Average Cost of Capital and Companies' witness Nelson testified that he did not use short-term debt in his

[23] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company to Adjust Each Companies' Transmission Cost Recovery Rider,* Case No. 08-1202-EL-UNC.

[24] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Modify Their Accounting Procedure for Certain Storm-Related Service Restoration Costs,* Case No. 08-1301-EL-AAM

[25] See Case No. 08-1202-EL-UNC, Finding and Order, p. 3, December 17, 2008 and Case No. 08-1301-EL-AAM, Finding and Order, p. 3, December 19, 2008.

calculations. (Companies' Ex. 7B, p. 7). Consequently, the debt rates proposed by OCEA are the long-term debt rates.

Finally, at page 93 of OCEA's brief, OCC and the Sierra Club assert that "OCC witness Smith recommended, a more appropriate rate for any carrying costs approved by the Commission is the short-term cost of debt." OCC and the Sierra club cite to Ms. Smith's pre-filed testimony at page 35. Ms. Smith's actual testimony reads: "If deferrals are approved by the commission, the **carrying costs should be set at the long-term cost of debt."** (OCC Ex. 10, pp. 34-35, emphasis added).

The Companies continue to believe that their WACC should be used for purposes of applying carrying charges to the FAC cost deferrals, whether those deferrals are over a three-year period as originally proposed by the Staff, a ten-year period as proposed by the Companies for the fuel deferrals, or a longer period. What must be noted from this discussion is the unreliability of the arguments, and the alleged support for those arguments, contained in OCEA's brief. Failing to provide for the cost of equity and long-term debt capital both of which must be employed to maintain a reasonable debt-to-equity ratio would be a failure to adequately compensate the Companies for their true cost of providing a phase-in for customers.

D. Automatic Increases to Non-FAC Generation Rates

As discussed pages 27-28 of their Initial Brief, the Companies' ESP contains a proposal to increase CSP's and OPCo's non-FAC portion of their generation rates by 3 percent annually and 7 percent annually, respectively. This component is challenged by a number of the intervenors. Staff proposed a modification to the Companies' proposal.

Before responding to the arguments presented in the briefs of Intervenors and the Staff, it is important to clarify this proposal which seems to have confused OCC and Sierra Club.

In their brief, OCC and Sierra Club state: "the automatic increases are supposed to recover 1) the 2009 carrying cost associated with the 2001-2008 environmental investments...." (OCEA Br. pp. 29-30). Section II. B. of the Companies' Application makes clear that there are two parts to their proposal to increase non-FAC generation rates. (Application, p. 5). First, the Companies propose increases related to carrying charges which will be incurred in 2009-2011 on a portion of environmental investments made during 2001-2008. Those increases, which are related to specific, calculated carrying charges, are not part of the support for the second part of the non-FAC generation rate increase, i.e. the 2009-2011, 3 percent and 7 percent automatic annual non-FAC generation rate increases. This second part includes as part of its support carrying charges on environmental investments to be made during the 2009-2011 ESP period. This second part is not cost-based and that is the focus of the opposition to the annual 3 percent and 7 percent increases.[26]

IEU argues that there must be a cost basis for the Companies' proposal. To support its position, IEU relies on Sec. 4928.42 (D), Ohio Rev. Code, which permits adjustments to the most recent Standard Service Offer for "known and measurable" cost changes. (IEU Br. p. 24). That IEU had to rely on language relating to a Market Rate Offer, because it could not find similar language in Sec. 4928.143, Ohio Rev. Code, is

[26] Having misunderstood the scope of the 3 percent and 7 percent proposed automatic increases, OCC and Sierra Club argue that the proposal violates past Commission orders. (OCEA Br. pp. 30-31). As explained elsewhere in this brief, the proposal to recover 2009-2011 carrying costs on 2001-2008 investments does not seek to recover pre-2009 costs and, therefore, does not violate any Commission orders.

telling. Further, its reliance on a pre-SB 221 Commission order (*Id.* at 18[27]) further demonstrates IEU's inability to find support for its position in Sec. 4928.143, Ohio Rev. Code. Moreover, even that pre-SB 221 order states that a standard service offer price does not need to reflect the sum of specific costs.

In an argument similar to IEU's, Kroger argues that the non-FAC increases must be offset by factors, such as any increases in accumulated depreciation of generating plant. Kroger would have an "accounting for all non-FAC costs associated with providing generating service...." (Kroger Br. p. 14). Kroger's argument that any non-FAC generation rate increase must reflect "the *net* cost of providing non-FAC generation service..." (*Id.* at 15 emphasis in original) is totally flawed. SB 221 did not reinstate cost-of-service rate making for generation service and there is no authority in Sec. 4928.143, Ohio Rev. Code, for the type of cost netting Kroger supports.

To argue that an ESP must be "reasonable" does not advance the inquiry. The question is whether reasonableness is determined by a component-by-component cost analysis, as argued by Intervenors, or by examining the ESP "in the aggregate" as compared to an MRO, as required by SB 221. OPAE/APAC's reliance on the testimony of OPAE witness Alexander and OCC witness Smith (OPAE/APAC Br. p. 6) that any increase to the current Standard Service Offer rates must be cost based (Tr. X, pp. 32-33; Tr. VI, pp. 87-88, 95, 102) fails to recognize the statutory framework for analyzing an ESP as a whole, rather than by each of its component parts. OEG's protest that the 3 percent and 7 percent should be rejected because the Companies have "not provided any cost basis in support" (OEG Br. p. 12) fails for the same reason.

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[27] *In the Matter of the Consolidated Duke Energy Ohio, Inc. Rate Stabilization Plan Remand and Rider Adjustment Cases,* Case Nos. 03-93-EL-ATA et al., Order on Remand (October 24, 2007).

Staff takes a different approach to this issue. Apparently assuming that today's economic situation will tend to reduce the kinds of costs the proposed 3 percent and 7 percent increases are intended to address, Staff proposed annual percentage rate increases of 1.5 percent (for CSP) and 3.5 percent (for OPCo). (Staff Br. p. 6). In addition, Staff proposes that the carrying charges on 2009-2011 environmental investment be treated separately. Staff recommends that the Companies be permitted to recover the carrying charges associated with actual 2009-2011 environmental investments. This recovery would be achieved by the annual filing for recovery in 2010 to request recovery of the additional 2009 carrying charges related to actual 2009 environmental investment and annually for each succeeding year. (*Id.* at 6-7).

Staff's approach would inject a cost-of-service flavor to the proposed automatic adjustment contemplated by Sec. 4928.143 (B) (2) (e), Ohio Rev. Code, and should not be adopted.

Instead, for the reasons stated in this brief and the Companies' Initial Brief the Commission should approve the automatic annual increase as proposed by the Companies.

III. FIXED DISTRIBUTION RATE INCREASE

A. The Commission should reject the Parties' proposal to defer distribution initiatives for consideration in a future distribution base rate case

On brief, Staff advances the recommendation in the testimony of Mr. Hess that the Companies should file a base distribution rate case to recovery the costs of the additional reliability programs, line extension, and amortization of regulatory assets that have been requested in this case. (Staff Br. p. 7). Likewise, OHA, OPAE/APAC, OMA, Kroger and IEU-OH all lobby for procrastination asserting that the Commission should not decide distribution-related issues in this ESP proceeding when the Commission could do so in the context of a separate rate case. (OHA Br. p. 17; OPAE/APAC Br. p.19; OMA Brief, p. 6; Kroger Br. p.18; and IEU-OH Br. p. 25). As a related matter, OHA reiterates the position initially advanced in the testimony of Staff witness Hess that the Companies are "due" for a distribution rate case based on recent industry changes and the time elapsed since the Companies' last rate cases. (OHA Br. p. 18). Finally in this regard, OHA and IEU-OH also similarly state that the Companies' distribution rates are subject to the provisions of R.C. 4909 and the consumer protections of the traditional ratemaking structure that ensure just and reasonable rates. (OHA Br. p.19; IEU-OH Br. p. 25).

These arguments simply reveal individual parties' concerns with newly enacted Sec. 4928.143(B)(2)(h), Ohio Rev. Code. This section was enacted as a key part of the legislative package contained within SB 221 to enable an EDU to propose a long-term energy delivery infrastructure modernization plan such as the ESRP. There can be no question that single-issue ratemaking is permitted *within an ESP case* and pursuant to the statutory deadlines imposed by the General Assembly for an ESP case. The test year and rate base concepts, which Mr. Hess included in his suggested cost deferrals, (Tr. XIII, p. 122), would not apply in the context of single-issue ratemaking. Kroger witness Higgins was even more direct in challenging the wisdom of the single-issue ratemaking provision in Sec. 4928.143(B)(2)(h), Ohio Rev. Code, by revealing his opinion that "adopting a distribution rate increase based on partial cost information would not be a reasonable course of action." (Kroger Ex. 1, p. 12). The General Assembly knew about the industry changes and it knew that electric utilities had not conducted base rate cases in recent years when it passed SB 221. The General Assembly also necessarily understood when it allowed single-issue ratemaking that a comprehensive view of a utility's finances would not be involved. The time to recommend changes to the legislation has passed and the Commission must apply the law as written.

The Companies are only seeking recovery of incremental costs for incremental reliability activities – that proposal is clearly permitted under Sec. 4928.143(B)(2)(h), Ohio Rev. Code. Staff's "earnings erosion, deferral and potential future recovery in another case" approach to cost recovery is inconsistent with the ESP statute. Similarly, OCEA's complaint that AEP Ohio has not demonstrated that implementing the ESRP "is beyond its existing resources" is irrelevant and an inappropriate standard by which to judge a long-term energy delivery infrastructure modernization plan under Sec. 4928.143(B)(2)(h), Ohio Rev. Code. (OCEA Br. p. 44). Claiming that there is not enough time and that the issues are better considered in a separate distribution rate case also completely emasculates the General Assembly's stated intentions and effectively repeals this integral provision within SB 221. Just because the parties are "piling on" to argue that the distribution issues should be left unresolved for a future case that has not even been filed, that does not mean the Commission should yield to the temptation to avoid addressing matters properly raised as part of the Companies' ESP proposal.

As a related matter, Kroger relies on the Commission's recent Opinion and Order (December 17, 2008) in the *FirstEnergy Electric Security Plan* proceeding, Case No. 08-935-EL-SSO ("*FirstEnergy ESP Order*") to support the notion that AEP Ohio's distribution proposals should be deferred to a future distribution base rate case. (Kroger

Br. p. 18). The situation addressed in the *FirstEnergy ESP Order* is easily distinguished. FirstEnergy had previously filed and fully litigated a base distribution rate case and all of the issues in the distribution case were briefed and awaiting a decision. FirstEnergy presented its ESP proposal to incorporate resolution of the pending distribution rate case issues. In issuing the *FirstEnergy ESP Order*, the Commission simply declined to decide two separate proceedings with two separate records within the ESP case:

> [T]he Commission declines to resolve in this case the substantive issues of the *FirstEnergy Distribution Rate Case*. The *FirstEnergy Distribution Rate Case* will be decided solely based upon the evidence in the record of that proceeding, and it is our intention to resolve those matters in the near future.

(*FirstEnergy ESP Order*, p. 35). By contrast, AEP Ohio's distribution proposals were raised exclusively in this proceeding and the entirety of the record exists within this record; the Companies have no pending distribution rate case and it is not clear at what point in the future their next base distribution rate case will be filed. Hence, the *FirstEnergy* ESP order is distinguished and does not support avoiding a decision in this case on AEP Ohio's distribution proposals. Instead, the Commission should reject the Parties' proposal to defer distribution initiatives for consideration in a future distribution base rate case.

B. The Companies' Enhanced Service Reliability Plan should be adopted

The Companies have demonstrated the merits of adopting its proposed ESRP through its testimony (Companies' Ex. 11) and through its Initial Brief (Companies' Br. pp. 72-84), including a detailed discussion of issues raised by the other parties' testimony. Below is a brief discussion of additional points raised on brief by other parties.

1. Additional Staff Arguments

Even though Staff on page 8 of its brief clearly indicates that the distribution issues should be deferred to a future base distribution rate case (as discussed above), the Staff also recommends on brief that the Commission *require* the Companies to implement the following list of initiatives:

- Enhanced overhead inspection and mitigation work initiative
- Replacement of cutouts
- Installation and replacement of arresters
- Replacement of three-phase reclosers with three single-phase reclosers
- Enhance the protection on existing 34.5kV circuits
- Installation of fault indicators on all three-phase overhead switches, all feeder exist riser poles and underground residential distribution (URD) riser poles
- Enhanced vegetation management initiative

(Staff Br. p. 10.). It is one thing to ignore legislative changes by putting off the distribution issues without deciding them as argued on page 8 of Staff's brief; it is quite another to order implementation of the proposed programs without cost recovery, as later suggested by the Staff on page 10. Aside from being internally inconsistent as to whether distribution issues should or should not be addressed in this case, Staff unreasonably asks for "the best of both worlds" by seeking implementation of enhanced reliability programs without providing for the cost recovery and, in doing so, invites the Commission to issue an order that would be overturned by the Supreme Court of Ohio as unreasonable and unlawful.

The Commission lacks the authority in this case to order enhancement programs without recovery by the Companies. The Supreme Court of Ohio found in *Forest Hills Utility Co. v. Pub. Util. Comm.* (1972), *31 Ohio St. 2d 46, 57; 285 N.E.2d 702,709,* that the Commission must provide recovery for improvements it orders utilities to institute. Specifically the Court stated,

> Public Utilities Commission possesses the power to require a utility to render adequate service, but it lacks the authority to require that certain installations and improvements be made before the utility may claim and receive a just and reasonable rate for the services actually being rendered with its existing property and facilities.

Id. Any Commission order to require the enhancement programs contemplated in this proceeding without rate relief is in direct contradiction to the *Forest Hills* doctrine and will be subject to reversal by the Supreme Court of Ohio. If the Commission determines to defer consideration of the distribution proposals (against the Companies' recommendation), it should not adopt the approach of requiring programs but denying cost recovery. This would take away value from the ESP package and inject a host of problematic legal issues into the case.

2. Additional OCEA Arguments

As a threshold matter, OCEA inaccurately claims that the Companies propose to collect $445 million based on the ESRP proposal. (OCEA Br. pp. 31-32). Companies' witness Roush testified that the total revenue requirement over the three-year ESP term that would be collected from customers for the ESRP is approximately $219 million –less than half of OCEA's claimed amount. (Companies' Ex. 1, DMR-1, DMR-4). After starting with this gross inaccuracy concerning the overall cost of the ESRP, OCEA proceeds to advance other misguided arguments.

For example, OCEA claims that AEP Ohio falls short of defining any tangible benefits of the ESRP and claims that the Companies have not shown that the additional investment it has proposed as part of the ESRP will noticeably enhance distribution system reliability. (OCEA Br. pp. 33, 37). During cross examination, OCC's own witness testified that he expected the ESRP programs would positively affect the

Companies' reliability. (Tr. VII, pp. 63-64). Mr. Cleaver generally insisted that most of the ESRP programs were good industry practices that address reliability and should all be done already. (Tr. VII, p. 66-67).

Further, Companies' witness Boyd, through his testimony, specifically established that positive reliability impacts are expected if the ESRP programs are undertaken and he presented a solid enhanced reliability plan for the Commission to consider as part of the entire ESP package. (*See e.g.* Companies' Ex. 11, pp. 24, 25, Chart 4 and p. 30, Chart 6). Other record evidence also supports the positive reliability impacts expected for the ESRP. (*See e.g.*, Tr. V, pp. 228; Staff Ex. 2, p. 11 citing the response to Staff data request 4-2(b); OCC Ex. 9A, Response to Staff Data Request 3-83). Beyond that, Mr. Boyd also indicated that the Companies are willing to work with Staff to adjust reliability targets based on implementation of the ESRP. (Tr. V, pp. 252-253). As a related matter, the OCEA brief maintains that the ESRP is not a "true enhancement" to current reliability activities. (OCEA Br. pp. 41-44). This entire line of argument was already thoroughly addressed in the Companies' Initial Brief. (Companies' Br. pp. 76-80). In reality, OCEA recognizes the value of the enhanced initiatives and simply wants AEP Ohio to implement the ESRP but avoid paying for it.

OCEA also criticizes the proposed ESRP since it "provides no disincentives for failure of the plan to meet any of its vague objections" and because the proposal lacks specific milestones to measure the outcome of the incremental programs.[28] (OCEA Br. pp. 34, 36). As referenced above, Companies' witness Boyd did estimate the expected reliability impacts associated with the ESRP and did indicate that the Companies are

[28] OPAE/APAC similarly complains that the Companies' ESRP proposal does not guarantee the level of service reliability that will be achieved or provide consequences for failure to achieve any reliability goals. (OPAE/APAC Brief, pp. 18-19).

willing to work with Staff to adjust reliability targets based on implementation of the ESRP. (Tr. V, pp. 252-253). But as with reliability targets for gridSMART Phase 1 and targets generally under ESSS Rule 10, results cannot be strictly guaranteed. There are many dynamic factors that impact service reliability index performance from one period to the next. And while the expected reliability impacts were good faith estimates of ESRP implementation, they may not be exact or certain when compared to the actual impact; thus, depending on the consequence attached to non-attainment, could actually create a net "liability" for the Companies in undertaking the initiative. The Companies are not opposed to being held accountable for a positive reliability impact but these practical impediments need to be addressed in that context. The Companies' preference for ensuring accountability would be to establish project milestones and reporting relating to the ESRP program implementation, rather than strictly tying success to the achievement of specific reliability impacts.

Regarding the appropriate standard by which the Commission should judge the ESRP, OCEA also attempts to inject several factors and considerations that go beyond Sec. 4928.132(B)(2)(h), Ohio Rev. Code, in a transparent attempt to ensure rejection of the ESRP. In this regard, OCEA makes several arguments based on "compliance with" the proposed rules in Case No. 08-777-EL-ORD. (OCEA Br. pp. 35-37). These procedural rules were not finalized or effective when the Companies' ESP application and testimony was filed or when the hearing was conducted in these cases. Moreover, Sec. 4928.143(C), Ohio Rev. Code, allows a utility to conform its filing to the rules upon their taking effect. Obviously, the General Assembly envisioned effective rules prior to the ESP cases being considered and decided. Because the rules are still not finalized or effective and remain pending, it would blatantly violate statutory and constitutional due process for the Commission to apply any form of the rules, directly or indirectly, in the decision phase of this case. In any case, OCEA misconstrues and misapplies the proposed rules and their arguments should be altogether ignored.[29]

OCEA also states on brief that the ESP case "has cast grave doubt as to whether AEP Ohio has been providing reliable service at the levels contemplated by the statute." (OCEA Br. p. 33). Similarly, OCEA states that its position in this case "is that AEP Ohio's distribution system reliability efforts in recent years have been inadequate and have not ensured safe and reliable service for AEP Ohio's customers – a position shared by the PUCO Staff." (OCEA Br. pp. 37-38). These overblown, dramatic statements are without basis in the record and both claims are made without citation to OCC's testimony in this case. It is not logical or credible to claim that the ESP filing that proposes to undertake incremental reliability programs has "cast grave doubt" on whether AEP Ohio has been providing reliable service. Further, such a conclusory "one-liner" allegation about the adequacy of AEP Ohio's service is inherently suspect given the complex nature of any adequate service investigation or issue.[30] In reality, these statements represent a shallow attack on brief that was simply not backed by any of the witnesses in this case and, consequently, was not subjected to cross examination or discovery. Moreover, OCEA's attempt to portray Staff's position as being the same as OCEA's is as

[29] For example, OCEA faults AEP Ohio for not providing an implementation schedule and indicating the number of customers affected, as would be required by proposed Rule 4901:1-35-03(C)(9)(g). (OCEA Brief, p. 36). As explained in the Companies' testimony, the ESRP affects all customers and the schedule is set forth through implementation of the specific programs at the stated incremental funding levels each year of the ESP. Even if the rules were effective, OCEA is wrong in claiming that AEP Ohio falls short of compliance.

[30] OCC clearly recognizes that such allegations are inappropriate for resolution in this case as further evidenced by OCC's request for investigation in Case No. 08-1299-EL-UNC (discussed below in greater detail).

presumptuous as it is unsupported. (Companies' Br. p. 79 note 26). In a similar vein, the Companies' Initial Brief already fully addressed the flawed notion that the Companies are "required" to undertake all of the proposed ESRP programs and activities. (Companies' Br. pp. 78-80).

Moreover, OCEA takes an unsubstantiated leap in its argument that the ESRP was developed to cope with past failures in the planning and budgeting processes. (OCEA Br. p. 45). OCEA attempts not only to carry the Staff's torch on reliability enforcement but to also advance positions not advanced by the Staff itself – including positions from prior cases 03-2570 and 06-222. (OCEA Br. pp. 38-40). Those historical issues have already been resolved and the cases closed; the issues are not relevant to the ESP case. If OCEA has a credible case of inadequate service, it can file a complaint case under Sec. 4905.26, Ohio Rev. Code. But accusations and innuendo are not enough to sustain an assertion of inadequate service. The Supreme Court of Ohio has been very clear in holding that the burden is upon the complainant to establish inadequate service in a R.C. 4905.26 complaint case. *Ohio Bell Tel. Co. v. Pub. Util. Comm.* (1984), 14 Ohio St. 3d 49, 471 N.E.2d 475, *citing Grossman* v. *Pub. Util. Comm.* (1966), 5 Ohio St. 2d 189, 190, 214 N.E.2d 666, 667. Absent sustaining the burden in a complaint case, OCEA has no role in enforcing reliability standards.

These statements by OCEA highlight its failure to appreciate the regulatory system in Ohio and the oversight and regulatory function already served by the Commission. The Commission oversees a regulatory system governed by administrative code rules that dictate a framework for reliability in the distribution system in Ohio. The Companies seek to enhance its efforts beyond that level ensured by the Commission through its rules and its Staff. OCEA confuses its opinion of the level of reliability required by the rules with the level of enhancements sought by the Companies. The issues are separate and distinct.

OCEA suggests that the reliability system has ongoing problems and that a filing made by the Consumers for Reliable Electricity in Ohio[31] ("CREO") in Commission Case No. 08-1299-EL-UNC, provides an appropriate docket to evaluate the Companies' past service reliability efforts. As pointed out by the Companies in their memorandum contra to CREO's request for a hearing, the arguments in that case are based on the same faulty innuendo advanced by OCEA in this case: that there are past failures unaddressed by the Commission.

The Commission has oversight of the distribution system in Ohio and has Staff in place to ensure that the level of service required by the rules is provided. The Commission's Service Monitoring and Enforcement Department is made up of 1) the Reliability and Service Analysis Division, 2) the Facility and Operations Field Division, 3) the Investigations and Audit Division), and 4) the Customer Education and Contact Division. Each division has its own duties related to enforcing the Commission's administrative code rules. These Staff members work year round to monitor and inform the electric utilities of issues related to individual customers, geographic areas, as well as particular pieces of equipment.

The rules that the Commission Staff monitor cover a wide variety of areas and ensure that the Commission has oversight of the reliability efforts of the EDUs across the state. In particular, Chapter 4901:1-10 contains a number of rules intended to ensure

[31] OCC is one of the parties in the CREO group on Case No. 08-1299-EL-UNC and one of the two parties in the OCEA group in this case.

attention to electric reliability and Commission oversight of the industry. The rules cover, among other requirements, the establishment and reporting of service indices used in weighing electric utility performance,[32] a plan for future investment and service reliability efforts and a report on satisfaction of previous goals[33], and requirements to ensure specific inspection, maintenance, repair, and replacement cycles for utility equipment[34] that must be followed by each and every electric distribution utility. These rules also provide for the director of the Commission's Service Monitoring and Enforcement Department to review action plans filed by the electric distribution utilities to address reliability needs and relay inadequacies to the Commission if the utilities' actions are insufficient.

The current regulatory environment has its checks and balances already built into the system to ensure a reliable network. The Commission and its staff have administrative rules that provide reports and ongoing oversight of reliability. Any assertion that there are ongoing reliability problems unaddressed by the Companies is an assertion that the Commission is not doing its job under the administrative code rules. That is not the case.

Further R.C. 4905.26 provides OCEA or any other entity with the ability to file a complaint case if it can prove problems with the Companies' reliability efforts, by establishing reasonable grounds for the complaint and bearing the burden of proof in the case. The members of OCEA and the members of CREO have not filed any such complaint. OCEA attempts to focus the Commission on the past, when OCEA itself has

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32. O.A.C. 4901:1-10-10.

33 O.A.C. 4901:1-10-26.

34 O.A.C. 4901:1-10-27.

failed to file a case supporting its accusations in the past. It is important that the Commission not be distracted by this red herring presented by OCEA in Commission Case No. 08-1299-EL-UNC. OCEA fails to recognize that the issue in this case is the Companies' efforts to enhance reliability practices beyond the level required in the rules. Instead, OCEA is focused on second guessing the Commission's past regulatory oversight addressing the very different issue of the level of service required in the administrative code. The Companies respectfully request that the Commission focus this issue on enhancements being sought and properly raised in this case.

3. Additional OHA Arguments

Throughout its discussion of the proposed ESRP, OHA parrots the arguments and cite pervasively to OCC witness Cleaver's testimony – without ever crediting OCC for the arguments or attributing the statements to witness Cleaver by name. (OHA Br. pp. 18-22.). Accordingly, the Companies do not separately address OHA's erroneous line of argument concerning the ESRP other than correcting two specific misstatements made by OHA in the course of attempting to restate OCC's arguments. First, OHA claims that "many of [the Companies' existing reliability] programs "were adopted as part of the Commission's ongoing investigation into AEP's electric distribution service reliability problems." (OHA Br. p.19.). This statement is false. The Commission does not have an ongoing or pending investigation concerning the Companies' reliability and it is simply not true that many of the Companies' existing programs were adopted as part of any Commission investigation. Second, OHA then proceeds to reference the Companies' 06-622 self-complaint filing where OHA claims that the Enhanced Distribution Reliability Plan (EDRP) expanded on the Companies' reliability programs, added incremental programs and provided for increased funding by ratepayers. (*Id.*). That statement is also false because it suggests that the EDRP was previously implemented. In fact, the proposed EDRP was never adopted and was withdrawn by the Companies after being met with legal objections to single-issue ratemaking. (May 16, 2007 Entry in Case No. 06-222-EL-SLF). But now the General Assembly has changed the law and erased the basis of those legal objections. SB 221 now allows single-issue ratemaking, and the Companies can hardly be faulted for attempting to again pursue enhanced reliability in a manner that is consistent with its prior EDRP filing.

4. Conclusion/Companies' Position on Cost Recovery

The Commission should adopt the ESRP as proposed by the Companies. Regarding the cost recovery mechanism for the ESRP, the Companies maintain that their percentage distribution increase (based on projected costs for both the ESRP and gridSMART initiatives) is reasonable and appropriate as part of the beneficial ESP package. But in recognition of Staff's apparent general preference for distribution riders and in an attempt to address consumer parties' concern with ensuring that incremental ESRP costs are actually spent,[35] the Companies would agree it is acceptable to instead approve a rider based for the ESRP initiative. Unlike the Staff's "zero dollar" rider, however, the Companies' alternative cost recovery proposal would avoid regulatory lag (which is critical to avoid in the current "credit crisis") by establishing the initial rider rate based on the 2009 revenue requirement calculation Mr. Roush made in Exhibit

[35] For example, OCEA complains that there is no provision in the ESRP for a review of the expenditures and what to do with funds allocated for the various reliability programs that are not spent. (OCEA Brief, p. 35). For example, OCEA also maintains that there is no assurance that the ESRP's vegetation management program would be followed as proposed. (OCEA Brief, p. 39). A rider would ensure complete transparency and that amounts collected from customers through rates would match the actual amount spent by the Companies to implement the ESRP.

DMR-4. The amount collected in year one would be subject to true-up and reconciliation based on the Companies' prudently incurred net costs during the first year and a new rider would be set based on the 2010 revenue requirement and account for the reconciliation, if any for the first year, and so on. This approach would permit timely cost recovery and reconcile actual prudently incurred expenses with amounts recovered from ratepayers.

C. gridSMART Phase 1

Most of the arguments Staff set forth on brief concerning gridSMART Phase 1 were straight from their testimony and, as such, the Companies already addressed those issues in detail within their Initial Brief. (*See* Companies' Br. p. 63 regarding operational cost savings, pp. 67-68 regarding the timing of dynamic price offerings, pp. 68-69 regarding deployment of PCTs, pp. 64-66 regarding quantification of customer and societal benefits, pp. 69-72 regarding the DA portion of the gridSMART initiative, and pp. 64-66 regarding customer and societal benefits associated with gridSMART.) The Companies stand behind each of those arguments but will not repeat them again here for efficiency; instead, the Companies would like to address additional points raised by Staff on page 14 of its brief.

Staff argues that AEP Ohio should share, with customers, the financial risks associated with its gridSMART initiative by having some portion of the investment paid for by shareholders, since the investment "benefits AEP just as much as it does customers." (Staff Br. p. 14.) In order for Staff's statement to hold true, the operational savings would have to equal or exceed the costs in order for the Company to receive as much benefit as the customers would from the investment. But the assertion that the gridSMART investment benefits AEP Ohio as much as it does customers is without basis in the record. In fact, the Companies have quantified the expected operational cost savings associated with gridSMART Phase 1 and netted them against the costs in order to request recovery of net costs only. (*See* Companies' Br. pp. 62-63). During cross examination, Staff witness Scheck acknowledged when asked whether operational cost savings would outweigh the costs of gridSMART implementation, he retrenched and stated that "I'm not suggesting that the operational savings will offset that entirely, by no means..." (Tr. VIII, p. 181). He also agreed that customer and societal benefits, whatever they are and however they are quantified, should not offset the utility's recovery of net costs. (Tr. VIII, p. 182).

The gridSMART Phase 1 initiative is an investment in CSP's distribution network to support the provision of electric service. If the Commission approves the deployment as being reasonable and prudent investment, there is no reason that customers should avoid paying the entire net costs as part of their distribution rate. No other party has provided evidence of record to rebut or counter the Companies' quantification of limited operational savings during gridSMART Phase 1. Thus, discounting the net costs to be recovered based on some vague, unsubstantiated notion of company benefit would be unfair and inappropriate. The Commission should not adopt this approach as it would simply be tantamount to denying the Companies appropriate cost recovery.

Staff on brief also advances the notion that AEP Ohio "should have some accountability for having its gridSMART initiative meet the minimum reliability standards." (Staff Brief at 14.) Being a new concept advanced for the first time on brief, it is not clear what Staff means by accountability to "meet the minimum reliability standards." Specifically, it is not clear what minimum reliability standards apply to gridSMART. Staff does not explain what minimum standards would apply to gridSMART as there are a number of options that could be considered (*e.g.*, develop a plan for specific measurement in the gridSMART area, verify attainment of the estimated reliability impacts provided by the Companies in discovery, modify the statewide ESSS reliability targets, etc.) Staff's new proposal on brief also does not indicate what consequences would occur if the standards were not met, although there are a number of different approaches that could be discussed in this context (*e.g.*, provide a report explaining other causes that may have impacted the result, develop an improvement plan to address a shortcoming, etc.).

Again, because Staff did not advance this notion in testimony, support it in the record or subject any such notion to cross examination during the hearing, it would be unfair for the Commission to unilaterally adopt the recommendation even if the Commission can discern what it means. The Companies did submit some expected reliability impacts associated with gridSMART Phase 1 in response to Staff data requests 3-73 and 4-2 –both of which were stipulated into the record as part of OCC Ex. 9A. The problem with making the Companies strictly accountable for achieving those improvements is twofold. First, because there are many dynamic factors that impact service reliability index performance from one period to the next, it would be difficult to accurately measure and verify the discrete impact of gridSMART deployment on a particular reliability index. Second, while these were good faith estimates of the impact of full implementation of gridSMART Phase 1 as proposed by the Companies, they may not be exact or certain when compared to the actual impact (assuming it can be accurately measured) and, depending on the consequence attached to non-attainment, could create a net liability for the Companies in undertaking the initiative. Moreover, reliability impact is only one of many potential benefits for deploying gridSMART and should not be the sole determinant of a successful implementation. The Companies are not opposed to being held accountable for a positive reliability impact but these impediments need to be addressed in that context. But the Companies' preference for ensuring accountability would be to establish project milestones relating to the deployment efforts, rather than tying success to the achievement of specific reliability impacts.

Finally in this regard, Staff sets forth yet another new idea on brief that is unclear. Staff states that "AEP should be prepared to offer specific tariff and rate provisions for customers who have already received the enabling gridSMART technology or, in the alternative, AEP should offer a critical peak pricing rebate until its tariff rates become available to customers." (Staff Br. p. 14.) The part of the recommendation to offer dynamic pricing is not new and the Companies already addressed this matter in their Initial Brief (on pages 67-68) by making clear that AEP Ohio would simultaneously roll out dynamic pricing with the implementation of the underlying gridSMART capabilities. But the "alternative" recommendation offered by Staff on brief is problematic and unclear. Apparently, Staff is suggesting that the Companies should offer critical peak pricing rebates to residential customers and a hedged price to commercial customers prior to its tariff offerings being approved. It is not clear how the Companies can make such offerings if they are not yet approved through tariffs –that is legally problematic under several provisions within Chapter 4905 of the Ohio Rev. Code. It is also unclear why the Companies would need to have pre-tariff offerings available when they have committed to simultaneously roll out dynamic pricing with the implementation of the underlying gridSMART capabilities. Once again, however, because Staff did not advance this notion in testimony, support it in the record or subject any such notion to cross examination during the hearing, the recommendation cannot be properly explained or tested.

OCEA asserts that AEP Ohio has not demonstrated that gridSMART Phase 1 is cost-effective, citing Sec. 4928.02(D), Ohio Rev. Code. (OCEA Br. pp. 77-82). OCEA also complains that the Companies did not provide appropriate detail supporting the cost estimates and the equipment that will be used. (OCEA Br. p. 81). Similarly, OPAE/APAC asserts that AEP Ohio requests approval of gridSMART Phase 1 without demonstrating its cost-effectiveness and advocates imposing a requirement that all benefits be specifically monetized and mathematically shown to equal or exceed the net costs. (OPAE/APAC Brief at 17-18.) The Companies do maintain that gridSMART is cost-effective but submit that a strict demonstration of cost-effectiveness of gridSMART Phase 1 is not required based on Sec. 4928.02(D), Ohio Rev. Code, as OCEA and OPAE/APAC suggest.

Although Sec. 4928.02(D), Ohio Rev. Code, makes reference to cost-effective supply- and demand-side retail electric service, Sec. 4928.66, Ohio Rev. Code, separately imposes mandatory energy efficiency and peak demand reduction benchmarks and other provisions within SB 221 apply to distribution modernization proposals –most notably Sec. 4928.143(B)(2)(h), Ohio Rev. Code. Indeed, Sec. 4928.143(B)(2)(h), Ohio Rev. Code, is the governing provision of law that applies to AEP Ohio's gridSMART Phase 1 initiative as part of its ESP proposal –and that provision contains no requirement for cost-effectiveness.

It also makes sense that the Commission should not focus on just one aspect of the gridSMART proposal because it is not a one-dimensional initiative. Rather, it is expected to yield various benefits to customers including an enhanced ability to conserve energy and manage demand, bill reductions associated with conservation and demand response, improved reliability through fewer outages and shorter outage durations, and improved meter reading and related services; company benefits include improved safety for field employees, real-time information for system operation, enhanced system operation and outage restoration and demand reduction. (Companies' Ex. 4, p. 7). There are secondary and largely intangible benefits anticipated from the initiative such as enhancements to power markets, environmental benefits and improved national energy independence and security. (*Id.*, p. 16).

Given the varied and far-reaching set of expected benefits, it is not practical to impose a requirement that all benefits be specifically monetized and mathematically shown to equal or exceed the net costs. Moreover, as Ms. Sloneker explained, with a phased approach to implementation, not all of the operational savings materialize in the initial phase and additional savings will occur as full implementation is pursued. (Companies' Ex. 4, p. 17). In any case, the Companies should not be required to monetize and mathematically demonstrate that the benefits equal or exceed the net costs.

As with any network investment designed to provide electric service, a conclusion as to whether the investment is cost-effective ultimately turns on the value assigned to receiving the functions and capabilities associated with the network investment. The Commission does not require a demonstration of the benefits of traditional meters versus the cost, prior to a determination that it is a prudent investment in distribution facilities.

Rather, because the functions and capabilities are deemed necessary and appropriate to providing electric service, the utility can recover prudently incurred costs associated with the investment. Likewise, assigning values to the quantifiable and intangible benefits associated with smart meters or a gridSMART initiative should not be required. Rather, it makes more sense to examine whether the functions and capabilities associated with gridSMART are reasonable and appropriate to enhance the provision of electric service, consistent with SB 221 and the forward-looking State energy policies found in Sec. 4928.02, Ohio Rev. Code.

In examining that question, the Commission should consider the several provisions within SB 221 adopted by the General Assembly designed to promote the deployment of smart metering, as discussed in the Companies' Initial Brief. (Companies' Br. pp. 65-66). If the Commission determines, as AEP Ohio has maintained, that the gridSMART Phase 1 deployment is an appropriate investment to enhance the provision of electric service in light of SB 221 and consistent with State energy policies, then the Companies should be authorized to proceed with the deployment.

Even though a company's operating savings should be quantified and netted from incurred costs to allow for regulatory recovery of net costs, the customer and societal benefits do not accrue to the company and are not needed in order to calculate the net costs that are appropriate for regulatory recovery. Rather, the Commission need only determine that the initiative fits within the parameters of Sec. 4928.143(B)(2)(h), Ohio Rev. Code, and is a beneficial component of the proposed ESP that, in the aggregate, is more favorable than the expected results of an MRO.

As discussed above and in the Companies' Initial Br. AEP Ohio has quantified the expected operational cost savings associated with gridSMART Phase 1 and they have been netted against the costs in order to request recovery of net costs only. (*See* Companies' Br. pp. 62-63). In proposing a percentage distribution increase based on gridSMART and the ESRP, the Companies have only asked for recovery of their estimated net costs. (Companies' Ex. 1, p. 10-11, DMR-4). Accordingly, the Commission should approve the gridSMART initiative as a prudent investment and a beneficial part of the Companies' ESP proposal under Sec. 4928.143, Ohio Rev. Code.

Regarding cost recovery, the Companies maintain that their percentage distribution increase is reasonable and appropriate as part of the beneficial ESP package. But in recognition of Staff's apparent general preference for distribution riders and in an attempt to address consumer parties' concern about the accuracy of AEP Ohio's cost estimates for gridSMART Phase 1, the Companies would agree to instead approve a rider based for the gridSMART Phase 1 initiative. Unlike the Staff's "zero dollar" rider, however, the Companies' alternative cost recovery proposal would avoid regulatory lag by establishing the initial rider rate based on the 2009 revenue requirement calculation Mr. Roush made in Exhibit DMR-4. The amount collected in year one would be subject to true-up and reconciliation based on CSP's prudently incurred net costs during the first year in deploying gridSMART Phase 1 and a new rider would be set based on the 2010 revenue requirement and account for the reconciliation, if any for the first year, and so on. This approach would permit timely cost recovery and reconcile actual prudently incurred expenses with amounts recovered from ratepayers.

D. The Companies' proposals under Sec. 4928.143(b)(2)(h) are limited to prudently incurred costs in an ESP proceeding.

IEU-OH claims that, relative to Sec. 4928.143, Ohio Rev. Code, the Commission has established precedent generally concluding that distribution rate changes approved in an ESP should be based on prudently incurred costs, including a reasonable return on investment for the utility. (IEU-OH Br. p. 25). In making this sweeping statement, IEU-OH relies solely on page 41 of the *FirstEnergy ESP Order*. (*Id.*). IEU-OH proceeds to categorically recommend that the Commission reject all of AEP Ohio's distribution riders "because they are not limited to the recovery of prudently incurred costs." (IEU-OH Br. pp. 25-26). OMA similarly mischaracterizes the Companies' proposed distribution increases as "an admittedly non-cost component" without citation or explanation. (OMA Br. p. 6).

The Commission discussion on page 41 of the *FirstEnergy ESP Order* broadly relied upon by IEU-OH was actually a specific discussion limited to distribution modernization riders proposed under Sec. 4928.143(B)(2)(h), Ohio Rev. Code; that passage did not set forth a general standard applicable to all distribution riders within ESP cases, as suggested by IEU-OH.[36] Even for distribution modernization proposals under Sec. 4928.143(B)(2)(h), Ohio Rev. Code, AEP Ohio questions whether the statements made by the Commission in the *FirstEnergy ESP Order* are binding in this case. Given that the case was terminated without being fully litigated and the Companies withdrew their ESP proposal rather than pursuing rehearing and/or appeal, the cited passage represents the Commission's initial thought on the matter as applied to

[36] As to cost recovery, AEP Ohio notes that its fixed distribution increases proposed as part of its ESP are based on the incremental cost of the ESRP and the incremental cost of gridSMART Phase 1 –neither proposal was for a distribution *rider* like the ones discussed in the FirstEnergy decision. AEP Ohio is willing, however, to accept a rider for ESRP cost recovery as further described above.

FirstEnergy's proposals presented in that case and certainly not necessarily the final interpretation of statutory requirements to be applied in all cases.

Regardless of those distinctions, IEU-OH's sweeping statement is of no avail since AEP Ohio only advances two initiatives under Sec. 4928.143(B)(2)(h), Ohio Rev. Code (gridSMART Phase 1 and the ESRP), and both of those proposals satisfy the standard of only recovering prudently incurred costs. As discussed in the Companies' Initial Brief (pp. 74-76), the ESRP initiative is based on recovery of incremental costs associated with incremental reliability activities. Similarly, the gridSMART Phase 1 proposal is based on projected costs – net of anticipated cost savings – for implementing the rollout. (Companies Initial Br. pp. 62-67). In considering and approving the Companies' ESRP and gridSMART proposals, the Commission would be endorsing the Companies' overall decision to undertake these initiatives and recover the prudently incurred costs through rates.

IV. OTHER ESP CHARGES

A. Provider of Last Resort Charge

The Companies discussed the proposed increase in their Provider of Last Resort (POLR) charge at pages 41-51 of their Initial Brief. In that discussion the Companies reviewed the applicability of the Black-Scholes model to pricing the cost of POLR service and responded to several arguments that had been raised at the hearing suggesting that the Companies could avoid the costs of offering POLR service.

The other parties' briefs raise a variety of additional arguments to which the Companies offer the following responses. First, some Intervenors contend that since POLR service is non-competitive the rate for that service must be based on a cost-of-service analysis. From there, they argue that the Black-Scholes model only predicts the Companies' cost of providing POLR service and the actual cost is not yet known. (IEU Br. p. 25; Kroger Br. p. 16; Schools Br. p. 8; Constellation Br. p. 13). That Constellation subscribes to this theory is quite interesting since its witness, Mr. Fein, testified that POLR "is solely related to the generation service because that's the service that is open to competition, if you will, that someone else can provide that service." (Tr. II, pp. 23,24).

However one wishes to characterize POLR service, the important point is that the cost of that service is based on the risk to the POLR provider, not the cost associated with a customer actually switching to a CRES provider, or actually returning to the POLR provider. As Mr. Baker explained.

> The risk exists because customers can [switch], not whether they exercise it .... [A]n option gives you a right to do something, and you pay for the right to do it. That is – its irrelevant whether you actually decide to exercise it or not.

(Tr. X, p. 212

OEG agrees that the Companies' approach to pricing POLR service may be "reasonable in concept" but has not verified that proposed rate level." (OEG Br. p. 17).

Some Intervenors contend that customers should not be required to purchase the option if they do not want to exercise the option. (OEG Br. p. 18, OHA Br. p. 16). They miss the point. The Companies are not selling the option to customers. The option to switch generation service to a competitive provider was legislatively provided by SB 3 and SB 221 enhances the opportunities for that option by providing added encouragement for government aggregation. (Sec. 4928.20 (J) and (K), Ohio Rev. Code).

Other Intervenors argue that if the Companies do not purchase options to protect against this risk there will be no cost to the Companies. (OCEA Br. p. 27). OEG, and of course the Companies disagree. As OEG states:

> [T]he Companies are required to 1) absorb the loss if the market becomes less expensive than the ESP price or 2) stand-by to serve potential return CRES customers in the event that the market becomes more expensive.

(OEG Br. p. 18).

Whether the Companies purchase options for the POLR risk or "self insure," the customers would be indifferent. Mr. Baker explained that:

> The company will decide over the period of the ESP whether to execute on options in order to hedge its risk or not. That's the company's decision.

(Tr. XIV, p. 200).

The only relevant question is whether the Companies properly priced the cost associated with the customers' options to switch and return. (Tr. X, pp. 213,214). Schools witness Frye agreed with the self insurance analogy and also agreed that it is not uncommon for people to pay for insurance and the event being insured against is never triggered. (Tr. XII, pp. 54, 57).

Several Intervenors also assert that the Companies' cost of being the POLR provider is not properly priced. There arguments are many, but in the main they fail to confront the nature of the POLR cost. As Mr. Frye explained in an earlier Commission proceeding, "POLR is a *financial obligation* an electric distribution company incurs in the competitive generation market ...." (Tr. XIII, pp. 48-49, emphasis added). As a "financial obligation" the Black Scholes model is well suited to determining the extent of the cost.

Nonetheless, some Intervenors assert the Black-Scholes model should not be used for this purpose because Mr. Baker could not point to other jurisdictions where it is used to value the cost of POLR service. (OCEA Br. p. 26, OPAE/APAC Br. p. 16; Schools Br. p. 9; Constellation Br. p. 14). Mr. Baker explained the unique circumstances in Ohio which support the use of the Black-Scholes model. When asked if this model is used elsewhere by other AEP operating companies for this purpose, he responded as follows:

> If I can look through our states, Texas does not have a situation where the distribution company is required to supply a generation supply, so there is no need for POLR because customers come and go to a unregulated wholesale or retail marketer so the distribution company has no need for it.
>
> In the other states, now with the change in legislation in Virginia and the change in legislation in Michigan, customers don't have the right to come and go so there is no need for a POLR because they don't have the options that are provided for in Senate Bill 221.
>
> And in the rest of the states, once again, the customers have no ability to come and go from the standpoint of shopping in the market and, therefore, there's not a need for the POLR.

(Tr. XI, pp 160-161).

When asked whether other states in the PJM region that have POLR charges use the Black-Scholes model to determine the cost of POLR service he responded as follows:

> Let's think about the environment in those states, the PJM states with competition and customer choice. In those states the distribution companies do not have generating assets for supply to the customer for them to come and go at a tariff-based rate that is not market.
>
> What happens in those states is the distribution company generally goes out for an auction. In the auction the POLR responsibility and the effects of customers

> coming and going then sits with the supplier, and we have bid on those auctions, and when we've bid on those auctions, we've put in as part of our market price a cost for the risk of customers coming and going, and we use the Black-Scholes model, in determining how to value that proposition in setting up the bid that we put in to serve those customers.
> (*Id.* at 162).

It is interesting that Mr. Fein testified that Constellation NewEnergy, which has a POLR obligation in Texas, builds into its price the cost associated with the risk of customers leaving. (Tr. VI, p. 39). He explained that the cost component acts as a hedge against the right of customers leaving and the eventuality of customers exercising that right. (*Id.* p. 48).

Others criticize the Companies for using their judgment regarding the choice of values assigned to the model's inputs and for making an indeterminate number of runs of the Black-Scholes model, effectively "manipulating" the inputs to the model. (OCEA Br. p. 26; OPAE/APAC Br. p. 17). Mr. Baker responded to this charge as follows:

> We did run it more than once, and what we did was we changed some of the inputs. For example, we would not have changed the term because it was three years from the start, it was three years at the end.
>
> We would have changed it for the, for example, for the ESP. As that developed and it changed over time, we would rerun it. And we would rerun it for changes in market price at various times.

(Tr. XIV, pp. 254,-255).

In other words, as the Companies developed their ESP the inputs necessary for the Black-Scholes model would change. There is nothing devious about this iterative process. In fact, as Mr. Baker explained, the final inputs to the model resulted in a conservatively understated POLR charge. (Tr. XIV, p. 224).

Several Intervenors also assert that the proposed POLR charges should be rejected because they represent too large an increase over the current POLR charge. (Constellation Br. p. 13; OCEA Br. p. 29), or because the current POLR charges are more reasonable (Staff Br. p. 17, OPAE/APAC Br. p. 18; OCEA Br. p. 29). These arguments fail to reflect the origin of the Companies' current POLR charges.

The current POLR charges are an outgrowth of the Companies' Rate Stabilization Plan (RSP) proceeding.[37] The Companies did not request a POLR charge in that proceeding. Nonetheless, the Commission considered two aspects of the RSP proposed by the Companies – RTO administrative charges and carrying charges associated with Construction Work in Progress and in-service plant expenditures – and authorized the rate recovery amounts sought by the Companies for those items as POLR charges and established those POLR charges as unavoidable riders applicable to all distribution customers. (Opinion and Order, January 26, 2005, pp. 27, 29).

School's witness Fein thought that the current POLR charges "were designed to address both of those issues" ("compensate the utility for standing ready and any associated costs that they have in waiting for that customer if that customer returns"). (Tr. VI pp. 45-46). However, OCC witness Medine was generally familiar with the way the current POLR charges were set. (OCC Ex. 10, p. 33). Assuming OCC also understood the background of the current POLR charges, it is surprising that they would argue that there is no evidence that the current charges – which have nothing to do with POLR cost - are insufficient. The Companies burden in this case is to prove that its proposals are reasonable, not that a current charge is unreasonable. Given the origin of

[37] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of a Post-Market Development Period Rate Stabilization Plan,* Case No. 04-169-EL-UNC.

the current POLR charges, any attempt to compare those charges with the Companies' POLR charges proposed in this case is fruitless.

In a truly remarkable argument, OHA states: "SB 221 *does not* mandate that the Commission compensate AEP (or any electric distribution utility) for POLR risks .... AEP has no entitlement to compensation as part of its proposed SSO rates, or a separate rider, for the very POLR risks it alone must bear." (OHA Br. p. 15, emphasis in original). In support of its position OHA contends that Sec. 4928.142, Ohio Rev. Code, mitigates the Companies' POLR risks. (*Id.*) OHA does not explain how the MRO statute mitigates POLR risk in an ESP. Whatever OHA's explanation might be, the idea that the General Assembly can impose a POLR obligation on the Companies and the Companies must bear the risks associated with POLR service, without compensation, must be summarily rejected.

Most of the remaining Intervenors' arguments relate to how they believe the Companies can avoid incurring POLR costs. Those arguments were addressed in the Companies' Initial Brief (pp. 46-51) and that discussion will not be repeated in this brief. A few matters, however, still need to be addressed.

For reasons known only to OMA, its brief attributes to Mr. Baker a reference to "the woman in the household" exercising a "call" on the Companies to return to SSO service. OMA has no record citation for that portion of its brief. For whatever reason OMA wanted to highlight that reference, it should have noted that it was OMA's counsel that made reference to a "housewife" (Tr. XI, p. 205) and Mr. Baker's actual reference in response to OMA's counsel's question was "as you described it, to the woman in the household." (*Id.* at 209).

Kroger alleges that even if market prices fell below the ESP "it is unlikely (sic) that a large majority of customers would not bother to switch from AEP ...." (Kroger Br. p. 16). Even if "the vast majority of customers do not check electric prices" (*Id.*), it is reasonable to expect that CRES providers and proponents of governmental aggregation would make it their business to be sure customers were informed of opportunities to save money on their electric bills.

Mr. Baker testified why he believes there will be shopping in Ohio, in contrast to other states, if wholesale market prices fall below the ESP:

> Prices for customers, residential customers, in these other states are set at a wholesale level. So you build in wholesale pricing at a distribution level with load shapes and they're a – a marketer has to go out and buy it wholesale to compete against a wholesale-shaped price. I'm not surprised there's a big – or hasn't been a lot of movement in that case for residential.
>
> What we're looking at here is the fact that our price will be set based on the ESP, not wholesale prices, and if wholesale prices drop, I would expect residential as well as commercial and industrials to shop.

(Tr. X, pp. 223-224).

Finally, OCC and Sierra Club emphasize that the Companies' proposed POLR charges are the same regardless of circumstances of the markets. (OCEA Br. p. 28). This statement reflects their fundamental misunderstanding of the Black-Scholes model. The model is sensitive to the price difference between the ESP and market prices. The closer those prices are, the greater the value of the optionality to switch and consequently, the greater the cost to the Companies of providing POLR service. Schools witness Fein also had it wrong when he testified that if market prices come down "there should be some downward movement in that [POLR] price." (Tr. VI, p. 58). When the relationship between market price and the ESP is properly understood, it supports Mr. Baker's assertion that determining the POLR charge using the first year ESP level for all three years, and a market price that others consider to be too high, significantly understates the Companies' POLR costs. (Tr. XI, p. 156).

The Companies' proposed POLR charges are based on a reliable determination of the costs associated with the optionality afforded to customers as a result of the statutorily imposed POLR obligation which the Companies' bear. These charges should be approved by the Commission as part of the Companies' ESPs.

B. Economic Development Rider and Partnership with Ohio Proposal

The Companies described their Economic Development Rider (EDR) proposal in their Initial Brief. (Companies' Br. pp. 129-132). OCEA makes three arguments concerning the Companies' proposed EDR: (1) the delta revenue should be shared with the Companies and not fully recovered from ratepayers through the EDR; (2) the Commission should annually review the Companies' economic development arrangements based on concerns about potential anti-competitive impacts; and (3) consumer parties should be permitted to actively participate to review the contracts initially and the implementation of the contracts over time. (OCEA Br. pp. 103-106). None of these arguments has merit.

First, the Companies already fully addressed why the Commission should reject witness Yankel's proposal for 50/50 sharing of delta revenues. (Companies' Br. pp. 131-132). Second, Mr. Yankel's allegation concerning the potential anticompetitive impact of the EDR is unfounded, given that: (a) the Commission will review and approve each special arrangement prior to it becoming effective or creating delta revenues for recovery through the EDR, and (b) the General Assembly specifically authorized riders to recover costs incurred in conjunction with any economic development and job retention program through SB 221's amendment of Sec. 4905.31(E), Ohio Rev. Code. In short, OCEA's suggestion to annually review special arrangements is unnecessary, bureaucratic and burdensome. Finally in this regard, OCEA's third argument that parties such as OCC should be permitted to actively participate in initial review and subsequent implementation of economic development contracts should also be rejected. This suggestion is not justified and tends to displace the Commission's own role in reviewing, approving and overseeing such arrangements; it also is unripe for consideration to the extent that it seeks a ruling that OCC or others can intervene in future cases involving such contracts.

As Companies' witness Hamrock explained, AEP Ohio's proposed economic development program also includes the establishment of AEP Ohio's $75 million "Partnership With Ohio" fund. (Companies' Ex. 3, p. 15). With respect to the Partnership With Ohio fund, OPAE/APAC complains that there is no guarantee that the $75 million will be spent at all should the Commission modify the ESP and that the application does not spell out how much will be spent protecting at-risk populations. (OPAE/APAC Brief at 19-20.) AEP Ohio has been clear all along that the $75 million funding proposal was advanced as part of the entire ESP package and that, if the Commission modifies the ESP, the Companies would have to evaluate the $75 million funding proposal.

Both Companies' witness Hamrock and witness Baker explained that AEP Ohio cannot presently determine whether the Partnership With Ohio funding proposal would be withdrawn or modified based on Commission-ordered modifications to the ESP without knowing what the particular modifications are and evaluating the modified ESP in its entirety. (Tr. III, pp. 137-138; Tr. X at 232-233). Thus, while OPAE/APAC is correct in stating that there is no guarantee that the $75 million will be spent at all should the Commission modify the ESP and that the application does not spell out how much will be spent protecting at-risk populations, these aspects of the proposal are reasonable and should not be the basis for criticism. Rather, the Commission should understand that the Companies' stated intention of funding approximately $25 million per year toward the Partnership With Ohio initiative is a significant proposal by AEP Ohio's shareholders (as part of the ESP package) to promote economic development and low-income energy efficiency and assistance.

OPAE/APAC, apparently in a further attempt to bolster its claim of devaluing the Partnership With Ohio proposal, allege that AEP Ohio has no demonstrated track record in administering funds to promote economic development. (OPAE/APAC Brief at 20.) This claim is without basis in the record and otherwise lacks merit. In the January 26, 2005 Opinion and Order in the Companies' RSP case (Case No. 04-169-EL-UNC), the Commission (page 39) required AEP Ohio to allot $14 million for low-income customers and economic development and ordered the Companies "to work with our Service Monitoring and Enforcement Department staff to work out the details for the allotted low-income and economic development dollars." Thus, the Commission delegated to its Staff the responsibility to oversee the Companies' implementation of the $14 million requirement. Given that the Staff has not raised any disputes concerning the Companies' fulfillment of this requirement and the Commission has not conducted any proceeding or made any findings regarding any noncompliance in this regard, there is no basis to conclude a problem exists and it is hardly credible to claim that the Companies have no demonstrated track record regarding the administration of such funds. In any case, there is no basis in the current record to support such a statement.

In further support of this line of argument, OPAE/APAC also criticized Companies' witness Baker for not reciting the details concerning prior economic development expenditures. (OPAE/APAC Brief at 20.) As Mr. Baker explained, his purpose in mentioning the $14 million expenditure in testimony was limited to its possible inclusion in the economic development adjustment to the baseline for compliance with SB 221 mandates. (Tr. X, pp. 267-268). He stated he did not have a specific breakdown on how the money was spent. (*Id.*). It is not reasonable to expect Mr. Baker to display instant memory recall regarding such minutia that is only tangentially related to one of numerous issues he was responsible for in this case. If OPAE/APAC had a need or desire to obtain that information, it could have obtained it as part of the thousands of pages of data provided by the Companies in response to discovery requests in these cases. It is truly ironic that OPAE/APAC, whose clients stand to benefit most from the Companies' Partnership With Ohio, should be the lone parties criticizing the substantial proposal.[38] But the criticisms are without merit and fail to acknowledge the true value of AEP Ohio's proposal.

[38] Although OCEA "supports the general concept" of the Partnership with Ohio fund, it urges the Commission to "ensure" that an additional rate increase does not occur because some of the programs currently undertaken by the Companies "may already be funded through customers' rates." (OCEA Br. p. 94). This is a strange point to make, given that the Companies are proposing to create shareholder funds for this effort. There is no reason to think that these programs are funded by current rates and, in any case, this potential concern is unripe and should be left for future consideration, if necessary. Aside from that point, no other party opposed or criticized the Partnership With Ohio proposal.

C. AEP Ohio's Energy Efficiency and Peak Demand Reduction Rider

As part of their ESPs, the Companies are proposing to implement a non-bypassable Energy Efficiency and Peak Demand Reduction Cost Recovery Rider (EE/PDR Rider). (Application, pp. 9-10). The Companies described in greater detail and supported the proposed Energy Efficiency and Peak Demand Reduction Rider in their Initial Brief. (Companies' Br. pp. 99-115). In this section of the brief, the Companies address a few additional issues raised by Staff and intervenors relative to the EE/PDR Rider.

1. Baselines for Advanced Energy Benchmarks, Energy Efficiency Benchmarks and Peak Demand Reduction Benchmarks

Regarding the Companies' proposed methodology for calculating the baselines for compliance with SB 221's alternative energy, energy efficiency and peak demand reduction benchmarks, the Staff "generally accepts the Companies baseline determination and adjustments, with one notable exception. The Companies propose to take an adjustment credit for the sales and peak load associated with the acquisition of the former Mon Power's service territory by Columbus Southern Power." (Staff Br. p. 18.) The appropriateness of excluding the former Mon Power customer load from the baselines, including a rebuttal of witness Scheck's factually incorrect statement that the load was acquired prior to 2006, was fully addressed in the Companies' Initial Brief (pp. 101-103) and will not be repeated here. The Companies would like to take this opportunity to reiterate, however, the importance of addressing these issues in this proceeding – especially given the substantial size of the Ormet and former Monongahela Power loads and resulting impact on the Companies' compliance plan.

As stated in AEP Ohio's ESP application, determination of the Companies' baselines is critical for immediate planning and activities being undertaken for SB 221 benchmark compliance. (Application, p. 10). Without receiving verification of the basic parameters of the baseline calculation, the Companies would be at a loss to determine their benchmarks and finalize their compliance plans. Moreover, leaving open issues such as whether the Ormet load (about 520 MW – Case No. 05-1057-EL-CSS) and load from the former Mon Power service territory (about 250 MW – Tr. XI, p. 240) are excluded from the compliance baselines would not only create significant uncertainties relative to mandate compliance but would also amount to a modification of the Companies' ESP; if those significant issues are simply left open, that would need to be evaluated by the Companies as if their positions are not accepted when considering whether to accept any modifications to the proposed ESP.

Finally regarding the Companies' methodology for calculating the baselines for mandate compliance, Mr. Castle indicated that any mercantile customer-sited resources that are committed will be reflected in an upward adjustment to the baseline. (Companies' Ex. 8, p. 4). In other words, to the extent that AEP Ohio is able to reach agreements with mercantile customers to commit their resources for integration into the Companies' compliance plan: (1) the impact of those customer-sited resources will count toward AEP Ohio's compliance with the benchmarks, and (2) there will be an adjustment to the baseline to reflect any existing resources that had historical impacts during the period measured in the baseline calculation. This approach is consistent with Sec. 4928.66(A)(2)(c), Ohio Rev. Code. On brief, Staff indicated that it "is not opposed to including the energy savings and peak demand reduction efforts from mercantile customers toward adjusting the electric utility's baseline. However, Staff recommends that the electric distribution utilities make a case-by-case submittal to the Commission to receive such credits." (Staff Br. p. 19.) This was the Companies' intended approach and they agree that this is an appropriate approach.

2. Energy Efficiency and Peak Demand Reduction Programs

OEG endorses the Companies' EE/PDR Rider as being a reasonable approach to cost recovery and supports the proposal. (OEG Br. p. 20.) Staff recommends that the Companies be allowed recovery of Energy Efficiency and Peak Demand Reduction programs as a distribution charge. (Staff Br. p. 18). Staff stated that it "generally approves" of the Companies' efforts, except that witness Scheck testified that a number of the proposed programs were expensive and unlikely to pass the Total Resource Cost test and he recommended that the Companies evaluate and pursue those programs that are most cost-effective. (Staff Br. p. 18.)

As Staff witness Scheck stated when asked whether the Companies should hold off on implementing EE/PDR programs in light of the looming compliance requirements for 2009:

> Well, I think you certainly should get that cost-effectiveness test. If you've already performed that task, I'm not aware of, but if you've already done that, then you have some basis to move forward. If that's the case and you have say motors or lighting for the commercial class that are cost-effective, without question, then I would expect you to move full speed ahead on those. * * * Clearly, if you get the market potential study back * * * I would think that you would want to get that back as soon as you possibly can and then get designing the programs and getting them rolled out before January of '09 as soon as possible.

(Tr. VIII, pp. 196-197).

Although OCC witness Gonzalez also expressed some current reservations about the level of administrative costs and the demonstrated cost-effectiveness of the proposed programs, he also stated that, generally speaking, the proposed $178 million estimated to support the proposed programs is at a level that should allow AEP Ohio to be successful in implementing the standards under SB 221. (OCC Ex. 5, pp. 6-7; Tr. IV, pp. 211-212). While OCEA's Brief makes critical comparisons (p. 96) between AEP Ohio's estimated administrative cost and the actual costs under Columbia Gas of Ohio programs and recommends (p. 97) a hard cap on administrative, educational and marketing expenses of 25 percent, Mr. Gonzalez agreed during cross examination that numerous factors and differences among programs cause the actual level of administrative costs to vary. (Tr. IV, p. 217). He never offered a hard cap on administrative expenses for AEP Ohio and indicated that he expected those matters to be worked out in the collaborative process based on his prior collaborative experiences. (OCC Ex. 5; Tr. IV, pp. 216-218).

Similarly, though the OCEA Brief criticizes (p. 96) AEP Ohio for using non-Ohio data in developing its estimates, Mr. Gonzalez during cross examination stated that he views AEP's DSM experience in other States "as a positive and I think Ohio could benefit from some of the program development that's taking place in those particular territories." (Tr. IV, p. 211). Ultimately regarding his concerns about the level of administrative costs included in AEP Ohio's projected cost estimate, Mr. Gonzalez indicated that such matters would be appropriate subjects for the collaborative group and that pursuing those matters in the collaborative, as well as subjecting the project costs to reconciliation based on actual costs, addresses his concerns. (Tr. IV, pp. 218-220).

OPAE/APAC also expressed some general concerns about the cost-effectiveness of the initial EE/DSM programs proposed by the Companies and criticized AEP Ohio for establishing a budget and rider though it has not settled on any program design. (OPAE/APAC Br. p. 21.) OPAE/APAC recommended that, instead of implementing the initial programs, the Companies should provide funding for programs that already exist and retain a third-party administrator that reports to the collaborative to manage program implementation. (OPAE/APAC Br. pp. 21-22.) OPAE witness Alexander, however, testified that she did not think that the cost-effectiveness analysis had to be litigated in this case but that it could be referred to the collaborative for further evaluation or consideration. (Tr. X, pp. 40-41).

AEP Ohio's intentions were explained by Companies' witness Sloneker who testified that all EE and PDR programs to be implemented by AEP Ohio will be cost-effective, with the possible exception of low-income programs. (Tr. III, pp. 270-271). She indicated that the market potential study would help ensure that AEP Ohio can implement effective programs and that the collaborative effort will help ensure that the Companies choose programs that are well received by their customers and delivered in a cost-effective manner. (*Id.* at 271). Thus, the parties' concerns about cost-effectiveness and administrative costs are duly noted by the Companies and should be taken up within the collaborative process. There is no need for the Commission to address those matters at this time.

Next, OPAE/APAC criticized AEP Ohio for not evaluating existing Ohio low-income programs for inclusion on the list of initial programs and not fully explaining the differences between the two programs initially proposed or how those programs coordinated with other Ohio assistance programs. (OPAE/APAC Br. pp. 20-21.) By contrast, OCEA specifically concludes that AEP Ohio's proposed programs for low-income customers appear to be adequate. (OCEA Br. p. 95). Moreover, OPAE's own witness Alexander stated in her written testimony that, although she had some current reservations, the programs proposed by AEP Ohio for low income and moderate income customers appear reasonable as an "interim" set of programs. (OPAE Ex. 1, pp. 16-17). OPAE/APAC's concern about additional low-income programs should be taken up within the collaborative process.

The collaborative group assembled by AEP Ohio will be instrumental in advising the companies as they proceed to ramp up their DSM activities. But the Companies oppose OPAE/APAC's recommendations that the collaborative have independent authority and/or report to the third-party administrator. It is AEP Ohio, not the collaborative or other stakeholders, that is bound to comply with Sec. 4928.66, Ohio Rev. Code, or be subjected to potential penalties. Accordingly, it also is AEP Ohio that must retain flexibility and discretion to manage and direct compliance activities.

Finally, Kroger advances its opt-out proposal on brief, consistent with the pre-filed testimony of Kroger witness Higgins. (Kroger Br. pp. 20-22.) The Companies oppose this proposal for the reasons already discussed in their Initial Brief. (Companies' Br. pp. 107-108.) Large commercial and industrial customers that have already implemented DSM efforts should pursue a case-by-case exemption within the framework of the mercantile provisions of SB 221.

In sum, Sec. 4928.66, Ohio Rev. Code, imposes requirements on electric distribution utilities regarding implementation of programs that achieve energy savings and programs designed to achieve peak demand reductions. The Companies are proposing to implement a variety of energy efficiency and peak demand reduction programs, which plans will be supplemented and refined upon completion of the pending market potential study and through the creation of a working collaborative group of stakeholders. The EE/PDR Rider is designed to recover the cost of compliance with Sec. 4928.66, Ohio Rev. Code and should be approved with the initial rate reflecting the Companies' cost estimate for 2009.

3. Use of Interruptible Capabilities as "Peak Demand Reduction" Programs Under Sec. 4928.66, Ohio Rev. Code

Staff recommends on brief, as it did in testimony, that no credit be given toward compliance with the peak demand reduction targets for the Companies' interruptible programs unless curtailments actually occur. (Staff Br. p. 19) Staff's conclusory position does not overcome the detailed statutory argument and policy rationale explained in AEP Ohio's Initial Brief for counting the demand response capabilities of AEP Ohio's interruptible customers as programs "designed to achieve" peak demand reductions. (Companies' Br. pp. 112-115) This is an important matter to resolve in this case as it could have a significant impact on the Companies' and their customers' plan to achieve compliance this year.

The Commercial Group maintains that AEP Ohio creates a "disparate impediment" to encouraging demand response and questions "why it is appropriate for AEP to receive credit for being able to reduce or curtail its customers load, while inappropriate for Ohio consumers to be able to receive the same benefit for agreeing to curtail under a PJM demand response program, or why one program should be favored over another." (Commercial Group Br. p. 7). While the merits of AEP Ohio's position on retail participation in PJM DR programs is discussed elsewhere, it is sufficient in this context to state that interruptible customers already receive the benefit of their demand response capability in the form of lower rates – whether or not they are asked to curtail – and AEP Ohio incorporates that demand response capability into its supply portfolio. By contrast, since PJM's curtailments are based on the PJM zonal load and are not based on AEP Ohio's peak load, the PJM participating customer's ability to interrupt is of no use to AEP Ohio for capacity planning purposes. There is no disparate treatment in allowing interruptible capabilities to count toward peak demand reduction targets while prohibiting retail participation in the wholesale PJM DR programs.

OCEA also registers three brief objections against counting interruptible tariff capabilities toward AEP Ohio's peak demand reduction program. (OCEA Br. pp. 102-103). First, OCEA maintains that SB 221's peak demand reduction mandates were imposed "in order to improve the reliability of the grid." This is without basis in the statute. From this false premise, OCEA concludes that counting interruptible capabilities would "provide a false representation of the grid's reliability." It is not at all clear what OCEA means by a false representation but, as AEP Ohio explained in its Initial Brief, it is evident that the historical purpose of the peak demand reduction mandates is to avoid building new power plants. (Companies' Br. pp. 114-115). Regardless of one's opinion of the purpose behind enactment of Sec. 4928.66, Ohio Rev. Code, however, the mandates do exist to implement programs "designed to achieve" peak demand reductions. The Companies' interruptible tariff capabilities squarely fit within this requirement.

Second, OCEA claims that because customers are able to control the load, interruptible capabilities should not count. Again, there is no statutory basis for this distinction. Moreover, it is only with discretionary/economic interruptions that the customer has a choice to "buy through" and avoid curtailment. Under those circumstances, the Companies' supply portfolio is not tapped for the power but the customer is effectively "buying through" to obtain replacement power at market prices. (Tr. IX, pp. 69-71). In any case, the load placed upon AEP Ohio's supply portfolio is reduced and this constitutes a peak demand reduction under the statute.

Finally, as a related matter, OCEA argues that, because the Companies could indirectly benefit from load reductions associated with certain interruptions under certain circumstances, the associated demand response capability should not count. Although there are circumstances where off system sales are indirectly enabled based on an economic/discretionary interruption, along with the existence of other circumstances such as an appropriate market price, those things do not change the fact that AEP Ohio's retail supply obligation is reduced through the customer's curtailment and the Companies' supply portfolio is not tapped to serve the retail customer –this constitutes a peak demand reduction under the statute. Whether the Companies might sell surplus power on the wholesale market under certain market and operating conditions, including where their offered price is cheaper and displaces a less efficient provider on the grid, is not relevant to the peak demand reduction that occurs for retail sales purposes. After all, if AEP's resources do not supply the off system need, another less economic source of generation would end up doing so – increasing the societal cost. In sum, none of OCEA's three objections are valid. Accordingly, the Commission should confirm that AEP Ohio's interruptible tariff capabilities count toward compliance as a program designed to achieve peak demand reduction.

D. Line Extension Charges

The Companies' proposal to modify their rates and certain terms and conditions of their line extension tariff schedules is reviewed at pages 93-96 of their Initial Brief. Among the other briefs filed in this case there are only two arguments raised against the Companies' proposal.

The first argument is procedural in nature. IEU and the Staff both argue that the Companies' line extension proposals should be dealt with in the context of an overall distribution rate case.[39] The Staff recognizes, however, that "SB 221 permits companies to request distribution rate relief as part of an ESP plan." (Staff Br. p. 20). There is no basis for a *carte blanche* barrier to the consideration of all distribution-related issues in the Companies' ESP. The Companies' line extension proposals present a discrete issue for the Commission. That issue has nothing to do with the service reliability or the overall revenue requirement issues on which the Staff relies for putting off all distribution-related issues for some future date.

As for the merits of the line extension proposals, the only opposition is based on the assertion by OCC and Sierra Club that the Companies did not prove that its costs of extending line extension facilities had increased. (OCEA Br. p. 85-87). While Companies' witness Earl could not recite pricing trends of steel, cooper and aluminum, his exhibits tell all that is necessary. As Mr. Earl explained, the current charge for lots in a single family development was based on an estimated per lot cost of $1300. (Companies' Ex. 10, p. 8). His Exhibit GAE-1 shows that based on 2007 and 2008 data the average cost per lot has escalated to over $1800. For multi-family units, for which the Companies propose an up-front charge of $200 per unit (Companies' Ex. 10, p. 7),

[39] IEU Br. p. 25 and Staff Br. p. 20

the average cost to the Companies, based on 2007 and 2008 data, was about $960 per unit.

OCC and Sierra Club can say what they want regarding the material costs underlying these figures, but the record is clear. Line extension costs have increased dramatically and the Companies' proposed up-front charges do not come close to fully recovering those costs. There is no reason to put off the implementation of the Companies' proposed modest increases.

E. Recovery of Historic Regulatory Assets

As noted in the Companies' Initial Brief there has been no opposition to the Companies' calculation of the value of these historic regulatory assets. (Companies' Br. p. 58). The only opposition to the Companies' proposal to begin recovering these regulatory assets in 2011 is found in Staff's brief at page 21. That opposition is based on nothing more than Staff's preference for dealing with this issue in a distribution rate case.

As noted in the discussion of line extension charges earlier in this brief, there is no compelling reason to erect an artificial barrier to the Companies' statutory right to address distribution issues in an ESP. The Staff's preference for looking at reliability issues and overall distribution rate issues in a distribution case should not involve these regulatory assets in any event. These regulatory assets have been accrued under authority of Commission orders. (Companies' Ex. 6, p. 31-32). Absent some showing of imprudence in the expenditures resulting in these regulatory assets, there is no basis for disallowing recovery of these values.

The Companies' proposal to begin recovering these regulatory assets in 2011 is a reasonable and lawful component of their ESPs. Even if the Commission accepts Staff's position on this issue the Commission should at least indicate that the June 30, 2008 values of the regulatory assets were not challenged by any party and will be deemed appropriate for use in such a future proceeding.

V. GENERAL ESP ISSUES AND TARIFF ISSUES

A. Corporate Separation Plan

There are two aspects to this issue. The first aspect, to which there is no opposition, is that the Companies be permitted to remain functionally separate during the three-year ESP. Related to that request, they also seek authority to retain their distribution and, for now, their transmission assets and to eventually move their generating assets to a to-be-formed affiliate company. This ultimate corporate separation conforms to Sec. 4928.17(A), Ohio Rev. Code.

The second aspect concerns the request for CSP to be authorized to sell or transfer its Darby and Waterford generating units and the Companies' intent in the future to sell or transfer CSP's contractual entitlements to the entire output of the Lawrenceburg Generating Station and both Companies' entitlement to a portion of the output from OVEC's Kyger Creek plant and IKEC's Clifty Creek plant. (*See* Companies' Br. p. 88).

The basic argument in opposition to the proposal to sell or transfer the Darby and Waterford plants is based on the absence of any current plan for CSP to sell or transfer those plants. (IEU Br. pp. 26, 27; OEG Br. p. 16; OCEA Br. p. 100). It is notable that OCEA's comment in this regard that "[m]uch can change in 3 years" (*Id.*) does not appear to affect OCC's conviction that market prices for electricity will be depressed throughout the ESP period.

Contrary to the Intervenors' argument, CSP should receive the authorization, as part of its ESP, to sell or transfer the Darby and Waterford plants. The investments in these plants have never been in rate base and the costs of operating and maintaining the plants are not built into the current SSO. The Waterford plant was purchased in September 2005 and the Darby plant was purchased in April 2007. (Companies' Ex. 2A, p. 42). Therefore, both purchases occurred after CSP's RSP proceeding. With no rate recovery, these plants were purchased in anticipation of generation rates being market-based under SB 3. CSP "took the risk on these plants and therefore, ... its appropriate for us to have the authority to, if we choose, to transfer or sell the assets at our discretion." (Tr. XIV, p. 155).

OEG notes that the sale or transfer of Darby and Waterford will increase CSP's capacity equalization charges under the AEP Interconnection Agreement. While that is true, it is unreasonable to benefit CSP's customers with reduced capacity equalization payments which will pass through the FAC while at the same time those same customers are not paying any rates that were ever associated with the "rate base" value of those plants. This is particularly true since the reduced capacity equalization charges which OEG covets would increase the potential for refunds under the Significantly Excessive Earnings Test.

Finally, the Staff states that it does not object to the sale or transfer of these assets. The Staff believes, however, that CSP should file a separate application when it is prepared to transfer them. (Staff Br. p. 24). A separate proceeding may make sense if the assets involved had been part of the historical revenue requirement in the embedded rates that were unbundled in compliance with SB 3 and inherently remain in the rates paid by customers. However, when customers' rates do not reflect, and never have reflected, the costs associated with those assets, the Commission should proceed to grant the requested authority within the ESP proceeding.

As noted in the Companies' Initial Brief, if the Commission precludes the sale or transfer of Darby or Waterford plants or the entitlements related to the Lawrenceburg, Kyger Creek and Clifty Creek units, then any expense related to them and not recovered in the FAC should be recovered in the non-FAC portion of the generation rate. This rate recovery would include about $50 million of carrying costs and expense related to Darby and Waterford annually. For OVEC, the demand charge of about $70 million annually should be included annually in the FAC. (Companies' Ex. 2E, pp. 20, 21).

B. PJM Demand Response Program Participation by AEP Ohio's Retail Customers

AEP Ohio does not oppose customers participating in the PJM demand response (PJM DR) programs so long as those customers have switched off of the Companies' standard service offer and to generation service at market-based rates from a CRES provider.[40] However, as explained by Companies' witness Roush in his direct testimony, AEP Ohio does not believe it is appropriate or contractually permitted for retail customers receiving regulated, standard service offer rates to resell utility power at

[40] OMA inaccurately claims that the Companies seek to prohibit PJM DR program participation by retail customers being served with generation by a competitive retail electric service provider. (OMA Br. p. 9). On the contrary, as Companies' witness Baker explained, AEP Ohio only objects to retail customers participating in PJM DR programs when those retail customers were purchasing power from the company at regulated rates. (Tr. II, pp. 31-32). Because this false premise was apparently the basis for which OMA joined the opposition to AEP Ohio's proposal (the tie-in with a CRES provider was mentioned four times in OMA's 1½-page argument on this subject), it is not clear they oppose AEP Ohio's actual proposal that would not limit retail participation by customers served by CRES providers. In any case, the difference between a customer who acquired their generation service from a CRES provider and a customer served by an EDU SSO highlights a fundamental policy and legal distinction in the context of retail participation in PJM DR programs. AEP Ohio only seeks to have the Commission limit retail participation for SSO customers (not those customers being served by CRES providers) to Commission-approved, Company-directed tariff DR programs.

market-based rates through PJM DR programs operated in the wholesale market. (Companies' Ex. 1, pp. 6-7). The fundamental purpose of a retail sale of electricity is for the customer to use the power to serve its own load, not to enable the customer to leverage a resale of the power in the regional power markets.

AEP Ohio supports demand response as a general matter, including the provisions within SB 221 as well as the existence of the PJM demand response programs within the wholesale market. But AEP Ohio maintains that in states that have bundled regulatory rate regimes participation in the PJM programs should be limited to load-serving entities (LSEs) within PJM and should be incorporated into the demand response programs implemented by LSEs. The FERC has agreed that States using different regulatory models for regulation should decide whether their retail customers participate in the PJM DR programs and has delegated to State commissions the ability to veto such participation. AEP Ohio is asking the Commission in this case to exercise that veto power in support of existing Commission-approved tariffs.

In addition, as discussed in greater detail below, the mercantile provisions of SB 221 can be utilized to commit demand-side resources of retail customers toward benchmark compliance. In this regard, it is evident that the PJM demand response programs would provide direct competition for an EDU's efforts to obtain a commitment from mercantile customers to dedicate their limited demand response capabilities and resources for the purpose of compliance with SB 221's energy efficiency and peak demand reduction mandates. In other words, the more demand response resources are dedicated to the PJM programs, the less demand response resources will be available to the State of Ohio generally and for AEP Ohio specifically. Integrys and IEU-OH criticize AEP Ohio's programs as inferior, relatively unattractive and inadequate. (Integrys Br. pp. 6-8; IEU-OH Br. p. 32) Integrys witness Wolfe plainly admits that if the Commission does not allow retail participation in the PJM demand response programs, customers "may be forced to opt for the programs offered by CSP and OPC..." (Integrys Ex. 2, p. 16). AEP Ohio seeks to expand its interruptible programs and to continue to improve demand response opportunities that it can offer to its customers, especially since it is facing compliance with SB 221's aggressive mandates for peak demand reduction. But allowing retail participation in the PJM DR programs would undermine that effort and sanction the exportation of Ohio's limited demand response resources.

While it is obvious that mercantile customers would like to have both PJM and AEP Ohio bidding for their demand response resources, that form of "competition" would certainly not benefit AEP Ohio or its other retail customers –and doing so does not fit within the General Assembly's design for use of customer-sited resources. Retail participation in PJM's existing DR programs results in the exportation of Ohio's limited demand response resources to the East Coast and causes the remaining retail customers of AEP Ohio to bear the cost of capacity planning associated with those retail customers that are profiteering under the PJM DR programs. The inequity of this situation is highlighted by the current context within which it arises. Even though SB 221 represents a partial retreat from market-based generation pricing and requires EDUs to face lower of cost or market based on concerns from large commercial and industrial customers, those same customers now assert an inalienable right to risk-free arbitrage profits from the wholesale power market using utility-provided power acquired at regulated rates. (Tr. I, p. 178).

AEP Ohio's proposal regarding the PJM DR programs is based on the interests of its customers that would bear the "hidden cost" of retail participation and because of the inequity that would be permitted in allowing power resale arbitrage in the regional power market of power by retail customers that have acquired the electricity from a utility at regulated rates. FERC, the creator of the PJM DR programs, has directly recognized in its Final Rule[41] that State commissions may have a legitimate interest in prohibiting participation in these programs and has expressly deferred to States to make that decision. As AEP Ohio has demonstrated, there are several important policy reasons supporting its request and it should be granted as part of this ESP proceeding.

1. The Commission has jurisdiction to grant AEP Ohio's request and prohibit retail participation in the PJM demand response programs

In the first major portion of its brief, Integrys claims that the Commission lacks authority to grant AEP Ohio's requested clarification concerning retail participation in PJM DR Programs.[42] (Integrys Br. pp. 9-14). Integrys characterizes AEP Ohio's proposal as asking the Commission to "regulate private entities" from participating in a wholesale electric program authorized by FERC. (Integrys Br. p. 11). Integrys claims that the FERC Final Rule requires a State commission to enact a "statewide policy" which Integrys claims can only be accomplished through enactment of a law directly addressing the matter or specifically delegating that authority to the PUCO. (Integrys Br. pp. 9-14). Following through on this result-oriented standard, Integrys points out that

[41] *Wholesale Competition in Regions with Organized Electric Markets* (Docket Nos. RM07-19-000 and AD07-7-000), 125 FERC ¶ 61,071 (October 17, 2008) ("*Final Rule*"). The Final Rule is contained in 18 CFR Part 35.

[42] Constellation makes some of the same claims as Integrys, both parties being represented by the same legal counsel, and AEP Ohio's responses to Integrys generally subsume Constellation's arguments on brief unless otherwise separately addressed. (Constellation Brief, pp. 20-23).

"[n]othing in Title 49 gives the Commission jurisdiction to regulate private entities participation in PJM demand response programs." (Integrys Br. p. 11). This argument lacks merit under Ohio law, ignores the content of FERC Final Rule and conflicts with Integrys' own portrayal of the legal issues presented in the FERC proceeding.

In advancing its narrow interpretation of Ohio law and Commission jurisdiction, Integrys relies upon *State, ex rel. Columbus Southern Power v. Fais* (2008), 117 Ohio St.3d 340. (Integrys Br. p. 11). Integrys uses the *Fais* decision as negative proof that "none of the statutory provisions cited by the Court make reference to regulation of PJM demand response program participation." (Integrys Br. p.11). The *Fais* decision does not advance Integrys' argument.

Ironically, it was AEP Ohio that initiated the *Fais* case in order to enforce the Commission's broad jurisdiction over utilities and the transactions relating to the provision of electric service. The *Fais* case involved a respondent Common Pleas Court Judge who had concluded that a municipality's "Home Rule" authority under the Ohio Constitution trumped the Commission's jurisdiction over matters addressed in CSP's tariffs. (*Fais*, 117 Ohio St. 3d at 346). In agreeing with AEP Ohio and granting an extraordinary writ of prohibition, the Supreme Court concluded that the General Assembly has created a "broad and comprehensive statutory scheme for regulating the business activities of public utilities" and held that the General Assembly "empowered [the Commission] with broad authority to administer and enforce the provisions of Title 49." (*Fais*, 117 Ohio St. 3d at 343). The Court also stated that "[i]t is readily apparent that the General Assembly has provided for Commission oversight of filed tariffs, including the right to adjudicate complaints involving customer rates and services."

(*Fais*, 117 Ohio St. 3d at 345) (internal citations omitted). Hence, the *Fais* case concerned the Commission's far-reaching jurisdiction over tariff disputes.

The "broad and comprehensive" jurisdiction over electric service recognized by the Supreme Court certainly includes the tariff provisions such as those at issue under AEP Ohio's proposal in this ESP case. By contrast, Integrys' narrow and constricting view of the Commission's jurisdiction would yield the conclusion that the Commission never had jurisdiction over CSP's current tariff that prohibits resale of power by retail customers and that the provision was never legally valid. That conclusion lacks credibility and conflicts with the *Fais* decision. There can be no question that the Commission has broad regulatory jurisdiction over terms and conditions of retail electric service.

The Commission frequently exercises jurisdiction over retail transactions in a way that involves or affects customers. The most prevalent example is a complaint filed under Sec. 4905.26, Ohio Rev. Code. This dispute over retail participation in PJM DR programs could have just as easily arisen in a complaint case. If AEP Ohio had unilaterally denied customers participation in the PJM DR programs, Integrys could have filed a R.C. 4905.26 complaint against the Companies and the Commission would have resolved the dispute on that basis.[43] Either way, the Commission is not "regulating" the individual retail customer or exercising extra-statutory jurisdiction; it regulates all aspects of the retail transaction including those that directly involve or affect the customer.

[43] Interestingly, Integrys on brief states that AEP Ohio's request "could have been and should have been proposed as part of a Section 4909.18, Ohio Rev. Code, 'application not for an increase in rates.'" (Integrys Br. p. 15). AEP Ohio does not disagree with the statement that its request could have been raised in a R.C. 4909.18 proceeding but does disagree with the notion that it should have been so filed. In any case, the complaint case example is not mentioned in an attempt to suggest that it should be Integrys' burden of proof to overcome AEP Ohio's proposal in this case. AEP Ohio agrees with Integrys' assertion that the Companies bear the burden in this case of proving their proposal is reasonable – the Companies have met that burden through their testimony and their briefs.

Integrys' related position, that the Ohio General Assembly is required to act in order to satisfy the FERC Final Rule's provision for a State veto of retail participation, is equally misguided and conflicts with the FERC Final Rule. (Integrys Br. p. 12). The FERC left it to State commissions to determine whether retail customers in their jurisdiction would participate in the PJM DR programs. In the lexicon of the Final Rule, FERC uses the term "relevant electric retail regulatory authority" which is defined as *the entity that establishes the retail electric prices and any retail competition policies for customers, such as* the city council for a municipal utility, the governing board of a cooperative utility, or *the state public utility commission.* (*Final Rule* ¶ 158). In the context of Integrys' position that the General Assembly must act in Ohio, the FERC would have specified if it contemplated that the State legislature would be required to act; instead, it refers to the "relevant electric retail regulatory authority" throughout the Final Rule and has deferred this determination to "the entity that establishes the retail electric prices and any retail competition policies for customers" – the Commission fulfills this purpose in Ohio.

In the Final Rule proceeding before FERC, the notice of proposed rulemaking (NOPR) was the basis for comments in the proceeding and the NOPR proposed to allow aggregation of retail customers (ARCs) under the PJM DR programs for participation in organized markets, "unless it is not permitted by the relevant regulatory authority." (*Final Rule*, ¶ 132). Parties in the instant ESP case pending before this Commission (Integrys and Wal-Mart), argued before the FERC in the Final Rule proceeding that the FERC should not make retail participation contingent on State commission permission and should act "without consulting with a state commission." (*Final Rule* ¶ 144 citing comments of Integrys and Wal-Mart). Thus, the principle issues presented to the FERC regarding this aspect of the Final Rule were: (1) whether the FERC should preempt any determination by State commissions regarding retail participation or defer that determination to State commissions, and (2) whether the State commission permission should be a mandatory prerequisite or subject to an after-the-fact State commission veto. The FERC's resolution of these binary issues in the Final Rule was unequivocal and not subject to ambiguity.

Regarding the decision of whether to preempt State commissions on the question of retail participation, the FERC squarely rejected that option and expressly permitted retail participation "unless the laws of the relevant retail electric regulatory authority do not permit a retail customer to participate." (*Final Rule* ¶ 154). In response to the commenters that advocated preemption of State commission approval, the FERC found that deferring to State commissions "properly balances the [FERC's] goal of removing barriers to development of demand response resources in the organized markets that we regulate with the interests and concerns of state and local regulatory authorities." (*Final Rule* ¶ 156). In doing so, the FERC extended due respect and appropriate deference for State commission jurisdiction over retail regulation. Again, the FERC does not say it defers to the State legislature but, instead, defers to *state and local regulatory authorities* and preserved a "continuing role" for State commissions. (*Final Rule* ¶ 157) Contrary to Integrys' interpretation of the Final Rule, the FERC refused to preempt State commissions and deferred to them the question whether retail customers participate in the PJM DR programs.

Regarding the form and manner of a State commission's expression of approval/permission, the FERC declined to automatically require State commission approval, recognizing that requiring State commission approval as a prerequisite "may have unintended consequences, such as placing an undue burden on the relevant electric retail regulatory authority." (*Final Rule* ¶ 155). Significantly, the FERC clarified that it "will not require a retail electric regulatory authority to make any showing or take any action in compliance with this rule." (*Final Rule* ¶ 155). Thus, FERC provided an open-ended veto opportunity to State commissions without imposing any necessary findings or applicable standard. Another very telling indication of FERC's intent was that the Final Rule acknowledged it would be appropriate for an RTO/ISO to require "certification that participation is not precluded by the relevant electric regulatory authority." (*Final Rule* ¶ 158) All of these statements consistently indicate that the FERC contemplated it would be a State commission issuing a ruling or declaration to exercise its veto power – contrary to Integrys' arguments here, FERC did not contemplate or require that a state law would need to be passed or that a formal administrative rule would be needed.

The written comments filed by Integrys in the Final Rule docket[44] reveal its true assessment of the FERC NOPR in this regard and, thus, of the Final Rule's adoption of the NOPR. In particular, the Integrys comments repeatedly interpret the NOPR as contemplating a State commission decision –not a rule or an act of the State legislature. For example, the Integrys comments asserted (page 4) in response to the NOPR that the FERC has jurisdiction to allow retail participation "without first consulting with state

[44] AEP Ohio has attached a copy of the Integrys comments to this brief as "Attachment A." These are publicly filed written comments filed with FERC by the same party now advocating on related issues. AEP Ohio submits that it is appropriate for the Commission to take administrative notice of the Integrys comments on brief for the purpose of evaluating Integry's arguments before this Commission.

commissions;" referred (page 5) to "the NOPR proposal to *allow state commissions to preclude their customers from participating* in RTO demand response programs;" acknowledged (page 5) that the NOPR proposal, while not ideal, "would give some *deference to state commissions*;" argues (page 5) that some commenters "are now trying to keep all retail customers out of RTO demand response programs unless their *state commission* explicitly authorizes such participation;" and concluded its position by advocating (page 6) that "at a minimum, Integrys Energy Services urges the [FERC] to keep RTO/ISO sponsored demand response programs open to customers in the absence of an explicit *order from the state commission* prohibiting customer participation, as proposed in the NOPR." (Emphasis added). Thus, not only was Integrys emphatically clear that it understood the State commission and not the State legislature would be exercising the veto power conveyed in the NOPR (as adopted in the Final Rule), it also clearly acknowledged that a Commission "order" would be the vehicle for that decision.[45]

Finally regarding the PUCO's authority to grant AEP Ohio's request, Integrys contends that any action by the Commission to ban PJM DR programs participation in this proceeding would be preempted. (Integrys Br. pp. 12-14). In particular, Integrys claims that "FERC has completely preempted the field regarding participation in demand response programs at the regional transmission organization ('RTO') level." (Integrys Br. p. 12). Integrys then proceeds to the conclusion that a favorable ruling in this case by the Commission on the AEP Ohio's request would be preempted. (*Id.*, p.13).

[45] Integrys also maintains concerning the PUCO's authority to rule on AEP Ohio's proposal that approval of a tariff is inadequate form of expression under the FERC Final Rule to prohibit retail participation. (Integrys Brief, pp. 10, 12, 13). This argument fails to recognize that tariffs are approved by Commission orders and that tariffs generally serve to implement and document the Commission's order. In other words, AEP Ohio requests that the Commission express its veto power through its order --the tariff would merely be filed to implement the Commission's decision.

An examination of Integrys' written comments filed in the Final Rule docket not only reveals its urgent plea for FERC to preempt State commissions but also shows that Integrys really viewed adoption of the NOPR proposal to defer to State commissions as a failure to exercise federal preemption. In the written comments before FERC, Integrys stated:

> Integrys Energy Services believes that the [FERC] has the jurisdiction to order the RTO/ISO to allow retail customers either on their own or through an aggregator to participate in RTO demand response programs without first consulting with state commissions. * * * The [FERC] has jurisdiction over demand response, which stems from its authority under the Federal Power Act. Not only does the [FERC] have Federal Power Act jurisdiction over "the sale of electric energy at wholesale in interstate commerce" but demand response is an integral component of wholesale markets.

(Integrys Comments, p. 4) (internal citations omitted). Integrys then stated that the adoption of the NOPR by FERC would represent a decision to decline exercising its jurisdiction to preempt State commissions:

> If the [FERC] *declines to exercise its jurisdiction*, then the NOPR proposal to allow state commissions to preclude their customers from participating in RTO demand response programs, while not ideal, would give some *deference to state commissions*. While this approach is not optimal, it would allow customers to participate in demand response programs *in at least some states*.

(Integrys Comments, p. 5) (emphasis added). Thus, although Integrys now claims before this Commission that it lacks jurisdiction to grant AEP Ohio's request in this case and would be preempted by the Final Rule from doing so because the FERC exercised preemptive jurisdiction, it argued before the FERC that adoption of the NOPR (which the Final Rule does) would be a decision to decline preemptive jurisdiction that would allow

State commissions to prevent PJM DR participation in their jurisdiction. Integrys' position before FERC was correct and its new-found interpretation advanced before this Commission is wrong. In any event, Integrys' preemption theory is belied by the very fact that FERC expressly and broadly defers to State commissions on the question of retail participation.

IEU-OH advances a different claim that the Commission lacks jurisdiction to grant AEP Ohio's request. IEU-OH argues that, even if PJM DR participation is viewed as a sale for resale, Sec. 4928.40(D), Ohio Rev. Code, "states that the Companies cannot impose an unreasonable restriction on resale." (IEU-OH Brief at 30). That provision, however, is aimed at ensuring retail competition through efforts such as aggregation and market participation CRES providers; it does not affect tariff provisions such as the term and conditions sought to be clarified by AEP Ohio in this case. The Companies' tariff provisions prohibiting resale by retail customers have remained effective and approved for the last ten years since enactment of SB 3. It is also telling that Integrys, the primary party interested in these issues that submitted a 30-page brief on this one topic, does not advance an argument based on Sec. 4928.40(D), Ohio Rev. Code. In short, IEU-OH misapprehends Sec. 4928.40(D), Ohio Rev. Code, and its interpretation should be rejected.

AEP Ohio is not attempting to unilaterally or directly impose restrictions on resale; instead, the Companies are seeking the Commission's approval for additional tariff language that would generally prohibit participation by retail customers in the wholesale PJM DR programs. As is envisioned by the FERC's Final Rule, it would be the Commission (not the Companies) that determines whether retail participation should occur. And the prohibition against retail participation in the wholesale PJM market is not a restriction on resale in the normal sense; it is really a component of retail regulation based on regulatory policy matters vested within the Commission and acknowledged by the creator of the wholesale program, FERC. Thus, even if PJM DR program participation is considered a restriction on resale (which it should not), the retail prohibition would be sanctioned by the Commission and could not be considered an "unreasonable condition" imposed by the EDU for purposes of Sec. 4928.40(D), Ohio Rev. Code. This approach is consistent with the FERC's invitation for State commission to make that determination.

2. The policy arguments advanced by AEP Ohio justify a decision to prohibit retail participation in the PJM demand response programs

IEU-OH argues that, because the Companies use their interruptible capabilities to satisfy the resource adequacy requirements of PJM, "the real question . . . is whether the Companies' customers should be allowed to do directly what the Companies are already doing indirectly." (IEU-OH Brief at 30). IEU-OH's answer to this question is affirmative, in part, because that SB 221 gives mercantile customers a choice about whether to dedicate their customer-sited capabilities to the Companies for integration into the Companies' portfolio. (IEU-OH Brief at 30-31). IEU-OH's concluding assertion is that customers should have the unqualified right to select how and when their demand response capabilities should be deployed. (*Id.*) Although this "right to choose" claim may be superficially appealing, IEU-OH's underlying position is inconsistent with SB 221 and otherwise misguided.[46]

The mercantile provisions in SB 221 allow customers to commit alternative energy, energy efficiency or peak demand reduction resources toward an EDU's compliance with the statutory benchmarks for each of these areas. AEP Ohio supports these innovative provisions and is actively working with mercantile customers to explore such options. Under that approach (and the design of SB 221), these "win-win" solutions between mercantile customers and EDUs can be harvested and the benefits used within Ohio and in satisfaction of Ohio law. By contrast, allowing retail participation in the PJM DR programs would encourage mercantile customers to *export* Ohio's limited demand response resources to the East Coast by allowing them to leverage the "lucrative payments" associated with the PJM DR programs against SB 221's design for operation of the innovative mercantile provisions. Moreover, it would be unfair to enforce the aggressive targets found in SB 221 and simultaneously allow major demand response resources to leave the State of Ohio to the detriment of other Ohio ratepayers. SB 221's plan for demand response lies with the EDU as regulated by the Commission under Ohio law – not with PJM or another Regional Transmission Organization regulated by FERC under federal law.

[46] A retail customer receiving power from the Companies does not take title to the power and does not have unrestricted rights to exercise concerning the power delivered by the EDU – contrary to EIU-OH's "right to choose" argument. On the contrary, a retail customer must act in accordance with retail service rules, including the restrictions and conditions approved by the Commission. In this specific context, as discussed above, the FERC's approval of the PJM DR programs has also been expressly conditioned on the veto power of the State regulatory commission. Likewise, under SB 221, mercantile customers' rights merely extend to whether a mercantile customer chooses to enter into an arrangement with the EDU to commit the customer's energy efficiency or peak demand reduction capabilities. That specific and narrow choice can be exercised without participation in the PJM DR programs and, in any case, does not override the Companies' interest in prohibiting retail participation in the PJM DR programs or the financial interests of the Companies' other customers.

In considering IEU-OH's argument, it must also be understood that a mercantile customer's exertion of control over its own customer-sited energy efficiency and peak demand reduction capabilities is fundamentally different than the Companies' use of its retail interruptible program as part of its resource portfolio. The terms and conditions embedded within the Companies' interruptible service offerings already reflect value for the participating customer through lower rates and the customer conveys value through its latent demand response capability. But retail customers obtaining SSO service from the Companies should not interface with the wholesale PJM power market or attempt to leverage the electricity obtained from the Companies in those markets. Rather, it is the utility's obligation to develop and manage integrated resource capabilities (traditionally including interruptible capabilities) in order to provide reliable electric service. And it is the EDU's obligation to fulfill SB 221's alternative energy portfolio requirements, the energy efficiency benchmarks and the peak demand reduction targets.

IEU-OH's argument ignores the fact that SB 221's mercantile provisions embody the method provided by the General Assembly for a retail mercantile customer to "sell" its demand response capabilities. Participation in the PJM DR programs directly by retail customers would necessarily involve an abandonment or bypass of that method specified designed by the General Assembly for a retail mercantile customer to "sell" its demand response capabilities. If the General Assembly had intended that wholesale options would be available to retail customers, it would have so indicated in the context of crafting the extensive mercantile provisions; it did not do so. If retail participation is allowed for the PJM DR programs in Ohio, the innovative and potentially beneficial mercantile provisions of SB 221 may well become a dead letter of the law.

As a related matter, Integrys wrongly argues that the Companies are required to show that their interruptible service offerings "are more beneficial" than the PJM DR programs. (Integrys Br. pp. 16-18). It is not a requirement of the ESP statute that each component be independently proven to be more beneficial to customers than the alternative. Rather, the applicable standard is that the ESP in the aggregate is more favorable than the expected results under an MRO. And this is not a static comparison to make since AEP Ohio is continuously trying to improve its interruptible and demand response options for customers – including through relevant proposals being offered in this case (*e.g.*, interruptible tariff expansions and gridSMART initiative). Of course, as with IEU-OH's arguments, the desired effect Integrys seeks is to have competing offers to purchase its demand response resources and capabilities. In light of mercantile customer provisions of SB 221 and the aggressive mandates for peak demand reduction being imposed, however, AEP Ohio submits that encouraging PJM DR program participation runs counter to the interests of Ohio ratepayers. (Companies' Br. pp. 116-117, 122-126).

In making its argument, Integrys misstates the testimony of Companies' witness Roush. Integrys states on brief that Mr. Roush "agreed that the Companies do not fund payments made by PJM under the PJM ILR program, admitting that the payments to Ohio customers are funded virtually entirely by non-Ohio load serving entities participating in the PJM capacity markets." (Integrys Br. p. 18 citing Tr. IX, p. 52). What Mr. Roush stated was that the RPM market includes entities outside of Ohio and that the FRR entities do not fund payments made under the PJM ILR programs. This does not support Integrys' statement that the payments to Ohio customers are "funded virtually entirely by non-Ohio load."[47] For example, Dayton Power & Light is a member of PJM and participates in the RPM capacity market. More to the point, AEP Ohio must continue to count the load of PJM demand response participants as firm under the FRR option and the cost of doing so will be reflected in AEP Ohio's retail rates – a cost that could be avoided if the customer participated in an AEP Ohio demand response program. (Tr. VIII, p. 165). Necessarily, the dollars that do come into Ohio from LSEs on the East Coast only flow in that direction because those LSEs avoid building new capacity in the eastern part of PJM – which would need to be added by AEP Ohio since it must treat a retail PJM DR customer as firm load. Thus, contrary to Integrys' oversimplified statement, a portion of the costs of retail participation in the PJM DR programs is, and would continue to be, borne by Ohio customers.

Integrys mischaracterizes the record in stating that Mr. Roush broadly "agreed that the PJM programs benefit wholesale market pricing, improve grid reliability, can be used to avoid rolling blackouts and improve awareness of energy usage." (Integrys Br. p.19 citing Tr. IX, pp. 29-34). Mr. Roush said that some benefits can occur if demand response programs are properly designed and he was conditional in agreeing to the benefits of the PJM DR programs. Mr. Roush stated that he was not necessarily sure the PJM ILR program improves reliability as the old ALM program did and he conditionally stated that "the benefit of the ILR program today is within a few subtleties towards grid reliability." (Tr. IX, pp. 31-32). Companies' witness Baker more directly testified, based

[47] Integrys offers this "funded virtually entirely outside of Ohio" characterization in several places in its brief (*e.g.*, pages 18, 20, 21) without ever being supported by a proper record-based citation. It even falsely attributes this statement to its own witness (page 21 note 62), when Mr. Wolfe was much more circumspect in stating stated that the payments were "unlikely to be subsidized" by other AEP Ohio customers, that the payments come "primarily" from out-of-state entities, and that the payments are unlikely to adversely affect other AEP Ohio customers "by an unreasonable degree." (Integrys Ex. 2, p. 17).

on his 40+ years of experience in the industry, that he did not think that AEP customers' non-participation in the PJM ILR program significantly affected reliability within PJM and that taking it away would not present a reliability risk. (Tr. I, pp. 184-185, 191-192). Further, Mr. Roush stated that demand response generally can positively influence wholesale market pricing "with the caveat that it has to be properly designed." (Tr. IX, pp. 33-34). In addition to being conditional, that statement was a general statement about demand response and did not relate specifically to PJM DR programs, contrary to Integrys' citation of the testimony. Thus, Integrys mischaracterized the state of the record on the reliability impacts and other purported benefits of the PJM DR programs.

Finally concerning policy arguments, Constellation generically claims that AEP Ohio's position concerning PJM DR programs "clearly violates the state Energy Policy as established in Sec. 4928.02, Ohio Rev. Code," rendering AEP Ohio's rationale for its proposal "moot." (Constellation Br. p. 20, 22). This assertion is without merit. On the contrary, removing the PJM DR programs that benefit the East Coast from the reach of retail customers helps promote cost effective demand response within the State of Ohio, consistent with the policy outlined in Sec. 4928.02(D), Ohio Rev. Code. Further, because allowing retail participation in the PJM DR programs ultimately increases the cost of generation supply for Ohio retail customers as explained above, it follows that prohibiting such retail participation helps keep the cost of generation supply lower for Ohio consumers. Although all components of generation supply are not necessarily based directly on cost within the context of an ESP, the price for which an EDU is willing to extend an SSO is certainly influenced by its cost to serve. Of course, the cost of generation supply to market participants also influences the wholesale price of power in the PJM market. Thus, a ban on retail participation in the PJM DR programs helps ensure the availability to consumers of reasonably priced retail electric service, consistent with the policy outlined in Sec. 4928.02(A), Ohio Rev. Code. Finally in this regard, as discussed above, AEP Ohio's position helps ensure vitality to the innovative mercantile provisions of SB 221.

As an alternative argument, Integrys advances the idea that retail participation in the PJM DR programs should count toward AEP Ohio's compliance with the peak demand reduction mandates found in Sec. 4928.66, Ohio Rev. Code. (Integrys Br. pp. 22-24). Similarly, OEG proposes that, even if it decides to adopt AEP Ohio's prohibition on direct retail participation, the Commission should require the Companies to offer PJM DR programs to customers on an optional basis via an ESP tariff rider and continue to convey the benefits of PJM DR programs to retail customers. (OEG Brief at 19). In the same vein, the Commercial Group suggests that AEP Ohio should be required to "coordinate and cooperate with its consumers in designing energy efficiency and demand response programs that incorporate all available programs that will further encourage customer participation in demand response programs in Ohio." (Commercial Group Br. pp. 8-9).

Although well-intentioned, these recommendations largely miss the point of AEP Ohio's concerns. AEP Ohio supports demand response and stands ready to work proactively with all of its customers –including mercantile customers with substantial resources – in order to aggressively pursue energy efficiency and peak demand reduction efforts to satisfy the mandates of SB 221. As previously explained, allowing retail customers to export their demand response resources in lieu of utilizing the innovative mercantile provisions within SB 221 does not serve Ohio's interests or the interests of other AEP Ohio customers. AEP Ohio's participation in the PJM DR programs, to the extent it can be coordinated with AEP Ohio's peak demand, would be integrated into its supply portfolio. (Companies' Ex. 1, p. 7).

3. Prospective implementation of retail participation restriction

Integrys advocates for a "prospective" application of any ban on retail participation in PJM DR programs. (Integrys Br. pp. 24-28). As to Integrys' concern about the enrollment for the 2009-2010 planning period, Mr. Baker testified as follows:

> The implication I believe in Mr. Wolfe's testimony is the customers should continue to be able to do this because they may have made investments in their facilities which allows them to participate currently. In my view those customers were fully aware that AEP is opposed to the participation through RTOs. We've been opposing it at a state level. We've been opposing it at a FERC level and a decision to make that investment was a risk that those customers chose to take that at some point that may no longer be available to them. So I don't see that as a reason specifically to take a position by the Commission in 2009 that those customers could participate in a 2009-2010 planning year.

(Tr. I at 180). Mr. Baker further suggested that interested customers not sign up but wait until there is an order in this case. (Tr. I, p. 183). Hence, because prospective enrollees for the upcoming 2009-2010 planning year have long been on notice that AEP has opposed participation by retail customers and would enroll at their own risk pending resolution of the issue by the Commission in this case.

Mr. Wolfe agreed that the PUCO has a right to decide the question that AEP Ohio has presented in this case as to the participation by retail customers in the PJM DR programs. (Tr. III at 25). He also acknowledged that the FERC Final Rule gave State

Commissions the right to opt out of the PJM DR for the retail customers in their jurisdictions. (Tr. III at 30-31, 33). As a related matter, Mr. Wolfe also admitted that there is already uncertainty today concerning retail customers in AEP Ohio's service territory registering and participating in the PJM DR programs for the 2009-2010 planning period. (Tr. III at 24).

If the Commission agrees that retail participation should not be allowed, it would be unfair to AEP Ohio to hold off enforcing a ban until the 2010-2011 planning year – half way through the Companies' ESP. PJM does not verify registrations until the April/May time period and, presumably, registrants could withdraw prior to the start of the planning year and/or PJM would reject any retail customer that has registered under the programs in Ohio if there was an intervening Commission decision asserting its veto authority conveyed in the Final Rule. Any decision to delay the impact of the Commission's decision would undermine the FERC's Final Rule providing full veto power to State commissions.

C. Deferral Authority for Possible Early Plant Closure

As discussed in their Initial Brief (pages 89-93), the Companies seek authority, as part of their ESP, to deal with the possibility of early closure of a generating plant. For a plant that actually would close during the ESP period the Companies request the authority to establish a regulatory asset for rate making purposes to defer any unanticipated net early closure costs. For shut downs that become anticipated during the ESP period, where a plant closure would occur at a future date still earlier than the retirement date being used for depreciation accrual purposes, the Companies request the authority to return to the Commission during the ESP period to determine the appropriate treatment for such accelerated depreciation and other early closure costs.

OCC and Sierra Club oppose the Companies' proposal. They argue that by including generating plants in rate base under traditional regulation the Companies accepted the risk that a plant might not be fully depreciated when it is removed from service. (OCEA Br. p. 102). In making this argument they have ignored Companies' witness Assante's testimony that if the Companies' generation business still was cost-based regulated (what OCC and Sierra Club characterize as "traditional regulation") "they would be able to avoid a loss by either charging the remaining investment to the Accumulated Reserve for Depreciation Account, Account 108, or by setting up the remaining net investment and any other closure related losses as a regulatory asset for future recovery." (Companies' Ex. 6, p. 24). Therefore, the risks that OCC and Sierra Club claim were assumed by the Companies when their generating plants were placed in rate base under cost-of-service regulation would not have to have been contemplated or anticipated. (*Id.* at 26).

OCC's and Sierra Club's fall-back position is that if the Commission accepts the Companies' proposal it should adopt what it refers to as the Staff's "offset" recommendation. Staff's proposal, however, is based on the incorrect premise that the Companies' generating plants will be earning a market value for their output. In other words the "negative stranded cost from the other plants" should be used to offset the costs discussed by Mr. Assante, even though that negative stranded cost is based on the market value of those plants, and even though the Companies Standard Service Offer will not be based on the market value of the plants. (Tr. XIII, pp. 118-119).

Staff witness Hess did not think the three-year ESP period was a long enough period of time to balance the Companies' inability to base its SSO on market rates with the potential risk of the type of early plant closure discussed by Mr. Assante. However, even if the Companies pursue an MRO beginning in 2012, the phase-in of market rates that would be required by Sec. 4918.142 (D), Ohio Rev. Code, still will offer a minimum of five additional years of protection from full market rates for customers. Therefore, the "offset" recommendation should be rejected.

Finally, Staff states:

> If the Companies decide to close a unit before its retirement date for depreciation accrual purposes, the Companies should request appropriate treatment for such accelerated depreciation and other early closure costs from the Commission at that time.

(Staff Br. p. 25).

This position is consistent with the Companies' request regarding units where a decision is made to shut down the unit earlier than the retirement date used for depreciation accrual purposes. Staff's position, however, does not resolve the Companies' request regarding a unit that is forced to permanently shut down during the ESP period. Both aspects of the Companies' request are reasonable and should be granted.

D. Green Pricing Program and REC Purchase Program

OCEA recommends that the Commission should require AEP Ohio to continue its Green Pricing Program. (OCEA Br. pp. 97-98). Further, OCEA advocates adoption of a separate residential and small commercial net-metering customer REC purchase program within the first three months of 2009. (OCEA Br. pp. 97-98). These recommendations should not be adopted as requirements.

It is too late to seek continuation of the Green Pricing Program as the Commission previously approved tariffs discontinuing the Green Pricing Program and, in fact, the program has already expired December 31, 2008, pursuant to a December 19, 2008 Finding and Order in Case No. 08-1302-EL-ATA. Mr. Hamrock, however, did indicate in his testimony that AEP Ohio plans to again offer a new green tariff option during the ESP term. (Companies' Ex. 3, p. 13). It is not necessary for the Commission to unilaterally order adoption of a new green tariff option or dictate details about the content or timing of the program in its order.

Regarding a standard offer program to purchase RECs, OCEA states that the price should be "no less than an Ohio mandatory market based rate with one rate for in-state solar electricity applications and a different rate for in-state wind and other renewable resources." (OCEA Br. p. 98). Interestingly, although OCC witness Gonzalez recommended adoption of a REC standard purchase contract in his testimony, OCEA's brief does not cite or otherwise refer to Gonzalez's testimony in making this recommendation. And the prescriptive pricing recommendations in OCEA's brief are at odds with Mr. Gonzalez's testimony.

In his written testimony, Mr. Gonzalez advocated REC purchase prices be based on the alternative compliance provisions in Sec. 4928.64(C)(2), Ohio Rev. Code. Upon cross examination by AEP Ohio counsel, Mr. Gonzalez "clarified" that he really wanted to suggest market-based prices similar to that in a renewable energy RFP. (Tr. IV, pp. 232-234). But he did not testify to what "an Ohio mandatory market based rate with one rate for in-state solar electricity applications and a different rate for in-state wind and other renewable resources" means as stated in the OCEA Brief. He also indicated during cross examination that the market price could be bundled with energy or unbundled just as a REC price, and was flexible in terms of how a market price should be established for this purpose. (Tr. IV, pp. 235-236). Significantly, witness Gonzalez also acknowledged that there were important logistical and administrative questions involved with his proposal, including cost effectiveness of the proposal – all of which should be taken to the collaborative in order to design and implement such a program. (Tr. IV, p. 235). Thus, OCEA's prescriptive recommendation on brief is not supported by the record and even OCC's own witness indicated that the proposal should be studied further prior to being implemented.

E. Alternate Feed Service

As part of the Companies' proposal for alternate feed service (AFS), existing customers of the service that are not paying for that service can continue to receive it until the Companies must upgrade or otherwise make new investments in the facilities providing the alternative feed. At that time, the customer may discontinue AFS, take partial AFS, or continue full AFS by paying for it under Schedule AFS. (Companies' Ex. 1, p. 8). The Companies' proposal contemplates that, when they notify customers of the need to make an election, customers would then have six months to make their election.

OHA recommends that existing AFS customers should be given 24 months to make the election. OHA and IEU also recommend that the Companies' proposed AFS schedules should not be approved as part of their ESPs, but instead should be addressed in a future proceeding. IEU argues that, in any event, the Commission should reject the proposed schedules because they are not limited to the recovery of prudently incurred costs. (OHA Br., pp. 22-23; IEU Br., p. 25).

While the Companies have some flexibility regarding the amount of notice that they can provide to existing AFS customers regarding their need to make one of the three elections, there are practical limits. One limit is the planning horizon for distribution facilities. Obviously, the projection of potential capacity deficiencies grows less accurate as the planning horizon lengthens. Another limit is the lead time that the Companies need to complete construction of the upgraded AFS facilities after the decision to construct them has been made. Accordingly, the question becomes, what is the outer limit of how much notice, in general, the Companies can afford to allow the customer to evaluate their options while still leaving enough time to construct facilities in the event the customer elects to maintain full AFS. While more than six months may be feasible, the Companies believe that anything more than 12 months would not be prudent. Obviously, specific circumstances might necessitate shortening the notification period to less than twelve months in particular cases where complex, long lead time system improvements would be required to add capacity but these should be the exception rather than the rule. In such cases, the Companies and customer should be able to work cooperatively to meet both parties' needs. In short, the Companies can commit, in general, to provide 12 months of notice to the existing AFS customers of the need to make an election.

However, Intervener recommendations to defer approval of AFS schedules to some future proceeding are not reasonable. The Companies' proposed AFS schedules codify existing practices currently being addressed on a customer-by-customer contract addendum basis. These practices are consistent with existing provisions of the Companies' respective Terms and Conditions of Service that address redundant extensions of service requested by a customer that are not supported by the distribution revenues attributable to their basic service. There is no good reason to delay codification of the existing practices. Nor is there any merit to IEU's contention that the Companies are proposing to use the AFS schedules to recover imprudent costs. First, IEU provides no support for the allegation, and there is none. Second, as noted earlier in this brief in another context, the presumption is that a public utility's conduct is prudent. That presumption is unrebutted in this proceeding.

The Commission should approve the Companies' proposed AFS schedules, with the understanding that the Companies will provide up to 12 months notice to existing customers of the need to make an election in the event an upgrade to or investment in facilities used to provide the service are necessary.

F. Net Energy Metering Service

OHA's Initial Brief, at pages 23-24, raises two objections to the Companies' proposed Net Energy Metering Service schedule for hospitals (NEMS-H). First, OHA contends that the facility ownership requirement of the Companies' proposed NEMS-H schedule has no legal basis. This objection is not well made. The plain language of the statutory provisions and the Commission's prior approved the Companies' existing NEMS schedule, which includes the ownership criterion, confirm that the ownership requirement for the NEMS-H schedule is lawful. SB 221 amended the net metering statute, Sec. 4928.67, Ohio Rev. Code, by adding subdivision (A)(2), which requires an EDU to develop a separate rate schedule that provides net metering service for a hospital which is also "a customer-generator." The definition of a "customer-generator, under Sec. 4928.02(A)(29), Ohio Rev. Code, is "a user of a net metering system." The statutory language clearly requires that, in order to qualify, the hospital must be a customer-generator. That definition, which clearly requires that the customer must be the generator, thus also indicates that the hospital must be the owner of the generation equipment. If the Legislature had intended to eliminate the ownership requirement, it could have defined "customer-generator" in the manner that it defined "self-generator," under Sec. 4928.02(Q)(32), Ohio Rev. Code, as an entity that "owns *or hosts on its premises*" an electric generating facility. In addition, the ownership criterion in the Companies' proposed Schedule NEMS-H simply reiterates the same ownership requirement that the Company previously included in the existing Schedule NEMS, which ownership requirement was approved as part of that schedule and, thus, is a lawful provision of that schedule. If the ownership criterion is a lawful provision in NEMS, it is also a lawful provision in NEMS-H.

OHA's second objection to the proposed Schedule NEMS-H is that the Companies' payments to the hospital customer-generator "may not" reflect alleged benefits in the form of a reduction line losses incurred to serve other customers in the locality of the hospital customer-generator. There is no record to support OHA's conjecture that there are any such secondary benefits, let alone that there are significant such benefits. The credit to the customer-generator that the Companies' proposed NEMS-H Schedule offers is what Sec. 4928.67, Ohio Rev. Code, requires, and OHA's criticism that additional payments should be required must be rejected.

The Staff's recommendation, at pages 24-25 of its brief, that the Companies should withdraw their proposed NEMS-H schedule and resubmit it when the rehearing in Case No. 08-653-EL-ORD is completed should not be adopted for the reasons provided in their Initial Brief, at page 129. Rehearing in that proceeding should not postpone achieving one of SB 221's objectives. If the results of that proceeding have an impact on the Companies' NEMS-H schedule, those impacts can be incorporated into the schedule at that time.

The Commission should approve the Companies' proposed NEMS-H schedules.

G. Generation Aggregation

Kroger recommends, at pages 22-23 of its Initial Brief, that the Companies' ESPs should be modified to incorporate a generation aggregation program that would allow customers with multiple accounts taking service under the GS-3 rate schedule to aggregate loads for the purpose of determining monthly peak demand for generation service. The Commission should not adopt this recommendation.

Kroger recognizes, at page 23 of its brief, that the Companies' rates already reflect the diversity of all their customers' demands, when it concedes that its proposal would "require a small, revenue-neutral increase in the demand charge for the rate schedule." Indeed, in order to adopt Kroger's generation aggregation recommendation, the existing diversity benefit reflected in current rates would have to be removed, and Kroger recognizes this through its concession, quoted above, that there would need to be increases to the rate schedule's demand charges.

There is no basis in the record for calculating what this upward adjustment to the GS-3 demand charges would be. Kroger attempts to address this problem by allowing that "[t] he amount of adjustment needed in the demand charge can be constrained at the outset through implementation [of the GS-3 generation aggregation proposal] on a pilot basis." (*Id.*) In other words, Kroger apparently would limit the generation aggregation program to Kroger and thereby limit the amount of the generation charge adjustment for the other customers. Yet, Kroger would have all of the other GS-3 cost customers pay for the cost reduction that Kroger obtains, This would not be fair. Instead, it would be discriminatory.

H. Electric Security Plan Timing Factor

In their Initial Brief, the Companies addressed this issue primarily by incorporating their December 3, 2008 Brief on 1/1/09 Plan. The Companies stated that the arguments in that brief were applicable to the final order to be issued in this proceeding, but that the arguments of others concerning their interpretation of Sec. 4928.141 (A), Ohio Rev. Code, were not applicable in the context of issuance of the Commission's final order. This view is supported by the Commission's January 7, 2009 Finding and Order in the *FirstEnergy* case.

The Commission discussed whether Sec. 4928.141 (A), Ohio Rev. Code, or Sec. 4928.143 (C) (2) (b), Ohio Rev. Code, was controlling in a situation where a final order modifying and approving an ESP had been issued, but the utility chose to terminate its ESP application. The Commission held that the relevant portion of Sec. 4928.141 (A), Ohio Rev. Code, "is applicable in those situation where the Commission has not taken action to approve, modify, or disapprove an ESP or MRO filed by an electric utility pursuant to Sec. 4928.143 (C) (2) (a) and (b), Ohio Rev. Code." (Finding and Order, p. 5).

Besides the Companies' discussion of its true-up proposal, the only other mention of this issue was in footnote 2 on page 2 of the OCEA brief. In describing the Companies' proposal, OCC and Sierra Club state that the Companies had not provided a "corresponding proposal to credit customers in the event that the rates ultimately approved by the PUCO result in over-charges." To the extent this statement is intended as a criticism of the Companies' true-up proposal the Companies offer the following responses.

First, as is fully developed in the Companies' December 3, 2008 brief, OCC should be precluded from opposing the Companies' true-up proposal. This position is based on the fact that OCC, in its pleadings seeking an extension of the procedural schedule, agreed that the true-up proposal was reasonable and should be adopted. The Companies' arguments concerning this issue did not mention Sierra Club because, although it was a joint movant for the extension of the procedural schedule, it had not reversed its position once it received the procedural schedule extension. To the extent OCC's and Sierra Club's footnote is intended as opposition to the Companies' true-up proposal, they both should be precluded from pursuing their "bait and switch" tactics.

The second point to be made is that Mr. Baker's testimony cited in OCC's and Sierra Club's footnote 2 (Tr. II, p. 53) fails to give the context of Mr. Baker's testimony. Starting on the prior page, where this line of questioning began, it is clear that Mr. Baker merely represented the Companies' opinion that the potential for customer credits does not exist because Sec. 4928.143, Ohio Rev. Code, does not permit the Commission to reduce the Companies' current Standard Service Offer rates. (Tr. II, p. 52). In fact, Mr. Baker testified that if Staff's proposal for some 1/1/09 increase had been adopted and then the Commission's final order had authorized a lower rate level than Staff had proposed, the true-up would go both directions, but only down to the level of current rates. (*Id.* at 52-53).

Finally, at page 2 of OEG's brief, OEG argues that "a statute shall be construed, if practicable, as to give effect to every part of it." The Companies agree. Sec. 4928.143 (C) (1), Ohio Rev. Code, requires that the Commission issue its final order in this proceeding no later than 150 days after the filing of an ESP application. That date (December 28, 2008) has not been met. Sec. 4928.143 (B) (2), Ohio Rev. Code, uses the phrase "without limitation" in describing components that are includable in the ESP. The Commission should interpret "without limitation" as permitting the true-up proposed as a reasonable and fair method by which the Commission can "give effect to" the part of the statute that mandated a 150-day deadline for issuing its order.

For these reasons, and for the reasons presented by the Companies in their prior briefs addressing the true-up proposed in Section V.E. of their Application, that component of the proposed ESP should be adopted by the Commission.

VI. ESP Versus MRO Comparison

As noted at the outset of this brief, while Intervenors are critical of components of the ESP with which they disagree, only the Companies, Staff, and OCC presented a comparison of the ESP in the aggregate to the results expected from an MRO. The Companies' analysis, as discussed by Companies' witness Baker, was reviewed at pages 132-137 of the Companies' Initial Brief. His analysis concluded that the Companies' ESP is more favorable in the aggregate versus the expected results of an MRO. While the Staff would prefer to reshape some provisions of the ESP, Staff's bottom line is that "the Companies' proposed ESP is more favorable than what would be expected under an MRO proposal." (Staff Br. p. 2).

Then there is OCC's analysis. To say that Ms. Smith's testimony concerning that issue was less than authoritative is being generous. Exhibits LS 2 and 3 to Ms. Smith's testimony (OCC Ex. 10, as corrected by OCC Ex. 10A) was the source of much confusion for Ms. Smith. (Tr. VII, pp. 161-173). During her unsuccessful attempt to explain the source of the numbers she used and how her numbers tied together she needed a break to try to be responsive to cross-examination (*Id.* at 166). Upon resuming she stated: "I can point to where all these pieces came from. (*Id.*). Not long after that she stated that she "can't answer that without further review." (*Id.* at 172). On redirect examination Ms. Smith indicated she "could put together an exhibit in about 10 minutes that would provide all that," i.e. answers to questions on her Exhibits LS2 and LS3. (*Id.* at 173) For reasons known only to OCC no such exhibit was provided for the record or otherwise.

Anyone can throw together numbers in an attempt to support a position. But the witness needs to be able to explain those numbers. Ms. Smith's inability to explain even the basics of her ESP/MRO comparison leaves the Commission with only two full analyses of the ESP/MRO comparison – Staff's and the Companies - and both of those analyses concluded that the proposed ESP is more favorable in the aggregate than the expected results of an MRO.

OCC's confusion continues in its brief filed with the Sierra Club. Those intervenors contest the ESP versus MRO comparison because the MROs "blended purchase power rate is included in the MRO at twice the level in the ESP..." (OCEA Br.

p. 21). Presumably this refers to the 10/20/30 percent of market rates for the MRO compared to only a 5/10/15 percent level in the ESP. This is indeed a strange criticism since OCC and the Sierra Club oppose any power purchase as part of the ESP Standard Service Offer. It is difficult to imagine that OCC would prefer that the Companies' proposed power purchase be increased to a 10/20/30 percent level. In any event, the 10/20/30 percent blending of market prices in an MRO represents a reasonable expectation of how an MRO would be structured.[48]

OCC and the Sierra Club also say the ESP versus MRO comparison is not done on a comparable basis because "the non-FAC rate in the ESP is automatically increased each year, but this increase is not included in the MRO." (Id.). While that is true, the result is that the cost of the ESP is increased in comparison to the MRO. Even with this cost disadvantaging the ESP, the Companies' ESP still is more favorable than an MRO. If those non-FAC generation cost increases that would be recoverable as part of an MRO had been added to the MRO for ESP comparison purposes the ESP would be even more favorable than an MRO.

Constellation, OCC, and the Sierra Club criticize the ESP versus MRO comparison for using too high a market price. Their criticism is without merit. First, Staff's ESP versus MRO comparison used its witnesses' market price, not the Companies. Second, the Companies' market price is the most appropriate for this three-year period, as explained in their Initial Brief at pages 133-135. As Mr. Baker testified:

> What I'm saying is to pick a specific instant or specific small period of time for the purposes of setting the competitive benchmark, this is all-around setting the competitive benchmark, that's not a valid way to approach it.

[48] IEU makes a similar argument at IEU Br. p. 33.

> You need to look over a longer period of time as we did when we looked over effectively almost a nine-month period, and if – once you do that, you get some stability to the pricing which should be more reflective of the future pricing than picking out a 1 day period or one 5-day period or one 15-day period, whatever choice it is, for one small spot. I just don't think that's a good approach.

(Tr. XIV, p. 241).

Mr. Bakers testimony is reflective of Kroger's statement that there are "increasingly volatile market rates" (Kroger Br. p. 13) and OCC's and the Sierra Club's statement that "[m]uch can change in 3 years." (OCEA Br. p. 100).

One other matter seems to affect certain Intervenors' perspectives of the ESP versus MRO comparison. At the hearings and in brief, OEG and OMA both harp on the Companies' recent returns on equity. (OEG Br. p. 4; and OMA Br. p. 16). The record is clear that the Companies object to any consideration of these past returns, arguing that consideration of those returns would have the effect of applying the SEET prospectively. Nonetheless, since that evidence is in the record, Mr. Baker offered testimony that placed those prior returns in context:

> When we had the discussion, first of all, I indicated that the numbers that were being talked about were Columbus & Southern numbers and those numbers were historical numbers, and I believe the numbers that were bantered around earlier in the day were 2007 numbers taken from things like FERC Form 1s.
>
> In the case of Columbus & Southern the earnings that had been achieved for the period in '7 and '8 mainly really come about from the acquisition of three generating units. These are gas-fired units that the company took the risk on and the shareholder took the risk on because we expected we'd be taking those units to market.

> The effects of the pool, the AEP power pool, created those earnings on a historical basis. I think you also then need to look at not the historical basis but the future basis, and we had filed some earnings pro formas as part of this case, and if one were to look at those, they'd see that the combined companies, which is the way we would propose to look at the earnings, are below 10 percent in year 2009, and in the case of Columbus & Southern, if would be 11.2 percent, as we reported it in those earnings pro formas.[49]
>
> But I think also important to keep in mind is that there is the significantly excessive earnings test, so whatever that rate is will be determined through this process and trueup – not the trueup process, but the determination process that will happen next year, and, in fact, if the numbers are considered to be significantly excessive, then the significantly excessive amount would be rebated to customers.

(Tr. II, pp. 69-70).

VII. SIGNIFICANTLY EXCESSIVE EARNINGS TEST

The Significantly Excessive Earnings Test (SEET) presents uncertainties to the Companies, as they explained in their introduction to this reply brief. Because the Companies will have the burden of proof regarding the test, it is important to address those uncertainties now, so that they can accurately assess the Commission's decision in this proceeding regarding their ESPs. In their Initial Brief, at pages 137-159, the Companies explained how those uncertainties should be addressed, discussed the parameters of an appropriate SEET methodology, as sponsored by their witness Dr. Makhija, and described the flaws in the competing proposals presented by the Staff and several Intervenors.

OEG agrees that the Commission should adopt a SEET methodology in this case, although it advocates that the test methodology should be as recommended by Mr. King

[49] Mr. Baker was referring to OCC Ex. 4.

and Mr. Kollen. (OEG Br. pp. 20-30). The Staff continues to criticize the Companies' proposed test on the grounds that it relies on statistical methods. (Staff Br. pp. 26-27). Moreover, the Staff urges the Commission to examine the appropriate methodology for the SEET within the framework of a future workshop, citing the Commission's decision in the *FirstEnergy* case. In that case the Commission noted that the goal of such a workshop "would be for the Staff to develop a common methodology for the excessive earnings test that should be adopted for all of the electric utilities and then report back to the Commission on its findings." Case No. 08-935-EL-SSO, Opinion and Order, at 64 (December 19, 2008). Certain of the Intervenors also believe that resolution of the appropriate SEET methodology should be taken up at a later date, such as in a workshop. (Commercial Group, Br. p. 9; OCEA Br. pp. 109-114; IEU Br. p. 26).

OEG's position that the Commission should adopt a SEET methodology in this case is correct. However, the methodology that OEG sponsored should not be adopted, for the reasons that the Companies provided in their Initial Brief, specifically at pages 153-155 and 158-159. The Companies thoroughly addressed the Staff's concerns about using a statistical approach to implement the methodology. In particular, the Companies pointed out that the foundation for any methodology, as even the Staff agrees, is the average earned return of the comparable risk group, and that this value is, itself, a statistic. The Companies also explained that, because the foundation of the exercise is a statistical value, the determination of the threshold for what is significantly in excess of that value naturally lends itself to a statistical approach also. They noted that the use of an adder that has no connection to the comparable risk group, such as the various adders that the Staff and several Intervenors have proposed, is disconnected from the statute's comparable risk group standard. (Companies' Br. p. 159). The Commission should adopt in its order in this proceeding the Companies' proposed methodology that Dr. Makhija sponsored, and indicate that it will apply that methodology in the manner that Companies' witness Baker recommended.

Moreover, the Commission should not defer addressing the current uncertainties regarding the SEET methodology or the manner in which it will be applied to a future workshop. First of all, such an approach would impair the Companies' ability to evaluate the Commission's decision on their ESPs.

Secondly, the Commission's decision and comments in the *FirstEnergy* case regarding a workshop approach, respectfully, do not support putting off resolution of the SEET issues for the Companies. It is highly unlikely that there is a "one size fits all" methodology for the SEET or for the manner of applying the test. For example, the FirstEnergy companies have, subsequent to the Commission's December 19, 2008, decision in their ESP case, withdrawn their electric security plans, and it appears that they may no longer be on a path toward the use of ESPs to establish their generation SSOs. If so, the SEET of Sec. 4928.143(F), Ohio Rev. Code, will not apply to them. If the First Energy companies pursue the MRO option for their SSO, they likely would not be able to wait for the results of a future workshop to the extent that those results would affect the application of a SEET at the front-end of their MRP. In addition, the FirstEnergy EDUs are distribution-only companies that have divested their generation and transmission assets, while the AEP Ohio Companies continue to own generation and transmission assets. Accordingly, their risk characteristics are fundamentally different, and this can have an impact on the appropriate SEET methodology and its application. Second, Duke

Ohio has already established through a settlement of its ESP proceeding how the SEET methodology will apply to its current ESP. Third, EDUs such as Duke Ohio and The Dayton Power and Light Company are also different from the AEP Ohio Companies because neither of them has an affiliated EDU in Ohio. The application of the appropriate SEET methodology will vary based on this difference. In particular, the Companies have demonstrated that the SEET logically should apply to the AEP Ohio Companies on a combined basis because investments in them are made, and their operation are conducted, on a combined basis.

For these reasons, the Companies urge the Commission to resolve in this proceeding the uncertainties that currently surround the SEET methodology and its application, and to do so by adopting the Companies' recommendations.

VIII. CONCLUSION

Perhaps because so few of the Intervenors attempted a full ESP versus MRO comparison, there seems to be considerable confusion regarding the scope of the rate effects of the Companies' ESP. The numbers range from a revenue increase of "$10.804 billion over the next three years, an average of $3.6 billion per year ...." (OPAE/APAC Br. p. 2) to an increase in its revenues "by as much as $686,412,652 over the course of three years...." (OHA Br. p. 6).

To set the record straight, the Companies set forth below a summary of the requested rate increases by CSP and by OPCo. These summaries are based on Companies' witness Roush's Exhibit DMR-1. They assume FAC revenues at the maximum level permissible while maintaining the Companies' target of increases at about a 15 percent limit.

Columbus Southern Power Company

Summary of Requested Rate Increases

($ in millions)

Description	Increase over Current Rates 2009	2010	2011
FAC Components	$147.9	$395.6	$668.8
Non-FAC Components	$40.2	$54.8	$69.9
POLR	$93.6	$93.6	$93.6
Distribution (7 percent Annual Increase)	$23.8	$49.3	$76.5
Energy Efficiency and Peak Demand Reduction	$13.6	$28.4	$38.0
Other*	($80.6)	($80.6)	($57.8)
Total Increase over Current Rates	**$238.5**	**$541.1**	**$889.0**
Total Increase over Prior Year	**$238.5**	**$302.6**	**$348.0**

* Includes effects of expiring and new (beginning 2011) Regulatory Asset Charges, Expiring Line Extension Surcharges, Universal Service Fund, Advanced Energy Fund, kWh Tax, expiring special contracts and other miscellaneous items.

Ohio Power Company

Summary of Requested Rate Increases
($ in millions)

Description	Increase over Current Rates 2009	2010	2011
FAC Components	$66.6	$274.1	$511.6
Non-FAC Components	$125.8	$170.5	$218.3
POLR	$21.2	$21.2	$21.2
Distribution (6.5 percent Annual Increase)	$21.2	$43.8	$67.8
Energy Efficiency and Peak Demand Reduction	$16.8	$34.6	$46.4
Other*	($27.1)	($27.1)	($11.9)
Total Increase over Current Rates	**$224.5**	**$517.0**	**$853.5**
Total Increase over Prior Year	**$224.5**	**$292.6**	**$336.5**

* Includes effects of expiring and new (beginning 2011) Regulatory Asset Charges, Expiring Line Extension Surcharges, Universal Service Fund, Advanced Energy Fund, kWh Tax, expiring special contracts and other miscellaneous items.

Based on the record in this proceeding and the arguments presented in the Companies' post-hearing briefs and their December 3, 2008 brief, the Commission should find that the Companies' proposed ESPs are more favorable in the aggregate than the expected results of an MRO. Therefore, the Commission should approve the proposed ESPs without modification and should adopt the Companies' proposed test for significantly excessive earnings.

Respectfully submitted,

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ATTACHMENT A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Wholesale Competition in Regions with Organized Electric Markets	))	**Docket Nos.**	**RM07-19-000** **AD07-7-000**

MOTION TO FILE COMMENTS OUT-OF-TIME AND COMMENTS OF INTEGRYS ENERGY SERVICES, INC.

Pursuant to the Notice of Proposed Rulemaking (the "NOPR")[1] the Commission issued on February 22, 2008 in the captioned dockets and Rule 212 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.212 (2008), Integrys Energy Services, Inc. ("Integrys Energy Services") moves to file comments out-of-time in support of meaningful opportunities for customers to participate in demand response programs. In support of this motion, Integrys Energy Services states as follows:

I BACKGROUND

A. The Commission's NOPR

The examination of wholesale competition within organized electric markets has been ongoing for a number of years. After a series of technical conferences and workshops, on June 22, 2007, the Commission issued an Advanced Notice of Proposed Rulemaking ("ANOPR") in order to address various competitive issues including demand response.[2] In response to this ANOPR, the Commission received "several thousand pages from over a hundred commenters".[3]

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1 *Wholesale Competition in Regions with Organized Electric Markets; Notice of Proposed Rulemaking*, 73 Fed. Reg. 12,576 (March 7, 2008), 122 FERC ¶ 61,167 (2008).

2 *Wholesale Competition in Regions with Organized Electric Markets, Advanced Notice of Proposed Rulemaking*, 72 Fed. Reg. 36,276 (July 2, 2007), FERC Stats. & Regs. ¶ 32,617 (2007).

3 NOPR at P.4.

Integrys Energy Services filed comments in support of the need to develop policies to encourage demand response and ensure that demand response services can be provided by a broad group of entities on a non-discriminatory basis.

As a result of the comments received in the ANOPR and those gathered during the meetings held by the Commission and its Staff, on February 22, 2008, the Commission issued the NOPR. In the NOPR, the Commission proposes several requirements for ISOs and RTOs. These proposals include requirements to: (1) accept bids from demand response resources in their markets for certain ancillary services, comparable to any other resources; (2) eliminate, during a system emergency, a charge to a buyer in the energy market for taking less electric energy in the real-time market than purchased in the day-ahead market; (3) permit an aggregator of retail customers (ARC) to bid demand response on behalf of retail customers directly into the organized energy market; (4) modify their market rules, as necessary, to allow the market-clearing price, during periods of operating reserve shortage, to reach a level that rebalances supply and demand so as to maintain reliability while providing sufficient provisions for mitigating market power; and (5) study whether further reforms are necessary to eliminate barriers to demand response in organized markets. As noted by the Commission, these changes would "require market rules to ensure that demand response can participate directly and is treated comparable to supply resources in the organized electric energy and ancillary services markets."[4]

B. Integrys Energy Services, Inc.

Integrys Energy Services provides wholesale and retail electric and gas service and associated products and services to customers throughout the United States. Integrys Energy

[4] NOPR at P.26.

Services is a wholly owned subsidiary of Integrys Energy Group, Inc., a diversified public utility. Integrys Energy Services participates in various RTO markets. As relevant to these Comments, Integrys Energy Services is a member of PJM Interconnection, LLC ("PJM"). Integrys Energy Services is also a registered Curtailment Service Provider ("CSP") in PJM, which enrolls end-use consumers in the PJM Load Response Programs. Integrys Energy Services serves a number of customers as a CSP and aggregator in PJM and other markets.

In its Comments filed in response to the ANOPR, Integrys Energy Services pointed out a number of concerns that it had with the implementation and provision of services associated with demand response in PJM. Integrys Energy Services identified as a barrier to demand response participation the undue influence of certain utilities which sought to limit the ability of end use and/or retail customers' participation in demand response, despite the clear benefits that accrue to the markets when there is a vibrant demand response market.

II.
MOTION TO FILE COMMENTS OUT-OF-TIME

Integrys Energy Services requests that the Commission accept these late-filed comments. Good cause exists to accept these comments at this time. Accepting these comments will not cause undue delay, disrupt the proceeding, unduly burden any party and will contribute to the Commission's analysis of the issues. As noted above, Integrys Energy Services filed comments to the ANOPR generally supporting the Commission's initiative to address the issues relative to demand response. In the NOPR, the Commission carried forward its proposals from the ANOPR and the comments supporting the ANOPR, including the Integrys Energy Services' comments. Because the NOPR adopted the ANOPR proposal that Integrys Energy Services supported, it concluded at that time that filing comments supporting the same proposals as set forth in the ANOPR would be an inefficient use of resources. Since that time, however, Integrys Energy

Services has become concerned with developments in PJM designed to attempt to undermine the existing demand response program done ostensibly consistent with the policies of the NOPR, and Integrys Energy Services believes that these changes would be a step backwards. In light of the continuing rise in electric prices, the increases in fuel costs and related input costs, demand response programs have taken on an even more important role since the issuance of the NOPR. Therefore, Integrys Energy Services respectfully requests that the Commission consider these supporting comments out-of-time.

III. COMMENTS

Integrys Energy Services believes that the Commission has the jurisdiction to order the RTO/ISO to allow retail customers either on their own or through an aggregator to participate in RTO demand response programs without first consulting with state commissions.[5] Unfettered access to demand response programs is the best way to maximize participation in those programs to bring clear and identified benefits to wholesale markets. The Commission has jurisdiction over demand response, which stems from its authority under the Federal Power Act. Not only does the Commission have Federal Power Act jurisdiction over "the sale of electric energy at wholesale in interstate commerce"[6] but demand response is an integral component of wholesale markets.[7] As an example of the Commission's jurisdiction over demand response, the Commission has previously determined that it has jurisdiction over disputes involving the PJM LRP under this same reasoning. For example, when the Commission accepted PJM's proposal to

5 *See* Hon. Jon Wellinghoff and David L. Morenoff, *Recognizing the Importance of Demand Response: The Second Half of the Wholesale Electric Market Equation*, 28 ENERGY L. J. 389, 405-408 (2007).

6 16 U.S.C. § 824(b). *See also New York v. FERC*, 535 U.S. 1, 19-20 (2002) (noting that the Federal Power Act authorizes federal regulation of "interstate transmissions as well as interstate wholesale sales").

7 *See, e.g., Report to Congress: Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design*, U.S. Department of Energy at 65 (April 30, 2003) (stating that demand response is a "vital ingredient for the efficient operation of wholesale electricity markets").

convert the LRP from experimental pilot to a multi-year program, it addressed jurisdictional issues. In its Order, the Commission reinforced its prior holdings that demand response transactions are wholesale transactions subject to the Commission jurisdiction and that this Program was a facet of the PJM markets, which are also subject to Commission jurisdiction.[8] The Commission has also asserted its jurisdiction in other LRP-related proceedings.[9] Unquestionably, FERC has jurisdiction over demand response programs and should exercise this jurisdiction to require any retail customer to participate in demand response so long as the customer can meet the operational requirements of the ISO/RTO Tariff.

If the Commission declines to exercise its jurisdiction, then the NOPR proposal to allow state commissions to preclude their customers from participating in RTO demand response programs, while not ideal, would give some deference to state commissions. While this approach is not optimal, it would allow customers to participate in demand response programs in at least some states. Integrys Energy Services continues to believe, however, that demand response is in the public interest and provides clear benefits to wholesale and retail markets such that states should not be inhibiting development of demand response.

While Integrys Energy Services did not initially comment on this aspect of the NOPR, other parties at PJM and in reply comments to the NOPR are now trying to keep all retail customers out of RTO demand response programs unless their state commission explicitly authorizes such participation. And at least one utility has filed a request to keep their customers from participating directly or through a CSP at PJM. This utility's filing before the state commission is a very complex case that includes many issues unrelated to demand response and

8 *See PJM Interconnection, L.L.C.*, 99 FERC ¶ 61,229 at pp. 61,938-939 (2002).

9 *See, e.g., California v. British Columbia Power Exch. Corp.*, 99 FERC ¶ 61, 247 at p. 62,247 (2002); *Old Dominion Elec. Coop. v. Publ. Serv. Elec. and Gas Co.*, 84 FERC ¶ 61,155 at p. 61,845 and n. 16 (1998); *South Carolina Publ. Serv. Auth.*, 81 FERC ¶ 61,192 at p. 61,851-852 (1997).

hundreds of pages of testimony. In some places utilities are expected to create demand response programs for their regulated business. These competing interests are likely to result in more requests to keep customers out of RTO demand response programs. Integrys Energy Services believes that market-based programs like PJM's will deliver the largest reductions in demand. Integrys Energy Services actively educates customers about their opportunities to participate in demand response programs and helps customers participate in those programs and sees direct benefits to the market as a result. While we remain committed to the view that no customer should be prohibited from participating in a demand response program, at a minimum, Integrys Energy Services urges the Commission to keep RTO/ISO sponsored demand response programs open to customers in the absence of an explicit order from a state commission prohibiting customer participation, as proposed in the NOPR.

A. Demand Response Provides Benefits to the Wholesale Market

The Commission, in the NOPR identified many of the benefits accruing to the market as a result of demand response programs. As noted by the Commission, demand response helps reduce prices in competitive wholesale markets.[10] An important component of demand response participation is the need for retail customer direct participation in demand response markets. For example, demand response affects the demand for wholesale services. "Demand response at retail, if not bid directly into the wholesale market by a retail customer, affects the wholesale market indirectly because it reduces the need for power by the retail customers' LSE and in turn reduces that LSE's need to purchase power from the wholesale market."[11]

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[10] NOPR at P.28.

[11] NOPR at P.29.

In addition, demand reduction reduces the peak power needs of a region. The Commission refers to this concept as a "flattener load profile."[12] Finally, demand response can assist in mitigating generation market power. This is accomplished because as more demand responsive resources are made available, downward pressure is placed on generator's bids to the market. These generators must take into account the price responsive nature of the load. Generators will have to re-think bidding strategies to ensure that, in order to be called to generate, the bid will have to be priced so that it will be picked.

In short, a vibrant demand response program with active participation benefits wholesale markets and ultimately all power consumers. It is for this reason that Congress, in the Energy Policy Act of 2005, ordered the Commission to further the development of various market and technological improvements. In Section 1252(f) of the Energy Policy Act of 2005, Congress provides:

> (f) Federal Encouragement of Demand Response Devices- It is the policy of the United States that time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated. It is further the policy of the United States that the benefits of such demand response that accrue to those not deploying such technology and devices, but who are part of the same regional electricity entity, shall be recognized.[13]

While some market participants may see jurisdictional limitations to the scope of the Commission's authority, it is clear to Integrys Energy Services that issues of jurisdiction should not be an impediment to implementation of robust demand response programs. First, while the

12 NOPR at P.30.

13 Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(f), 119 Stat. 594 (2005).

implementation and participation in demand response falls squarely in the wholesale arena due to the bidding and service offerings provided through an ISO/RTO, states have also been brought into the fold to improve demand response programs. In EPAct Section 1252(d)(2), Congress ordered the U.S. Department of Energy to work with states to coordinate energy policies responses "to provide reliable and affordable demand response services to the public." In this regard, the DOE has authority to provide assistance to states to aid states in "developing plans and programs to use demand response to respond to peak demand or emergency needs."[14] It is in the "we are all in this together" frame of mind that the Commission should act to institute the reforms outlined in the NOPR and do so expeditiously.

B. The Proposals Outlined in the NOPR Will Advance Demand Response in Organized Markets

The Commission, in the NOPR identified four major requirements that would be implemented in ISO/RTO environments: the RTO/ISO would: (1) accept bids from demand response resources in ancillary services markets on a comparable basis as other resources; (2) eliminate during system emergencies charges to buyers in the relevant energy market who take less energy in the real-time market than purchased in the day-ahead market; (3) permit an ARC to bid in demand response resources on behalf of its retail customers "unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate" and (4) modify market rules to allow market clearing prices to reflect the value of energy when there is an operating reserve shortage.[15] Integrys Energy Services remains committed to the view that barriers to participation in demand response should be eliminated. While allowing states the ability to deny customer participation in demand response programs

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[14] EPAct Section 1252(e)(2)(C).

[15] NOPR at P.46.

will create a new barrier, Integrys Energy Services recognizes the FERC's need to respond to state commission concerns.

The Commission's support in the NOPR for the need for each RTO/ISO to accept bids from demand response resources in ancillary service markets on a comparable basis are sound and well founded. Integrys Energy Services believes that demand response resources can and should be permitted to participate in ancillary services markets. Integrys Energy Services supports the Commission's requirement that RTOs and ISOs would have to "allow demand response resources to specify limits on the frequency and duration of their service in their bids to provide ancillary services – or their bids into the joint energy-ancillary services market in the co-optimized RTO markets." As the Commission notes, these limits are comparable to those allowed by generators and will allow demand resources to participate in spinning reserves, supplemental reserves and regulation and frequency response markets.

Just as proposals governing participation of demand response in ancillary services markets, Integrys Energy Services supports the Commission's proposal to eliminate deviation charges assessed on a buyer when it takes less energy in the real-time market when the RTO/ISO has declared an operating reserve shortage or has taken steps to avoid an operating reserve shortage. A customer should never be penalized for taking action that assists the market in an emergency or to avoid an emergency. Removal of penalties/charges should remove a powerful disincentive for participating in demand response programs.

With respect to aggregation of retail customers, Integrys Energy Services supports the Commission's proposal to allow the aggregation of retail customers to bid demand response directly into the RTO/ISO organized market. Specifically, the Commission proposes:

> to require RTOs and ISOs to amend their market rules as necessary to permit an ARC to bid demand response on behalf of retail customers directly into the

> RTO's or ISO's organized markets, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate.[16]

Integrys Energy Services believes that this proposal is one of the most important to be implemented in order for robust participation in demand response programs. Many retail customers have the ability to engage in demand response behaviors, yet do not have the size, wherewithal or resources to participate in organized electric markets. CSPs in PJM like Integrys Energy Services can aggregate those customers and, together, meet the minimum size thresholds for participating in wholesale markets. As sophisticated market participants, marketers providing services to aggregated retail customers or larger retail customers alone can increase the customer's participation and provide further benefits to the wholesale markets.

One important feature of the Commission's proposal is the stance in which participation is permitted. As currently proposed, an ARC can participate if it is not prohibited from doing so by a state retail regulatory authority. As noted above, Integrys Energy Services does not believe that the Commission should cede jurisdiction to the states to determine who can and who cannot provide valuable services in the wholesale market. However, absent the exercise of jurisdiction by the Commission, this assumption that ARCs can participate *unless* there is a prohibition in state law is important. Otherwise, an additional barrier will be presented to the marketer and retail customer with demand resources to provide – the entities will have to prove that they can participate before they can sign up to participate. In light of the direction of Congress to encourage the development of demand resources at the state and federal level, it is consistent with policy to afford the opportunity to participate by all unless there is a state law prohibition. This will also result in efficiency because, as time goes by and more states join the support for

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[16] NOPR at P.86.

demand responses after seeing the benefits to their retail customers through reduced wholesale prices, the RTO/ISO will not have to modify continually its Tariff to account for these additional state law changes. As will be shown in the next section, this "default" must be implemented in order to avoid stifling of demand response in PJM.

C. <u>Action on the NOPR is Needed – Certain ISO/RTO Markets, Including PJM May Implement Market Rule/Tariff Changes That Inhibit Development of Demand Response Resource Participation</u>

Integrys Energy Services believes strongly that a vibrant demand response market in organized RTO/ISO markets will reduce wholesale prices and bring identifiable benefits to wholesale and retail customers. In order for demand response resources to perform a positive function, participation must be widely available.

While the Commission has pending the NOPR and further market enhancements, PJM, through its Demand Response committees, may severely restrict the ability of demand response resources to participate in PJM markets. It is because of this concern that Integrys Energy Services files Comments to the NOPR at this time. If certain factions are successful, PJM's demand response program will be undermined. Some utilities, such as AEP, seek to add language to the PJM Tariff that would restrict participation in demand response to those entities whose state regulatory authority affirmatively approves participation by retail customers. If AEP were successful, this language would be a step back from what is in the PJM Tariff currently and what is proposed in the NOPR. Thus, it is important for the Commission to act expeditiously and be supportive of demand response programs, even when the state regulatory environment is in flux.

IV.
CONCLUSION

In sum, demand response programs are a critical feature for RTO/ISO markets. Further availability of demand response, as promoted by Congress in the Energy Policy Act at both the state and federal level, can only further enhance wholesale markets to the benefit of not only wholesale customers but retail customers as well. Commission policies must promote unequivocally demand response and should encourage state participation through continued dialogue. If necessary, however, the Commission must be prepared to step in and act when the effects of state commission action are contrary to the functioning of markets within RTO/ISOs.

Integrys Energy Services submits these Comments out-of-time, yet it has shown that good cause supports acceptance of the Commission and consideration of the thoughts expressed herein.

WHEREFORE, Integrys Energy Services respectfully requests that the Commission accept the Comments out-of-time and consider the comments in deliberations leading to issuance of a Final Rule.

Respectfully submitted,

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Dated: September 9, 2008

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document on each person listed on the Official Service List compiled by the Secretary in these proceedings.

Dated in Washington, DC this 9th day of September, 2008.

Eliz W. Wh

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CERTIFICATE OF SERVICE

I hereby certify that a copy of Columbus Southern Power Company's and Ohio Power Company's Reply Brief was served by electronic mail upon the individuals listed below this 14th day of January, 2009.

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