BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

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 R.C. § 4928.143 in the Form of an Electric Security Plan.	)	Case No. 12-1230-EL-SSO

APPLICATION FOR REHEARING BY THE OFFICE OF THE OHIO CONSUMERS' COUNSEL AND CITIZEN POWER

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August 17, 2012

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AND
CITIZEN POWER

The undersigned parties, to protect 1.9 million Ohioans, each respectively apply for rehearing of the Opinion and Order ("Order") issued by the Public Utilities Commission of Ohio ("PUCO" or "the Commission") on July 18, 2012 in the above-captioned case. The undersigned parties submit that the Commission's Order, is unreasonable and unlawful in the following particulars:

A. The Commission Erred, to Consumers' Detriment, by Finding the Stipulation Reasonable Under the Three-Prong Test That It Uses to Consider Settlements.

1. The Commission erred, as a matter of law, in adopting the Stipulation that lacked the necessary diversity of interests among those signing it, to the detriment of FirstEnergy's residential customers.

2. The Commission erred when it determined that the settlement as a package benefits ratepayers and the public interest, as its determination is in violation of the State policy in R.C. 4928.02(A) mandating the availability of "reasonably priced retail electric service."

a. The three-year auction process will not result in reasonably priced retail electric service as required by R.C. 4928.02(A).

b. The Commission erred when it disregarded statutory requirements regarding distribution ratemaking and reliability in approving an electric security plan.

c. The PUCO's use of deferrals and carrying charges to extend the period for collecting from customers the renewable energy credits results in unreasonably priced retail electric service under R.C. 4928.02(A).

d. The PUCO erred by failing to require a reduction in the deferred charges that customers will be asked by FirstEnergy to pay for renewable energy credits, to reflect that FirstEnergy has paid unreasonably high prices – higher than any other Ohio electric utility for renewable energy credits.

e. Energy Efficiency and Peak Demand Reduction charges result in customers paying unreasonably priced retail electric service in violation of R.C. 4928.02(A).

i. The Commission erred by deciding that the costs of economic load response and optional load response programs should be collected from all customer classes instead of only from non-residential customers.

ii. The Commission erred by finding the Utilities' actions bidding energy efficiency and peak demand response resources into the 2015/2016 base residual auction were reasonable.

f. The Commission erred in its treatment of the lost distribution revenues that customers pay the Utilities, because the Order is not supported by the facts in the record and will lead to the collection of unreasonably priced retail electric service.

3. The Commission erred in concluding that the Stipulation did not violate any regulatory principles.

a. The Commission erred in deciding the FirstEnergy ESP 3 proposal is "more favorable in the aggregate as compared to the expected results that would otherwise apply under

[an MRO],” in violation of this requirement for customer protection in R.C. 4928.143.

b. The Commission erred in its approval of the SEET calculation included in the FirstEnergy proposal because the order conflicts with a previous Commission determination, is not supported by the facts in the record and therefore violates R.C. 4903.09 that requires PUCO opinions based upon findings of fact.

B. The Commission erred in deciding the FirstEnergy ESP 3 Proposal is “More Favorable in the Aggregate as Compared to the Expected Results that Would Otherwise Apply Under [an MRO],” in Violation of R.C. 4928.143(C)(1).

1. The Commission erred in finding that the ESP is more favorable in the aggregate for customers than an MRO under a quantitative analysis.

a. The Commission erred by concluding that the costs of Rider DCR and costs of a distribution rate case are a wash for customers.

b. The Commission erred by concluding that the PIPP auction benefit supports the ESP over an MRO, in violation of state policy pursuant to R.C. 4928.02.

c. The Commission erred by not recognizing the low-income fuel funds are an indirect benefit for FirstEnergy, and should have been excluded as a quantitative benefit of the ESP 3.

2. The Commission erred by concluding that the ESP is more favorable in the aggregate for customers than an MRO under a qualitative analysis.

a. It was unreasonable for the Commission to modify the bid schedule for a three-year product in order to capture current lower generation prices and blend those with potentially higher prices in order to provide rate stability as a purported benefit for customers.

b. In consideration of the $405 million delivery capital rider spending authorized in the ESP 3, it was unreasonable for the Commission to consider the distribution rate increase “stay-out” for an additional two years of the ESP 3 to provide rate certainty, predictability, and stability as a purported benefit for customers.

c. The Commission erred by deciding that the preservation of the economic load response rate was a qualitative benefit of the ESP proposal for customers.

d. It was unreasonable for the Commission to consider the additional benefits provided via the Stipulation to interruptible industrial customers, schools, and municipalities as a benefit of the ESP.

e. The Commission erred by concluding shareholder funding for assistance to low-income customers should also be recognized as a qualitative benefit of the ESP 3.

C. The Commission Erred by Approving the Utilities' Unjust and Unreasonable Standard Service Offer Proposal in Violation of R.C. 4905.22.

D. The Commission erred by approving FirstEnergy's corporate separation plan as part of the ESP 3 Stipulation—a result that does not provide Ohioans with the intended result under law of promoting fair electric competition.

E. The Commission Erred by Violating the Due Process Rights of the Non-Signatory Parties In This Case.

1. The Commission-approved timeline for this case was inadequate and prejudiced the non-signatory parties in this case.

2. The Commission's rulings affected intervention in contravention of Ohio Law.

3. The Commission erred by taking administrative notice of information from the Utilities' MRO and ESP 2 cases.

The reasons for granting this Application for Rehearing are more fully set forth in the attached Memorandum in Support.

Respectfully submitted,

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MEMORANDUM IN SUPPORT

I. INTRODUCTION

The Commission has raised concern about the bargaining power of the electric distribution utilities ("EDU") in cases involving electric security plans ("ESP"), in the context of its review of an ESP settlement.[1] The Utilities' bargaining power was evident in this case (FirstEnergy's third ESP or "ESP 3"), where the Commission made very minimal modifications to the Stipulation.[2]

Parties that did not sign the settlement made significant arguments against the Utilities' proposal and the Stipulation before the Commission. Commissioner Roberto, who filed a dissenting opinion, found merit in many arguments raised by non-signatory parties including OCC and Citizen Power. Commissioner Roberto concluded that: "[b]ecause I find the ESP 3 is not superior to an MRO and it does not benefit ratepayers

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[1] [1] *In re FirstEnergy's 2008 ESP Case*, Case No. 08-935-EL-SSO, Second Finding and Order, Opinion of Commissioner Cheryl L. Roberto Concurring in Part and Dissenting in Part (March 25, 2009) at 1-2 .

[2] Order at 43-44 (July 18, 2012) (the Commission made five relatively minor modifications to the Stipulation).

and/or violates important regulatory principles or practices, in at least the various ways detailed below, I reject the proposed ESP 3 and thereby dissent from the majority."[3]

Commissioner Roberto also found the ESP 3 to not be superior to an MRO because (1) Regional Transmission Expansion and Planning ("RTEP") value is absent and 2) benefits of laddering are too ambiguous to value.[4] In addition, Commissioner Roberto found that the ESP 3 does not benefit ratepayers or the public interest and violates important regulatory principles and practices in seven ways. Her seven points are: 1) Contracting with an affiliated company for an un-bid contract to serve Percentage of Income Payment Plan ("PIPP") customers provides ambiguous benefits to ratepayers, is not in the public interest, and undermines market development; 2) Paying above-market rates for demand response does not benefit customers or the public interest and undermines market development; 3) Gifting stipulation signatories with obligation-free energy efficiency dollars does not benefit customers or the public interest and violates cost-effective rule requirements; 4) Regarding continuation of Rider DCR, utility and customer expectations are not aligned and without alignment utility gains additional revenues without produc[ing] additional customer value; 5) Lost Distribution Revenue recovery mechanism has out-lived its value to customers and should be permitted to expire; 6) Adequacy of the Utilities' current corporate separation is a legitimate question worthy of Commission consideration; and 7) The timing of the matter and bundling of disparate issues does not benefit customers or the public interest.[5]

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[3] Order at Dissenting Opinion of Commissioner Cheryl L. Roberto page 1 (July 18, 2012).

[4] Order at Dissenting Opinion of Commissioner Cheryl L. Roberto page 1-2 (July 18, 2012).

[5] Order at Dissenting Opinion of Commissioner Cheryl L. Roberto pages 1-7 (July 18, 2012).

Many of these same issues were raised by OCC and Citizen Power in this case, and will be discussed in more detail below to provide the rationale for the Commission to grant this Application for Rehearing.

II. HISTORY OF THE CASE

On April 13, 2012, FirstEnergy filed an Application pursuant to R.C. 4928.141 to provide customers a new standard service offer for service commencing as early as May 2, 2012, but no later than June 20, 2012, and ending May 31, 2016.[6] The Application was for an ESP, filed pursuant to R.C. 4928.143. On the very same day that FirstEnergy filed its Application, it also filed a settlement of the case. The settlement, in a Stipulation, was agreed to by various parties regarding the terms of the proposed ESP 3. The Utilities sought an expedited timeline for the approval of the Stipulation. And they also filed a Motion for Waiver of Rules in an attempt to avoid compliance with the standards for ESPs under Ohio Adm. Code 4901:1-35-03(C).

Six days later, on April 19, 2012, the Attorney Examiner issued an Entry establishing a procedural schedule for this case.[7] On April 17, 2012, the Consumer Advocates[8] filed a Joint Motion to Bifurcate and a Joint Memorandum Contra FirstEnergy's Motion for Waiver of Rules. In addition, on April 23, 2012, the Consumer Advocates filed an Interlocutory Appeal of the April 19 Entry.

On April 25, 2012, the Commission issued a ruling on FirstEnergy's Motion for Waiver of Rules ("April 25 Entry"). The Commission's Entry granted some of

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[6] Stipulation at 6 (April 13, 2012).

[7] Entry at 2-3 (April 19, 2012).

[8] For purposes of April 17 pleading, the Consumer Advocates were comprised of the following parties in this case: Environmental Law and Policy Center ("ELPC"), Natural Resources Defense Council ("NRDC"), Northeast Ohio Public Energy Council ("NOPEC"), Northwest Ohio Aggregation Coalition ("NOAC") and OCC.

FirstEnergy's waiver requests and denied others.[9] In denying certain of the requests, the PUCO obligated the Utilities to file additional materials with the Commission by May 2, 2012, which FirstEnergy did. Part of that information was a typical bill analysis comparing certain rates of the existing ESP 2 with years one and two of the ESP 3. The Utilities' typical bill comparison did not include a comparison of the generation rates that customers will pay under the proposed ESP 3 compared to the ESP 2 plan.

On April 23, 2012, the Utilities filed Supplemental Testimony of William Ridmann.[10] The stated purpose of Mr. Ridmann's supplemental testimony was to describe the efforts the Utilities expended in order to qualify and quantify the PJM-qualifying energy efficiency resources that could be available to offer into the PJM Base Residual Auction ("BRA"). Also, the testimony was filed to further describe the qualitative benefits Mr. Ridmann described in his initial direct testimony and to provide additional support regarding WRR Attachment 1 included with his initial direct testimony.[11]

On April 26, 2012, the Consumer Advocates filed a Joint Motion for an extension of the procedural schedule for this matter, and to continue the evidentiary hearing.[12] On May 2, 2012, the Attorney Examiner issued an Entry revising the procedural schedule, but not to the extent requested by the Consumer Advocates.[13] Under the revised schedule, the testimony of parties who did not sign the settlement was due on May 21,

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[9] Entry at 5-6 (April 25, 2012).

[10] FirstEnergy Hearing Ex. No. 4.

[11] *Id.* at 1.

[12] For purposes of the April 26 pleading, the Consumer Advocates were comprised of the following parties in this case: ELPC, NRDC, Sierra Club, Ohio Environmental Council, NOPEC, NOAC and OCC.

[13] Joint Motion to Extend the Procedural Schedule and Joint Motion to Continue the Evidentiary Hearing at 6 (April 26, 2012) (Consumer Advocates had requested a four-week continuance, the Commission granted only two weeks.)

2012, and the evidentiary hearing was to commence on June 4, 2012.[14] The case proceeded under that schedule.

The Commission issued its Opinion and Order ("Order") on July 18, 2012. This pleading is filed to seek rehearing of that Order.

III. STANDARD OF REVIEW

Applications for Rehearing are governed by R.C. 4903.10 and Ohio Adm. Code 4901-1-35. This statute provides that, within thirty days after the Commission issues an order, "any party who has entered an appearance in person or by counsel in the proceeding may apply for rehearing in respect to any matters determined in the proceeding."[15] Furthermore, the application for rehearing must be "in writing and shall set forth specifically the ground or grounds on which the applicant considers the order to be unreasonable or unlawful."[16]

In considering an application for rehearing, Ohio law provides that the Commission "may grant and hold such rehearing on the matter specified in such application, if in its judgment sufficient reason therefore is made to appear."[17] Furthermore, if the Commission grants a rehearing and determines that "the original order or any part thereof is in any respect unjust or unwarranted, or should be changed, the Commission may abrogate or modify the same * * *."[18]

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[14] Entry at 5 (May 2, 2012).

[15] R.C. 4903.10.

[16] *Id.*

[17] *Id.*

[18] *Id.*

OCC and Citizen Power meet the statutory requirements applicable to an applicant for rehearing pursuant to R.C. 4903.10. Accordingly, OCC and Citizen Power respectfully request that the Commission grant rehearing on the matters specified below.

IV. ARGUMENTS ON ASSIGNMENTS OF ERROR

A. The Commission Erred, to Consumers' Detriment, by Finding the Stipulation Reasonable Under the Three-Prong Test That It Uses to Consider Settlements.

The standard for consideration of a stipulation has been discussed in a number of Commission cases and by the Ohio Supreme Court. As the Ohio Supreme Court stated in *Duff*:

> A stipulation entered into by the parties present at a commission hearing is merely a recommendation made to the commission and is in no sense legally binding upon the commission. The commission may take the stipulation into consideration, but must determine what is just and reasonable from the evidence presented at the hearing.[19]

The Court in *Consumers' Counsel* considered whether a just and reasonable result was achieved with reference to criteria adopted by the Commission in evaluating settlements:

> 1. Is the settlement a product of serious bargaining among capable, knowledgeable parties?
>
> 2. Does the settlement, as a package, benefit ratepayers and the public interest?
>
> 3. Does the settlement package violate any important regulatory principle or practice?[20]

[19] *Duff v. Pub. Util. Comm*. (1978), 56 Ohio St.2d 367.

[20] *Consumers' Counsel*, 64 Ohio St.3d at 126, 592 NE 2d at 1373.

The Commission's Order determined that: "the Stipulation, as modified, meets the three criteria for adoption of stipulations, is reasonable and should be adopted."[21] We respectfully disagree. And we ask the PUCO to rehear its rulings.

1. The Commission erred, as a matter of law, in adopting the Stipulation that lacked the necessary diversity of interests among those signing it, to the detriment of FirstEnergy's residential customers.

The Commission should have determined that the Stipulation fails the first prong of the Commission's test for the adoption of stipulations. FirstEnergy alleged that there was a "broad range of interests" represented by the signatories to the Stipulation.[22] But there is not a broad residential interest represented in the Stipulation. The Stipulation lacked a signatory party that represented all residential customers, by far the largest number of the Utilities' customers at 1.9 million. The Stipulation fails to protect the interests of most of FirstEnergy's customers -- the residential customers -- and thus fails to meet the first prong of the Commission's standard for judging stipulations.

The Commission should have looked deeply at the facts and circumstances in this case to ascertain the motivation of the parties signing the settlement. The Commission did not do so. The Commission stated:

> Further, the Commission notes that many signatory parties receive benefits under the Stipulation, **but the Commission will not conclude that these benefits are the sole motivation of any party in supporting the Stipulation**, as AEP Retail alleges without any evidentiary support. The Commission expects that parties to a stipulation will bargain in support of their own interests in deciding whether to support that stipulation. **The question for the Commission under the first prong of our test for the consideration of stipulations is whether the benefits to parties**

[21] Order at 57 (July 18, 2012).

[22] FirstEnergy Hearing Ex. No. 3, Direct Testimony of William Ridmann at 11 (April 13, 2012).

are fully disclosed as required by Section 4928.145, Revised Code.[23]

For example, the Commission should have delved deeper into the nature of participation by Ohio Partners for Affordable Energy ("OPAE"), the Cleveland Housing Network, the Empowerment Center and the Consumer Protection Association in order to ascertain the motivation behind their decisions to support the Stipulation.

Those parties do not represent all residential customers. Their interests in the Stipulation can be determined by the benefits they received. It was included in the Stipulation that OPAE would received $1 million (divided equally between 2015 and 2016) for its fuel fund programs.[24] In addition, the Cleveland Housing Network, Empowerment Center and the Consumer Protection Association received in total $8 million (divided equally between 2015 and 2016) for their fuel fund programs.[25] Their narrow interests, as evidenced by the payments received in exchange for supporting the Stipulation, do not provide the necessary diversity of residential customers' interests for adoption of the Stipulation in this case.

OPAE, Cleveland Housing Network, Empowerment Center and the Consumer Protection Association signed the Stipulation without conducting any discovery. Discovery is an important aspect of any case and the development of a party's understanding and preparation. The importance of this process is evidenced by the fact that nine of the Commission's 38 Administrative Provisions and Procedure rules address discovery.[26] Other than OPAE's Counsel making an appearance on the first day of the

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[23] Order at 27 (July 18, 2012).

[24] FirstEnergy Hearing Ex. No. 1, Stipulation at 40 (April 13. 2012).

[25] Id at 41-42.

[26] Ohio Adm. Code 4901-1-16 through Ohio Adm. Code 4901-1-24.

evidentiary hearing,[27] the attorneys for these parties did not cross-examine a single witness and did not file an Initial Brief or Reply Brief in this case.

Contrast the involvement of OCC, the statutory representative of residential utility customers in Ohio,[28] with the Parties the Commission relies upon to represent residential customers in support of the Stipulation. OCC served six sets of discovery, sponsored three expert witnesses on numerous issues in this case, filed -- or jointly filed[29] -- five pleadings pertaining to procedural aspects of the case,[30] a significant Initial Post-Hearing Brief[31] and significant Reply Brief.[32] A Stipulation that finds OCC as a non-signatory should be more closely scrutinized by the Commission to assure that those parties being relied upon for support of the Stipulation do indeed have the best interests of the residential customers in mind. The Stipulation should not be driven by narrow self-interests, as has been the case here. In light of these facts, the Commission erred by approving the Stipulation in this case.

The Commission in past cases has raised concerns about the relative bargaining power of the EDU in ESP cases. As Commissioner Roberto testified in FirstEnergy's initial ESP case filed in 2008:

> When parties are capable, knowledgeable and stand equal before the Commission, a stipulation is a valuable indicator of the parties' general satisfaction that the jointly recommended result will meet

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[27] Tr. Vol. I at 13 (Mooney) (August 4, 2012).

[28] R.C. 4909.11.

[29] OCC filed jointly with inter alia NOPEC, NOAC, Citizen Power who have also advocated for the consumer interests in this proceeding.

[30] Joint Motion to Bifurcate Issues and Joint Memo Contra FirstEnergy's Motion for Waivers(April 17, 2012); Joint Motion to Strike FirstEnergy's Reply (April 23, 2012); Request for Interlocutory Appeal (April 24, 2012); Joint Motion to Extend the Procedural Schedule and Joint Motion for Continuance of Evidentiary Hearing (April 26, 2012); Joint Motion for Continuance of Evidentiary Hearing or In the Alternative Joint Motion for Partial Continuance (June 1, 2012).

[31] Joint Initial Brief OCC and Citizen Power (June 22, 2012).

[32] Joint Reply Brief OCC and Citizen Power (June 29, 2012).

> private or collective needs. It is not a substitute, however, for the Commission's judgment as to the public interest. The Commission is obligated to exercise independent judgment based on the statutes that it has been entrusted to implement, the record before it, and its specialized expertise and discretion.
>
> In the case of an ESP, the balance of power created by an electric distribution utility's authority to withdraw a Commission-modified and approved plan creates a dynamic that is impossible to ignore. I have no reservation that the parties are indeed capable and knowledgeable but, because of the utility's ability to withdraw, the remaining parties certainly do not possess equal bargaining power in an ESP action before the Commission. **The Commission must consider whether an agreed-upon stipulation arising under an ESP represents what the parties truly view to be in their best interest – or simply the best that they can hope to achieve when one party has the singular authority to reject not only any and all modifications proffered by the other parties but the Commission's independent judgment as to what is just and reasonable.** In light of the Commission's fundamental lack of authority in the context of an ESP application to serve as the binding arbiter of what is reasonable, a party's willingness to agree with an electric distribution utility application can not be afforded the same weight due as when an agreement arises within the context of other regulatory frameworks. As such, the Commission must review carefully all terms and conditions of this stipulation.[33]

The fact that the signatory parties who purportedly represented the interests of residential customers did not conduct discovery nor submit evidence in support of the Stipulation should have led the Commission to conclude that the disclosed benefits were merely the best that these parties thought they could hope to achieve for low-income customers. The best interests of **all** residential customers is not reflected in the Stipulation.

The Commission should not have stopped its inquiry into whether all benefits were disclosed. The Commission had a duty to look deeper into the level of participation by the signatory parties to determine if the parties bargained solely in their own self

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[33] *In re FirstEnergy's 2008 ESP Case*, Case No. 08-935-EL-SSO, Second Finding and Order, Opinion of Commissioner Cheryl L. Roberto Concurring in Part and Dissenting in Part (March 25, 2009) at 1-2 . (Emphasis added).

interests or did their participation demonstrate that a broader perspective was taken towards the outcome of the case. Therefore, the Commission should grant rehearing on this issue.

2. The Commission erred when it determined that the settlement as a package benefits ratepayers and the public interest, as its determination is in violation of the State policy in R.C. 4928.02(A) mandating the availability of "reasonably priced retail electric service."

The Commission relied in the Order on several specific features of the Utilities' ESP 3 Stipulation to support its ultimate conclusion that the Stipulation, as modified, benefits ratepayers and the public interest.[34] In reaching that conclusion, the Commission relied on the following Stipulation provisions: (a) Competitive Bid Process (Order at 31-32); (b) Distribution Rate Freeze and Rider DCR (Order at 33-34); (c) Renewable Energy Credit Recovery Period (Order at 34-36); (d) Energy Efficiency/Peak Demand Reduction (Order at 35-38); and (e) Lost Distribution Revenue (Order at 38-40). However, these provisions do not provide customers with reasonably priced retail electric service.

R.C. 4928.02(A) states:

> It is the policy of this state to do the following throughout this state:
>
> (A) Ensure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, **and reasonably priced retail electric service.** (Emphasis added).

Each of those provisions will be discussed below, and explanations are provided as to why the Commission erred by relying on these provisions for approval of the Stipulation.

[34] Order at 44 (July 18, 2012).

a. The three-year auction process will not result in reasonably priced retail electric service as required by R.C. 4928.02(A).

The Commission has concluded that the three-year auction product should be considered a benefit for consumers. That is in error. The Commission stated:

> The Commission agrees with the Companies and Staff that the laddering of products in order to smooth out generation prices, mitigating the risk of price volatility, will benefit ratepayers and the public interest.[35]

OCC and Citizen Power provided evidence establishing the uncertainty of generation prices in the American Transmission System Incorporated ("ATSI") zone due to generation plant retirements and transmission constraints that placed limitations on importing power from outside the ATSI zone.[36] This evidence supported a finding that the three-year auction product would necessitate the auction bidders to include higher risk premiums that would result in higher future generation prices to customers.[37] The Commission dismissed that evidence and rejected any such finding.

The Commission stated:

> The Commission finds that OCC/CP and AEP Retail's arguments have merely established that future prices are uncertain; however, unlike OCC/CP and AEP Retail, the Commission believes that future price uncertainty makes laddering of products in order to mitigate volatility an even greater benefit for ratepayers.[38]

OCC and Citizen Power did establish that future prices are uncertain. But it was also shown that the three-year auction product would not benefit customers due to the hedging of the identified uncertainties.

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[35] Order at 32 (July 18, 2012).

[36] Joint Initial Brief at 2-3 (June 22, 2012).

[37] See Joint Initial Brief at 17 (June 22, 2012), see also Joint Reply Brief at 2 (June 29, 2012).

[38] Order at 32 (July 18, 2012).

Switching to a three-year auction product at this time creates risks that will result in expected risk premiums for market participants and which in turn raises costs that are paid by FirstEnergy's customers: "Future generation supply and prices for the ATSI zone must be considered highly uncertain at this time, due to the large amount of plant retirements, the numerous planned transmission upgrades, and the uncertain market reaction to provide new generation, demand response and energy efficiency capacity."[39] The ATSI zone is constrained[40] and will have generally higher prices than the surrounding areas of the grid.[41] But the extent to which this will occur is unknown at this time.[42]

These risks that are three or more years ahead are difficult to hedge.[43] And as hedging becomes more difficult, suppliers include larger risk premiums in their bids or decline to participate in the auctions.[44] Larger risk premiums mean higher rates for customers.[45] Accordingly, going to a three-year product, under these circumstances, means that FirstEnergy's customers will pay in rates for the higher risk premiums for their electric service.

AEP Retail argued that customers losing the lower generation costs under the ESP 2 term are actually harmed by the Utilities' proposal.[46] For example, AEP Retail argues that these planned nominally lower rates will be replaced by nominally higher rates that reflect the new costs that must be paid up front in return for nominally lower rates to be

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[39] OCC Hearing Ex. No. 9, Direct Testimony of James Wilson at 17.

[40] AEPR Hearing Ex. No. 1.

[41] OCC Hearing Ex. No. 9, Direct Testimony of James Wilson at 17.

[42] OCC Hearing Ex. No. 9, Direct Testimony of James Wilson at 17.

[43] OCC Hearing Ex. No. 9, Direct Testimony of James Wilson at 23.

[44] OCC Hearing Ex. No. 9, Direct Testimony of James Wilson at 23.

[45] OCC Hearing Ex. No. 9, Direct Testimony of James Wilson at 23.

[46] See also Order at Dissenting Opinion of Commissioner Cheryl L. Roberto page 2 (July 18, 2012).

expected in the 2015/2016 year.[47] Commissioner Roberto made a similar point in her dissenting opinion by stating:

> To achieve any benefit, we must assume that a bidder for a three-year product will capture all of the benefit of the prices provided by the one-year product and offer them back to the customers and, in addition, offer a lower price than they would otherwise for the product covering years two and three. There is nothing in the record to suggest that this will be true. In fact, the only suggested benefit is averaging the lower prices (which customers would already receive) with the anticipated higher prices – in essence simply paying ahead for the ability to experience less of a price change on June 1, 2014.[48]

Not only are the generation costs to consumers uncertain going forward under the Utilities' proposal in this case, the laddering of a three-year auction product that blends the lower generation rates from 2013-2015 harms the SSO customers under FirstEnergy's ESP 2 Case.

As explained above, the three-year auction process will not lead to the provision of reasonably priced retail electric service as required pursuant to R.C. 4928.02(A). Therefore, the Commission should have rejected the Stipulation or modified the Stipulation by requiring the Utilities to conduct a one- or two-year auction instead of a three-year auction. The Commission chose not to do so. That decision was inappropriate under law and reason. Therefore, for all these reasons, the Commission should grant rehearing on this issue.

b. The Commission erred when it disregarded statutory requirements regarding distribution ratemaking and reliability in approving an electric security plan.

The Commission, without elaboration, concluded that: "the Utilities have demonstrated the appropriate statutory criteria to allow continuation of Rider DCR as

[47] AEP Retail Reply Brief at 9-10 (June 29, 2012).

[48] Order, Dissenting Opinion of Commissioner Cheryl L. Roberto at 2 (July 18, 2012).

proposed in the Stipulation."[49] That is in error. Ohio law establishes that it is incumbent upon the Commission to review the reliability of the EDU's distribution system and ensure that the customers' and the EDU's expectations are aligned. R.C. 4928.143(B)(2)(h) states:

> As part of its determination as to whether to allow in an electric distribution utility's electric security plan inclusion of any provision described in division (B)(2)(h) of this section, **the commission shall examine the reliability of the electric distribution utility's distribution system and ensure that customers' and the electric distribution utility's expectations are aligned and that the electric distribution utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system**. (Emphasis added.)

The Commission failed to adhere to the statutory requirements in authorizing the continuation of Rider DCR as proposed by the Stipulation.

OCC and Citizen Power made extensive arguments that established: (1) the reliability standards reviewed by the Staff were achieved in 2011, long before the Rider DCR distribution costs are to be recovered as proposed by the Utilities ESP 3 Stipulation,[50] (2) the existing information about customer expectations will be stale by the beginning of the ESP 3 term,[51] (3) the Utilities' and customers' expectations are not aligned,[52] (4) resources dedicated to enhanced distribution service are excessive[53] and (5) there is no remedy to address excessive distribution-related spending in the annual DCR audit cases.[54] Those arguments were dismissed by the Commission.

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[49] Order at 34 (July 18, 2012).

[50] Joint Initial Brief at 26 (June 22, 2012).

[51] Id. at 28 (June 22, 2012).

[52] Id. at 29 (June 22, 2012).

[53] Id. at 30 (June 22, 2012).

[54] Id. at 31 (June 22, 2012).

The Commission in disregarding the above arguments focused its attention on the continuation of Rider DCR by stating: "As discussed in Staff's testimony, Staff examined the reliability of the Utilities' system and found that the Utilities complied with the applicable standards (Staff Ex. 2 at 5-6)."[55] However, reliance on Staff's testimony is problematic for the Commission.

There is a significant disconnect between the timing of the reliability analysis performed by Staff Witness Baker and the timing of the application of the statutory requirements in R.C. 4928.143(B)(2)(h) with regard to the ESP 3 proposal. An integral part of the statutory requirement is that expectations of the EDUs and their customers are aligned. However, the alignment that Mr. Baker testified to is an alignment that existed in 2011. Despite Mr. Baker's conclusion that the alignment between FirstEnergy's and its customers' expectations exist, the record in this case is void of evidence that shows such alignment will continue to exist when the $405 million will be potentially collected from customers during the ESP 3 period of June 1, 2014 through May 31, 2016.

The Commission also finds solace in the annual audit of the cost recovery under the proposed Stipulation. The Commission stated: "[f]urther, the Stipulation provides for an annual audit of recovery under Rider DCR and requires the Utilities to demonstrate what they spent and why the recovery sought is not unreasonable."[56] But, to protect consumers, the audit should include a review of the relationship between the reasonableness of distribution investment spending and reliability performance during the same period of the distribution investment. Adding that consumer protection to the audit would increase the potential that customers' and the Utilities' expectations are aligned,

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[55] Order at 34 (July 18, 2012).

[56] Order at 34 (July 18, 2012).

and would require the Utilities to demonstrate that they are dedicating sufficient resources to the reliability of their distribution systems.

The Commission also defends authorization of Rider DCR because the amount of DCR costs, to be collected from customers, are a maximum amount and not a set amount. The Commission stated:

> Additionally, the Commission notes that the caps on Rider DCR do not establish certain amounts that the Companies will necessarily recover – thus, the Commission emphasizes that the $405 million figure discussed by NOPEC/NOAC and OSC is the maximum that could be collected under Rider DCR and is not a guaranteed amount.[57]

It is not enough to decide that the $405 million is not guaranteed and could ultimately be less. Rather, the Commission should have decided that the distribution investment costs to be collected from customers are unreasonable at any level because Rider DCR violates the requirement in R.C. 4928.143(B)(2)(h) that customers' and the electric distribution utility's expectations be aligned. .

OCC and Citizen Power pointed out in their Initial Brief that the Utilities' witness Brad Ewing, in a prior reliability case, made a compelling reliability benefit-cost argument. Mr. Ewing stated in testimony:

> It is necessary for each of the Companies to strike a balance between the responsibility to provide adequate electric service and the need to do so at an acceptable cost to customers. Improving reliability by just one hundredth of a percent would require significant expenditures over and above those now required simply to maintain the distribution system. CEI could rebuild its electrical system to greatly reduce line and equipment failures at an estimated cost of $3 billion. But customers are unlikely to approve such an expense -- the benefit to customers would simply be dwarfed by the cost.[58]

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[57] Order at 34 (July 18, 2012).

[58] OCC Hearing Ex. No. 11, Direct Testimony of Wilson Gonzalez at 25 (May 21, 2012) citing *In re First Energy Reliability Case,* Case No. 09-759-EL-ESS, Direct Testimony of Brad Ewing at 2-3 (November 1, 2010).

What FirstEnergy said in 2010 should have been heeded here.

There must be a nexus between the annual DCR audits and the Utilities' annual reliability performance reviews in order to ensure that the Utilities are not dedicating excessive resources to enhanced distribution service. But the Commission has failed to require such a connection. And the Commission has not pointed to the record where the Utilities have demonstrated that future DCR spending to enhance distribution service is necessary to maintain existing reliability performance. Therefore, the Utilities and the PUCO's Order adopting the Utilities' proposal, have not met the statutory requirements. The Commission erred by authorizing the Utilities to collect up to $405 million from customers through Rider DCR without requiring the Utilities to meet the statutory requirements of R.C. 4928.143(B)(2)(h). Therefore, the Commission should grant OCC's and Citizen Power's rehearing request.

In her dissent, Commissioner Roberto determined that the continuation of Rider DCR is not supported by the record.[59] The Commissioner found that the statute requires the Utilities to demonstrate they are sufficiently emphasizing the placement of resources for the reliability of their distribution systems.[60] However, Commissioner Roberto viewed the Utilities' performance in the base residual auction as sufficient rationale for denying the Utilities continuation of Rider DCR. She stated:

> The Companies may only avail themselves of the benefits of single-issue rate-making pursuant to Section 4928.143, Revised Code, after they have successfully made this demonstration. The information in our record is insufficient to find that the Companies dedicated sufficient resources to reliability, particularly in the form of participation in the base residual auctions whose very purpose is reliability. For this reason, I find that continuation of Rider DCR is not supported by this record.[61]

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[59] Order, Dissenting Opinion of Commissioner Roberto at 5.

[60] See R.C. 4928.143(B)(2)(h).

[61] Order, Dissenting Opinion of Commissioner Roberto at 5 (July 18, 2012)

The Commission in its Order recognized the need for distribution projects to be undertaken to help mitigate the transmission constraints in the ATSI zone in order to reduce capacity charges resulting from future base residual auctions.[62] Basing the disapproval of Rider DCR on the reliability aspects of the base residual auction was insightful on the part of Commissioner Roberto, and should provide another reason for the Commission to grant rehearing on this issue.

By approving the Utilities' proposal, which will result in unreasonably priced retail electric service pursuant to R.C. 4928.02(A) through the collection of up to $405 million from customers during the term of the ESP 3, the Commission violated Ohio law. Therefore, the Commission should grant OCC and Citizen Power's Application for Rehearing.

c. The PUCO's use of deferrals and carrying charges to extend the period for collecting from customers the renewable energy credits results in unreasonably priced retail electric service under R.C. 4928.02(A).

And

d. The PUCO erred by failing to require a reduction in the deferred charges that customers will be asked by FirstEnergy to pay for renewable energy credits, to reflect that FirstEnergy has paid unreasonably high prices – higher than any other Ohio electric utility - for renewable energy credits.

The Utilities allege that an additional rate design benefit of the ESP 3 includes extending the collection (from customers) of renewable energy credit costs through deferral accounting.[63] The Commission accepted this FirstEnergy proposal as being

[62] Order at 41 (July 18, 2012).

[63] FirstEnergy Initial Brief at 34 (June 22, 2012).

beneficial for customers and the public interest.[64] The Commission stated: "the Commission believes that mitigating the risks of price volatility and smoothing of prices is a benefit for ratepayers and is in the public interest. Further, the Commission finds that the mitigating effects of this benefit outweigh the potential carrying costs."[65] The Commission is wrong.

There is no calculation or cost benefit analysis in the record that demonstrates the alleged benefits outweigh the carrying costs as the Commission concluded. What the record does show, as OCC and Citizen Power argued on brief, is that allowing the Utilities to defer costs that customers will pay to them later will cost customers nearly $680,000 in carrying charges associated with Rider Alternative Energy Resource ("AER") deferrals for the year 2011.[66] And those carrying charges will continue and carry forward at different levels into the 2012 through 2016 timeframe.[67]

As was further pointed out in the Joint Initial Brief, the separate impacts -- deferring of AER costs and blending current lower auction prices with the anticipated higher capacity and energy prices -- appear to work at cross purposes.[68] The recommendation from OCC and Citizen Power was instead to auction a one- or two-year product, as proposed by OCC witness Wilson, and to keep the AER Rider as is. That approach would have accomplished a similar price-smoothing effect without customers having to pay the carrying charges to the Utilities.

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[64] Order at 35 (July 18, 2012).

[65] Order at 35 (July 18, 2012) citing FirstEnergy Hearing Ex. No. 3, Direct Testimony of William Riddman at 8 (April 13, 3012).

[66] OCC Hearing Ex, No. 5.

[67] Tr. Vol. I at 224 (Ridmann) (June 4, 2012).

[68] Joint Initial Brief at 63 (June 22, 2012).

The Commission analysis of the ESP and MRO failed to consider these carrying charges in violation of R.C. 4928.143(C). R.C. 4928.143(C) states:

> The burden of proof in the proceeding shall be on the electric distribution utility. The commission shall issue an order under this division for an initial application under this section not later than one hundred fifty days after the application's filing date and, for any subsequent application by the utility under this section, not later than two hundred seventy-five days after the application's filing date. Subject to division (D) of this section, the commission by order shall approve or modify and approve an application filed under division (A) of this section if it finds that the electric security plan so approved, including its pricing and all other terms and conditions, **including any deferrals and any future recovery of deferrals,** is more favorable in the aggregate as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code. (Emphasis added).

Nowhere in the Commission's analysis is there recognition of the carrying charges associated with the future recovery of these deferrals, as required by Ohio law. Therefore, the Commission's analysis is incomplete under R.C. 4928.143 and violates R.C. 4903.09. The matter should be reheard.

There is another reason why the Commission should rehear its decision to allow FirstEnergy to collect from customers the costs related to renewable energy. The Commission opened a docket (Case No. 11-5201-EL-RDR) for the purposes of reviewing the Utilities' AER Rider.[69] The Commission retained Exeter Associates, Inc. ("Exeter") for the purpose of performing a Management Performance Audit ("Exeter Report").[70] The Commission also selected Goldberg Schneider to conduct the Financial Audit

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[69] *In the Matter of the Review of the Alternative Energy Rider Contained in the Tariffs of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company,* Exeter Report at i (August 15, 2012).

[70] . *In the Matter of the Review of the Alternative Energy Rider Contained in the Tariffs of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company,* Exeter Report at i (August 15, 2012).

("Financial Audit).[71] On August 15, 2012 the Commission docketed the Exeter Report and the Financial Audit Report.[72] The audit included the Utilities' procurement of renewable energy credits ("REC") for purposes of compliance with Ohio's Alternative Energy Portfolio Standards ("AEPS").[73] Exeter's findings and recommendations with regard to the Utilities REC procurement are concerning. Exeter's findings were as follows:

> Findings:
>
> 1. The prices paid by the Companies for All-States All Renewables RECs were reasonably consistent with other regional RECs prices.
>
> 2. While lower prices would have been available to the Companies were fewer RECs purchased under RFP 1 and more RECs purchased under RFP 3, the Companies' decisions to purchase the bulk of the 2009, 2010, and 2011 requirements under RFP 1 were not unreasonable.
>
> 3. The lower prices available for All-States SRECs in the 2011 timeframe could not have been reasonably foreseen by the Companies. The prices paid by the Companies for All- States SRECs are consistent with SRECs price regionally.
>
> 4. The FirstEnergy Ohio utilities did not establish a maximum (or limit) price that the Companies were willing to pay for In-State All Renewables RECs prior to the issuance of the RFPs.
>
> 5. The FirstEnergy Ohio utilities paid unreasonably high prices for In-State All Renewables RECs purchased from [original redaction]
>
> 6. Prices for In-State All Renewable RECs in the range of $ [original redaction] to $ [original redaction] exceeded the reported prices paid for non-solar compliance RECs anywhere in the country between July 2008

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[71] *In the Matter of the Review of the Alternative Energy Rider Contained in the Tariffs of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company* , Financial Audit Report at 3 (August 16, 2012).

[72] The Commission should take administrative notice of this information contained within the Exeter Report (Attached hereto as Attachment 2).and the Financial Audit Report (Attached hereto as Attachment 3).

[73] *In the Matter of the Review of the Alternative Energy Rider Contained in the Tariffs of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company*, Case No. 11-5201-EL-RDR, Exeter Report (redacted) at i (August 15, 2012) (Emphasis added). Id. at i.

> and December 2011 by at least $ [original redaction] to $ [original redaction].
>
> 7. The FirstEnergy Ohio utilities had several alternatives available to the purchase of high-priced In-State All Renewables RECs, none of which were considered or acted upon.
>
> 8. The FirstEnergy Ohio utilities should have been aware that the prices bid by FirstEnergy Solutions reflected significant economic rents and were excessive by any reasonable measure.
>
> 9. The procurement of In-State Solar RECs by the FirstEnergy Ohio utilities was competitive and, when Ohio SRECs became reasonably available, the prices paid for those SRECs by the Companies were consistent with prices for SRECs seen elsewhere.[74]

As a result of these Findings, Exter made the following recommendation:

> Recommendations:
>
> Based on the findings presented above, **we recommend that the Commission examine the disallowance of excessive costs associated with purchasing RECs to meet the FirstEnergy Ohio utilities' In-State All Renewables obligations.**[75]

FirstEnergy's ESP 3 proposed to defer these costs with interest, for future collection from customers. In light of the Exeter Report, it is questionable whether FirstEnergy should be authorized to collect these procurement costs from customers at all, let alone deferring these costs for customers to pay with interest (as was proposed in their ESP 3 plan and approved by the PUCO). Therefore, as a result of the Exeter Report recommendation for disallowance of "excessive costs" resulting from the acquisition of RECs, the Commission should grant rehearing to hear evidence on the subject of assuring

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[74] *In the Matter of the Review of the Alternative Energy Rider Contained in the Tariffs of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company*, Case No. 11-5201-EL-RDR, Exeter Report (redacted) at iii-iv (August 15, 2012) (Emphasis added).

[75] *In the Matter of the Review of the Alternative Energy Rider Contained in the Tariffs of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company*, Case No. 11-5201-EL-RDR, Exeter Report (redacted) at iv (August 15, 2012) (Emphasis added).

that FirstEnergy will be limited in its collection from customers to only prudently incurred costs.

The concerns raised above regarding FirstEnergy's REC procurement costs are further borne out by the Financial Audit ("Financial Audit Report") of the Alternative Energy Resource Rider of the FirstEnergy Ohio Utility Companies performed by Goldenberg Schneider, LPA ("Finacial Auditor"). The Financial Auditor made a compelling showing that FirstEnergy paid a significant higher cost for RECs than other Ohio electric utilities. The Financial Auditor included a chart on page 9 of the Financial Audit Report that shows that while other Ohio electric utilities were paying between .0115 and .0802 cents/kwh (using the 2011 numbers), FirstEnergy was paying between .2776 and .4699 cents/kwh.[76] This is a significant difference, and led the Financial Auditor to conclude: "[t]he table above shows that FirstEnergy's Operating Companies consistently have a significantly higher Rider AER rate than the other Ohio Investor Owned Utilities." The Financial Auditor's conclusion supports the Exeter Report recommendation for disallowance of "excessive costs" resulting from the acquisition of RECs; therefore, the Commission should grant rehearing to assure FirstEnergy will be limited to the collection from customers of only prudently incurred costs.

The Commission has touted the ESP 3 proposal for its contribution to promoting shopping in FirstEnergy's service territory.[77] However, the extension of collection of renewable energy costs harms shopping. The Commission addressed this issue in its Order by stating:

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[76] *In the Matter of the Review of the Alternative Energy Rider Contained in the Tariffs of Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company* , Financial Audit Report at 9 (August 16, 2012).

[77] Order at 57 (July 18, 2012 ("Specifically, the proposed ESP 3 supports competition and aggregation by avoiding standby charges, supports reliable service through the continuation of the DCR mechanism, supports business owners' energy efficiency efforts, protects at-risk populations, and supports industry in order to support Ohio's effectiveness in the global economy.").

> Further, as to RESA/Direct Energy's argument that extension of the recovery period will artificially lower the Companies' price-to-compare and inhibit shopping, the Commission finds that, as argued by FirstEnergy, CRES providers are not prohibited from seeking to extend the period for recovery of alternative energy compliance costs to lower their own prices. Consequently, the Commission finds that the extension of the recovery period for renewable energy credits is competitively neutral.[78]

The Commission's resolution of this issue is wrong.

It is mistaken to suggest that competitive retail electric service ("CRES") providers can extend the period for recovery of alternative energy costs to lower their own prices. CRES providers cannot extend the collection period and later also collect carrying costs from customers, unlike an EDU. The Commission's solution is not realistic for the CRES providers who would have to absorb any effects of the time value of money associated with a decision to defer collection of costs they are charged from FirstEnergy.

Also, the Utilities did not carry their burden of proof on this issue because they failed to conduct a cost/benefit analysis. The Commission erred by accepting the Utilities' argument on this issue, absent a cost/benefit analysis to support FirstEnergy's claim. The Commission's approval of the proposed modification to the extended AER recovery period will lead to the collection from customers of unwarranted carrying charges. The Commission's approval of this feature of the FirstEnergy proposal will contribute to a result of customers paying unreasonably priced retail electric service. Therefore, the Commission should grant the rehearing request on this issue.

[78] Order at 35 (July 18, 2012).

e. Energy Efficiency and Peak Demand Reduction charges result in customers paying unreasonably priced retail electric service in violation of R.C. 4928.02(A).

i. The Commission erred by deciding that the costs of economic load response and optional load response programs should be collected from all customer classes instead of only from non-residential customers.

The Utilities are requesting that all of their customers –-including residential customers—pay for the costs associated with economic load response ("ELR") and optional load response ("OLR.") OCC and Citizen Power argued that the program costs should be assigned for payment purposes to the respective non-residential rate classes whose customers are eligible for the program.[79] Therefore, energy efficiency ("EE") and peak demand reduction ("PDR") costs for programs for nonresidential customers should not be paid by residential customers.[80] The Commission disagreed with OCC and Citizen Power's position, stating in its Order:

> The Commission agrees with FirstEnergy and Nucor that OCC/CP have failed to support their recommendations that the costs related to Riders ELR and OLR should not be collected from all customers, and no reason is apparent in light of the fact that all customer classes benefit from the rates related to ELR.[81]

The Commission's decision disregards the argument that OCC and Citizen Power made. The problem with the Commission's Order is the disparate cost payment treatment that the PUCO has sanctioned between the large customer load control programs (i.e., ELR and OLR) and the residential load control programs. Large customers are not required to pay for residential EE and PDR programs, such as the Utilities' Direct Load Control Thermostat program. But all customers benefit from the residential load control

[79] OCC Hearing Ex. No. 11, Direct Testimony of Wilson Gonzalez at 41-42 (May 21, 2012).

[80] OCC Hearing Ex. No. 11 Direct Testimony of Wilson Gonzalez at XX (May 21, 2012) citing the March 21, 2012 Opinion and Order in AEP Case No. 11-5568-EL-POR approved similar language on page 11.

[81] Order at 37 (July 18, 2012).

programs just as the Commission decided that all customers benefit from the ELR and OLR programs.[82]

The Commission erred by approving the disparate treatment between non-residential and residential load control programs. The harm to residential customers arises because the ESP 3 proposal requires residential customers to pay all of the costs associated with the Utilities' residential load control programs and to pay certain costs for large customer interruptible PDR programs that are used to meet the Utilities' PDR requirements. The Commission should have established a symmetrical approach in order to mitigate the impact of these FirstEnergy load control programs on residential customers. To remedy the disparity, either residential customers should not have to pay the costs associated with the ELR and OLR programs, or all customers should be required to pay a portion of the costs associated with the residential load control programs. Otherwise, residential customers will be harmed by being required to subsidize the non-residential peak demand response program costs.

The Stipulation, as approved, fails to provide residential customers with reasonably priced retail electric service under R.C. 4928.02. Therefore, the Commission should grant rehearing on this issue.

ii. The Commission erred by finding the Utilities' actions bidding energy efficiency and peak demand response resources into the 2015/2016 base residual auction were reasonable.

The Commission was unwilling to delve into the Utilities' performance in the base residual auction. The Commission's Order states in part that:

> With respect to energy efficiency and participation in base residual auctions, the Commission finds that this proceeding was not opened to investigate the Companies' actions in the 2015/2016

[82] OCC Hearing Ex. No. 11, Direct Testimony of Wilson Gonzalez at 42 (May 21, 2012).

> base residual auction **and that the record does not support a finding that the Companies' actions in preparation for bidding into the 2015/2016 base residual auction were unreasonable**. Sierra Club witness Neme acknowledged that the ownership concerns are legitimate, and no party has claimed that it brought these concerns to FirstEnergy's attention in its energy efficiency collaborative or raised this issue before the Commission in the Companies' most recent program portfolio proceeding. In re FirstEnergy, Case Nos. 09-1947-EL-POR, et al. (Tr. I at 352-353, 363-365). The Commission did open a proceeding to review FirstEnergy's preparations for the 2015/2016 base residual auction, and, in response, the Companies did bid energy efficiency resources into the auction.[83]

The problem is that customers pay for the costs of the energy efficiency and peak demand response programs. To the extent these programs are successful, customers are asked to pay for the Utilities' alleged lost distribution revenues. Where customers are rewarded for the benefits to be derived from these programs is in the reduced demand for capacity, and theoretically, the reduced cost of the capacity, as a result of the energy efficiency or peak shaving brought about by these programs. It is the under-recognition of these capacity resources that the Commission failed to address in its Order in this case.

The Utilities' bid of 36 MWs into the PJM Reliability Pricing Model ("RPM") BRA was inadequate for what should have been a greater consumer benefit under the Ohio statutory framework. Nevertheless, the Utilities try to discredit the more reasonable potential bid of 339 MWs (that should have been bid into the RPM BRA) as calculated by Sierra Club witness Neme, by emphasizing the term "ball park number" in their brief.[84] They also contend that witness Neme cannot possibly come up with a credible estimate of energy efficiency because "he has never been an employee of an investor-owned utility."[85] That witness Neme, when employed by the Vermont Efficiency

[83] Order at 38 (July 18, 2012).

[84] FirstEnergy Initial Brief f at 70 (June 21, 2012).

[85] Id.

Investment Corporation, managed an energy efficiency portfolio and was involved in bidding in energy efficiency into the ISO New England capacity market is surely more relevant than whether he ever worked at a utility.[86]

However, witness Neme's estimate of available FirstEnergy energy efficiency resources -- that should have been bid into the RPM BRA -- is significantly more realistic than the 36 MWs the Utilities actually bid (and that the PUCO accepted). FirstEnergy challenged Mr. Neme's estimates, but a healthy dose of skepticism is appropriate. The Utilities did not make available detailed information regarding their upcoming three-year energy efficiency and peak demand reduction portfolio.[87] In fact, the Utilities filed their portfolio plan on July 31, 2012, and they estimated in said filing that by 2015, the plan will yield 658.3 MWs (or 460.3 MWs minus the large Mercantile projects).[88] The Commission erred by not determining that there was economic harm inflicted on FirstEnergy's customers (estimated at over $600 million[89]) by their not bidding a reasonable amount of energy efficiency into the RPM BRA. Therefore, the Commission should grant rehearing.[90]

f. The Commission erred in its treatment of the lost distribution revenues that customers pay the Utilities, because the Order is not supported by the facts in the record and will lead to the collection of unreasonably priced retail electric service.

By approving the Utilities' proposal, the Commission has not resolved the lost distribution revenue issue, but rather the PUCO has just perpetuated the problem into the future. This problem is not minor as OCC estimates that the Company will collect from

[86] Tr. Vol. I (Neme) at 344 (June 4, 2012).

[87] OCC Hearing Ex. No. 11, Direct Testimony of Wilson Gonzalez at 4 (May 21, 2012).

[88] Case No. 12-2190-EL-POR. See attached hereto as Attachment 1.

[89] Sierra Club Hearing Ex. No. 5, Direct Testimony of Christopher Neme at 3 (May 21, 2012) at 15.

[90] Id. at 3.

residential customers over $91 million during the terms of ESP 2 and ESP 3, not the $11.1 million estimated by the Company for all customers in response to OCC Set 1-INT-1 Attachment 1.[91]

If the lost revenue calculation is not capped by either a dollar amount or a time period, the balances -- that customers will be asked to pay -- can grow quite large. The Commission found that the lost distribution revenues are capped by the term of the ESP 3. The PUCO's decision impose a true cap on lost distribution revenues. The Commission states:

> Further, in contrast to OCC/CP's assertion, the provision in the Stipulation is not open-ended but clearly states that the collection of lost distribution revenues by the Companies after May 31, 2016, is not addressed or resolved by the Stipulation. Thus, as of June 1, 2016, the Commission will have the opportunity to revisit the lost distribution revenue collection mechanism.[92]

The Commission's finding lacks reason. Under its theory, the ESP 2 capped lost distribution revenues by the term of the ESP 2. However, the Commission-imposed ESP 2 cap only held true until the Commission approved the ESP 3, and the lost distribution revenue provision contained therein. Therefore, the perceived lost distribution revenue limitation to the term of the ESP 3 can be eradicated by the Commission's subsequent approval of FirstEnergy's next ESP proposal containing a provision to further extend the Utilities' collection of lost distribution revenue. This logic can lead to the Utilities recovering lost distribution revenues for the lifetime savings of the programs or over $235 million for residential customers.[93]

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[91] See attached OCC Table 1.

[92] Order at 39-40 (July 18, 2012).

[93] See attached OCC Table 1.

Finally, the Commission is comforted by the fact that the Stipulation provides the Commission authority to institute a changed revenue-neutral rate design to address the lost distribution revenue issue. The Commission Order states:

> The Commission also emphasizes that the Stipulation provides that the Commission may, with the Companies' concurrence, institute a changed revenue-neutral rate design, which would also permit the Commission to revisit the lost distribution revenue collection mechanism (Co. Ex. 1, Stip, at 12).[94]

There are two problems with that. First, the Utilities' will claim that such changes to rate design should be revenue-neutral--which means FirstEnergy would not lose any revenues as a result of any rate design change. In that circumstance, there should be no expectation of a potential future cap to this collection, but rather only the potential changing of responsibility among the various customer classes for paying the lost distribution revenues. Second, any change to the rate design must be agreed to by the Utilities, because the Utilities have the ability to dictate the outcome. This provision is in the Utilities' favor, and will not result in FirstEnergy foregoing any lost distribution revenue collection for the benefit of customers.

The concerns of OCC and Citizen Power with regard to lost distribution revenues were supported by the Dissenting Opinion of Commissioner Roberto. Commissioner Roberto stated:

> The ESP 3 provides that during its term, the Companies shall be entitled to receive lost distribution revenue for all energy efficiency and peak demand reduction programs approved by the Commission, except for historic mercantile self-directed projects. In adopting the Companies' energy efficiency portfolio on March 23, 2011, Chairman Snitchler penned a concurring opinion that I joined then and find worth repeating a portion of that now:

[94] Order at 40 (July 18, 2012).

> I strongly encourage the Companies, the other electric utilities in this state, and all other stakeholders to provide the Commission, in both that docket and in future rate proceedings, with proposals for innovative rate designs that promote both energy efficiency as well as the state policies enumerated in Section 4928.02, Revised Code.

> The lost revenue mechanism should be permitted to expire under the terms of the ESP 2. It has out-lived its value to customers.[95]

The Commission should have denied the Utilities' collection of lost distribution revenues in the ESP 3 Case. The Commission should grant rehearing on this issue and protect consumers now from paying for unreasonably priced retail electric service regarding R.C. 4928.02(A).

3. The Commission erred in concluding that the Stipulation did not violate any regulatory principles.

a. The Commission erred in deciding the FirstEnergy ESP 3 proposal is "more favorable in the aggregate as compared to the expected results that would otherwise apply under [an MRO]," in violation of this requirement for customer protection in R.C. 4928.143.

The Utilities failed to demonstrate that the ESP was more favorable in the aggregate than an MRO. The PUCO should have found that this statutory test, as required by R.C. 4928.143, was not met. And this failure to meet the statutory test also is a violation of the third prong of the Commission's three-part test for approving stipulations, i.e., whether the settlement package violates any important regulatory principle or practice. The Commission, in finding the ESP to be more favorable in the aggregate than an MRO, dismissed this argument. The Commission stated in its Order:

> The Commission also notes that our finding in this section that the ESP 3 is more favorable in the aggregate than the expected results that would otherwise apply under an MRO also resolves the

[95] Order, Dissenting Opinion of Commissioner Roberto at 6 (July 18, 2012).

> arguments by several parties that the settlement package violates important regulatory principles by failing the ESP v. MRO test.[96]

This decision is in error and the Commission should grant rehearing on this issue.

[96] Order at 48 (July 18, 2012).

b. The Commission erred in its approval of the SEET calculation included in the FirstEnergy proposal because the order conflicts with a previous Commission determination, is not supported by the facts in the record and therefore violates R.C. 4903.09 that requires PUCO opinions based upon findings of fact.

OCC and Citizen Power argued that the reported financial results (such as net income) should be used in calculating FirstEnergy's return on equity ("ROE") for the purpose of the significantly excessive earnings test ("SEET").[97] The SEET is a fundamental customer protection -- against customers paying too much to electric utilities -- in the law resulting from Senate Bill 221. But this Order protects the Utilities, and not customers as intended in the law.

Specifically it was argued, in opposition to the FirstEnergy proposal, that deferrals, and the deferred interest income in particular, should be included in the applicable SEET calculation.[98] Paragraph B(3) of the Stipulation (pages 23-24) addresses how the ESP will be treated in regards to the SEET and excludes all deferred carrying charges from the ROE calculation. Specifically, the Stipulation provides that:

> Any charges billed through Rider DCR will be included as revenue in the return on equity calculation for purposes of SEET and will be considered an adjustment eligible for refund. For each year during the period of this ESP, adjustments will be made to exclude the impact: (i) of a reduction in equity resulting from any write-off of goodwill, (ii) **of deferred carrying charges,** and (iii) associated with any additional liability or write-off of regulatory assets due to implementing this ESP 3 or the ESP in Case No. 10-388-EL-SSO. The significantly excessive earnings test applicable to plans greater than three years and set forth in R.C. §4928.143(E) is not applicable to this two-year ESP. (Emphasis added).

The Commission; however rejected OCC's and Citizen Power's proposals to protect consumers on this issue. The Commission stated:

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[97] OCC Hearing Ex. No. 10, Direct Testimony of Dr. Daniel J. Duann at 8-9.

[98] Joint Initial Brief at 44-46 (June 22, 2012).

> We find that the provision of the Stipulation that provides for the exclusion of deferred carrying charges from the SEET does not violate an important regulatory principle or practice. Although the AEP-Ohio SEET Case stands for the principle that deferrals, including deferred carrying charges, generally should not be excluded from the SEET, Section 4928.143(F), Revised Code, specifically requires that consideration "be given to the capital requirements of future committed investments in this state." Rider DCR will recover investments in distribution, subtransmission, and general and intangible plant. Therefore, the Commission finds that, in order to give full effect to this statutory requirement, we may exclude deferred carrying charges from the SEET where, as in the instant proceeding, such deferred carrying charges are related to capital investments in this state and where the Commission has determined that such deferrals benefit ratepayers and the public interest. Accordingly, we find that the Stipulation provision excluding deferred carrying charges from the SEET does not violate an important regulatory principle or practice.[99]

It should be noted that no party, including FirstEnergy, suggested the rationale for exclusion of deferred carrying charges from the SEET calculation was for the purpose of meeting future capital requirements. Therefore, the Commission's decision is void of record support, in violation of Ohio law.[100]

The PUCO is a creature of statute, and as such does not have the authority to act beyond the authority provided under Ohio statutes.[101] Ohio law requires the Commission to base its decision on findings of fact from the record in the proceeding. R.C. 4903.09 states:

> In all contested cases heard by the public utilities commission, a complete record of all of the proceedings shall be made, including a transcript of all testimony and of all exhibits, and the commission shall file, with the records of such cases, findings of fact and written opinions setting forth the reasons prompting the decisions arrived at, based upon said findings of fact.

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[99] Order at 48 (July 18, 2012).

[100] R.C. 4903.09.

[101] See, e.g., *Canton Storage and Transfer Co. v. Public Util. Comm.* (1995), 72 Ohio St.3d 1, 5, 647 N.E.2d 136.

The Commission's decision to approve a Stipulation provision that violates Commission precedent is unreasonable. First, the Commission's decision is not supported by the record from this case. Second, such treatment is contrary to the Commission's holding on this subject. The Commission has ruled that deferrals should not be excluded from an electric utility's ROE for the purposes of the SEET.[102] For these reasons, the Commission should grant rehearing on this issue.

B. The Commission erred in deciding the FirstEnergy ESP 3 Proposal is "More Favorable in the Aggregate as Compared to the Expected Results that Would Otherwise Apply Under [an MRO]," in Violation of R.C. 4928.143(C)(1).

Ohio law requires that when the Commission evaluates the record evidence in this case it must make a determination as to whether, in the aggregate, the ESP is more favorable than the expected outcome from an MRO. The Commission unreasonably determined that FirstEnergy's proposal passed this test.

R.C. 4928.143(C)(1) states:

> The burden of proof in the proceeding shall be on the electric distribution utility. The commission shall issue an order under this division for an initial application under this section not later than one hundred fifty days after the application's filing date and, for any subsequent application by the utility under this section, not later than two hundred seventy-five days after the application's filing date. Subject to division (D) of this section, **the commission by order shall approve or modify and approve an application filed under division (A) of this section if it finds that the electric security plan so approved, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code.** Additionally, if the commission so approves an application that contains a surcharge under division (B)(2)(b) or (c) of this section, the commission shall ensure that the benefits derived for any purpose for which the

[102] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Administration of the Significantly Excessive Earnings Test under Section 4928.143(F), Revised Code, and Rule 4901:1-35-10, Ohio Administrative Code*, Case No. 10-1261-EL-UNC, January 11, 2011 Opinion and Order at 31.

> surcharge is established are reserved and made available to those that bear the surcharge. Otherwise, the commission by order shall disapprove the application. (Emphasis added).

The Commission analyzed both the quantitative and qualitative factors in reaching its conclusion.[103] The Commission's decision, however, is wrong in the following respects.

1. The Commission erred in finding that the ESP is more favorable in the aggregate for customers than an MRO under a quantitative analysis.

The Commission, in reviewing the quantitative factors, concluded that the RTEP costs that will not be recovered from customers should not be reflected as a benefit of the ESP 3. This decision is correct and consistent with arguments made by OCC, Citizen Power, Staff, AEP Retail, NOPEC and NOAC.[104] The Commission stated:

> Although the Companies' witness Ridmann testified that a credit reflecting the estimated RTEP costs that will not be recovered from customers should be reflected as a quantitative benefit of the ESP 3, the Commission agrees with Staff witness Fortney, OCC/CP, NOPEC/NOAC, and AEP Retail that the benefit of this credit was a result of the Commission's decision in the ESP 2 Case and cannot be considered a benefit of the ESP 3 to be reflected in the ESP v. MRO analysis.[105]

The only other quantitative factor that the Commission considered in its review of FirstEnergy's proposal was the treatment of Rider DCR costs under an ESP and an MRO. In concluding that the ESP 3 was more favorable in the aggregate than an MRO, one aspect of that conclusion required the Commission to determine that the Rider DCR costs and costs to be recovered through distribution rate filings, under an MRO scenario, would be a wash.[106] OCC and Citizen Power take exception to the Commission's treatment of Rider DCR and other quantitative benefits as discussed below.

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[103] Order at 55-57 (July 18, 2012).

[104] Order at 55 (July 18, 2012).

[105] Order at 55 (July 18, 2012).

[106] Order at 55-56 (July 18, 2012).

a. The Commission erred by concluding that the costs of Rider DCR and costs of a distribution rate case are a wash for customers.

The Commission unreasonably decided that the costs of Rider DCR and costs of a distribution rate case would be a wash. The Commission in its Order stated:

> Nevertheless, the Commission also notes that Staff witness Fortney testified that costs to consumers of Rider DCR, which are included in FirstEnergy witness Ridmann's ESP analysis, and the costs of a distribution rate case, which are included in FirstEnergy witness Ridmann's MRO analysis, would simply be a wash (Staff Ex. 3 at 4-5). The Commission agrees with Staff witness Fortney that these costs should be considered substantially equal and removed from the ESP v. MRO analysis. Upon the removal of these costs, as well as the RTEP credit, the Commission finds that, quantitatively, the ESP 3 is better in the aggregate than an MRO by $21.4 million (Staff Ex. 3 at 5).[107]

There are several problems for customers with the Commission's conclusion.

First, $405 million to be collected through Rider DCR and projected distribution base rate case rate relief during the term of the ESP 3 are not a wash. According to the Utilities' own testimony, Rider DCR contained in the Stipulation is less beneficial to customers (i.e., more costly to customers) than if the Utilities sought to increase rates through a fully litigated distribution rate case.[108] Utilities' witness Ridmann's WRR Attachment 1 lists collection from customers of $405.0 million over two years through Rider DCR whereas the same attachment lists the collection of $376.0 million if FirstEnergy filed a separate distribution rate case. According to witness Ridmann, the $29.0 million net cost attributed to this element of the ESP in comparison to the MRO is

[107] Order at 55-56 (July 18, 2012).

[108] FirstEnergy Hearing Ex. No. 3, Direct Testimony of William Ridmann at WRR-1 (April 13, 2012).

due to the lag in distribution cost recovery because of two assumed distribution rate cases with dates certain of August 2013 and 2014, respectively.[109]

As OCC witness Gonzalez pointed out in his direct testimony, this is a conservative estimate of savings attributed to the result of an MRO, as a distribution rate case would afford all parties and the PUCO an extensive period to review any rate increase request, including inquiries in discovery, the consideration of expert testimony, and the presentation of argument by all affected persons to assure that the resulting distribution rates approved by the Commission are just and reasonable.[110] In the past, such a deliberative process -- under the comparatively strict statutory formula for rate cases in R.C. 4909.15 -- has most often led to a reduction of the Utilities' original rate increase request. The distribution rate case filed in 2007 -- the first in a decade for each company -- requested $340 million in annual rate increases. The Commission awarded just $137 million in annual rate increases.[111] And even that increase included amounts not normally awarded in rate cases according to standard regulatory principles and practices.[112]

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[109] FirstEnergy Hearing Ex. No. 3, Direct Testimony of William Ridmann at 18 (April 13, 2012). Both Companies' witness Ridmann in his Supplemental Testimony (page 7) and Staff witness Fortney in his Prefiled Testimony (page 5) cite the Commission's December 14, 2011 Opinion and Order in the AEP ESP cases (11-346 and 11-348) to dismiss the regulatory lag dollar impacts in Attachment WRR-1 to FirstEnergy Hearing Ex. No. 3. They fail to mention, however, that the Commission rescinded that order in its February 23, 2012 Entry on Rehearing where the Commission stated (on page 12), "[t]hus, we find that the Stipulation must be rejected and the application, as modified by the Stipulation, must be disapproved."

[110] R.C. 4909.15. See also Tr. Vol. II at 265 (Fortney) (June 5, 2012) (In this respect, witness Fortney personally agrees with witness Gonzalez regarding rate cases. "I like rate cases. I believe that that's what the Commission staff, especially the utility department of the Commission staff, does best.").

[111] *In re FirstEnergy 2007 Distribution Rate Case*, Case No. 07-551-EL-AIR, Order at 48, paragraph (23) (January 21, 2009).

[112] OCC Hearing Ex. No. 11, Direct Testimony of Wilson Gonzalez at 22-23 (May 21, 2012) citing *In re FirstEnergy RCP Case*, Case No. 05-1125-EL-ATA, Opinion and Order at 9 (January 4, 2006). The 05-1125 Order stated:

> [W]e find that *exigent circumstances exist* to deviate in a controlled way from the above stated public utility regulatory principles. * * * We are mindful that such deferrals must be scrutinized to assure that the costs to be deferred are reasonable, appropriately incurred, clearly and directly related to specifically necessary infrastructure

In addition, to suggest, as the PUCO Staff has done, that "in the long run"[113] the Utilities would recover an equivalent of the same costs under the DCR or through distribution rate proceedings, is disingenuous. The ESP 3 term is for two years. The DCR Rider caps provide the Utilities with the opportunity to recover from customers $405 million over that two-year period. The ESP versus the MRO test is not an "over the long run" analysis, and Mr. Ridmann's direct testimony most accurately makes the point that the quantitative assessment of the DCR is that it is detrimental to FirstEnergy's customers. The DCR significantly contributes to the determination that the ESP **is not** more favorable in the aggregate than an MRO, and the Commission should have rejected or modified the Stipulation in this case.

Finally, the Commission is inconsistent in its analysis. In the quantitative analysis, the Commission relies on a mistaken comparison that "these costs [Rider DCR and the authorized revenue requirement from a hypothetical distribution rate case] should be considered substantially equal * * *."[114] In the qualitative analysis, the Commission turns around and considers the "continuation of the distribution rate increase stay-out" as a benefit of the FirstEnergy proposal. If the $405 million cost of Rider DCR is considered equal to a distribution rate case, then that conclusion should prevent the

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> improvements and reliability needs of the Companies, and in excess of expense amounts already included in the rate structures of each of the Companies. We will approve the deferral concept in this case premised upon the understanding that the expenses related to infrastructure improvement and the increased expenses for maintenance of infrastructure and reliability will yield necessary improvements that otherwise would have been realized, for company financial reasons, over a much longer period of time.

(Emphasis added.) This 2006 Order resulted in the increased distribution rates above those that would have otherwise been approved in the 2007 distribution rate case. *In re FirstEnergy 2007 Distribution Rate Case*, Case No. 07-551-EL-AIR, Order, at 11 (January 21, 2009). No claim of "exigent circumstances" has been made that would provide similar increases in a newly filed rate case.

[113] Staff Hearing Ex. No. 3, Direct Testimony of Robert Fortney at 5 (May 7, 2012).

[114] Order at 56 (July 18, 2012).

Commission from finding a FirstEnergy is agreeing to distribution rate case stay-out. The Commission has unreasonably sought to extract value from Rider DCR in both its quantitative and qualitative analysis of the Utilities' proposal.

The Commission has unreasonably concluded that an ESP is more favorable in the aggregate than the expected results under an MRO on the basis of its removal of the RTEP issue from consideration and considering Rider DCR and distribution rate relief a wash.[115] The Commission concluded that the ESP was more favorable by 21.4 million,[116] which is comprised by the PIPP discount ($10.4 million), fuel fund contributions ($9.0 million) and economic development contributions ($2.0 million).[117] The Commission erred by failing to discuss the relative value of any of these components that led to the Commission's conclusion. OCC and Citizen Power on brief argued why these components should not be considered benefits in a quantitative analysis in the ESP versus MRO test, and the rationale supporting OCC and Citizen Power's position is discussed below.

b. The Commission erred by concluding that the PIPP auction benefit supports the ESP over an MRO, in violation of state policy pursuant to R.C. 4928.02.

The Stipulation provides for separate treatment of PIPP customers by carving out their load and sole-sourcing their generation supply through a contract with FES at a 6 percent discount from the price to compare for these customers.[118] The Commission has considered this a benefit of the ESP. The Commission stated:

> Additionally, the Commission notes in response to OCC/CP's arguments that the six percent discount for PIPP customers is not a

[115] Order at 55-56 (July 18, 2012).

[116] Order at 56 (July 18, 2012).

[117] FirstEnergy Hearing Ex. No. 3, Direct Testimony of William Ridmann at WRR-1 (April 13, 2012).

[118] Stipulation at 9-10 (April 13, 2012).

> benefit and that FES should not have been given the sole opportunity to bid on this load, that the Commission previously rejected these arguments in the ESP 2 Case. ESP 2 Case, Opinion and Order (Aug. 25, 2010) at 33. Further, as in the ESP 2 Case, the Commission notes that ODOD continues to retain its authority to competitively shop the aggregated PIPP load if a better price can be obtained. Section 4928.54, Revised Code. Thus, as in the ESP 2, the six percent discount to be provided to PIPP customers represents the minimum discount during the proposed ESP 3, and a better price may be obtained by ODOD through a competitive bid.[119]

This conclusion is wrong.

First, consideration of this issue in the ESP 2 does not pass muster. In the ESP 2 Case, OCC was the only entity making this argument, and was criticized by the Commission for not having any evidence that CRES providers would be interested in serving this load. However, in this case, AEP Retail,[120] IGS, RESA and Direct Energy have indicated an interest in serving the PIPP load.[121] That is evidence that was not on the record in the ESP 2 Case.

In addition, the Commission has fallen back on its argument that ODOD under the law can conduct a competitive bid to serve the PIPP load. However, in her dissenting opinion, Commission Roberto makes a compelling argument against the majority's position on this issue. Commissioner Roberto states:

> The majority notes that the Ohio Department of Development is authorized to bid out this load – as it has been for more than a decade but has not exercised this authority. Relying on the Department of Development to inject competition when the remainder of the load is going to auction is nonsensical. This solution adds a layer of complexity on an agency which has no reason to have expertise in running electricity auctions. Contracting with an affiliated company for an un-bid contract to

[119] Order at 56 (July 18, 2012).

[120] AEP Retail Initial Brief at 9-11 (June 22, 2012).

[121] OCC Hearing Ex. No. 11, Direct Testimony of Wilson Gonzalez at Attachment 3 (May 21, 2012).

> serve PIPP customers provides ambiguous benefits to ratepayers, is not in the public interest, and undermines market development.

While no party has disputed that ODOD has the authority under the law to serve this load though a competitive bid, in reality the likelihood that ODOD would exercise its authority is extremely remote. Therefore, it was unreasonable for the Commission to rely on the ODOD authority to justify the Utilities' actions in this case -- entering into an un-bid bilateral contract with its affiliate to serve the PIPP load.

The PIPP provision of the Stipulation also violates the state policies established in R.C. 4928.02. The favoritism shown to FirstEnergy's affiliate under the Stipulation fails to ensure a diversity of electric suppliers.[122] This particular Stipulation provision also fails to encourage market access for cost effective supply. [123] And the continuation of this same provision from the ESP 2 Case hinders the emergence of competitive electricity markets.[124] It also raises concerns with regard to market power because other providers are denied the opportunity to compete for the load because the affiliate has been given the load through an awarded un-bid contract.[125]

Finally, one attribute that the ESP 3 Case has over the ESP 2 Case is time. This point was made by RESA and Direct Energy in their Initial Brief. RESA and Direct Energy stated:

> Thus, FirstEnergy, following a Commission decision in this case, has plenty of time to conduct a simple RFP asking if any supplier was willing to contract for more than a 6% discount. An RFP would establish a true, proven worth of the exclusive contract for the PIPP load. The proposed contract between FirstEnergy and its affiliate cannot be considered an arms-length negotiation.[126]

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[122] R.C. 4928.02(C).

[123] R.C. 4928.02(D).

[124] R.C. 4928.02 (G).

[125] R.C. 4928.02 (I).

[126] RESA and Direct Energy Initial Brief at 7 (June 22, 2012).

Because the delivery of the PIPP service is not slated to begin until June 1, 2014, there was ample time for the Utilities to conduct a competitive bid to serve the PIPP load and determine if the speculative benefit relied on by the Commission could be justified.[127] The Commission failed to use the available time to competitively bid the PIPP load to ascertain whether the discount derived from FirstEnergy's affiliate is the best offer available for serving those customers.

For all the above reasons, the Commission erred by finding the PIPP provision of the Stipulation contributed to concluding that the ESP 3 is more favorable in the aggregate than an MRO. Therefore, the Commission should grant rehearing.

c. The Commission erred by not recognizing the low-income fuel funds are an indirect benefit for FirstEnergy, and should have been excluded as a quantitative benefit of the ESP 3.

The Commission Order failed to address this issue in analysis of the ESP 3 versus MRO test. In our Joint Brief, OCC and Citizen Power challenged the inclusion of fuel funds in the quantitative calculation because, except for the administrative fees absorbed from the Utilities' contribution, the remaining fuel fund (90%) is actually an indirect benefit to the Utilities.[128] OCC and Citizen Power pointed out in the Joint Initial Brief that any consideration of the Utilities' contribution to a fuel fund as a quantitative or qualitative benefit must be diluted because of the indirect benefit the Utilities derived from receiving fuel fund dollars back for low-income bill payment assistance.[129] Therefore, the Commission should not consider the Utilities' contribution to a fuel fund as a quantitative or qualitative benefit of the ESP 3 Case.

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[127] Order at 56 (July 18, 2012).

[128] Joint Initial Brief at 56-57 (June 22, 2012) ($4,050,000 of the annual fuel fund contribution of $4,500,000 should be considered an indirect benefit for FirstEnergy.).

[129] Tr. Vol. I (Ridmann) at 57 (June 4, 2012).

For all the reasons argued above, the quantitative analysis demonstrates that, in the aggregate, the ESP **is not** more favorable than an MRO. Therefore, the Commission should grant OCC's and Citizen Power's Application for Rehearing in this case.

2. The Commission erred by concluding that the ESP is more favorable in the aggregate for customers than an MRO under a qualitative analysis.

In concluding that the Utilities' proposal is more favorable in the aggregate than the expected results under an MRO, the Commission relied on several qualitative factors. The statutory test is supposed to be a protection for customers. In its use of qualitative factors to justify an electric security plan, the PUCO has nullified that protection. The Commission stated:

> Further, the Commission finds that the proposed ESP 3 is more favorable qualitatively than an MRO. The Commission finds that the additional qualitative benefits of an ESP, which would not be provided for in an MRO, include [a] modification of the bid schedule to provide for a three-year product in order to capture current lower market-based generation prices and blend them with potentially higher prices in order to provide rate stability; [b] continuation of the distribution rate increase "stay-out" for an additional two years to provide rate certainty, predictability, and stability for customers; [c] continuation of multiple rate options and programs to preserve and enhance rate options for various customers provided in the ESP 2; and * * *. [d] Further, the Commission finds that the additional benefits provided via the Stipulation to interruptible industrial customers, schools, and municipalities, [e] as well as shareholder funding for assistance to low-income customers, also make the proposed ESP 3 more favorable qualitatively than an MRO.[130]

OCC and Citizen Power have argued that the qualitative benefits are illusory. These items should not have been considered benefits when the Commission analyzed the benefits of the ESP 3 compared to an MRO. Therefore, the Commission erred by relying

[130] Order at 56 (July 18, 2012).

on the qualitative benefits of the ESP 3 in determining it to be more favorable in the aggregate than an MRO.

a. It was unreasonable for the Commission to modify the bid schedule for a three-year product in order to capture current lower generation prices and blend those with potentially higher prices in order to provide rate stability as a purported benefit for customers.

As argued supra, the three-year auction product is not a qualitative benefit to FirstEnergy's customers, and should not have been included as a qualitative benefit by the Commission as part of the ESP versus MRO test. This position was also supported by Commissioner Roberto in her dissenting opinion.[131] The Commission should not have considered the three-year auction product a benefit of the ESP, and should therefore grant rehearing.

b. In consideration of the $405 million delivery capital rider spending authorized in the ESP 3, it was unreasonable for the Commission to consider the distribution rate increase "stay-out" for an additional two years of the ESP 3 to provide rate certainty, predictability, and stability as a purported benefit for customers.

As argued supra, under the Stipulation FirstEnergy will be allowed to collect costs associated with investments in enhanced distribution service through Rider DCR up to $195 million and $210 million in years one and two of the ESP 3, respectively, or $405 million in total.[132] Customers will see an increase in collections through the Rider DCR between ESP 2 and ESP 3 of up to $45 million.[133] The Commission determined that the Rider DCR Costs and the anticipated result under distribution rate cases to be

[131] Order, Dissenting Opinion of Commissioner Cheryl L. Roberto at 1-2 (July 18, 2012).

[132] OCC Hearing Ex. No. 4.

[133] OCC Hearing Ex. No. 4.

"substantially equal."[134] In light of the PUCO authorized $405 million in DCR spending during the term of the ESP 3, it was unreasonable for the Commission to endorse this misleading characterization that there is a benefit of the Stipulation in a distribution rate freeze during the ESP 3. Therefore, the Commission erred by considering a distribution rate case "stay-out" as a qualitative benefit to consumers when comparing the ESP to an MRO.

In order for the Commission to have found a rate case "stay-out," to be a benefit of the ESP 3, the Commission should have denied the Utilities cost recovery through Rider DCR, and instead, the Commission should have instructed the Utilities to file for rate relief if it was justified. This position was also supported by Commissioner Roberto who stated:

> Finally, the Companies have a remedy for cost recovery for prudent distribution system investments in the form of a distribution rate case. If the Companies require additional resources, they may file requests under traditional rate-making processes.[135]

As argued previously, the rate case process -- with its more defined formula -- is more favorable for customers than allowing distribution rate increases in ESP cases., The Commission erred by including the rate case "stay out" as a qualitative benefit of the ESP 3, and therefore should grant rehearing on this issue.

c. The Commission erred by deciding that the preservation of the economic load response rate was a qualitative benefit of the ESP proposal for customers.

The Commission unreasonably decided that preservation of the ELR rate was a qualitative benefit of the ESP 3.[136] As argued supra, the ELR and OLR rate options

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[134] Order at 55-56 (July 18, 2012).

[135] Order at Dissenting Opinion of Commissioner Cheryl L. Roberto page 5 (July 18, 2012).

[136] Order at 56 (July 18, 2012).

should not be considered a benefit for residential customers because of the disparate cost payment treatment. Furthermore, the Commission's Order in this case lacks compelling support.[137] A review of Mr. Ridmann's direct testimony, will demonstrate that there was no substantive discussion of this issue and the substance of the qualitative benefit being touted. An argument exists that ELR rate option is not exclusive to an ESP. Under an MRO there could be rate offers incentivizing customers to reduce their peak load consumption. Therefore, it was inappropriate for the Commission to consider the preservation of the ELR rate option as a qualitative benefit as part of an ESP versus MRO analysis.

d. It was unreasonable for the Commission to consider the additional benefits provided via the Stipulation to interruptible industrial customers, schools, and municipalities as a benefit of the ESP.

As stated previously, customers pay for the costs of the energy efficiency and peak demand response programs (e.g. interruptible programs). To the extent interruptible programs are successful, customers are asked to pay for the Utilities' alleged lost distribution revenues. Where customers are rewarded for the benefits to be derived from these programs is in the reduced demand for capacity, and theoretically, the reduced cost of the capacity, as a result of the energy efficiency or peak shaving brought about by these programs. However, the Utilities bid only36 MW of energy efficiency resources into the PJM 2015/16 BRA auction on May 7, 2012. This was below the 65 MW identified by the Utilities that could have been bid. And significantly below the 339 MW that the Sierra Club stated the Utilities should have bid into the auction to protect customers' rates. In fact, the Utilities filed their portfolio plan on July 31, 2012, and

[137] The Commission Order at 56 cites Staff Ex. No. 3 (Mr. Fortney's direct testimony) at 3-4, Mr. Fortney's testimony at 3-4 merely references Companies' witness Ridmann's testimony without citation. At Mr. Ridmann's testimony at 5 he discusses the ELR rate with regards to the preservation of certain rate options.

they estimated in said filing that by 2015, the plan will yield 658.3 MWs (or 460.3 MWs minus the large Mercantile projects).[138]

Sierra Club witness Neme estimated a lost revenue opportunity for not bidding the additional energy efficiency at from $22-$39 million (meaning customers will pay too much).[139] Witness Neme has also estimated the additional capacity costs for the ATSI zone of not bidding the incremental energy efficiency at the base residual auction at $600 million--of which a significant portion of that cost will be borne by the Utilities' customers.[140] Because of the failure of the Utilities to adequately bid an appropriate level of energy efficiency resources into the base residual auction, the Commission should have rejected the interruptible program as a qualitative benefit of the ESP.

e. The Commission erred by concluding shareholder funding for assistance to low-income customers should also be recognized as a qualitative benefit of the ESP 3.

The Commission found the shareholder funding for bill payment assistance to be a qualitative benefit of the ESP 3. The Stipulation provides $9 million during the term of the ESP 3 for funding a fuel fund to assist low-income customers[141]

But including this funding as a benefit fails to recognize the indirect benefit the Utilities receive from the fuel fund contribution. It was argued by OCC and Citizen Power that this funding is predominantly a benefit to the Utilities because the assistance means that the Utilities will receive the assistance back in the form of revenues by enabling bill payments. Therefore, it should have been excluded from the Commission's qualitative analysis.

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[138] Case No. 12-2190-EL-POR. See attached OCC Table 1.

[139] Sierra Club Hearing Ex. No. 5, Direct Testimony of Christopher Neme at 13 (May 21, 2012).

[140] *Id.* at 15.

[141] Stipulation at 40-41 (April 13, 2012).

For all these reasons, the Commission should not have concluded that the ESP, in the aggregate, was more favorable than the anticipated results of an MRO under the qualitative analysis. The PUCO should grant rehearing.

C. The Commission Erred by Approving the Utilities' Unjust and Unreasonable Standard Service Offer Proposal in Violation of R.C. 4905.22

The PUCO is a creature of statute, and as such does not have the authority to act beyond the authority provided under Ohio law.[142] Ohio law requires the Commission to assure that public utilities' charges for service are just and reasonable. R.C. 4905.22 states:

> Every public utility shall furnish necessary and adequate service and facilities, and every public utility shall furnish and provide with respect to its business such instrumentalities and facilities, as are adequate and in all respects just and reasonable. **All charges made or demanded for any service rendered, or to be rendered, shall be just, reasonable**, and not more than the charges allowed by law or by order of the public utilities commission, and no unjust or unreasonable charge shall be made or demanded for, or in connection with, any service, or in excess of that allowed by law or by order of the commission. (Emphasis added).

By approving the ESP 3, the Commission has violated Ohio law and authorized FirstEnergy to implement charges that are unjust and unreasonable.

The Utilities have promoted their ESP 3 Case as an "extension" of their ESP 2.[143] This, however, is a mischaracterization of the Stipulation's affect. The Utilities' proposal not only extends certain provisions of the ESP 2, but the proposal also modifies the ESP 2 through the laddering provisions of the three-year auction process that will blend the lower generation costs from the last year of ESP 2 (June 1, 2013 through May 31, 2014) and the fist year of ESP 3 (June 1, 2014 through May 31, 2015) with the higher anticipated generation prices from year 2 of the ESP 3 (June 1, 2015 through May 31,

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[142] See, e.g., *Canton Storage and Transfer Co. v. Public Util. Comm.* (1995), 72 Ohio St.3d 1, 5, 647 N.E.2d 136.

[143] Application at 1 (April 13, 2012).

2016). As argued supra, there is harm to FirstEnergy's SSO customers during the ESP 2 case as a result of the Commission's approval of the Utilities' ESP 3.

AEP Retail argued that these planned nominally lower rates from the ESP 2 period will be replaced by nominally higher rates that will be blended with the new higher costs from the ESP 3 period. It is unjust and unreasonable for the Commission to alter the benefit of the bargain from the ESP 2 Case, and replace it with higher generation rates from the ESP 3 period. Moreover, under R.C. Chapter 4903, the process for modifying the ESP 2 would have included a timely filed application for rehearing and, barring a change on rehearing, an appeal to the Supreme Court of Ohio. That didn't happen as part of how the PUCO has now (unlawfully) changed its ESP 2 Order.

Furthermore, the higher costs must be paid for up front when the ESP 2 rates are blended with the higher rates from the 2015/2016 year.[144] Commissioner Roberto made a similar point in her dissenting opinion by stating:

> To achieve any benefit, we must assume that a bidder for a three-year product will capture all of the benefit of the prices provided by the one-year product and offer them back to the customers and, in addition, offer a lower price than they would otherwise for the product covering years two and three. There is nothing in the record to suggest that this will be true. In fact, the only suggested benefit is averaging the lower prices (which customers would already receive) with the anticipated higher prices – in essence simply paying ahead for the ability to experience less of a price change on June 1, 2014.[145]

Not only are the generation costs to consumers uncertain going forward in this case, but the laddering of a three-year auction product that blends the lower generation rates from 2013-2015 harms SSO customers under FirstEnergy's ESP 2 Case. This result is unjust

[144] AEP Retail Reply Brief at 9 (June 22, 2012).

[145] Order, Dissenting Opinion of Commissioner Cheryl L. Roberto at 2 (July 18, 2012).

and unreasonable. Therefore, the Commission should grant OCC's and Citizen Power's Application for Rehearing.

D. The Commission erred by approving FirstEnergy's corporate separation plan as part of the ESP 3 Stipulation—a result that does not provide Ohioans with the intended result under law of promoting fair electric competition.

The Commission erred by approving FirstEnergy's corporate separation plan as part of the ESP 3 Proposal. OCC shares the concerns of Commissioner Roberto that "the Commission should not be eager to re-approve and extend the Companies' current corporate separation plan without a more deliberate review."[146]

Corporate separation is essential for fair competition. R.C. 4928.17, in numerous subsections, refers to the "competitive advantage and abuse of market" that the law seeks to prevent through the filing of a corporate separation plan. In subsection (A)(2), the Commission is tasked with evaluating a corporate separation plan to determine if it "satisfies the public interest in preventing unfair competitive advantage and preventing the abuse of market power." Additionally, the Commission must determine under subsection (A)(3) whether the plan is sufficient to ensure that the utility will not extend any "undue preference or advantage" to its affiliate. Section (B) of the statute requires the PUCO to adopt rules regarding corporate separation that include limitations on affiliate practices "to prevent unfair competitive advantage."

R.C. 4928.02(H) also conveys this theme, but uses slightly different terminology. It establishes, as one of the state policies, ensuring effective competition by avoiding anticompetitive subsidies flowing from a non-competitive retail service to a competitive retail service. This is one of the state policies the PUCO must ensure is effectuated under R.C. 4928.06.

[146] July 18 Order, Dissenting Opinion at 6.

The corporate separation plan that the Commission is again approving in this case was filed on June 1, 2009, in Case No. 09-462-EL-UNC. To date, FirstEnergy's corporate separation plan has eluded the in-depth review and analysis that the law contemplates. The Commission has never determined that FirstEnergy's corporate separation plan meets the requirements of the law (R.C. 4928.17) as mandated by R.C. 4928.17(C).[147] Instead, FirstEnergy's corporate plan has only been considered based on the criteria for reviewing a settlement in PUCO cases—a three-part standard that gives deference to the package of stipulated terms as opposed to scrutiny to the individual element of corporate separation. The Commission's approval of a corporate separation plan without the review and determination mandated by R.C. 4928.17 is unlawful.

FirstEnergy's corporate separation plan must be reviewed by the Commission now to determine whether that plan is meeting the intent of the statute. OCC presented evidence at hearing that is indicative of the existing plan not satisfying R.C. 4928.17(A)(2) and/or (3).[148] Accordingly, it was unlawful for the Commission to re-approve FirstEnergy's corporate separation plan without determining whether the plan met the requirements of the law mandated in R.C. 4928.17.

As a result and pursuant to R.C. 4928.17(D), the Commission should rehear this issue and reject the approval of FirstEnergy's corporate separation plan. A rehearing should be held to provide OCC, Citizen Power and other interested parties with the

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[147] R.C. 4928.17(C) provides that "The commission shall issue an order approving or modifying and approving a corporate separation plan under this section, to be effective on the date specified in the order, only upon findings that the plan reasonably complies with the requirements of division (A) of this section and will provide for ongoing compliance with the policy specified in section 4928.02 of the Revised Code. However, for good cause shown, the commission may issue an order approving or modifying and approving a corporate separation plan under this section that does not comply with division (A)(1) of this section but complies with such functional separation requirements as the commission authorizes to apply for an interim period prescribed in the order, upon a finding that such alternative plan will provide for ongoing compliance with the policy specified in section 4928.02 of the Revised Code."

[148] *See* Joint Initial Brief by OCC and Citizen Power at pp. 3, 22-24.

opportunity to raise specific objections and propose modifications to the corporate separation plan in order to ensure compliance with R.C. 4928.17 and the Commission's rules—in the interest of fair electric competition for Ohioans.

E. The Commission Erred by Violating the Due Process Rights of the Non-Signatory Parties In This Case.

1. The Commission-approved timeline for this case was inadequate and prejudiced the non-signatory parties in this case.

The Utilities' desire to expedite this case—that affects 1.9 million consumers—through the PUCO's hearing process does not comport with Ohio law. Ohio law establishes 275 days as the period of time for the Commission to review an ESP filing.[149] While the law provides for a 275-day period to review an ESP plan, the procedural schedule in this case allowed only 52 days.[150] In the rush to conclude this proceeding, the Commission denied non-signatory parties their rights for meaningful participation in this proceeding, including their right for ample discovery under R.C. 4905.082. This error unfairly prejudiced the non-signatory parties.

The Commission supported its timeline in this case. The Commission stated: "The time period is not an unusually brief length of time between the filing of a stipulation and the hearing in an SSO proceeding."[151] That is unreasonable. The Commission's statement is made without citation and fails to recognize the resource limitations of certain parties in the case or the fact that other major PUCO cases were

[149] R.C. 4928.143(C)(1).

[150] Entry at 2 (April 19, 2012).

[151] Order at 47 (July 18, 2012).

going on during the same period of time. Those two points were made by Commissioner Roberto in her dissent.[152]

The short timeline did not come close to the time allotted under R.C. 4928.143(C)(1).[153] Allowing just 52 days between the filing of the Application and the commencement of the evidentiary hearing unduly prejudiced the non-signatory parties.

Furthermore, the rationale given by the Utilities for expediting the procedural schedule was not sufficient for the Commission to adhere to FirstEnergy's request for an expedited schedule. This view was shared by Commissioner Roberto who observed:

> [T]he urgency that seemed to accompany this matter seems out of proportion to any real need to act. The ESP 2 is in effect until May 31, 2014. The Commission has up to 275 days after an application is filed to act.[154]

This point is especially true given that the Utilities' primary reason for needing an expedited process – for bidding demand response resources and PJM-qualifying energy efficiency resources into the 2015/2016 PJM Base Residual Auction commencing on May 7, 2012 – was invalidated by the original procedural schedule setting the hearing for May 21, 2012, fifteen days after the auction.

For all the reasons stated above, the non-signatory parties were prejudiced by the expedited procedural schedule in this case. The Commission should thus grant rehearing on this issue.

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[152] Order, Dissenting Opinion of Commissioner Cheryl L. Roberto at 7 (July 18, 2012).

[153] It is noteworthy that parties had just 31 days longer to prepare for the hearing than to brief it.

[154] Order, Dissenting Opinion of Commissioner Cheryl L. Roberto at 7 (July 18, 2012).

2. The Commission's rulings affected intervention in contravention of Ohio Law.

Another deficiency in the procedural schedule relates to intervention. The Commission's finding disregards the concerns raised by OCC and Citizen Power, regarding an open and transparent process where all interested parties can participate.. The Commission stated: "No party was denied intervention, and intervention out of time was granted to a party that missed the deadline to intervene. Entry (May 15, 2012) at 2."[155]

Concomitant with its Application, FirstEnergy filed a motion for waiver of several rules, including Ohio Adm. Code 4901:1-34-06.[156] Section (B) of the rule provides that "[i]nterested persons wishing to participate in the hearing shall file a motion to intervene no later than forty-five days after the issuance of the entry scheduling the hearing, unless ordered otherwise by the commission, legal director, deputy legal director, or attorney examiner." FirstEnergy had asked that interested persons be able to intervene within only **seven days from the filing of the Application**.[157] Given that FirstEnergy requested an expedited ruling,[158] the Attorney Examiner needed to wait seven days before ruling on the waivers, to ensure that there were no objections.[159]

On April 19, 2012 – six days after the Application was filed and the day before responses to the waiver request were due[160] – the Attorney Examiner issued the first procedural Entry essentially granting FirstEnergy's request regarding intervention. The

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[155] Order at 47 (July 18, 2012).

[156] FirstEnergy Motion for Waiver at 5 (April 13, 2012).

[157] *Id.*

[158] *Id.* at 2.

[159] Ohio Adm. Code 4901-1-12(C).

[160] Although the Consumer Advocates and Direct Energy Services, et al. had filed separate memoranda contra the request for waivers before the April 19 Entry was issued, AEP Retail Services made a timely filing opposing the waivers on April 20, 2012, the day after the Entry.

Entry gave interested persons seven days from the date of the Entry – rather than the 45 days provided under the rules – to file a motion to intervene.[161] This unduly short timeframe may have deterred some interested persons from participating in this proceeding.[162]

Further complicating the unduly short time frame authorized by the Commission for parties to intervene, was the lack of notice regarding FirstEnergy's Application. The Utilities requested a waiver from their obligation to provide notice of their Application through newspaper publication.[163] Despite the Utilities' statement they would publish notice as ordered by the Attorney Examiner, the Attorney Examiner granted this waiver request by Entry dated April 25, 2012, and did not order FirstEnergy to publish a newspaper notice as contemplated by Ohio Adm. Code 4901:1-35-04 (B). Notice is a critical component of due process protections, and was summarily dismissed by the Attorney Examiner in this case.

For these reasons, the Commission should grant OCC's and Citizen Power's Application for Rehearing.

3. The Commission erred by taking administrative notice of information from the Utilities' MRO and ESP 2 cases.

After FirstEnergy's initial request for the Commission to take administrative notice of the entire record of the ESP 2 Case, FirstEnergy provided a "List of Documents for Administrative Notice." The list was provided on June 6, 2012 (the third day of the

[161] April 19 Entry at 2.

[162] One party, the Cleveland Municipal Schools, sought and was granted intervention out of time. Entry (May 15, 2012) at 2. This, however, is not an indication that no other party would have sought intervention, since it is not unusual for parties to file motions to intervene in ESP cases 30 or more days after the procedural entry is issued.

[163] Motion for Waiver at 4 (April 13, 2012) ("The Companies will publish a notice for newspaper publication as ordered by the Attorney Examiner(s). However, to the extent more is required to be included with the Application, the Companies herein request a waiver of this rule requirement.").

evidentiary hearing and the final day of the direct case). The list included materials from both the ESP 2 Case and FirstEnergy's MRO Case. The Attorney Examiner granted FirstEnergy's request for administrative notice. As a result, the Commission has taken administrative notice of certain documents from the Utilities' MRO Case (Case No. 09-906-EL-SSO) and from their ESP 2 Case (Case No. 10-388-EL-SSO). The Commission supported the Attorney Examiners' decision in this regard by stating:

> The Commission notes that, with respect to the arguments raised by parties regarding the taking of administrative notice of certain documents, the Supreme Court has held that there is neither an absolute right for nor a prohibition against the Commission's taking administrative notice of facts outside the record in a case. Instead, each case should be resolved on its facts. The Court further held that the Commission may take administrative notice of facts if the complaining parties have had an opportunity to prepare and respond to the evidence and they are not prejudiced by its introduction. Canton Storage at 8. In addition, the Court has held that the Commission may take administrative notice of the record in an earlier proceeding, subject to review on a case by case basis. **Further, parties to the prior proceeding presumably have knowledge of, and an adequate opportunity to explain and rebut, the evidence, and prejudice must be shown before an order of the Commission will be reversed**. Allen v. Pub. Util. Comm., 40 Ohio St.3d 184,185-186,532 N.E.2d 1307 (1988).[164]

However, there are problems with the Commission's decision. The following are parties in this case that were not parties to the Utilities' MRO Case: AEP Retail, Sierra Club, Ohio Power Company, Cleveland Municipal School District, and ELPC. In addition, of the above listed parties AEP Retail, Sierra Club, Ohio Power Company and Cleveland Municipal School District were also not parties to the Utilities' ESP 2 Case. Therefore, it was unreasonable for the Commission to conclude that all parties in this case have knowledge of the prior proceedings.

[164] Order at 19 (July 18, 2012) (Emphasis added).

The Utilities entered this case with the expectation that certain required elements of their case may be met through administrative notice of the ESP 2 proceeding. In their Application, the Utilities stated: "[t]he Utilities further request that the Commission take administrative notice of the evidentiary record in the Utilities current ESP, Case No. 10-388-EL-SSO, and thereby incorporate by reference that record for the purpose of and use in this proceeding."[165]

The PUCO found fault with parties' failure to conduct discovery on the Utilities' administrative notice request. However, the Utilities' opening salvo involved the Commission taking administrative notice of the entire ESP 2 Case docket.[166] When the Attorney Examiners denied that request, FirstEnergy provided a "List of Documents for Administrative Notice" during the hearing and when the hearing was almost concluded. The "List of Documents for Administrative Notice," included: (i) seven specific pages from four separate volumes of transcript testimony from the evidentiary hearing in the ESP 2 Case out of approximately 941 total pages; and (ii) prefiled testimony of three witnesses from the ESP 2 Case who did not even testify in the ESP 3 Case, who were not subject to cross-examination and who otherwise did not participate in the ESP 3 case (Hisham Choueiki, Tamara Turkenton, and John D'Angelo).[167] Two of the witnesses (Choueiki and Turkenton) are on the PUCO staff, and thus are typically considered exempt from discovery under Ohio Adm. Code 4901-1-16(I).

In addition, when the Utilities first provided the list of documents for which administrative notice was being sought, that was the first time FirstEnergy requested that administrative notice be taken of the Utilities' application in the MRO Case (Case No 09-

[165] Application at 5.

[166] Tr. Vol. I at 29 (Price) (June 4, 2012).

[167] Joint Interlocutory Appeal by OCC, NOPEC and NOAC at 5 (June 11, 2012). See also Tr. Vol. III at 10-12 (Kutic) (June 6, 2012).

906-EL-SSO).[168] Under these circumstances, the Commission unreasonably concluded that: "the parties had ample opportunity to explain or rebut the evidence for which FirstEnergy sought administrative notice, * * *."[169] The Utilities' only direct witness was off the stand, at the time the list was offered; therefore, it is unclear how exactly the Commission can conclude that parties had ample time to explain or rebut this evidence.

The Commission has concluded that parties were not prejudiced by the Attorney Examiner's ruling with regard to administrative notice in this case. The Commission stated:

> Further, the Commission finds that the parties have not demonstrated that they were prejudiced by the taking of administrative notice of evidence in the record of the ESP 2 Case or the MRO Case.[170]

The prejudice in this case comes from the totality of the circumstances discussed above, as well as the Attorney Examiners taking administrative notice beyond facts. The Attorney Examiners in this case did not limit administrative notice to facts, but rather extended administrative notice far outside factual boundaries to opinion. At the evidentiary hearing the Attorney Examiner clarified his ruling:

> MS. YOST: Your Honor, in regards to some of the documents that were listed on FE -- what they provided this morning, you spoke of facts in regards to Commission precedent. So that would exclude any opinions that are listed in regards to these –
>
> EXAMINER PRICE: All the documents that are listed we've taken administrative notice, whether it's facts or opinion. I think we -- the rationale that I explained applies equally to facts as -- to opinion as it would to facts.[171]

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[168] Tr. Vol. I at 29.

[169] Order at 20 (July 18, 2012).

[170] Order at 20 (July 18, 2012).

[171] Tr. Vol. III at 171-172 (Price) (June 6, 2012).

Such a ruling was unjust and unlawful.

Since the non-signatory parties did not have knowledge of the documents to be administratively noticed until the close of the evidentiary hearing on June 6, 2012, they had no opportunity to explain and/or rebut such documents. Until the Attorney Examiner took administrative notice on June 6, 2012, there were not any facts administratively noticed, and therefore no opportunity to explain or rebut them existed. And, there was no opportunity granted to the parties after June 6, 2012 to explain or rebut the facts administratively noticed.

The matters that are proper subjects of administrative notice by the PUCO were examined by the Supreme Court of Ohio in *Canton Storage & Transfer Co. v. Public Util. Comm.*:

> The Commission may take administrative notice *facts* if the complaining parties have had an opportunity to prepare and respond to the evidence, and are not prejudiced by its introduction.[172] (Emphasis added).

The *Canton Storage* decision is also consistent with the Ohio Rules of Evidence which states:

> A judicially noticed *fact* must be one not subject to reasonable dispute in that it is either (1) generally known within the territorial jurisdiction of the trial court or (2) capable of accurate and ready determination by resort to sources whose accuracy cannot reasonably be questioned.[173]

However, the Commission did not adhere to prior Commission precedent or Ohio Rules of Evidence in this case. The Commission did not require the Utilities to limit their

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[172] *Canton Storage & Transfer Co. v. Public Util. Comm.* (1995), 72 Ohio St. 3d 1, 9, 647 N.E.2d 136, 144 citing *Motor Service. Co. v. Public Util. Comm.* (1974), 39 Ohio St.2d 5, 68 O.O.2d 3, 313 N.E.2d 803 (emphasis added).

[173] Ohio Evid. R. 201 (B).

request to facts, let alone facts generally known or facts capable of accurate and ready determination. The Commission's administrative notice decision in this case was unlawful and should result in the Commission granting rehearing.

V. CONCLUSION

For all the reasons stated above, the Commission should grant rehearing in this case.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a copy of this *Application for Rehearing* was served on the persons stated below, electronically this 17th day of August, 2012.

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Estimated Megawatts That Could Have Been Bid in by the Ohio FE Companies in 2015/2016 PJM BRA (OCC Attachment 1
And Estimated Lost Revenues in ESP Order

	2013	2014	2015	2016 (6 months)
MegaWatt Potential (1)				
Ohio Edison (MW)	225.8	268.6	302.5	
Cleveland Electric Illuminating (MW)	174.1	204	228.3	
Toledo Edison (MW)	211.9	109.6	127.5	
Totals	611.8	582.2	658.3	
Totals minus Large Mercantile	319.6	393.7	460.3	
Energy Savings Leading to Lost Distribution Revenues* (1)				
Ohio Edison (MWH)	40,613	124,062	206,795	
Cleveland Electric Illuminating (MWH)	18,751	53,819	92,127	
Toledo Edison (MWH)	12,791	42,538	68	
Totals	72,155	220,419	298,990	149,495
Residential Lost Distribution Revenue	$ 4,219,121	$ 10,480,232	$ 17,615,903	$ 8,807,952
Lost Distribution Revenue from 2011-2012 (WRR...	$ 22,200,000	$ 11,100,111	$ 11,100,111	$ 5,550,056
Total Lost Distribution Revenue by Year	$ 26,419,121	$ 21,580,343	$ 28,716,014	$ 14,358,007
Total Lost Distribution Revenue for ESP 2 & ESP 3 Term	$ 91,073,485			

Maximum Lost Distribution Revenues base on Lifetime Savings* (2)	Lifetime Savings
Ohio Edison (MWH)	2,239,692
Cleveland Electric Illuminating (MWH)	1,081,536
Toledo Edison (MWH)	700,663
Totals	4,021,891
Lifetime Lost Distribution Revenues for FE EE/PDR Portfolio	$ 235,287,827
Distribution Rates Used (3)	
OE Distribution Rate (kWh)	0.058148
CEI Distribution Rate (kWh)	0.06069
TE Distribution Rate (kWh)	0.056255

*Only Residential Energy Savings used so lost revenue calculations are conservative.
(1) Attachment A, B, C, Appendix C-3, Table PUCO 2 (Summary of Energy & Demand Savings) in Company Application in Case No. 12-2190-EL-POR
(2) Attachment A, B, C, Appendix C-3, Table PUCO 4 (Program Summaries) in Company Application in Case No. 12-2190-EL-POR
(3) From FE Ohio Operating Companies Residential Tariff Sheets and Residential Charge in DCR Rider.

Attachment 1

ATTACHMENT A

Ohio Edison Company

Energy Efficiency & Peak Demand Reduction Program Portfolio

(For the Period January 1, 2013 through December 31, 2015)

July 31, 2012

Docket No. 12-2190-EL-POR

Appendix C-3

PUCO 2: Summary of Portfolio Energy and Demand Savings

Ohio Edison Summary of Portfolio Energy and Demand Savings - Pro rata						
	Program Year 2013		Program Year 2014		Program Year 2015	
MWh Saved for Consumption Reductions kW Saved for Peak Load Reductions	MWh Saved	kW Saved	MWh Saved	kW Saved	MWh Saved	kW Saved
Residential Sector (inclusive of Low- Income) - Cumulative Projected Portfolio Savings	40,613	48,708	124,062	61,536	206,795	73,986
Small Enterprise - Cumulative Projected Portfolio Savings	29,994	44,442	105,656	63,859	184,642	81,934
Mercantile - Cumulative Projected Portfolio Savings	40,166	39,450	68,705	44,017	88,789	47,230
Mercantile-Utility (Large Enterprise)- Cumulative Projected Portfolio Savings	10,050	93,165	29,631	99,140	49,610	99,259
Government Sector - Cumulative Projected Portfolio Savings	75	18	251	36	438	54
Transmission & Distribution	0	0	0	0	0	0
Portfolio Plan Total - Cumulative Projected Savings	120,898	225,783	328,307	268,587	530,273	302,463

Appendix C-3

PUCO 4: Program Summaries

Ohio Edison Program Summaries								
	EE Program (check box)	PDR Program (check box)	Program Name	Program Market	Program Two Sentence Summary	Net Lifetime MWh Savings	Net Peak Demand kW Savings	Percentage of Portfolio and Total Lifetime MWh savings %
Residential Portfolio Programs (Inclusive of Low Income)		X	Direct Load Control Program	RES	The program consists of a customer having their central air conditioning compressor cycled during summer peak periods.	-	24,669	0.0%
	X		Appliance Turn-In Program	RES	The program consists of customers receiving a rebate for turning in a working refrigerator, freezer, or room air conditioner.	312,404	58,143	4.9%
	X		Energy Efficient Products Program	RES	The program provides rebates to consumers and financial incentives and support to retailers that sell energy efficient products, such as HVAC, appliances, lighting, home electronics, and other electricity conservation products.	985,821	137,354	15.6%
	X		Home Performance Program	RES	This program is a combination of the existing Comprehensive Residential Retrofit, Online Audit, and Efficient New Homes programs. In addition, this program also consists of energy efficiency kits and a behavioral program being offered to customers.	925,319	123,094	14.6%
	X		Low-Income Program	LI RES	The program consists of weatherization services being offered to low-income customers.	16,149	2,103	0.3%
			Totals for Residential Sector			***2,239,692***	***345,363***	***35.3%***

Appendix C-3

PUCO 4: Program Summaries

Ohio Edison Program Summaries								
	EE Program (check box)	PDR Program (check box)	Program Name	Program Market	Program Two Sentence Summary	Net Lifetime MWh Savings	Net Peak Demand kW Savings	Percentage of Portfolio and Total Lifetime MWh savings %
Small Enterprise	X		C&I Energy Efficiency Equipment Program-Small	Small C&I	Provides financial incentives (Prescriptive & Performance) and support to customers directly or through retialers for implementing energy efficient equipment and products. Other delivery mechanisms may include EE kits provided to participants.	1,490,971	409,605	23.5%
	X		Energy Efficient Buildings Program-Small	Small C&I	Provides financial incentives and support to customers for implementing energy efficient custom building shell or system improvements. Other delivery mechanisms include EE kits provided to participants and incentives towards energy efficiency audits.	302,840	60,856	4.8%
			Totals for Small Enterprise			***1,793,810***	***470,462***	***28.3%***

Appendix C-3

PUCO 4: Program Summaries

Ohio Edison Program Summaries								
	EE Program (check box)	PDR Program (check box)	Program Name	Program Market	Program Two Sentence Summary	Net Lifetime MWh Savings	Net Peak Demand kW Savings	Percentage of Portfolio and Total Lifetime MWh savings %
Mercantile	X		Mercantile Customer Program		Captures energy efficiency and peak demand reduction projects committed to the Company by Mercantile customers as provided for by O.R.C. 4928.01 and 4928.66	1,331,828	213,093	21.0%
			Totals for Mercantile			***1,331,828***	***213,093***	***21.0%***
Mercantile-Utility (Large Enterprise)		X	Demand Reduction Program	Large C&I	Captures load curtailment and curtailable capacity from the Companies' Interruptible Load Programs (Economic Load Response and Optional Load Response) and from additional demand resources including resources participating in the PJM market or through contracts for demand response attributes with customers or PJM CSPs.	-	198,229	0.0%
	X		C/I Energy Efficient Equipment Program-Large	Large C&I	Provides financial incentives (Prescriptive & Performance) and support to customers directly or through retialers for implementing energy efficient equipment and products. Other delivery mechanisms may include EE kits provided to participantsparticipants and incentives towards energy efficiency audits.	864,830	186,212	13.6%
	X		Energy Efficient Buildings Program-Large	Large C&I	Provides financial incentives and support to customers for implementing energy efficient custom building shell or system improvements. Other delivery mechanisms include EE kits provided to participants and audits coupled with direct installation of low cost measures.	100,619	11,486	1.6%
			Totals for Large Enterprise			***965,448***	***395,927***	***15.2%***

Appendix C-3

PUCO 4: Program Summaries

Ohio Edison Program Summaries								
	EE Program (check box)	PDR Program (check box)	Program Name	Program Market	Program Two Sentence Summary	Net Lifetime MWh Savings	Net Peak Demand kW Savings	Percentage of Portfolio and Total Lifetime MWh savings %
Government Portfolio Programs	X		Government Tariff Lighting Program	Gov't	Provides financial incentives and support to customers for implementing energy efficient street lighting or traffic lighting technologies.	5,979	539	0.1%
			Totals for Gov't Sector Programs			*5,979*	*539*	*0.1%*
Transmission & Distribution	X	X	Conservation Voltage Reduction	T&D	The Company is proposing to study a Conservation Voltage Reduction (CVR) Program by carefully analyzing their distribution circuit designs to identify operational changes that potentially could achieve additional energy savings and demand reductions.	-	-	0.0%
	X	X	T&D Improvements	T&D	Capture savings achieved through various T&D projects that reduce line losses, which in turn results in a more efficient delivery system.	-	-	0.0%
		X	Smart Grid Modernization Initiative	T&D	The intent of the project is to produce an an integrated system of protection, performance, efficiency and economy that extends across the energy delivery system for multiple stakeholder benefits.	-	-	0.0%
			Totals for T&D Sector Programs			-	-	*0.0%*
Total for Plan						6,336,758	1,425,383	100.0%

ATTACHMENT B

The Cleveland Electric Illuminating Company

Energy Efficiency & Peak Demand Reduction Program Portfolio

(For the Period January 1, 2013 through December 31, 2015)

July 31, 2012

Docket No. 12-2191-EL-POR

Appendix C-3

PUCO 2: Summary of Portfolio Energy and Demand Savings

Cleveland Electric Summary of Portfolio Energy and Demand Savings - Pro rata						
	Program Year 2013		Program Year 2014		Program Year 2015	
MWh Saved for Consumption Reductions kW Saved for Peak Load Reductions	MWh Saved	kW Saved	MWh Saved	kW Saved	MWh Saved	kW Saved
Residential Sector (inclusive of Low- Income) - Cumulative Projected Portfolio Savings	18,751	33,341	53,819	39,608	92,127	46,363
Small Enterprise - Cumulative Projected Portfolio Savings	20,125	37,463	68,367	49,776	121,185	62,100
Mercantile - Cumulative Projected Portfolio Savings	18,999	49,317	32,297	51,684	41,797	53,374
Mercantile-Utility (Large Enterprise)- Cumulative Projected Portfolio Savings	5,881	53,972	17,667	62,864	29,999	66,395
Government Sector - Cumulative Projected Portfolio Savings	93	9	351	18	659	27
Transmission & Distribution	0	0	0	0	0	0
Portfolio Plan Total - Cumulative Projected Savings	63,849	174,101	172,501	203,949	285,767	228,259

Appendix C-3

PUCO 4: Program Summaries

Cleveland Electric Program Summaries								
	EE Program (check box)	PDR Program (check box)	Program Name	Program Market	Program Two Sentence Summary	Net Lifetime MWh Savings	Net Peak Demand kW Savings	Percentage of Portfolio and Total Lifetime MWh savings %
Residential Portfolio Programs (inclusive of Low Income)		X	Direct Load Control Program	RES	The program consists of a customer having their central air conditioning compressor cycled during summer peak periods.	-	14,418	0.0%
	X		Appliance Turn-In Program	RES	The program consists of customers receiving a rebate for turning in a working refrigerator, freezer, or room air conditioner.	207,864	39,102	5.7%
	X		Energy Efficient Products Program	RES	The program provides rebates to consumers and financial incentives and support to retailers that sell energy efficient products, such as HVAC, appliances, lighting, home electronics, and other electricity conservation products.	387,297	58,824	10.6%
	X		Home Performance Program	RES	This program is a combination of the existing Comprehensive Residential Retrofit, Online Audit, and Efficient New Homes programs. In addition, this program also consists of energy efficiency kits and a behavioral program being offered to customers.	465,833	61,251	12.8%
	X		Low-Income Program	LI RES	The program consists of weatherization services being offered to low-income customers.	20,542	2,744	0.6%
			Totals for Residential Sector			***1,081,536***	***176,338***	*29.7%*

Appendix C-3

PUCO 4: Program Summaries

Cleveland Electric Program Summaries								
	EE Program (check box)	PDR Program (check box)	Program Name	Program Market	Program Two Sentence Summary	Net Lifetime MWh Savings	Net Peak Demand kW Savings	Percentage of Portfolio and Total Lifetime MWh savings %
Small Enterprise	X		C&I Energy Efficiency Equipment Program-Small	Small C&I	Provides financial incentives (Prescriptive & Performance) and support to customers directly or through retailers for implementing energy efficient equipment and products. Other delivery mechanisms may include EE kits provided to participants.	1,162,177	310,390	31.9%
	X		Energy Efficient Buildings Program-Small	Small C&I	Provides financial incentives and support to customers for implementing energy efficient custom building shell or system improvements. Other delivery mechanisms include EE kits provided to participants and incentives towards energy efficiency audits.	150,634	29,285	4.1%
			Totals for Small Enterprise			***1,312,811***	***339,675***	*36.0%*

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PUCO 4: Program Summaries

Cleveland Electric Program Summaries								
	EE Program (check box)	PDR Program (check box)	Program Name	Program Market	Program Two Sentence Summary	Net Lifetime MWh Savings	Net Peak Demand kW Savings	Percentage of Portfolio and Total Lifetime MWh savings %
Mercantile	X		Mercantile Customer Program		Captures energy efficiency and peak demand reduction projects committed to the Company by Mercantile customers as provided for by O.R.C. 4928.01 and 4928.66	626,951	111,582	17.2%
			Totals for Mercantile			***626,951***	***111,582***	*17.2%*
Mercantile-Utility (Large Enterprise)		X	Demand Reduction Program	Large C&I	Captures load curtailment and curtailable capacity from the Companies' Interruptible Load Programs (Economic Load Response and Optional Load Response) and from additional demand resources including resources participating in the PJM market or through contracts for demand response attributes with customers or PJM CSPs.	-	133,765	0.0%
	X		C/I Energy Efficient Equipment Program-Large	Large C&I	Provides financial incentives (Prescriptive & Performance) and support to customers directly or through retialers for implementing energy efficient equipment and products. Other delivery mechanisms may include EE kits provided to participantsparticipants and incentives towards energy efficiency audits.	535,017	108,298	14.7%
	X		Energy Efficient Buildings Program-Large	Large C&I	Provides financial incentives and support to customers for implementing energy efficient custom building shell or system improvements. Other delivery mechanisms include EE kits provided to participants and audits coupled with direct installation of low cost measures.	74,326	8,485	2.0%
			Totals for Large Enterprise			***609,343***	***250,549***	*16.7%*

Appendix C-3

PUCO 4: Program Summaries

Cleveland Electric Program Summaries								
	EE Program (check box)	PDR Program (check box)	Program Name	Program Market	Program Two Sentence Summary	Net Lifetime MWh Savings	Net Peak Demand kW Savings	Percentage of Portfolio and Total Lifetime MWh savings %
Government Portfolio Programs	X		Government Tariff Lighting Program	Gov't	Provides financial incentives and support to customers for implementing energy efficient street lighting or traffic lighting technologies.	11,060	269	0.3%
			Totals for Gov't Sector Programs			***11,060***	***269***	*0.3%*
Transmission & Distribution	X	X	Conservation Voltage Reduction	T&D	The Company is proposing to study a Conservation Voltage Reduction (CVR) Program by carefully analyzing their distribution circuit designs to identify operational changes that potentially could achieve additional energy savings and demand reductions.	-	-	0.0%
	X	X	T&D Improvements	T&D	Capture savings achieved through various T&D projects that reduce line losses, which in turn results in a more efficient delivery system.	-	-	0.0%
		X	Smart Grid Modernization Initiative	T&D	The intent of the project is to produce an an integrated system of protection, performance, efficiency and economy that extends across the energy delivery system for multiple stakeholder benefits.	-	-	0.0%
			Totals for T&D Sector Programs			-	-	*0.0%*
Total for Plan						3,641,701	878,413	100.0%

ATTACHMENT C

ToledoEdison®
A FirstEnergy Company

Toledo Edison Company

Energy Efficiency & Peak Demand Reduction Program Portfolio

(For the Period January 1, 2013 through December 31, 2015)

July 31, 2012

Docket No. 12-2192-EL-POR

Appendix C-3

PUCO 2: Summary of Portfolio Energy and Demand Savings

Toledo Edison Summary of Portfolio Energy and Demand Savings - Pro rata						
	Program Year 2013		Program Year 2014		Program Year 2015	
MWh Saved for Consumption Reductions kW Saved for Peak Load Reductions	MWh Saved	kW Saved	MWh Saved	kW Saved	MWh Saved	kW Saved
Residential Sector (inclusive of Low- Income) - Cumulative Projected Portfolio Savings	12,791	11,847	42,538	16,403	68,222	19,704
Small Enterprise - Cumulative Projected Portfolio Savings	16,140	14,899	53,753	24,408	88,578	31,815
Mercantile - Cumulative Projected Portfolio Savings	20,115	40,006	33,877	42,208	43,405	43,732
Mercantile-Utility (Large Enterprise)- Cumulative Projected Portfolio Savings	13,335	145,147	39,410	26,522	66,091	32,276
Government Sector - Cumulative Projected Portfolio Savings	13	4	39	7	64	11
Transmission & Distribution	0	0	0	0	0	0
Portfolio Plan Total - Cumulative Projected Savings	62,393	211,903	169,617	109,548	266,360	127,538

Appendix C-3

PUCO 4: Program Summaries

Toledo Edison Program Summaries								
	EE Program (check box)	PDR Program (check box)	Program Name	Program Market	Program Two Sentence Summary	Net Lifetime MWh Savings	Net Peak Demand kW Savings	Percentage of Portfolio and Total Lifetime MWh savings %
Residential Portfolio Programs (Inclusive of Low Income)		X	Direct Load Control Program	RES	The program consists of a customer having their central air conditioning compressor cycled during summer peak periods.	-	3,264	0.0%
	X		Appliance Turn-In Program	RES	The program consists of customers receiving a rebate for turning in a working refrigerator, freezer, or room air conditioner.	95,118	17,624	2.7%
	X		Energy Efficient Products Program	RES	The program provides rebates to consumers and financial incentives and support to retailers that sell energy efficient products, such as HVAC, appliances, lighting, home electronics, and other electricity conservation products.	291,820	42,312	8.4%
	X		Home Performance Program	RES	This program is a combination of the existing Comprehensive Residential Retrofit, Online Audit, and Efficient New Homes programs. In addition, this program also consists of energy efficiency kits and a behavioral program being offered to customers.	305,187	39,473	8.8%
	X		Low-Income Program	LI RES	The program consists of weatherization services being offered to low-income customers.	8,538	1,139	0.2%
			Totals for Residential Sector			***700,663***	***103,813***	***20.2%***

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PUCO 4: Program Summaries

Toledo Edison Program Summaries								
	EE Program (check box)	PDR Program (check box)	Program Name	Program Market	Program Two Sentence Summary	Net Lifetime MWh Savings	Net Peak Demand kW Savings	Percentage of Portfolio and Total Lifetime MWh savings %
Small Enterprise	X		C&I Energy Efficiency Equipment Program-Small	Small C&I	Provides financial incentives (Prescriptive & Performance) and support to customers directly or through retialers for implementing energy efficient equipment and products. Other delivery mechanisms may include EE kits provided to participants.	732,125	211,540	21.1%
	X		Energy Efficient Buildings Program-Small	Small C&I	Provides financial incentives and support to customers for implementing energy efficient custom building shell or system improvements. Other delivery mechanisms include EE kits provided to participants and incentives towards energy efficiency audits.	106,597	21,130	3.1%
			Totals for Small Enterprise			***838,722***	***232,670***	***24.1%***

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PUCO 4: Program Summaries

Toledo Edison Program Summaries								
	EE Program (check box)	PDR Program (check box)	Program Name	Program Market	Program Two Sentence Summary	Net Lifetime MWh Savings	Net Peak Demand kW Savings	Percentage of Portfolio and Total Lifetime MWh savings %
Mercantile	X		Mercantile Customer Program		Captures energy efficiency and peak demand reduction projects committed to the Company by Mercantile customers as provided for by O.R.C. 4928.01 and 4928.66	651,077	104,172	18.7%
			Totals for Mercantile			***651,077***	***104,172***	***18.7%***
Mercantile-Utility (Large Enterprise)		X	Demand Reduction Program	Large C&I	Captures load curtailment and curtailable capacity from the Companies' Interruptible Load Programs (Economic Load Response and Optional Load Response) and from additional demand resources including resources participating in the PJM market or through contracts for demand response attributes with customers or PJM CSPs.	-	139,840	0.0%
	X		C/I Energy Efficient Equipment Program-Large	Large C&I	Provides financial incentives (Prescriptive & Performance) and support to customers directly or through retialers for implementing energy efficient equipment and products. Other delivery mechanisms may include EE kits provided to participantsparticipants and incentives towards energy efficiency audits.	1,131,677	250,079	32.6%
	X		Energy Efficient Buildings Program-Large	Large C&I	Provides financial incentives and support to customers for implementing energy efficient custom building shell or system improvements. Other delivery mechanisms include EE kits provided to participants and audits coupled with direct installation of low cost measures.	153,709	17,547	4.4%
			Totals for Large Enterprise			***1,285,386***	***407,467***	***37.0%***

Appendix C-3

PUCO 4: Program Summaries

Toledo Edison Program Summaries								
	EE Program (check box)	PDR Program (check box)	Program Name	Program Market	Program Two Sentence Summary	Net Lifetime MWh Savings	Net Peak Demand kW Savings	Percentage of Portfolio and Total Lifetime MWh savings %
Government Portfolio Programs	X		Government Tariff Lighting Program	Gov't	Provides financial incentives and support to customers for implementing energy efficient street lighting or traffic lighting technologies.	755	108	0.0%
			Totals for Gov't Sector Programs			*755*	*108*	*0.0%*
Transmission & Distribution	X	X	Conservation Voltage Reduction	T&D	The Company is proposing to study a Conservation Voltage Reduction (CVR) Program by carefully analyzing their distribution circuit designs to identify operational changes that potentially could achieve additional energy savings and demand reductions.	-	-	0.0%
	X	X	T&D Improvements	T&D	Capture savings achieved through various T&D projects that reduce line losses, which in turn results in a more efficient delivery system.	-	-	0.0%
		X	Smart Grid Modernization Initiative	T&D	The intent of the project is to produce an an integrated system of protection, performance, efficiency and economy that extends across the energy delivery system for multiple stakeholder benefits.	-	-	0.0%
			Totals for T&D Sector Programs			-	-	*0.0%*
Total for Plan						3,476,604	848,229	100.0%

Attachment 2

FILE

FINAL REPORT (REDACTED)

MANAGEMENT/PERFORMANCE AUDIT

OF THE ALTERNATIVE ENERGY RESOURCE RIDER (RIDER AER)

OF THE FIRSTENERGY OHIO UTILITY COMPANIES

FOR OCTOBER 2009 THROUGH DECEMBER 31, 2011

CASE NO. 11-5201-EL-RDR

PREPARED FOR:

PUBLIC UTILITIES COMMISSION OF OHIO

180 EAST BROAD STREET

COLUMBUS, OHIO 43215-3793

JUNE 15, 2012

PREPARED BY

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway
Suite 300
Columbia, Maryland 21044

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Executive Summary

On September 20, 2011, the Public Utilities Commission of Ohio ("PUCO") issued an entry on rehearing In the Matter of the Annual Alternative Energy Status Report of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company, Case No. 11-2479-EL-ACP. In that entry on rehearing, the PUCO stated that it had opened Case No. 11-5201-EL-RDR for the purposes of reviewing the Alternative Energy Resource Rider ("Rider AER") of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, "FirstEnergy Ohio utilities" or "Companies"). Additionally, the PUCO indicated that its review would include the Companies' procurement of renewable energy credits for purposes of compliance with Ohio's Alternative Energy Portfolio Standard ("AEPS"). The PUCO further noted that it would determine the necessity and scope of an external auditor for this matter.

The PUCO subsequently decided that an external auditor would be necessary for the review, and on January 18, 2012 directed Staff to issue a request for proposals ("RFP") for audit services. After consideration of the proposals received, the PUCO selected Exeter Associates, Inc. ("Exeter"), to conduct the management/performance portion of the audit and Goldenberg Schneider, LPA, to conduct the financial portion of the audit.

This report presents the findings of Exeter's management/performance audit of the Rider AER of the FirstEnergy Ohio utility companies for the time period October 2009 through December 31, 2011.[1] Dr. Steven L. Estomin and Mr. Thomas S. Catlin acted as the primary investigators for this audit.

The principal information on which this management/performance audit is based is from a variety of sources, including:

- Responses of the First Energy Ohio utilities to requests for information prepared by Exeter Associates, Inc.
- Independent research conducted by Exeter Associates, Inc. related to the availability and market prices of SRECs and RECs in Ohio and elsewhere.
- Orders issued by the Public Utilities Commission of Ohio related to Ohio's AEPS and the FirstEnergy Ohio utilities Rider AER.
- Interview of personnel from the FirstEnergy Ohio utilities and Navigant Consulting, Inc., consultant to the Companies.

General SREC/REC Acquisition Approach

The FirstEnergy Ohio utilities employed Requests for Proposals ("RFPs"), with responses provided in sealed bids, to secure all four categories of Renewable Energy Credits

[1] Though the Rider AER was in place beginning in October 2009, the Companies undertook activities related to compliance with the Ohio AEPS earlier in 2009. This management/performance audit report addresses those activities undertaken by the Companies beginning earlier in 2009 to facilitate compliance with the AEPS requirements.

("RECs") – In-State Solar RECs; All-State Solar RECs; In-State All Renewables RECs; and All-State All Renewables RECs. In total, six RFP's were issued.

Exeter examined the FirstEnergy Ohio utilities procurement process for evaluation relative to the following important characteristics: (1) competitiveness; (2) transparency; (3) cost; and (4) ability to obtain adequate industry response. Each of these considerations appears to have been satisfied by the REC acquisition approach employed by the Companies.

Exeter also considered the key elements of the RFPs issued as well as the processes associated with advance market research, issuance, dissemination of information to potential bidders, evaluation of bids, and handling of feedback obtained from bidders. The RFPs were assessed for the following key elements: (1) clarity; (2) financial/security requirements; (3) time between bid receipt and award; and (4) bidder feedback. Also examined was the RFP planning process which was assessed for: (1) preparation and mechanics; (2) market research; and (3) contingency planning.

Exeter's analysis led to the following findings and recommendations on the RFPs and RFP processes:

Findings.

1. The RFPs issued by the FirstEnergy Ohio utilities are reasonably developed and do not appear to incorporate any provisions or terms that could be assessed to be anti-competitive.
2. The basic terms and conditions contained in the RFPs were generally acceptable by the industry and to the extent that individual bidders were unwilling to provide bids in response to the solicitations, those decisions were based on specific elements contained in the RFPs that were at odds with the business models of the individual potential bidders. Such conditions include the duration of the contract periods and the firmness of the supply requirements.
3. The security requirements contained in the RFPs are assessed to strike a reasonable balance between safeguarding the FirstEnergy Ohio utilities and making the RFP attractive to potential bidders.
4. The processes in place to disseminate information to potential bidders and to address issues and questions that arose during the time that potential bidders were deciding whether to proffer a bid and the offer due dates were adequate.
5. The mechanisms in place to review and evaluate the bids were adequate, although a shorter period of time between the bid due date and the award in the first RFP would have been an improvement. The approximately three-week review period established by the FirstEnergy Ohio utilities was generally deemed excessive by industry participants and this was rectified by the FirstEnergy Ohio utilities in subsequent RFPs.
6. The mechanisms in place to solicit industry feedback, through both the nature of the questions and comments raised by potential bidders and the conduct of a survey by NCI, are seen as an acceptable approach to inform the FirstEnergy Ohio utilities about the strengths and weaknesses of the issued RFPs. Further, the information obtained through

the process was effectively used and served as a basis for modifications in RFPs subsequent to the conduct of the survey.

7. Market information for In-State Solar and All Renewables RECs was limited prior to the first two RFPs.
8. The contingency planning in place for the first three RFPs was inadequate and should have encompassed a specific set of fall-back approaches, or in the alternative, specified a mechanism by which to distill the information gained from the solicitations to develop a modified approach.

Recommendations.

1. The FirstEnergy Ohio utilities should implement a more robust contingency planning process as it relates to the procurement of RECs and SRECs in compliance with Ohio's AEPS. We also recommend that the contingency plan be subject to review by the PUCO Staff prior to its implementation.
2. A thorough market analysis should precede the issuance of any future RFPs by the FirstEnergy Ohio utilities for RECs and SRECs in compliance with Ohio's AEPS.
3. The FirstEnergy Ohio utilities should consider a mark-to-market approach to the security requirement for future procurements when the RECs and SRECs market mature to a point when a mark-to-market approach is feasible.

Solicitation Results and Procurement Decisions

As part of the management/performance audit, Exeter Associates, Inc. reviewed the results of the FirstEnergy Ohio utilities' procurement of SRECs and RECs to meet the Ohio AEPS requirements for 2009, 2010, and 2011. In particular, Exeter reviewed the quantities of SRECs and RECs bid, the prices associated with those bids, and the decisions of the FirstEnergy Ohio utilities regarding the bids (quantity and price) received. Exeter's analysis resulted in the following findings and recommendations.

Findings:

1. The prices paid by the Companies for All-States All Renewables RECs were reasonably consistent with other regional RECs prices.
2. While lower prices would have been available to the Companies were fewer RECs purchased under RFP 1 and more RECs purchased under RFP 3, the Companies' decisions to purchase the bulk of the 2009, 2010, and 2011 requirements under RFP 1 were not unreasonable.
3. The lower prices available for All-States SRECs in the 2011 timeframe could not have been reasonably foreseen by the Companies. The prices paid by the Companies for All-States SRECs are consistent with SRECs price regionally.
4. The FirstEnergy Ohio utilities did not establish a maximum (or limit) price that the Companies were willing to pay for In-State All Renewables RECs prior to the issuance of the RFPs.

5. The FirstEnergy Ohio utilities paid unreasonably high prices for In-State All Renewables RECs purchased from [redacted].
6. Prices for In-State All Renewable RECs in the range of $[redacted] to $[redacted] exceeded the reported prices paid for non-solar compliance RECs anywhere in the country between July 2008 and December 2011 by at least $[redacted] to $[redacted].
7. The FirstEnergy Ohio utilities had several alternatives available to the purchase of high-priced In-State All Renewables RECs, none of which were considered or acted upon.
8. The FirstEnergy Ohio utilities should have been aware that the prices bid by FirstEnergy Solutions reflected significant economic rents and were excessive by any reasonable measure.
9. The procurement of In-State Solar RECs by the FirstEnergy Ohio utilities was competitive and, when Ohio SRECs became reasonably available, the prices paid for those SRECs by the Companies were consistent with prices for SRECs seen elsewhere.

Recommendations:

Based on the findings presented above, we recommend that the Commission examine the disallowance of excessive costs associated with purchasing RECs to meet the FirstEnergy Ohio utilities' In-State All Renewables obligations.

Miscellaneous Issues

During the course of conducting the management/performance audit of the FirstEnergy Ohio utilities, several issues emerged that warrant brief discussion, though these issues are not directly related to the FirstEnergy Ohio utilities and affect all of the regulated utilities in Ohio with respect to compliance with Ohio's AEPS legislation. Specifically, there are three aspects of either the legislation or the method by which the legislation is implemented that may warrant some reconsideration by the appropriate bodies.

Recovery of ACP Charges

Ohio's AEPS legislation does not permit the Ohio utilities to recover the costs associated with Alternative Compliance Payments. The fundamental purpose of the ACP is to set a limit on the exposure of retail customers for the costs of RPS (or AEPS) compliance. Not allowing recovery of the ACP provides a significant deterrent to regulated firms from employing the ACP in lieu of the procurement of RECs, even at prices well in excess of the ACP.

Commission Approval of RECs Purchases

A second modification that merits consideration is a requirement that the Commission approve the purchase of RECs for the retail suppliers of SSO before the RECs contracts are signed. That requirement would eliminate some of the issues that have arisen in the context of this management/performance audit.

Application of the Three-Percent Rule

The legislation does not clearly lay out how the "three-percent rule" is to be applied. The apparent intent of the rule is to limit the degree to which retail customers are exposed to excessive costs related to the satisfaction of the renewable energy requirements. The rule, however, is based on "expected" impacts. An algorithm based on expected sales volumes that accounts for customer migration and projections of market pricing for power is recommended as an improved approach.

FINAL REPORT (REDACTED)

MANAGEMENT/PERFORMANCE AUDIT

OF THE ALTERNATIVE ENERGY RESOURCE RIDER (RIDER AER)

OF THE FIRSTENERGY OHIO UTILITY COMPANIES

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I. INTRODUCTION

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[2] Though the Rider AER was in place beginning in October 2009, the Companies undertook activities related to compliance with the OHIO AEPS earlier in 2009. This management/performance audit report addresses those activities undertaken by the Companies beginning earlier in 2009 to facilitate compliance with the AEPS requirements.

The principal information on which this management/performance audit is based is from a variety of sources, including:

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- Independent research conducted by Exeter Associates, Inc. related to the availability and market prices of SRECs and RECs in Ohio and elsewhere.
- Orders issued by the Public Utilities Commission of Ohio related to Ohio's AEPS and the FirstEnergy Ohio utilities Rider AER.
- Interview of, and communications with, personnel from the FirstEnergy Ohio utilities and Navigant Consulting, Inc., consultant to the Companies.

The remainder of this management/performance report is organized into three sections. The following section, Section 2, addresses the approach used by the Companies to procure Solar and Non-solar Renewable Energy Credits. This section includes assessment of the general approach, the structure of the Requests for Proposals, the Companies' treatment of industry feedback on the solicitation documents, market research, and contingency planning.

Section 3 of the report addresses the results of the acquisition process, including the effectiveness of the solicitations and the prices ultimately paid for Solar and Non-solar Renewable Energy Credits, both in-State and out-of-State.

Section 4 of the report addresses certain miscellaneous issues that emerged during the conduct of the management/performance audit.

Findings and recommendations are presented throughout the document following the discussion of the relevant issues.

II. GENERAL SREC/REC ACQUISITION APPROACH

The FirstEnergy Ohio utilities employed Requests for Proposals ("RFPs"), with responses provided in sealed bids, to secure all four categories of Renewable Energy Credits ("RECs") – In-State Solar RECs; All-States Solar RECs; In-State All Renewables RECs; and All-States All Renewables RECs. Because the competitive RFP approach did not fully satisfy all of the FirstEnergy Ohio utilities' requirements for in-State solar and non-solar for 2010 and 2011, the Companies also pursued broker transactions and bilateral arrangements following the issuance of the third RFP (October 2010). In addition, a limited number of Solar RECs ("SRECs") were available to the Companies internally from the operation of programs to promote renewable energy development within their service areas. In total, six RFP's were issued. The specifics of the RFP approach employed by the Companies is addressed below followed by an assessment of the alternative approaches employed to supplement the bids received through the RFP process.

A. RFP Approach Overview

The appropriateness of any particular acquisition approach needs to be judged on basis of several important characteristics. Most important among the characteristics are: (1) competitiveness; (2) transparency; (3) cost; and (4) the ability to obtain adequate industry response. Each of these considerations appears to have been met by the approach employed by the Companies.

The sealed bid RFP protocol used by the FirstEnergy Ohio utilities entailed a two-part submission, which is a common practice used in the electric utility industry for the purchase of not only RECs but also for electric power supplies. Potential bidders are required to submit documents verifying credit-worthiness and the financial capability of meeting the requirements of the RFP. Once the credit/financial qualifications have been reviewed and a set of qualified bidders identified, the Phase 2 price/quantity bids submitted in response to the RFP are then evaluated purely on the basis of least cost, that is, lowest price. Offers are accepted from lowest price to highest until the specified requirement is filled. Typically, the seller conditions the RFP to permit rejection of bids even if the full requirement is not met. This allows the buyer to avoid paying for supplies assessed to be above market or to adjust the amount purchased due to circumstances that have developed since the issuance of the RFP.

Competitiveness. – The sealed-bid pricing requirement of the RFPs for SRECs/RECs issued by the FirstEnergy Ohio utilities is assessed to be competitive and to minimize the potential for bidder collusion and "gaming" of the process. Because bidders recognize that there may be only one opportunity to secure a buyer, bidders tend to provide competitive prices reflective of market conditions.

Winning bidders are paid their own individual bid prices, in contrast to certain other competitive procurement methods (for example, descending clock auctions) where all selected bidders are paid the marginal bid, that is, the highest price bid selected that fulfills the established requirement. Paying the individual bid prices eliminates incentives on the part of bidders to potentially influence the clearing price, for example by bidding some supplies at low prices and other supplies at higher prices. Because all bids are paid the bid price, no bidder can influence the price paid to bidders below the marginal price – the price of the last accepted bid.

Transparency. – The sealed-bid RFP process is transparent due to its simplicity and tractability. A paper trail exists for the bids and the awards, and the approach is straightforward and one with which industry participants are familiar and comfortable.

RFP Cost. – The sealed bid RFP method is relatively low-cost in comparison to alternative approaches that rely on a live auction platform. Using an RFP does not require monitoring of the bid process to attempt to identify collusive bidding practices. Bid evaluation is straightforward. Because the FirstEnergy Ohio utilities issued multiple RFPs, the same set of documents with only minor modifications were able to be relied upon, which eliminated the incurrence of duplicative costs.

Adequate Industry Response. – The RFPs issued by the FirstEnergy Ohio utilities generally succeeded in obtaining bids from a variety of potential suppliers and were structured so as not to prelude bids from small entities wishing to bid only a small number of SRECs/RECs. The table below (Table 1) shows the number of successful bids and the number of successful bidders responding to each of the six RFPs. To place the number of responses in context, the type of RECs solicited in each RFP are also shown. Note that for bids with no responses, in some cases the requisite RECs/SRECs had been previously secured by the Companies and in some cases, the market was not sufficiently developed to allow industry response (for example, RFP1 for In-State Solar RECs).

Table 1 FirstEnergy Ohio REC RFPs 2009 – 2011

	In-State Solar		In-State All Renewables		All-States Solar		All-States All Renewables	
	Number of Successful Bidders	Number of Successful Bids	Number of Successful Bidders	Number of Successful Bids	Number of Successful Bidders	Number of Successful Bids	Number of Successful Bidders	Number of Successful Bids
RFP1	---	---	2	6	---	---	2	46
RFP2	2	6	1	6	2	5	---	---
RFP3	10	18	2	3	3	9	2	8
RFP4	2	2	---	---	---	---	---	---
RFP5	8	9	---	---	3	7	---	---
RFP6	7	10	2	2	---	---	---	---

B. RFP Elements

This section addresses the key elements of the RFPs issued by the FirstEnergy Ohio utilities, as well as the processes associated with advance market research, issuance, dissemination of information to potential bidders, evaluation of bids, and handling of feedback obtained from bidders.

Clarity. – All six RFPs issued by the FirstEnergy Ohio utilities were assessed for clarity with respect to the submissions required; the deadlines for submission; the type, quantities, and vintage of RECs sought to be procured; and the means by which potential bidders could obtain additional information and have questions addressed. All RFPs were found to be adequate with respect to clarity.

Financial/Security Requirements. – All RFPs contained financial and security documentation requirements to ensure that the bidders had the financial capabilities of satisfying the contract terms and conditions based on the number of RECs bid in aggregate by the bidder. Additionally, posting of security following award was required. The security requirements serve to protect the FirstEnergy Ohio utilities in the event that the supplier defaults on the contract and one or more of the Companies must then go back to the market to obtain the necessary RECs. This circumstance could emerge, for example, in the case of a winning bidder filing for bankruptcy protection before fulfillment of the contract. If market prices for RECs increased during the contract period, the contract could be voided by a bankruptcy judge and FirstEnergy required to replace the undelivered RECs with RECs obtained at market prices higher than those contained in the contract. Security requirements, however, often serve as an impediment to bidders, especially smaller companies.

The first five RFPs contained financial/security terms that exempted bidders offering less than $100,000 of RECs from having to obtain security guarantees. This arrangement facilitated participation by smaller entities offering a relatively small number of RECs. For those bidders offering RECs with an aggregate value (the product of price and the number of RECs) greater than $100,000, security of ten percent of the value of the bid was required. The requirement was placed on the aggregate value to avoid suppliers attempting to circumvent the security requirement by offering multiple smaller bids. Since the potential existed that the bidder would be awarded all the bids proffered, the aggregate bid requirement utilized by the FirstEnergy Ohio utilities was appropriate.

The sixth RFP, which was to obtain in-State SRECs for a term up to 10 years, raised the threshold for security from $100,000 to $250,000. Given the longer term of the resulting contracts, the $100,000 threshold, if left intact, would serve only to exempt bidders offering only a very small number of SRECs. The higher threshold did not serve to put the Companies, or the Companies' customers, at a significant additional risk relative to the lower security threshold

contained in the prior RFPs since any risk exposure was spread out over a ten-year period rather than concentrated in just one or two years.

RFPs are sometimes issued with a requirement that security be posted not later than the time of the bid, that is, the bidder must provide a security commitment (for example, a letter of credit, a parent-company guarantee, or cash) on or before the submission of the price/quantity bid. If the bidder is not selected, the security commitment can then be cancelled. The RFPs issued by the FirstEnergy Ohio utilities did not require the posting of security until the contract was awarded. The approach employed by the FirstEnergy Ohio utilities reduces the cost associated with bid preparation and is conducive to enhancing to pool of potential bidders without imposing added risks on the Companies or the Companies' electric customers.

An alternative approach to the one used by the Companies is to adjust the security periodically on a mark-to-market ("MtM") basis. Under this alternative approach, the winning bidders are required to increase the amount of security in accordance with the differential between the market price and the bid price. If market prices rise above the bid (award) price such that the initial security requirement is insufficient to cover the differential in the event of default, the seller is required to post additional security to provide protection to the buyer. When market prices decline below the bid (award) price, the level of security can be reduced since the buyer would not require price protection in the event of default, that is, the relevant commodity can be purchased in the market by the buyer at a price below the bid (award) price. The contracts awarded by the FirstEnergy Ohio utilities do not contain an MtM security adjustment mechanism. The absence of an MtM adjustment clause in the contracts is appropriate given the nature of the market for Ohio RECs. Determining the market price in any meaningful way, particularly for In-State Solar and In-State All Renewables RECs, would have proven difficult given the lack of maturity in those markets at the time that the RFPs were issued. Consequently, any MtM adjustment would have been subject to significant uncertainty given the lack of liquidity in the markets. As the markets mature, however, and market price data become more transparent and more readily available, the Companies should give consideration to reliance on an MtM security mechanism, particularly for longer term contracts where the potential for differences between the market prices and the bid prices can become more pronounced over time.

Time Between Bid Receipt and Award. – The amount of time between the receipt of bids by the buyer and the award of contracts affects the risk to which the bidders are exposed. The longer the time interval, the greater the degree of risk since market conditions could change and adversely affect the financial position of the sellers. To compensate for increased risk related to an extended time between bid and award, bidders will sometimes increase the bid price over what it would be were the interval shorter. While the interval between bid receipt and award is much more important in the context of electric power supply procurement than it is for the procurement of RECs, bidders have a strong preference for shorter intervals (e.g., a few days) compared to longer intervals (e.g., two or more weeks).

The first RFP issued by the FirstEnergy Ohio utilities for the procurement of both SRECs and RECs, both in-State and out-of-State, contained a time interval of 17 days. This was shortened in subsequent RFPs to less than a week in response to feedback obtained from bidders. This bid/award interval, as modified following the issuance of the first RFP, is reasonable and appropriate, affords the Companies adequate time to evaluate the bids and select a suite of awards, and does not expose the bidders to unwanted and unnecessary risk.

Bidder Feedback. – Obtaining the perspective of potential bidders is critically important to structuring an RFP that is capable of eliciting broad industry participation. The FirstEnergy Ohio utilities held bidder conferences to address questions and also received questions from bidders outside of the bidder conferences. Questions and responses were posted and available to all potential bidders so as not to provide any bidding advantage to any one entity.

In addition to compiling and addressing the comments of potential bidders on each of the RFP issuances, the FirstEnergy Ohio utilities also directed Navigant Consulting, Inc. ("NCI") to conduct a survey of supplier views on the 2009 RFPs.[3] Various types of suppliers were contacted (e.g., regional developers, national developers, marketers, generators) to allow NCI to obtain a range of views on the RFPs based on the alternative perspectives of various survey participants. Several of the modifications suggested by the various survey respondents were implemented by the FirstEnergy Ohio utilities, including: (1) shortening the time between bid and award notification,[4] (2) allowing for unit-contingent bids, and (3) extending the length of the contract period.

C. RFP Planning

Planning for the issuance of the RFP can be divided into three elements:

- Preparation of the relevant documents and the putting in place of the mechanisms to effectuate the execution of the issuance of the RFP and the evaluation of results;
- Market research prior to issuance of the RFP; and
- Contingency planning.

Each of these elements is addressed below.

Preparation and Mechanics. – The FirstEnergy Ohio utilities appear to have exercised reasonable care in preparation of the documents for the solicitations and arranged the appropriate mechanisms for the evaluation of the bids received to allow award to be made within the timeframes specified in the solicitations. The Companies also put in place adequate mechanisms

[3] Navigant Consulting, *Market Research Report Regarding Supplier Views on REC RFPs*, June 3, 2010. Prepared for FirstEnergy. Provided as a confidential response to Exeter Associates, Inc.'s first information request, interrogatory 3.

[4] The modification was implemented in the second RFP issued by the FirstEnergy Ohio utilities, prior to the compilation of the survey by NCI.

to address issues and questions raised by potential bidders and to resolve those issues within a reasonable amount of time.

Market Research. – The RECs markets within which the FirstEnergy Ohio utilities operate currently, and during the period addressed by this management and performance audit, are extremely complex. The markets contain geographic and product definition dimensions which need to be recognized and information available as to the quantity of applicable RECs generated (or that will likely be generated during the contract performance period) is difficult to assemble and verify. This is largely the result of the nascent nature of the markets, particularly in 2009 and 2010 and also, although to a lesser extent, in 2011.

In essence, the FirstEnergy Ohio utilities were operating in four separate, but overlapping, markets: the All-States All Renewables market; the All-States Solar market; the Ohio All Renewables market; and the Ohio Solar market. In the case of the All-States All Renewables market, the RECs available to the FirstEnergy Ohio utilities are also (largely) eligible to satisfy the Renewable Portfolio Standards ("RPS") in other states located in the mid-Atlantic area. For example, wind power generated in West Virginia, the RECs for which would be eligible to be used for compliance with the Ohio requirement, can also be used to satisfy RPS requirements for Pennsylvania; Maryland; Delaware; Washington, D. C.; New Jersey; and other states. In assessing the market, the quantity of such RECs that would be available to the FirstEnergy Ohio utilities cannot be viewed in isolation, but must also consider the requirements of the other states for which those RECs are eligible. Confounding that analysis is that the various states have different definitions of what types of fuels and technologies can be used for RPS compliance. For example, Pennsylvania's list of eligible resources includes facilities that produce electricity from waste coal; and Maryland's list of eligible resources includes facilities generating electric power from black liquor (a waste by-product of paper production). Consequently, West Virginia wind power competes against these eligible resources in those states, which affects the availability of the West Virginia resources to meet the Ohio AEPS requirements. These considerations extend to the Ohio All Renewables market, recognizing that RECs generated in Ohio can be used to not only satisfy the Ohio requirements but also the requirements in other states for which those resources are eligible.

The market research conducted by FirstEnergy prior to the issuance of the first and second RFPs consisted principally of review of the prices for RECs being traded in nearby states and contacting brokers to obtain information on Ohio-eligible RECs and SRECs. This avenue of research is limited with respect to what information might be able to be gleaned as it would relate to the initial two RFPs.

While information on market prices that the FirstEnergy Ohio utilities could expect to pay for All-States All Renewables and All-States Solar RECs would be reasonably obtainable from these sources, the amount of available (or potentially available) RECs and SRECs meeting the Ohio in-State criterion would not be available in any meaningful way. In the context of

prices for In-State All Renewables RECs and In-State Solar RECs, those markets were nascent at the time of the first two RFPs and market data were not generally reported and available to potential market participants. The information from the PJM queue would also be of little help, since most of the projects in the queue at any particular time, and at the time of the first two RFPs in particular given the nation's economic condition, do not ultimately get developed.

Following the issuance of the second RFP, and prior to the issuance of the third RFP, the FirstEnergy Ohio utilities directed NCI to conduct a market analysis. That study was completed in July 2010. A previous study focusing on In-State Solar and All Renewables RECs was conducted by Navigant in October 2009. By the time these studies were completed, the FirstEnergy Ohio utilities had already purchased virtually all of the All Renewables RECs required (both In-State and All-States) to meet the utilities' requirements for years 2009 and 2010 and a portion of the 2011 requirements.

Contingency Planning. – FirstEnergy Ohio indicated that it relied on the "FirstEnergy Corp FE Utilities Commodity Portfolio Risk Management Policy"[5] to provide guidance on contingency planning for the purchase of RECs and SRECs to satisfy the Ohio AEPS requirements for 2009, 2010, and 2011. The document (2009, 2010, and 2011 versions) was reviewed and there is no requirement for contingency planning contained therein.

Based on the actions undertaken by the FirstEnergy Ohio utilities following the issuance of the first RFP, the general approach was to re-issue RFPs with relatively minor modifications in hopes of attracting a larger pool of bidders than the previous RFP for particular categories of RECs. No formal contingency plan was in place to guide the follow-up actions of the FirstEnergy Ohio utilities in the event insufficient bids were received or if bid prices were excessive based on pre-established criteria.

As a follow-up to a telephone discussion held among Exeter, PUCO Staff, and the FirstEnergy Ohio utilities, the Companies provided a copy of the Direct Testimony of Dean W. Stathis on behalf of the four FirstEnergy Pennsylvania electric utilities regarding the Companies' Default Service plans for the period from June 1, 2013 to May 31, 2015. Contained within that testimony is a description of the Pennsylvania Companies' contingency plans related to the procurement of Default Service power supply and Solar RECs for compliance with Pennsylvania's Alternative Energy Portfolio Standard. The FirstEnergy Ohio utilities indicated that "...the Companies use similar contingency planning for RECs as it does for power supply. Also, similar contingency planning to that which is used in Pennsylvania is also used in Ohio."[6] Exeter reviewed Mr. Stathis' Direct Testimony and found that the contingency plan proposed by the FirstEnergy Pennsylvania utilities with respect to Default Service power supply issues

[5] Provided in response to Exeter Associates' request for information, set 5, item 1.

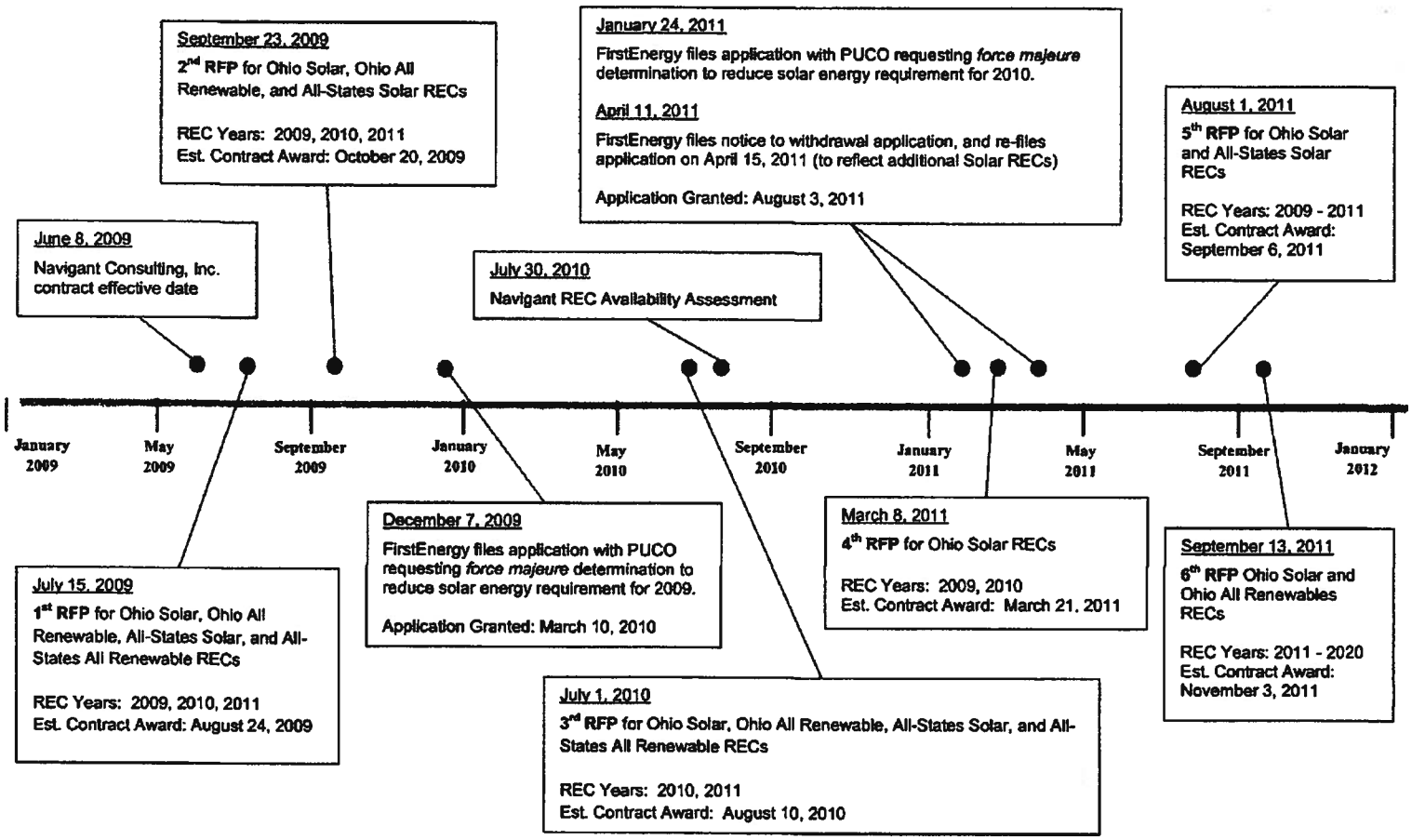
[6] Email transmission from Meghan C. Moreland (FirstEnergy, Rate Strategy) to Steven Estomin (Exeter Associates, Inc.), June 13, 2012 (received 12:16 p.m. EDT). Mr. Stathis' Direct Testimony, filed with the Pennsylvania Public Utility Commission, was included with the email as an attachment.

entailed short-term purchases on the PJM spot market (which has no meaningful application to RECs markets) followed by inclusion of the unfilled (or defaulted upon) Default Service power supply tranches in the next available power supply RFP. With respect to compliance with Pennsylvania's AEPS requirement, Mr. Stathis' Direct Testimony indicates that the FirstEnergy Pennsylvania utilities, if faced with unfilled solar tranches (or solar tranches on which the competitive supplier defaulted), would conduct short-term procurements at market prices pending the approval of the Pennsylvania PUC of an alternative mechanism.[7] These contingency plans, however, have only limited applicability in Ohio with regard to the satisfaction of the Ohio AEPS. The contingency approach adopted by the FirstEnergy Ohio utilities in response to insufficient bidder participation, as noted previously, was to reissue the RFP with certain modifications to the terms and conditions. We also note that the contingency plans proposed for Pennsylvania Default Service (both power supply and RECs) address supplier default and insufficient bidder response. The contingency plans do not address the issue of unacceptable bids due to non-competitive pricing.

Figure 1 shows the dates of RFP issuance and the RECs solicited under each of the six RFPs along with other key dates related to SREC/REC procurement activities.

[7] Direct Testimony of Dean Stathis before the Pennsylvania Public Utility Commission, Docket Nos. P-2011-2273650, P-2011-2273668, P-2011-2273669, and P-2011-2273670 (Default Service Programs for the Period June1, 2013 to May 31, 2015 on behalf of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company, pp. 11-14 and 20-22).

Figure 1Timeline of RFPs for RECs by FirstEnergy Ohio Utilities
Calendar Years: 2009, 2010, and 2011



D. Findings and Recommendations on RFPs and RFP Processes

Based on the foregoing discussion and analysis, the following findings and recommendations are provided:

Findings.

1. The RFPs issued by the FirstEnergy Ohio utilities are reasonably developed and do not appear to incorporate any provisions or terms that could be assessed to be anti-competitive.
2. The basic terms and conditions contained in the RFP were generally acceptable by the industry and to the extent that individual bidders were unwilling to provide bids in response to the solicitations, those decisions were based on specific elements contained in the RFPs that were at odds with the individual business models. Such conditions include the duration of the contract periods and the firmness of the supply requirements.
3. The security requirements contained in the RFPs are assessed to strike a reasonable balance between safeguarding the interests of the FirstEnergy Ohio utilities and their customers and making the RFP attractive to potential bidders.
4. The processes in place to disseminate information to potential bidders and to address issues and questions that arose during the time that potential bidders were deciding whether to proffer a bid and the offer due dates was adequate.
5. The mechanisms in place to review and evaluate the bids were adequate, although a shorter period of time between the bid due date and the award in the first RFP would have been an improvement. The approximately three-week review period established by the FirstEnergy Ohio utilities was generally deemed excessive by industry participants and this was rectified by the FirstEnergy Ohio utilities in subsequent RFPs.
6. The mechanisms in place to solicit industry feedback, through both the nature of the questions and comments raised by potential bidders and the conduct of a survey by NCI, are seen as an acceptable approach to inform the FirstEnergy Ohio utilities about the strengths and weaknesses of the issued RFPs. Further, the information obtained through the process was effectively used and served as a basis for modifications in RFPs subsequent to the conduct of the survey.
7. Market information for In-State Solar and All Renewables RECs was limited prior to the issuance of the first and second RFPs.
8. The contingency planning in place for the first three RFPs was inadequate and should have encompassed a specific set of fall-back approaches, or in the alternative, specified a mechanism by which to distill the information gained from the solicitations to develop a modified approach.

Recommendations.

1. The FirstEnergy Ohio utilities should implement a more robust contingency planning process as it relates to the procurement of RECs and SRECs in compliance with Ohio's AEPS. We also recommend that the contingency plan be subject to review by the PUCO Staff prior to its implementation.
2. A thorough market analysis should precede the issuance of any future RFPs by the FirstEnergy Ohio utilities for RECs and SRECs in compliance with Ohio's AEPS. While market information was relatively modest prior to the issuance of the first two RFPs, greater market information regarding In-State Solar and All Renewables is currently available.
3. The FirstEnergy Ohio utilities should consider a mark-to-market approach to the security requirement for future procurements.

III. SOLICITATION RESULTS AND PROCUREMENT DECISIONS

As part of this management/performance audit, Exeter Associates, Inc. reviewed the results of the FirstEnergy Ohio utilities' procurement of SRECs and RECs to meet the Ohio AEPS requirements for 2009, 2010, and 2011. In particular, Exeter reviewed the quantities of SRECs and RECs bid, the prices associated with those bids, and the decisions of the FirstEnergy Ohio utilities regarding the bids (quantity and price) received. In the broadest terms, the procurement results can be characterized as follows:

- All-States All Renewables
  - All required RECs were secured at reasonable prices, though additional temporal diversity in establishing the REC portfolio would be desirable.
- All-States Solar
  - Based on information available at the time the bids were received, the Companies' purchasing decisions are found to be generally reasonable.
- In-State All Renewables
  - The Companies purchased significant quantities of RECs for 2009, 2010, and 2011 compliance years at prices assessed to be unreasonable on their face and also in comparison to prices paid elsewhere throughout the country.
- In-State Solar
  - The unavailability of Ohio SRECs in 2009 and 2010 led the Companies to request *force majeure* determinations from the Commission, which were granted. The procurements of Ohio SRECs made by the Companies when such SRECs became available were made at prices comparable to SRECs traded elsewhere.

While the principal concerns of the procurements center on the costs of the In-State All Renewables RECs, each of the categories of SREC and REC purchases are discussed below.

A. All-States All Renewables RECs

Table 2 provides a summary of the bids received for All-States All Renewables RECs by the FirstEnergy Ohio utilities by compliance year and by RFP issued. Where SRECs and/or RECs were acquired through bilateral transactions or supplied by the FirstEnergy Ohio utilities directly, that is so indicated.

The bulk of All-States All Renewables RECs required to meet the 2009, 2010, and 2011 AEPS requirements were procured through the first RFP. Under that RFP, all of the 2009 requirement, 93 percent of the 2010 requirement (based on kWh sales data available in 2009), and 60 percent of the 2011 requirement (based on kWh sales data available in 2009) were

procured. Prices ranged between $[redacted] and $[redacted] for the 2009 requirement, $[redacted] and $[redacted] for the 2010 requirement, and $[redacted] and $[redacted] for the 2011 requirement.

Additional RECs for 2010 were acquired through a transfer of excess 2009 RECs from 2009. This level of RECs purchases more than fulfilled the 2010 RECs requirement.

Table 2 FirstEnergy Ohio – All-States All Renewables RECs

	2009		2010		2011	
REC Requirement [1] [2] [3]	57,965		111,477		176,156	
RECs Acquired [4]	**2009**		**2010**		**2011**	
RFP1	87,360		104,000		105,084	
RFP2	(a)		(a)		(a)	
RFP3	(a)		(a)		49,351	
RFP4	(a)		(a)		(a)	
RFP5	(a)		(a)		(a)	
RFP6	(a)		(a)		(a)	
Bilateral Transactions	(b)		(b)		(b)	
Adjustment/Transfer	(29,396)		29,396 (21,920)		21,920	
TOTAL	87,360		133,396		176,355	
Percent of Total	**2009**		**2010**		**2011**	
RFP1	151%		93%		60%	
RFP2	(a)		(a)		(a)	
RFP3	(a)		(a)		28%	
RFP4	(a)		(a)		(a)	
RFP5	(a)		(a)		(a)	
RFP6	(a)		(a)		(a)	
Bilateral Transactions	(b)		(b)		(b)	
Adjustment/Transfer	(51%)		26% (20%)		12%	
TOTAL	100%		100%		100%	
Price Range ($/REC) [4]	**2009**		**2010**		**2011**	
	MIN	MAX	MIN	MAX	MIN	MAX
RFP1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
RFP2	(a)	(a)	(a)	(a)	(a)	(a)
RFP3	(a)	(a)	(a)	(a)	[redacted]	[redacted]
RFP4	(a)	(a)	(a)	(a)	(a)	(a)
RFP5	(a)	(a)	(a)	(a)	(a)	(a)
RFP6	(a)	(a)	(a)	(a)	(a)	(a)
Bilateral Transactions	(b)	(b)	(b)	(b)	(b)	(b)
Adjustment/Transfer			0.00	0.00	[redacted]	[redacted]
Weighted Average Price ($/REC) [4]	**2009**		**2010**		**2011**	
RFP1	[redacted]		[redacted]		[redacted]	
RFP2	(a)		(a)		(a)	
RFP3	(a)		(a)		[redacted]	
RFP4	(a)		(a)		(a)	
RFP5	(a)		(a)		(a)	
RFP6	(a)		(a)		(a)	
Bilateral Transactions	(b)		(b)		(b)	
Adjustment/Transfer			0.00		[redacted]	

Table 2 FirstEnergy Ohio – All-States All Renewables RECs (Continued)

Notes:

(a) This RFP did not solicit the indicated type of REC for the given energy year.

(b) No RECs were procured through bilateral transactions for the given energy year.

Sources:

(1) PUCO Case No. 10-499-EL-ACP, Annual Status Report and 2009 Compliance Review, Appendix A: 2009 Alternative Energy Resource Benchmarks and Compliance Reconciliation.

(2) PUCO Case No. 11-2479-EL-ACP, Annual Status Report and 2010 Compliance Review, Appendix A: 2010 Alternative Energy Resource Benchmarks and Compliance Reconciliation.

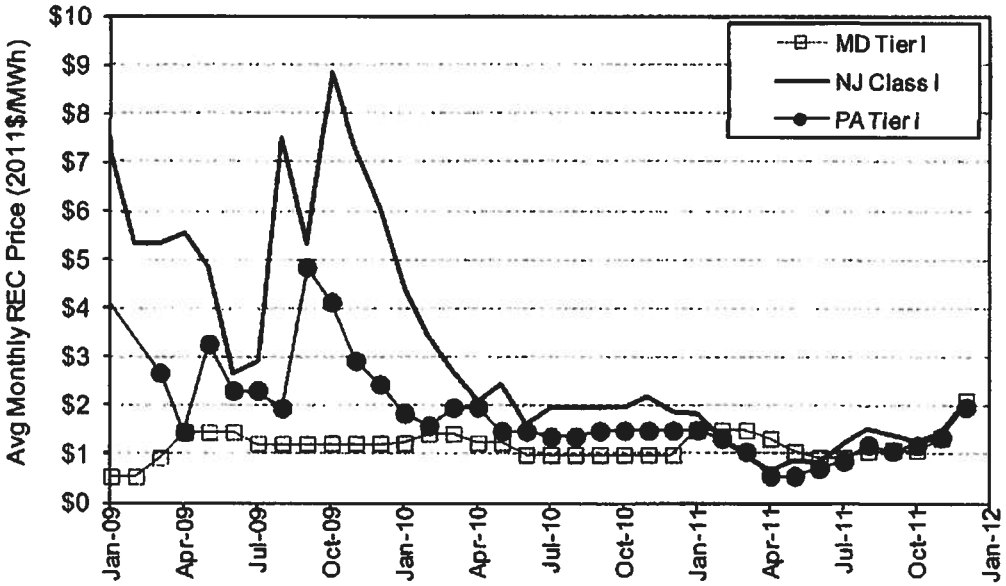
(3) PUCO Case No. 12-1246-EL-ACP, Annual Status Report and 2011 Compliance Review, Appendix A: 2011 Alternative Energy Resource Benchmarks and Compliance Reconciliation.

(4) Calculated based on EA Set 1-INT-5 Attachment 1.

For 2011, an additional 49,351 All-States All Renewable RECs were procured through the third RFP issued in July 2010, and 21,920 All-States All Renewable RECs, which fulfilled the 2011 requirement, were obtained through a transfer of excess 2010 RECs. The 2011 All-States All Renewable RECs were bid at prices between $[redacted] and $[redacted]. The transferred RECs were purchased at a price of $[redacted] per REC.

Figure 2 shows non-solar REC prices in Pennsylvania, Maryland, and New Jersey over the 2009 through 2011 period. As is shown in Figure 2, RECs prices in New Jersey tended to be above the prices paid by the FirstEnergy Ohio utilities in 2009 for 2009-Vintage RECs and the Pennsylvania RECs are shown to entail prices below the RECs purchased by the FirstEnergy Ohio utilities. The pattern of prices evident in New Jersey and Pennsylvania is not atypical of RECs price trends elsewhere, that is, in the first years of enactment of a state portfolio standard, prices tend to be higher than in following years as the market adjusts and more projects become built and certified.

Figure 2 Historical Maryland, New Jersey, and Pennsylvania Compliance RECs Prices



Sources: Evolution Markets (through 2007) and Spectron (2008 onward). Plotted values are the last trade (if available) or the mid-point of Bid and Offer prices, for the earliest compliance year traded in each month.

Note: Figure provided to Exeter by personnel from the National Renewable Energy Laboratory (NREL), May 2012

As seen with the FirstEnergy Ohio utilities' experience, substantially higher prices were paid in 2009 (for 2009, 2010, and 2011 vintage RECs) than were experienced in 2011 for 2011 vintage RECs. These price relationships indicate that lower-cost compliance would have been achieved for the All-States All Renewables component of the AEPS requirement had the FirstEnergy Ohio utilities procured a greater proportion of 2011 RECs in 2011 and, perhaps, a portion of 2010 RECs in 2010. This conclusion is clear from *ex post* analysis.

With respect to whether an alternative strategy for procurement of these RECs should have been pursued by the FirstEnergy Ohio utilities based on *ex ante* information is less clear. The Companies indicated during the Exeter interview conducted on April 20, 2012, that there was concern on the part of the Companies that the needed RECs might not be available in the timeframe required for compliance were the Companies to defer the purchase of 2010 and 2011 RECs in 2009. Notwithstanding this concern, a preferred method of risk management would have been to temporally diversify the purchases to avoid exposure to prevailing prices at one point in time. This method to help manage risk would have been beneficially employed by the FirstEnergy Ohio utilities with respect to REC purchases, that is, purchases of RECs should have been spread out over time.[8]

[8] We note that this approach is not employed for purposes of cost minimization but rather for purposes of risk mitigation.

Related to the issue of risk mitigation is the pattern of REC prices that has tended to emerge following the implementation of renewable energy portfolio standards in other states. The general downward trend, fueled by increases in the availability of RECs that has come from industry response, should have informed the FirstEnergy Ohio utilities' decision to purchase almost all RECs needed to meet the 2009 through 2011 All-States All Renewables requirement in 2009.

While we believe that an alternative approach should have been relied upon by the FirstEnergy Ohio utilities, there are considerations that may have reasonably influenced the Companies' decision to maximize purchases in 2009 to fulfill the 2009 through 2011 AEPS requirements for All-States All Renewables RECs. One such consideration, as noted above, was the potential unavailability of the necessary RECs in later months. Given the annual increases in the percentage renewable requirements over time, not only in Ohio but in other states from which the FirstEnergy Ohio utilities could expect to draw RECs, this perspective is not without some basis. A related concern would emerge in the context of pricing, which could increase in the face of tightening market conditions. Even with growth in the amount of RECs available, the increases in RECs offered on the market would need to be greater than the increase in renewable requirements to induce downward pressure on prices and ensure availability.

A final factor simply relates to the structure of incentives faced by the FirstEnergy Ohio utilities. The Companies were required to secure the necessary RECs for the 2009 through 2011 period. Absent the availability of RECs post 2009, the Companies would be faced with either obtaining a *force majeure* ruling from the Commission, for which a risk would be incurred (i.e., the Commission could deny the request) or, in the event that the required number of RECs were unavailable, the Company could pay the alternative compliance payment ("ACP") of $45 per REC. The Companies, however, could not recover the ACP expense from customers pursuant to the legislation. As a consequence, the Companies had every incentive to secure the required number of RECs and avoid the incurrence of any risk that the RECs would be unavailable in the future. In that way, the Companies would avoid any potential of incurring a non-recoverable ACP expense.

<u>Findings</u>

1. The prices paid by the Companies for All-States All Renewables RECs were reasonably consistent with other regional RECs prices.
2. While lower prices would have been available to the Companies were fewer RECs purchased under RFP 1 and more RECs purchased under RFP 3, given Finding No. 1, above, the Companies' decision to purchase the bulk of the 2009, 2010, and 2011 requirements under RFP 1 was not unreasonable.

B. All-States Solar RECs

Table 3 shows a summary of the RFP results (and bilateral arrangements) related to the procurement of All-States Solar RECs by the FirstEnergy Ohio utilities. As shown in Table 3, the Companies procured enough Solar RECs in each year to meet their All-States Solar RECs requirements. Though the first RFP failed to solicit any All-States Solar REC purchases, the second RFP (in 2009) resulted in the successful procurement of enough 2009 All-States Solar RECs to meet the 2009 requirement along with a small number of 2010 and 2011 All-States Solar RECs. Prices for the 2009 All-States Solar RECs ranged from $[redacted] to $[redacted].

The third RFP, issued in 2010, resulted in the Companies procuring 550 vintage 2010 All-States Solar RECs. However, the majority of the Solar RECs procured in the 2010 auction were for the 2011 compliance year (3,331 vintage 2011 SRECs). The Companies engaged in extensive efforts to execute deals with brokers and make bilateral trades to meet the bulk of the 2010 All-States Solar RECs requirement. The Companies purchased a total of 2,454 Solar RECs from brokers and through other bilateral arrangements. The price range for the vintage 2010 All-States Solar RECs procured through the 2009 RFP was $[redacted] to $[redacted]. The price range for the vintage 2010 All-States Solar RECs procured through the 2010 RFP was very similar -- $[redacted] to $[redacted]. As noted earlier, the bulk of the 2010 All-States Solar RECs were procured through bilateral trades and the price range for these transactions was $[redacted] to $[redacted].

Table 3 FirstEnergy Ohio – All-States Solar RECs

	2009		2010		2011	
SREC Requirement [1] [2] [3]	48		3,169		5,447	
SRECs Acquired [4]	**2009**		**2010**		**2011**	
RFP1	0		0		0	
RFP2	48		208		4	
RFP3	(a)		550		3,331	
RFP4	(a)		(a)		(a)	
RFP5	0		0		2,200	
RFP6	(a)		(a)		(a)	
Bilateral Transactions	(b)		2,454		37	
TOTAL	48		3,212		5,572	
Percent of Total	**2009**		**2010**		**2011**	
RFP1	0%		0%		0%	
RFP2	100%		7%		0%	
RFP3	(a)		17%		61%	
RFP4	(a)		(a)		(a)	
RFP5	0%		0%		40%	
RFP6	(a)		(a)		(a)	
Bilateral Transactions	(b)		77%		1%	
TOTAL	100%		101%		102%	
Price Range ($/SREC) [4]	**2009**		**2010**		**2011**	
	MIN	MAX	MIN	MAX	MIN	MAX
RFP1	N/A	N/A	N/A	N/A	N/A	N/A
RFP2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
RFP3	(a)	(a)	[redacted]	[redacted]	[redacted]	[redacted]
RFP4	(a)	(a)	(a)	(a)	(a)	(a)
RFP5	N/A	N/A	N/A	N/A	[redacted]	[redacted]
RFP6	(a)	(a)	(a)	(a)	(a)	(a)
Bilateral Transactions	(b)	(b)	[redacted]	[redacted]	[redacted]	[redacted]
Weighted Average Price ($/SREC) [4]	**2009**		**2010**		**2011**	
RFP1	N/A		N/A		N/A	
RFP2	[redacted]		[redacted]		[redacted]	
RFP3	(a)		[redacted]		[redacted]	
RFP4	(a)		(a)		(a)	
RFP5	N/A		N/A		[redacted]	
RFP6	(a)		(a)		(a)	
Bilateral Transactions	(b)		[redacted]		[redacted]	

Notes:
(a) This RFP did not solicit the indicated type of REC for the given energy year.
(b) No RECs were procured through bilateral transactions for the given energy year.
Sources:
(1) PUCO Case No. 10-499-EL-ACP, Annual Status Report and 2009 Compliance Review, Appendix A: 2009 Alternative Energy Resource Benchmarks and Compliance Reconciliation.
(2) PUCO Case No. 11-2479-EL-ACP, Annual Status Report and 2010 Compliance Review, Appendix A: 2010 Alternative Energy Resource Benchmarks and Compliance Reconciliation.
(3) PUCO Case No. 12-1246-EL-ACP, Annual Status Report and 2011 Compliance Review, Appendix A: 2011 Alternative Energy Resource Benchmarks and Compliance Reconciliation.
(4) Calculated based on EA Set 1-INT-5 Attachment 1.

For the 2011 compliance year, the Companies procured 3,331 All-States Solar RECs through the 2010 RFP (RFP3) at a price range of $[redacted] to $[redacted]. The Companies also procured 37 vintage 2011 All-States Solar RECs through an internal bilateral trade executed in 2011 at a price of $[redacted] per SREC. The remaining portion of the 2011 All-States Solar RECs requirement was procured through an RFP held in mid-2011. The price range for the 2,200 All-States Solar RECs purchased through this RFP was $[redacted] to $[redacted], significantly lower than the prices paid for the vintage 2011 All-States Solar RECs procured in the 2009 and 2010 RFPs and through the bilateral internal trade.

As with the All-States All Renewables RECs, an *ex post* analysis indicates that FirstEnergy Ohio utilities would have paid significantly less for 2011 All-States Solar RECs if they had waited until 2011 to purchase these SRECs. As discussed in the section on All-States All Renewables RECs, the Companies expressed concerns that the needed SRECs might not be available in the timeframe required to meet for compliance.

As discussed previously in this audit report, the appropriateness and reasonableness of any particular RECs transaction cannot be assessed on the basis of information that would not have been available at the time of the transaction, such as RECs prices that would have been knowable only after the fact. The prices paid by the FirstEnergy Ohio utilities for All-States Solar RECs were roughly consistent with prices paid in other nearby states with a solar set-aside. SREC prices in Pennsylvania in 2009 averaged about $275 and in 2010 rose to approximately $325 per SREC.[9] New Jersey SRECs (which must all be generated in-State) were generally priced between $600 and $700 in 2009, 2010, and the first half of 2011.[10] By the end of 2011, New Jersey SREC prices declined to between $150 and $250.[11] In Maryland, which also requires that SRECs be generated in-State, prices in 2010 were between $350 and $400; between $100 and $350 in 2011; and declined to about $200 in 2012.[12]

While neither New Jersey nor Maryland SRECs can be used in Ohio to satisfy the All-States Solar requirement, both New Jersey and Maryland SRECs can be used in Pennsylvania. Pennsylvania SRECs can be used for the Ohio All-States Solar requirement. Therefore, while the pricing dynamics are complicated, there are relationships among the SREC prices in New Jersey, Maryland, Pennsylvania, and Ohio.

As a general proposition, temporal diversity in purchasing to help manage risk is a prudent practice. The number of All-States SRECs that the FirstEnergy Ohio utilities were purchasing in the 2009 and 2010 timeframe were relatively small, and through the circumstances that evolved over the procurement history, a degree of temporal diversity was achieved. In

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[9] www.srectrade.com/blog/SREC/SREC-markets/Pennsylvania/page/3 (and page/4).
[10] http://markets.flettexchang.com/new-jersey-SREC
[11] Ibid.
[12] http://markets.flettsexchange.com/maryland-SREC

aggregate, the 2009 and 2010 requirement was approximately 3,200 RECs, which were purchased through two RFPs and a set of bilateral transactions.

2011 All-States Solar RECs were almost entirely purchased through two RFPs (RFP 3 and RFP 5). The average price of Solar RECs under the RFP 3 procurement was approximately $[redacted]. The RFP 5 Solar RECs prices averaged $[redacted] and some Solar RECs under that procurement were purchased for less than $[redacted]. This pattern of Solar RECs prices over the 2009 through 2011 time period is consistent with the pricing observed in other nearby states as the supply of available Solar RECs generally exceeded the Solar RECs compliance requirements in the regional market. The excess supply of All-States Solar RECs evident in 2011 is not a circumstance that the FirstEnergy Ohio utilities could have been reasonably expected to foresee.

Findings

The lower prices available for All-States SRECs in the 2011 timeframe could not have been reasonably foreseen by the Companies. The prices paid by the Companies for All-States SRECs are consistent with SRECs prices regionally.

C. In-State All Renewables RECs

Fifty percent of the All Renewables requirement under the Ohio AEPS legislation is set aside for qualifying renewable energy generated in Ohio. In 2009, the supply of Ohio-generated RECs appears to have approximated (or was slightly below) the State-wide compliance requirement.[13] The FirstEnergy Ohio utilities were able to successfully procure the required number of 2009, 2010, and 2011 In-State All Renewables RECs through bids offered in four RFPs. RFP 1 provided 2009 and 2010 RECs; RFP 2 provided RECs for all three compliance years; RFP 3 provided RECs for 2010 and 2011; and RFP 6 secured additional 2011 vintage RECs.

The fundamental issue associated with the FirstEnergy Ohio utilities' procurement of In-State All Renewables RECs for compliance with the 2009, 2010, and 2011 requirements centers on the prices paid for the RECs. Significant numbers of RECs were purchased at prices as high as $[redacted] per REC. Table 4 summarizes the procurement history of the In-State All Renewables RECs for the 2009, 2010, and 2011 compliance years. As seen on Table 4, all of the 20,000 RECs purchased through RFP 1 for 2009 were priced at $[redacted]. In addition, the 50,000 RECs purchased in RFP 1 for 2010 were priced between $[redacted] and $[redacted], with a weighted average price of $[redacted]. RFP 2, which resulted in purchases of RECs for all three compliance years addressed in this audit (2009, 2010, and 2011), had associated weighted average prices of $[redacted], $[redacted], and $[redacted], respectively. In aggregate, 95,849 In-State All Renewables RECs were purchased through this solicitation. RFP 3 resulted in procurement of almost 180,000 In-State All Renewables

[13] Ed Holt and Associates, Inc. and Exeter Associates, Inc., *Alternative Energy Resource Market Assessment*, prepared for the Public Utility Commission of Ohio and the National Association of Regulatory Utility Commissioners, September 30, 2011, p.6.

RECs, with average prices of $[redacted] (for the 29,676 RECs purchased for 2010) and $[redacted] for the 150,269 RECs purchased for 2011. RFP 6 entailed the purchase of an additional 20,000 2011 RECs at an average price of $[redacted].

Table 4 FirstEnergy Ohio – In-State All Renewables RECs

	2009		2010		2011	
REC Requirement [1] [2] [3]	57,965		111,477		176,155	
RECs Acquired [4]	**2009**		**2010**		**2011**	
RFP1	20,000		50,000		0	
RFP2	37,965		31,800		26,084	
RFP3	(a)		29,676		150,269	
RFP4	(a)		(a)		(a)	
RFP5	(a)		(a)		(a)	
RFP6	(a)		(a)		20,000	
Bilateral Transactions	(b)		1		(b)	
TOTAL	57,965		111,477		196,353	
Percent of Total	**2009**		**2010**		**2011**	
RFP1	35%		45%		0%	
RFP2	65%		29%		15%	
RFP3	(a)		27%		85%	
RFP4	(a)		(a)		(a)	
RFP5	(a)		(a)		(a)	
RFP6	(a)		(a)		11%	
Bilateral Transactions	(b)		0%		(b)	
TOTAL	100%		100%		111%	
Price Range ($/REC) [4]	**2009**		**2010**		**2011**	
	MIN	MAX	MIN	MAX	MIN	MAX
RFP1	[redacted]	[redacted]	[redacted]	[redacted]	N/A	N/A
RFP2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
RFP3	(a)	(a)	[redacted]	[redacted]	[redacted]	[redacted]
RFP4	(a)	(a)	(a)	(a)	(a)	(a)
RFP5	(a)	(a)	(a)	(a)	(a)	(a)
RFP6	(a)	(a)	(a)	(a)	[redacted]	[redacted]
Bilateral Transactions	(b)	(b)	[redacted]	[redacted]	(b)	(b)
Weighted Average Price ($/REC) [4]	**2009**		**2010**		**2011**	
RFP1	[redacted]		[redacted]		N/A	
RFP2	[redacted]		[redacted]		[redacted]	
RFP3	(a)		[redacted]		[redacted]	
RFP4	(a)		(a)		(a)	
RFP5	(a)		(a)		(a)	
RFP6	(a)		(a)		[redacted]	
Bilateral Transactions	(b)		[redacted]		(b)	

Notes:

(a) This RFP did not solicit the indicated type of REC for the given energy year.

(b) No RECs were procured through bilateral transactions for the given energy year.

Sources:

(1) PUCO Case No. 10-499-EL-ACP, Annual Status Report and 2009 Compliance Review, Appendix A: 2009 Alternative Energy Resource Benchmarks and Compliance Reconciliation.

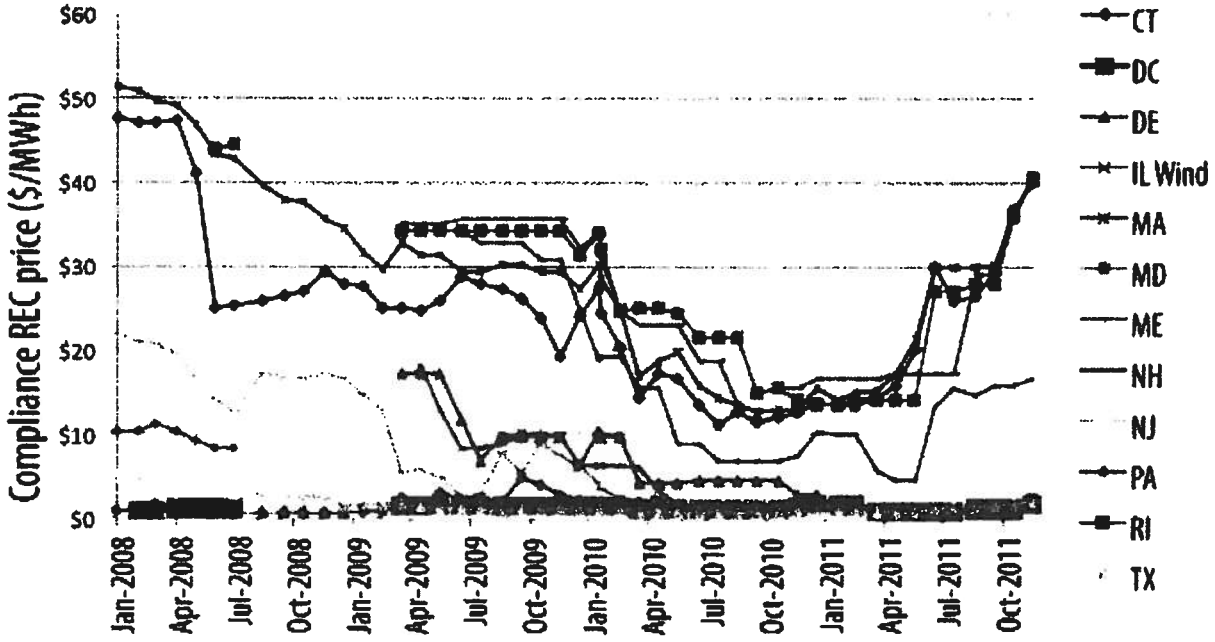
(2) PUCO Case No. 11-2479-EL-ACP, Annual Status Report and 2010 Compliance Review, Appendix A: 2010 Alternative Energy Resource Benchmarks and Compliance Reconciliation.

(3) PUCO Case No. 12-1246-EL-ACP, Annual Status Report and 2011 Compliance Review, Appendix A: 2011 Alternative Energy Resource Benchmarks and Compliance Reconciliation.

(4) Calculated based on EA Set 1-INT-5 Attachment 1.

The U.S. Department of Energy ("DOE") reports on solar and non-solar RECs prices throughout the U.S. Between mid-2008 and December 2011, none of the non-solar REC prices reported by DOE was above $45 and in almost all cases significantly below that level.[14] The states covered include Connecticut, the District of Columbia, Delaware, Illinois (wind RECs), Massachusetts, Maryland, Maine, New Hampshire, New Jersey, Pennsylvania, Rhode Island, and Texas (See Figure 3).[15] Additionally, the overall trend in REC prices has been declining during the period from January 2008 through mid-2011. Beginning in mid-2011, there have been marked increases in the prices of RECs for some of the states included in the DOE reporting due to certain state changes to renewable eligibility and also increasing percentage requirements for renewables.

Figure 3 Compliance Markets for RECs



Compliance market (primary tier) REC prices, January 2008 to December 2011
Source: apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5

Note: Plotted values are the last trade (if available) or the mid-point of bid and offer prices for the current or nearest compliance year for various state compliance RECs.

[14] http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5. While this graph contains information through 2011, the pricing information for earlier years was available contemporaneously.
[15] We note that there are significant differences among the RPS programs in the various states with respect to eligible resources (technologies and locations), the percentage renewable requirements, and set-asides for particular technologies.

Two qualifications, however, should be noted. First, the price decreases over time were not monotonic over the time period considered. While the average annual prices declined over time, there were interim months in which prices increased compared to prior months. Second, the specifics of the Renewable Portfolio Standard legislation in place in the various states differ from the Ohio AEPS legislation. These differences include the types of renewable resources eligible to meet the requirements and the geographic areas from which the RECs may originate. Particularly with respect to the second factor, the Ohio AEPS legislation is more restrictive than the legislation in other states, including the New Jersey, Maryland, and the Pennsylvania legislation, which, other factors equal, could result in higher REC prices in Ohio than elsewhere. We also note that the prices shown on Figure 3 do not represent the mid-point of offer and bid prices for the full market. These data are based on surveys and published data and likely exclude certain bilateral market transactions which could serve to move the reported numbers either up or down. Consequently, the non-Ohio REC prices discussed above cannot serve as a proxy for Ohio In-State All Renewables RECs prices. Rather, they provide a broad reference to what RECs have been trading for elsewhere over the relevant period under a wide range of RPS specifics and market conditions.

Table 5 shows the details of the purchases of In-State All Renewables RECs by the FirstEnergy Ohio utilities, including the dates of the purchases, the vintage year of the purchases, the quantity purchased, and the price paid. Total RECs purchased and costs incurred are also shown. The issue that is addressed below, which draws heavily on the information contained in Table 5, is the reasonableness of the prices paid by the FirstEnergy Ohio utilities for In-State All Renewables RECs for the compliance years 2009, 2010, and 2011. In addressing the reasonableness of these purchases, we avoid assessment based on *ex post* analysis and restrict the assessment to what would be considered reasonable at the time the transactions were entered into.

Table 5 In-State All Renewables RECs Prices Paid by FirstEnergy Ohio Utilities

2009 Vintage	Purchase Date	Quantity	Price/REC	Total
	August 2009	20,000	$ [redacted]	$ [redacted]
	October 2009	960	[redacted]	[redacted]
		37,005	[redacted]	[redacted]
	February 2010	13	[redacted]	[redacted]
	SUBTOTAL	57,978		$ [redacted]
2010 Vintage	August 2009	10,000	$ [redacted]	$ [redacted]
		10,000	[redacted]	[redacted]
		10,000	[redacted]	[redacted]
		10,000	[redacted]	[redacted]
		10,000	[redacted]	[redacted]
	October 2009	30,400	[redacted]	[redacted]
		1,400	[redacted]	[redacted]
	August 2010	29,676	[redacted]	[redacted]
	April 2011	1	[redacted]	[redacted]
	SUBTOTAL	111,477		$ [redacted]
2011 Vintage	October 2009	1,084	$ [redacted]	$ [redacted]
		25,000	[redacted]	[redacted]
	August 2010	145,269	[redacted]	[redacted]
		5,000	[redacted]	[redacted]
	November 2011	5,000	[redacted]	[redacted]
		15,000	[redacted]	[redacted]
	SUBTOTAL	196,353		$ [redacted]
	TOTAL	365,808		$ [redacted]

Based on our review of the legislation, the responses of the FirstEnergy Ohio utilities to our requests for information, and various Commission filings, and our interview with FirstEnergy Ohio utility personnel and personnel from Navigant Consulting, there do not appear to be any technical violations of the Ohio's AEPS statute and the FirstEnergy Ohio utilities appear not to have violated the letter of the legislation. That said, we believe that the management decisions made by the FirstEnergy Ohio utilities to purchase non-solar RECs at prices in some cases more than 15 times the price of the applicable forty-five-dollar Alternative Compliance Payment to have been seriously flawed. The prices paid by the FirstEnergy Ohio utilities for these RECs were well above the prices customarily seen in any of the other RECs markets throughout the country contemporaneous with (as well as preceding and subsequent to) the purchasing decisions made by the FirstEnergy Ohio utilities.

The mechanism employed by the FirstEnergy Ohio utilities for purchasing RECs through the RFP process was to stack the conforming bids received from eligible bidders from lowest price to highest price and to purchase the number of RECs needed to comply with the In-State

All Renewables requirement regardless of the price bid. No limit price was established by the Companies prior to the receipt of bids, that is, the Companies indicated that prior to the receipt of bids, the Companies did not establish a maximum price that they would be willing to pay for RECs, or a price that would trigger embarking on a contingency plan. Reliance on this approach resulted in the purchase of more than 337,000 In-State All Renewables RECs at prices between $[redacted] and $[redacted] dollars.

There are several issues that were considered in our assessment of the reasonableness of the high-priced RECs transactions entered into by the FirstEnergy Ohio utilities. Each is discussed in turn below.

Statutory Violations – While this audit is not a legal review and the following opinion is not based on a legal review, we found no indication that the FirstEnergy Ohio utilities operated outside of the legal requirements established by the Ohio AEPS legislation. There is nothing in the legislation that limits the price that the Companies could pay for RECs, other than the requirement that on an expected (forward looking) basis, the cost of compliance should not exceed three percent of the Companies charges for the provision of power supply. This limitation appears not to have been violated based on a reasonable application of the rule.

The solicitations issued by the Companies, as discussed earlier in this report, were competitive and the rules for the determination of winning bids appear to have been applied uniformly. We found nothing to suggest that the FirstEnergy Ohio utilities operated in a manner other than to select the lowest cost bids received from a competitive solicitation to satisfy the annual In-State All Renewables requirement established by the legislation.

Market Information – At the time the solicitations resulting in the procurement of the high-cost RECs were conducted, the market for In-State All Renewables in Ohio was still nascent; reliable, transparent information on market prices, future renewable energy projects that may have resulted in future RECs trading at lower prices, or other information that may have directly influenced the Companies' decision to purchase the high-priced RECs was generally not available. While information on planned renewable energy projects can be gleaned from the PJM interconnection queues, that information is highly unreliable. Some projects are entered multiple times (with variations on project specifics such as location or size) and most projects appearing in the queues do not come to fruition. The unreliability of the PJM queue information was further exacerbated by the economic recession and the difficulties faced by renewable energy developers in obtaining project financing. Consequently, we believe that there was significant uncertainty associated with assessing changes in future RECs prices and the potential availability of future RECs.

Market Competition – We have noted above that the procurement methods employed by the Companies are assessed to have been competitive. That does not mean, however, that the market in which the Companies were operating was competitive. The bids received by the

FirstEnergy Ohio utilities should have been interpreted by the Companies as indicative of serious market disequilibrium. The fundamental concept behind the creation of renewable energy portfolio standards, regardless of the state implementing the standard, is that to promote the development of renewable energy resources, an additional stream of revenue is required to be provided to the project owners to overcome the higher cost of renewable energy relative to energy generated from conventional sources. Absent the additional revenue stream associated with the marketability of the environmental attributes of renewable energy, i.e., the renewable energy credits, renewable technologies would not be able to effectively compete in the power markets. The market value of the RECs, therefore, should approximate the additional revenue required by project owners to facilitate the development of eligible renewable projects. We would expect, and in fact see, different values of RECs in different states based on a multitude of factors, most importantly including:

- The geographical area from which eligible RECs can be drawn; generally, the larger the geographical area from which the RECs can originate, the lower the price of the RECs;
- The types of resources that qualify as "renewable"; those states allowing relatively low-cost resources to qualify as renewable, such as black liquor or waste coal, tend to exhibit lower prices for RECs;
- The level of prevailing energy prices; the higher the price of energy, the lower the price of RECs, other factors equal;
- The size of the renewable requirement; the larger the percentage of the power supply that is required to be supplied from renewable resources, the higher is the price of the RECs, other factors equal;
- The size of the alternative compliance payment (ACP); the size of the ACP limits the market price of the RECs since RECs would not be purchased at prices higher than the ACP if energy providers can pay the ACP in lieu of paying for higher-priced RECs.

As noted previously in this report, none of the RECs prices elsewhere in the country were trading at prices more than $45 per REC during the relevant period, and many were selling for prices considerably lower. While this information does not translate to what RECs prices in Ohio should be, the underlying economic factors are the same, that is, the price of RECs should be adequate to cover the higher costs of generation using renewable technologies, subject to the economic impacts of the differences in state legislation. There is no basis for concluding that the cost of renewable energy development in Ohio differs so markedly from the cost of renewable development elsewhere in the country so as to warrant RECs prices of $[redacted] or more in Ohio compared to the RECs prices seen elsewhere.

RECs prices of that magnitude clearly indicate that some degree of market power is being exercised by a segment of the market given offered prices well above the cost of production. Consequently, the prices offered for the high-priced RECs, and accepted by the Companies, were composed largely of economic rents.[16] As regulated entities, those costs were in turn passed on to Standard Service Offer ("SSO") customers.

[redacted][17]

Available Alternatives – The FirstEnergy Ohio utilities' decisions related to acceptance of the bids for In-State All Renewables RECs at prices ranging from $[redacted] to $[redacted] needs to be assessed in the context of alternatives that were available to the Companies. If the Companies had no option other than to purchase these RECs at the prices offered, the decision would be evaluated differently than if alternatives existed. We believe that at least three alternatives were available to the Companies, and each of these is discussed below.

- Alternative Compliance Payment – One of the options available to the Companies was payment of the ACP in lieu of the procurement of RECs. The Companies indicated that they did not view the ACP as an alternative to the procurement of RECs and that payment of the ACP did not relieve them of the requirement to actually purchase RECs.[18] Under the assumption that the Companies' interpretation of the legislation is incorrect, that is, that the ACP could have been used as an alternative to the procurement of RECs, that

[16] We note that the economic rents received may not necessarily accrue to the party selling the RECs to the FirstEnergy Ohio utilities. For example, if the seller purchased the RECs from a third party at high prices, the rents may have accrued to the third party. Economic rents can be defined as the return to the investment in excess of the minimum required to induce the investment.

[17] The Companies' decisions to purchase the high-priced RECs were consistent with the recommendations of its consultant, NCI.

[18] The issue of reliance on the ACP as an alternative to the procurement of the high-priced RECs was raised during the April 20, 2012 interview with FirstEnergy Ohio utilities and Navigant Consulting personnel. During the interview, the personnel from the Companies expressed the perspective that the Alternative Compliance Payment is not an alternative to procuring RECs. In a separate request for information, the Companies' were unwilling to provide a legal opinion on this issue, but noted that there is no language in the legislation to suggest that the Alternative Compliance Payment is an alternative to compliance through the procurement of RECs. (FirstEnergy Ohio utilities response to Exeter Associates' request for information, set 5, item 3.)

option was available to the Companies. The legislation, however, precludes the Companies from recovery of any costs related to Alternative Compliance Payments.[19] This provision of the legislation provides a serious deterrent to the State's utility companies from reliance on the ACP and payment of the ACP rather than procuring RECs, even at prices higher than the $45 ACP. Personnel from the Companies indicated during the April 20, 2012 interview that they did not consider use of the ACP as a mechanism to avoid the cost of the high-priced RECs.

- Consultation with the Commission – FirstEnergy Ohio utilities' personnel were asked whether they considered informing the Commission of the status of the bids received to obtain Commission input regarding a decision to purchase. The Companies indicated during the April 20, 2012 interview that approaching the Commission and explaining the circumstances of the solicitation results was not considered. While the Companies were under no statutory obligation to obtain approval by the Commission for RECs purchases, the prices for the In-State All Renewables RECs that were received through the solicitation process were so far above customary prices outside of Ohio that consultation with the Commission should certainly have been at least considered by the Companies prior to transacting.

- Rejection of High-Priced Bids – As part of the solicitation process, the Companies retained the right to reject any and all bids. In the face of the high prices received [redacted] for the provision of In-State All Renewables RECs, the Company had the option of simply rejecting the bids. That would likely have necessitated the Companies filing a *force majeure* determination request with the Commission on the basis that In-State All Renewables RECs were not "reasonably" available (which appears to be accommodated in the legislation).[20]

  A second alternative would have been to procure the high-priced RECs for compliance with the 2009 requirements, but reject those bids for the 2010 and 2011 requirements. That decision would be based on an assessment that In-State All Renewables RECs would become more available over time and could be secured at lower prices in the future. The risk of that approach, expressed by FirstEnergy Ohio utilities personnel, was that In-State All Renewables RECs would not increase in availability and would be in shorter supply in the coming years. That circumstance would expose the Companies to being unable to procure the requisite RECs for compliance years 2010 and 2011. Based on information available from other states, a decision to delay the purchases of RECs would have been preferred. For example, the Companies were able to procure 20,000 2011-vintage RECs in 2011 at an average price of $[redacted] compared to the average prices

[19] Competitive suppliers are also precluded from explicit recovery of these costs, that is, a competitive supplier cannot include a line item on its invoices separately identifying ACP costs as part of its billing. Competitive suppliers, however, can incorporate the ACP into their overall energy price to recover their costs. That option, however, is not available to regulated utilities supplying SSO energy.

[20] Note that this is not a legal opinion and is based on a lay reading and interpretation of the statute.

of $[redacted] (RFP 2) and $[redacted] (RFP 3). While the Companies could not know with certainty that prices would be declining over time or that the required number of In-State All Renewables RECs would be available at any price in sufficient time to meet the compliance requirements, the experience in other states suggests that prices would be declining and that RECs would be increasingly available as markets respond to the newly created demand for RECs. If circumstances emerged such that In-State All Renewables RECs were not available in later years, the Companies would have had a basis for requesting a *force majeure* determination by the Commission.

Findings

Based on the foregoing discussion, our findings related to the FirstEnergy Ohio utilities procurement of In-State All Renewables RECs for compliance years 2009, 2010, and 2011 are:

1. The FirstEnergy Ohio utilities did not establish a maximum price that the Companies were willing to pay for In-State All Renewables RECs prior to the issuance of the RFPs.
2. The FirstEnergy Ohio utilities paid unreasonably high prices for In-State All Renewables RECs purchased from [redacted].
3. Prices for In-State All Renewable RECs in the range of $[redacted] to $[redacted] exceeded the prices paid for non-solar compliance RECs anywhere in the country by at least $[redacted] to $[redacted].
4. The FirstEnergy Ohio utilities had several alternatives available to the purchase of high-priced In-State All Renewables RECs, none of which were considered or acted upon.
5. The FirstEnergy Ohio utilities should have been aware that the prices bid by [redacted] reflected significant economic rents and were excessive by any reasonable measure.

Recommendations

Based on the findings presented above, we recommend that the Commission examine the disallowance of excessive costs associated with purchasing RECs to meet the FirstEnergy Ohio utilities' In-State All Renewables obligations.

D. In-State Solar RECs

Table 6 shows a summary of the RFP results (and bilateral arrangements) related to the procurement of In-State Solar RECs by the FirstEnergy Ohio utilities. As shown on Table 6, the Companies were unable to secure adequate solar RECs from in-State sources to meet the 2009

requirement, which necessitated a request for a *force majeure* ruling from the Commission. The Commission determined that adequate solar RECs were not available to the Companies and granted the *force majeure* request, moving the 2009 In-State Solar requirement to 2010. A similar *force majeure* request was made in 2010 for 2010 vintage In-State Solar RECs, and was again granted by the Commission. The unfulfilled obligation for 2010 was extended to 2011.

Table 6 FirstEnergy Ohio – In-State Solar RECs

	2009	2010	2011
SREC Requirement [1] [2] [3]	13	1,629	7,026
SRECs Acquired [4]	**2009**	**2010**	**2011**
RFP1	0	0	0
RFP2	0	6	1,347
RFP3	(a)	182	946
RFP4	0	11	(a)
RFP5	0	0	4,653
RFP6	(a)	(a)	5,000
Bilateral Transactions	13	1,569	1,057
TOTAL	13	1,768	13,003
Percent of Total	**2009**	**2010**	**2011**
RFP1	0%	0%	0%
RFP2	0%	0%	19%
RFP3	(a)	11%	13%
RFP4	0%	1%	(a)
RFP5	0%	0%	66%
RFP6	(a)	(a)	71%
Bilateral Transactions	100%	96%	15%
TOTAL	100%	109%	185%

Price Range ($/SREC) [4]	2009		2010		2011	
	MIN	MAX	MIN	MAX	MIN	MAX
RFP1	N/A	N/A	N/A	N/A	N/A	N/A
RFP2	N/A	N/A	[redacted]	[redacted]	[redacted]	[redacted]
RFP3	(a)	(a)	[redacted]	[redacted]	[redacted]	[redacted]
RFP4	N/A	N/A	[redacted]	[redacted]	(a)	(a)
RFP5	N/A	N/A	N/A	N/A	[redacted]	[redacted]
RFP6	(a)	(a)	(a)	(a)	[redacted]	[redacted]
Bilateral Transactions	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Weighted Average Price ($/SREC) [4]	2009	2010	2011
RFP1	N/A	N/A	N/A
RFP2	N/A	[redacted]	[redacted]
RFP3	(a)	[redacted]	[redacted]
RFP4	N/A	[redacted]	(a)
RFP5	N/A	N/A	[redacted]
RFP6	(a)	(a)	[redacted]
Bilateral Transactions	[redacted]	[redacted]	[redacted]

Notes:

(a) This RFP did not solicit the indicated type of REC for the given energy year.

Sources:

(1) PUCO Case No. 10-499-EL-ACP, Annual Status Report and 2009 Compliance Review, Appendix A: 2009 Alternative Energy Resource Benchmarks and Compliance Reconciliation.

(2) PUCO Case No. 11-2479-EL-ACP, Annual Status Report and 2010 Compliance Review, Appendix A: 2010 Alternative Energy Resource Benchmarks and Compliance Reconciliation.

(3) PUCO Case No. 12-1246-EL-ACP, Annual Status Report and 2011 Compliance Review, Appendix A: 2011 Alternative Energy Resource Benchmarks and Compliance Reconciliation.

(4) Calculated based on EA Set 1-INT-5 Attachment 1.

With respect to the 2009 and 2010 procurements for In-State Solar RECs, our assessment comports with the Commission rulings. The Companies exercised reasonable efforts to secure the subject Solar RECs and market conditions were such that the RECs were not available in the quantities needed. Given the Commission's review and decisions, no further examination of the Companies' efforts to secure 2009 and 2010 In-State Solar RECs was conducted pursuant to this management/performance audit.

For 2011, the Companies were able to obtain the required number of In-State Solar RECs through a combination of bilateral contracts and the issuance of the sixth RFP, which provided additional flexibility to bidders relative to previous RFPs. In particular, bidders were provided the option of bidding unit-contingent Solar RECs rather than having to bid firm quantities. This arrangement (also included in the fourth and fifth RFPs) eliminated an important source of risk for the In-State Solar RECs bidders. A second and more substantial change to the RFP structure was that the time period covered by the solicitation was extended to ten years. The longer duration of the contracts was an issue raised by the regional developers surveyed by NCI on behalf of the Companies and also was raised as an issue in the context of questions submitted to the Companies by certain potential bidders in the earlier RFP rounds. Finally, the security requirements were modified to accommodate protection under the longer contract period, while at the same time not being so onerous as to discourage bidders.

The prices paid for In-State Solar RECs for 2011 generally comport with prices seen in other nearby markets (e.g., Pennsylvania, New Jersey). As is the case for non-solar RECs, Solar RECs prices in any particular state reflect the market parameters contained in the governing legislation. New Jersey, for example, only allows for Solar RECs generated in-State to be used to meet the solar requirement. The same is true for Maryland. Maryland, however, has a fixed Solar ACP specified in the legislation whereas New Jersey's Solar ACP is established by the Board of Public Utilities. Pennsylvania allows out-of-State Solar RECs to be used to meet the Pennsylvania solar energy requirement and the Commission determines the ACP based on a multiple of prevailing market prices. The In-State Solar RECs market in Ohio is influenced by the markets in other nearby states. Ohio In-State Solar RECs can be used to satisfy the Pennsylvania RPS requirement, as can Maryland, Delaware, and New Jersey Solar RECs. Consequently, there are complex interrelationships among these various markets.

Irrespective of the differences in the levels of the Solar RECs carve-outs contained in the legislation of the various states, the level of prevailing energy prices, and the nature/levels of the ACPs, the prices paid by the FirstEnergy Ohio utilities for In-State Solar RECs (2011 vintage) were comparable to the prices for Solar RECs in other states. Table 7 shows the Solar RECs prices for 2011 RECs in several nearby jurisdictions compared with the prices paid by the FirstEnergy Ohio utilities. Based on the information presented in Table 7, the competitive solicitations (as modified over time to elicit greater market response) issued by the FirstEnergy Ohio utilities appear to have successfully secured In-State Solar RECs at reasonable prices.

Table 7 Weighted Average Monthly SREC Prices ($/SREC)

2011	Delaware	Maryland	New Jersey	Pennsylvania
Jan	229.49	332.72	573.62	293.97
Feb	275.92	335.07	614.88	274.03
Mar	210.34	275.34	632.14	233.13
Apr	197.19	304.94	638.17	227.17
May	259.04	298.08	632.17	239.82
Jun	158.08	271.79	610.38	172.25
Jul	205.34	285.38	588.92	223.01
Aug	259.51	276.52	541.27	222.24
Sep	210.40	274.39	558.45	135.41
Oct	197.56	288.67	553.47	182.85
Nov	119.00	257.17	448.74	143.18
Dec	192.29	256.86	405.89	212.38

Source: PJM GATS

Findings

The procurement of In-State Solar RECs by the FirstEnergy Ohio utilities was competitive and, when Ohio SRECs became reasonably available, the prices paid for those SRECs by the Companies were consistent with prices for SRECs seen elsewhere in the mid-Atlantic region.

IV. MISCELLANEOUS ISSUES

During the course of conducting the management/performance audit of the FirstEnergy Ohio utilities, several issues emerged that warrant brief discussion, though these issues are not directly related to the FirstEnergy Ohio utilities and affect all of the regulated utilities in Ohio with respect to compliance with Ohio's AEPS legislation. Specifically, there are three aspects of either the legislation or the method by which the legislation is implemented that may warrant some reconsideration by the appropriate bodies. These issues are addressed below.

A. Recovery of ACP Charges

Ohio's AEPS legislation does not permit the Ohio utilities to recover the costs associated with Alternative Compliance Payments. The ACP is currently set at $45, which is comparable to the ACPs in other states. The fundamental purpose of an ACP is to set a limit on the exposure of retail customers for the costs of RPS (or AEPS) compliance. While the Ohio legislation is applicable to both regulated and competitive companies, the workings of the market are such that the legislation only affects the regulated utilities. Not allowing recovery of the ACP provides a significant deterrent to regulated firms from employing the ACP in lieu of the procurement of RECs, even at prices well in excess of the ACP. Consequently, the ACP does not accomplish what it is designed to accomplish for customers purchasing power from the regulated utilities.

One of the presumed goals of the legislation is to provide a strong inducement to the power suppliers to satisfy the renewable energy requirements using RECs rather than ACPs. One method to effectively ensure this result would be to require a regulated utility to seek Commission approval to use the ACP rather than RECs and to make a showing that RECs were not available at prices at or below the ACP. Such a modification would serve three related purposes. First, it would protect retail customers from high compliance costs. Second, it would discipline the market, that is, sellers of RECs would not be inclined to offer RECs at prices above the ACP. Third, it would limit (though not eliminate) the economic rents to sellers of RECs.[21]

B. Commission Approval of RECs Purchases

A second modification that merits consideration is a requirement that the Commission approve the purchase of RECs for the retail suppliers of SSO before the RECs contracts are signed. That requirement would eliminate some of the issues that have arisen in the context of this management/performance audit. While the review and authorization requirement would add time to the procurement process, that is, the time between when the bid is made and when a purchase commitment can be made, the review and authorization activities can be structured so

[21] The ACP needs to be set at a level that would generate some reasonable level of economic rent as a mechanism to induce market entry. The current ACP of $45 accomplishes that goal since the costs of renewable energy production are below the level of the ACP when added to the market prices of energy.

as not to add more than a day or two. This additional time should not adversely affect the price of the bids to any significant degree. This approach is successfully employed in other States, including Pennsylvania and Maryland.

C. Application of the Three-Percent Rule

The legislation does not clearly lay out how the "three-percent rule" is to be applied. The language in the legislation related to the three-percent rule is:

> Calculations involving a three percent cost cap shall consist of comparing the total expected cost of generation to customers of an electric utility or electric services company, while satisfying an alternative energy portfolio standard requirement, to the total expected cost of generation to customers of the electric utility or electric services company without satisfying that alternative energy portfolio standard requirement.[22]

The apparent intent of the rule is to facilitate the limitation of the degree to which retail customers are exposed to excessive costs related to the satisfaction of the renewable energy requirements. The rule, however, is based on "expected" impacts, and it is not unreasonable for the utilities to base the calculations related to the rule on the same algorithm used to compute the quantity of RECs required for compliance in any particular compliance year, that is, the average level of MWh sales in the prior three years. This approach, at least temporarily, has an upward bias since over time we would expect that the number of shopping customers (the number of customers taking competitive electric service) to increase. An algorithm based on expected sales volumes that accounts for customer migration and projections of market pricing for power is recommended in order to eliminate this bias.

[22] Ohio Code; Chapter 4901:1-40 [Alternative Energy Portfolio Standard], Section 4901:1-40-07 Cost Cap. (C).

FILE

Goldenberg Schneider, LPA

Final Report

Financial Audit 1
of the

Alternative Energy Resource Rider
of the FirstEnergy Ohio Utility Companies

Case No. 11-5201-EL-RDR

for

The Public Utilities Commission of Ohio

June 15, 2012

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I. BACKGROUND

Ohio's current electric law, Senate Bill 221, initiated an alternative energy portfolio standard (AEPS) that requires electric distribution utilities and electric service companies to acquire specific minimum percentages of electricity from renewable and advanced energy resources.[1] The AEPS was codified into Ohio Administrative Code (OAC) 4901:1-40. The renewable energy requirements, which include specific solar requirements, included annual compliance obligations beginning in 2009.

On February 19, 2009, the Ohio Edison Company (OE), The Toledo Edison Company (TE), and The Cleveland Electric Illuminating Company (CEI) (or jointly referred to as Operating Companies, Companies or FirstEnergy) submitted an Amended Application in Case No. 08-935-EL-SSO that indicated the following for the recovery of costs associated with complying with the AEPS:

> Renewable energy resource requirements for the period January 1, 2009 through May 31, 2011 will be met using a separate RFP process to obtain Renewable Energy Credits. A generation rider will be established to recover, on a quarterly basis, the prudently incurred cost of such credits pursuant to R.C. § 4928.64 including the cost of administering the RFP and carrying charges on any unrecovered balances including accumulated deferred interest. The aforementioned generation rider shall be reconciled quarterly and will be bypassable to a shopping customer consistent with R.C. 4928.64, and the supplier of such shopping customer shall provide the requisite renewable energy resources. Carrying charges shall accrue at a rate of 0.7066 percent per month and without reduction for accumulated deferred income taxes.

The Public Utilities Commission of Ohio (Commission) accepted the Companies' proposed treatment of prudently incurred AEPS compliance costs in its Second Opinion and Order in Case No. 08-935-EL-SSO.[2]

The Alternative Energy Resource Rider (Rider AER) is the bypassable generation rider used by the Operating Companies to recover their costs of complying with the AEPS, including but not limited to, the cost of:

- acquiring renewable energy credits (RECs);
- acquiring solar renewable energy credits (S-RECs);
- conducting requests for proposals (RFPs) for RECs or S-RECs; and
- associated carrying costs.

[1] Ohio Revised Code (R.C.) §§4928.64 and 4928.65
[2] Second Opinion and Order (p. 9) dated March 25, 2009

Rider AER, which began in October 2009, requires quarterly adjustments. The Operating Companies must make ongoing filings to the Commission no later than March 1st, June 1st, September 1st, and December 1st proposing adjusted rates to become effective one month later on April 1st, July 1st, October 1st, and January 1st, respectively, unless otherwise ordered by the Commission.[3]

This process has been tested in several cases. In Case No. 09-1922-EL-ACP, the Operating Companies requested approval of a Force Majeure determination pursuant to R.C. §4928.64(C)(4) and OAC 4901:1-40-06 for a portion of their 2009 solar energy resources (SER) benchmark requirement. The Commission found the application to be reasonable and granted the request. The Commission also noted that although the stipulation in the Electric Security Plan proceeding envisioned that FirstEnergy could meet its renewable energy resource requirements by using an RFP process to obtain RECs, FirstEnergy would be held responsible for meeting the statutory SER benchmarks through all means available, even if the RFP process was inadequate. Further, pursuant to R.C. §4928.64(C)(4)(c), the Commission's approval of FirstEnergy's application was contingent upon FirstEnergy meeting revised 2010 SER benchmarks, which were to be increased to include the shortfall experienced in the 2009 SER benchmarks. In response, the Operating Companies filed Annual Status Report and 2009 Compliance Review in Case No. 10-0499-EL-ACP.

The next year, the Operating Companies again requested approval of a Force Majeure determination for a portion of their 2010 solar energy resources benchmark requirement in Case No. 11-0411-EL-ACP. More specifically, the Operating Companies requested the Commission to reduce the Companies' Ohio Solar Benchmark to the amount of S-RECs they purchased towards their Ohio Solar Benchmark. The Operating Companies withdrew the application on April 11, 2011 in order to include additional Ohio S-RECs they later purchased. Re-filing the request also re-started the 90 day review period.

The re-filed application was included in the FirstEnergy's 2010 Annual Status Report and 2010 Compliance Review in Case No. 11-2479-EL-ACP. In the application, FirstEnergy asserted that despite its best efforts it was only able to acquire 1,629 of the 3,206 S-RECs required to meet its 2010 in-state SER benchmark. Consequently, FirstEnergy requested a force majeure determination for the 1,577 S-REC shortfall.

Staff received adverse comments from several parties arguing that the Companies exceeded the 3 percent cost consideration included in R.C. §4928.64(C)(3), While warranting further investigation, Staff determined that the 3 percent cost consideration was distinct from a force majeure determination and would be more appropriately addressed in the Companies' Rider AER proceedings. Consequently, Staff recommended

[3] In Case No. 08-935-EL-SSO, the Commission approved Rider AER to recover REC costs through May 31, 2011. In Case No. 10-388-EL-SSO, the Commission approved the Operating Companies' Combined Stipulation and Recommendation extending Rider AER from June 1, 2011 through May 31, 2014.

that an external auditor should be retained by the Commission to assist in the investigation of these issues. Such an audit would review the Operating Companies' status relative to R.C. §4928.64(C)(3) as well as the reasonableness of their aggregate compliance costs. Additionally, the Operating Companies would pay for the audit and seek to recover this cost through Rider AER.

In its Order, the Commission accepted Staff's recommendation finding that FirstEnergy had presented sufficient grounds for force majeure and to reduce the Operating Companies' overall 2010 SER benchmark to the level of S-RECs acquired in 2010. Additionally, pursuant to R.C. §4928.64(C)(4)(c), the Commission's approval of FirstEnergy's application was contingent on FirstEnergy meeting its revised 2011 SER benchmark, which was increased to include the 2010 SER benchmark shortfall amount plus any shortfall carried over from the Companies' 2009 SER benchmark.

As a result, the Commission initiated Case No. 11-5201-EL-RDR for Rider AER review, including this Financial Audit 1 to review the financial aspects of the recovery mechanism under Rider AER and actual costs incurred from October 2009 through December 31, 2011. Attachment 2 of the RFP under this Case describes the scope of work to be performed and the requirements of the Audit in more detail.

Finally, the Operating Companies filed Annual Status Report and 2011 Compliance Review in Case No. 12-1246-EL-ACP. According to the filings, the Operating Companies assert that they were able to achieve full compliance with the 2011 renewable energy and solar energy benchmarks, including the solar carryover from 2009 and 2010.

II. AUDIT OBJECTIVES AND SCOPE

Goldenberg Schneider, LPA (Goldenberg) was selected by the Commission to conduct Financial Audit 1 of the Companies' operation under Rider AER. Generally speaking, Goldenberg was to verify the mathematical accuracy of the Companies' calculations involving Rider AER and the associated compliance transactions, as well as to review the Operating Companies' accounting treatment of such compliance activities. Goldenberg was also to evaluate the Companies' status relative to the 3% provision contained within R.C. §4928.64(C)(3). To do so, Goldenberg's considered the Operating Companies' Rider AER filings and background and supporting information for the period July 1, 2009 to December 31, 2011.

More specifically, the scope and objectives of Financial Audit 1 were to:

- Determine that the Companies have procedures in place to properly record costs associated with processing Rider AER receipts, expenditures, deferrals of unrecovered costs and carrying cost calculations.
- Review the Companies' Rider AER quarterly filings during the audit period to verify the accuracy of the calculations.
- Review the individual components (including but not limited to transactions of RECs and S-RECs and costs of implementing associated RFPs) that may

have been included within the Companies' Rider AER calculations in order to verify the costs were appropriately included.

- Verify the Rider AER filings include all appropriate revenues billed.
- Review the accuracy of the calculations related to any carrying charges included in the Companies' quarterly Rider AER calculations.
- Verify that Rider AER rates were properly applied to customer bills.
- Compare the costs recovered through the Companies' Rider AER during the audit period to the costs incurred.
- Review the Companies' accounting treatment related to Rider AER and associated compliance activities.
- Review the accuracy of projected costs, sales volumes and Rider AER rates.
- Review the Companies' status relative to the 3% provision contained within Ohio Revised Code 4928.64(C)(3) and as further detailed in the Ohio Administrative Code Rule 4901:1-40-7.
- Review any other specific items as identified by the Commission or its Staff.

III. FINANCIAL AUDIT STANDARDS UTILIZED

This review was performed in accordance with the standards as defined in RFP No. EE12-FEAER-1. Goldenberg performed the following activities in this audit:

- Reviewed Ohio Revised Code § 4928.64 and 4928.65 and Ohio Administrative Code Rule 4901:1-40 to understand the alternative energy portfolio standards and the annual compliance obligations of electric distribution utilities and electric service companies.
- Reviewed the Commission's Second Opinion and Order approving the Companies' Stipulation and Recommendation in Case No. 08-935-EL-SSO as it applies to RECs, S-RECs and Rider AER to understand the Companies' compliance requirements.
- Reviewed the Commission's Opinion and Order approving the Companies' Combined Stipulation and Recommendation in Case No. 10-388-EL-SSO as it applies to RECs, S-RECs and the continuation of Rider AER to understand the Companies' compliance requirements.
- Reviewed the documents in Case No. 09-1922-EL-ACP, In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Force Majeure Determination for a Portion of The 2009 Solar Energy Resources Benchmark Requirement Pursuant to Section 4928.64(C)(4) of the Ohio Revised Code.
- Reviewed the documents in Case No. 10-0499-EL-ACP, In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company's Annual Status Report and 2009 Compliance Review.

- Reviewed the documents in Case No. 11-0411-EL-ACP, In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Force Majeure Determination for a Portion of The 2010 Solar Energy Resources Benchmark Requirement Pursuant to Section 4928.64(C)(4) of the Ohio Revised Code and 4901:1-40-06 of the Ohio Administrative Code.
- Reviewed the documents in Case No. 11-2479-EL-ACP, In the Matter of the Alternative Energy Status Report of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Force Majeure Determination for Their In-State Solar Resources Benchmark Pursuant to R.C. § 4928.64(C)(4)(a).
- Reviewed the documents in Case No. 11-5201-EL-RDR, In the Matter of the Review of the Alternative Energy Rider Contained in the Tariffs of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company.
- Reviewed the documents in Case No. 12-1246-EL-ACP, In the Matter of the Annual Alternative Energy Status Report of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company.
- Interviewed personnel responsible for the purchase of RECs and S-RECs.
- Interviewed a representative from the consultant retained to be the administrator of the RFP process.
- Interviewed personnel responsible for the 3% provision.
- Interviewed personnel involved with accounting for Rider AER revenues and expenditures.
- Interviewed personnel involved with billing Rider AER.
- Interviewed personnel involved in the calculation of Rider AER and preparation of Rider AER tariff filings.
- Reviewed quarterly Rider AER filings and supporting work papers
    - Reviewed REC, S-REC, administrative expenses and carrying cost components of the Rider AER rate;
    - Reviewed the forecasting methods used to project non-shopping sales volumes;
    - Verified the accuracy of Rider AER tariff rates in the billing system;
    - Verified the mathematical accuracy of Rider AER calculations;
    - Traced calculated Rider AER rates to quarterly filed tariff sheets;
- Reviewed supporting documentation, including:
    - Relevant pages from the Companies' Aligne subledger
    - Relevant pages from the Companies' general ledger
    - Relevant bidder and supplier contracts.
    - Work papers supporting the costs to be recovered in each Rider AER calculation.
- Traced compliance costs included in the Rider AER filings to the applicable contract and/or invoice.

- Verified the Companies' calculation of carrying charges booked in the Regulatory Asset and to be included in Rider AER.
- Randomly selected and tested customer bills from each quarter of the audit period to confirm application of the Rider AER rates in the Companies' billing system.
- Traced selected customer bills to the monthly billing report and to the proper General Ledger revenue account.
- Verified the Companies' accounting for Rider AER revenues, REC inventory, REC expenses, and the related Regulatory Asset.
- Reviewed RFP consulting costs.
- Confirmed renewable energy resource targets (Ohio, non-Ohio, solar and non-solar)
- Reviewed the Companies' calculation of the 3% Test and explored alternative methods of calculating the 3% Test.
- Discussed the impact of the renewable generation on the cost of electricity for the years 2009 – 2011.
- Reviewed Sarbanes Oxley controls regarding AEPS compliance costs, revenues recognition and the Regulatory Asset balance.
- Selected the four largest REC suppliers representing more than 98% of all RECs purchased and verified the transactions from the bid, to the contract, to the invoice, to the Aligne system and to the general ledger inventory account.
- Compared balances to the FERC Form 1 where applicable.

IV. EXECUTIVE SUMMARY

The following is a summary of Goldenberg's significant findings, conclusions, and recommendations. FirstEnergy's processes, procedures, and practices provide assurance that the information contained in its Rider AER filings can be relied upon for setting Rider AER rates after correcting the findings noted in this Financial Audit 1 Report.

A. Calculation of Quarterly Rider AER

Goldenberg verified the mathematical accuracy of the quarterly Rider AER calculations and traced the data to various sources provided by FirstEnergy. We observed several issues, but these issues, noted below, did not result in a large variance in the Rider. The significant recommendations are:

1. The quarterly calculations should recover all of the appropriate costs during the following calendar quarter.
2. The costs to be recovered should include estimated REC expenditures, RFP and other administrative costs and estimated carrying costs.
3. Each quarterly calculation should be trued-up and any over or under recovery included in the calculation two quarters later.

4. Each Operating Company should charge the overall Rider AER rate calculated for the quarter to all rate classes rather than allocating the overall rate to rate classes based on Loss Factors.
5. Forecasted sales volumes for non-shopping customers to be included in Rider AER calculations should be reviewed each quarter and the best estimate at the time should be used for cost recovery to help assure appropriate recovery.

B. Calculation of Carrying Costs

FirstEnergy should calculate carrying costs for each Operating Company based on the difference between monthly revenues booked and expenditures incurred for the month. Instead, carrying costs are being calculated based on the difference between revenues booked and expense recognized rather than cash expenditures.

C. Purchase of RECs

We were able to verify invoices to the contracts.

D. Retirement of RECs

FirstEnergy used a different method for selecting RECs to be retired in each of the three year periods, 2009 – 2011. The 2011 policy should be used in the future except in the third tier where the highest cost RECs should be retired first to reduce future carrying costs, recognizing necessarily that any RECs expiring first, regardless of price, will need to be retired first. It should also be acknowledged that the Companies are currently required by the Commission to retire Residential REC Program and 10-year RFP RECs prior to RECs obtained from other sources.

E. 3% Provision as Provided for in the Ohio Revised Code

A range of alternative methodologies to determine the Operating Companies' status relative to the three percent provision are discussed in Section VI. To assist the Commission in evaluating alternative methodologies to calculate the 3% provision, we recommend the Commission require each Operating Company to develop the following 3% provision calculations:

- A projected calculation of the 3% provision for the next calendar year.
- A projected calculation of the 3% provision for the balance of the current SSO period.
- A historical calculation of the 3% provision to determine the Companies' status with regard to the three percent provision.

V. FINDINGS AND CONCLUSIONS

A. Summary of Rider AER Rates

Cleveland Electric Illuminating (cents per kWh)

	2009	2010				2011			
	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Overall	. 0611	. 3486	.3313	.3017	.4384	.4612	.4699	.4699	.4699
RS	. 0623	. 3557	.3380	.3078	.4473	.4706	.4795	.4795	.4795
GS	. 0623	. 3557	.3380	.3078	.4473	.4706	.4795	.4795	.4795
GP	. 0602	. 3434	.3263	.2972	.4318	.4543	.4628	.4628	.4628
GSU	. 0585	. 3337	.3171	.2888	.4196	.4415	.4498	.4498	.4498
GT	. 0584	. 3334	.3168	.2885	.4192	.4410	.4493	.4493	.4493
STL	. 0623	. 3557	.3380	.3078	.4473	.4706	.4795	.4795	.4795
TRF	. 0623	. 3357	.3380	.3078	.4473	.4706	.4795	.4795	.4795
POL	. 0623	. 3557	.3380	.3078	.4473	.4706	.4795	.4795	.4795

Ohio Edison (cents per kWh)

	2009	2010				2011			
	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Overall	. 0647	. 3288	. 3317	.2844	.3097	.2927	.2776	.2776	.2776
RS	. 0660	. 3354	. 3384	.2901	.3159	.2986	.2832	.2832	.2832
GS	. 0660	. 3354	. 3384	.2901	.3159	.2986	.2832	.2832	.2832
GP	. 0637	. 3238	. 3266	.2800	.3050	.2882	.2734	.2734	.2734
GSU	. 0619	. 3147	. 3174	.2722	.2964	.2801	.2657	.2657	.2657
GT	. 0619	. 3143	. 3171	.2719	.2961	.2798	.2654	.2654	.2654
STL	. 0660	. 3354	. 3384	.2901	.3159	.2986	.2832	.2832	.2832
TRF	. 0660	. 3354	. 3384	.2901	.3159	.2986	.2832	.2832	.2832
POL	. 0660	. 3354	. 3384	.2901	.3159	.2986	.2832	.2832	.2832

Toledo Edison (cents per kWh)

	2009	2010				2011			
	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Overall	. 0696	. 3363	.3211	.3255	.4232	.4031	.3695	.3695	.3695
RS	. 0719	. 3472	.3316	.3361	.4370	.4162	.3815	.3815	.3815
GS	. 0719	. 3472	.3316	.3361	.4370	.4162	.3815	.3815	.3815
GP	. 0694	. 3352	.3201	.3244	.4218	.4018	.3683	.3683	.3683
GSU	. 0674	. 3258	.3110	.3153	.4099	.3905	.3579	.3579	.3579
GT	. 0674	. 3254	.3107	.3150	.4095	.3901	.3576	.3576	.3576
STL	. 0719	. 3472	.3316	.3361	.4370	.4162	.3815	.3815	.3815
TRF	. 0719	. 3472	.3316	.3361	.4370	.4162	.3815	.3815	.3815
POL	. 0719	. 3472	.3316	.3361	.4370	.4162	.3815	.3815	.3815

The overall rates stated above were traced to the Rider AER calculations and the rates by rate schedule were traced to the quarterly tariff filings with the Commission. They were also traced to a sample bill calculation for each quarter and the rates used for billing were correct without exception.

Below is a comparison of the Rider AER rates for FirstEnergy's Operating Companies (overall) to the other Investor Owned Utilities in Ohio during the audit period[4]:

Ohio Investor Owned Utilities (cents per kWh)

	2009	2010				2011			
	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
CEI	.0611	.3486	.3313	.3017	.4384	.4612	.4699	.4699	.4699
OE	.0647	.3288	.3317	.2844	.3097	.2927	.2776	.2776	.2776
TE	.0696	.3363	.3211	.3255	.4232	.4031	.3695	.3695	.3695
DP&L	.0115	.0115	.0115	.0115	.0115	.0115	.0115	.0115	.0115
DE-O	.1378	.0209	.0274	.0264	.0420	.0358	.0339	.0350	.0341
CSP	.0077	.0709	.0593	.0380	.0763	.0802	.0773	[5]	[5]
OP	.0079	.0582	.0480	.0338	.0628	.0603	.0589	[5]	[5]

The table above shows that FirstEnergy's Operating Companies consistently have a significantly higher Rider AER rate than the other Ohio Investor Owned Utilities.

FirstEnergy has allocated it's Operating Companies' overall quarterly Rider AER rate to the various rate schedules using each rate classes' Loss Factors compared to FirstEnergy's overall Loss Factor. The Company explains its reason for this as being consistent with the design of the energy portion of its Generation Service Rider. They state that "since the RECs are the attributes associated with renewable energy generated (one REC is associated with each MWh of renewable energy produced) it is consistent to treat the design of these riders in the same manner."[6]

The overall difference to FirstEnergy on a consolidated basis of billing Rider AER at the overall rate versus the allocated rate is minimal, approximately $200,000 for the audit period. However, the difference by rate schedule is more significant. The following shows the consolidated difference between billing at the overall rate versus the allocated rates for the audit period:

[4] Several of the companies included their Alternative Energy Portfolio Standards compliance costs in their Fuel Adjustment Clause Rider. Either these costs were broken out separately in the filing or were calculated based on data from the filing.

[5] We were unable to obtain values for these two quarters.

[6] Response to GS Set-3 INT-13.

Rate Class	Bill Difference[7]
RS	($ 1,122,429)
GS	($ 494,613)
GP	$ 63,310
GSU	$ 262,213
GT	$ 1,165,730
Lighting	($ 70,971)

Since Rider AER is calculated and billed on delivered kWh and the RECs / S-RECs are purchased to meet a compliance requirement based on billed sales, we recommend using one Operating Company rate (the overall rate) for all of that Operating Companies' rate schedules. This would also eliminate the detriment to the residential, commercial and lighting customers to the benefit of the larger customers.

B. Summary of Rider AER Revenues

Quarter	CEI	OE	TE
2009 - Q4	1,351,015	2,031,437	807,855
2010 - Q1	7,492,657	10,286,065	3,421,070
- Q2	5,721,618	7,928,498	2,665,260
- Q3	5,246,124	7,235,554	2,932,623
- Q4	6,013,287	6,151,145	3,386,202
Total 2010	24,473,686	31,600,862	12,405,155
2011 - Q1	4,457,696	5,655,539	3,104,800
- Q2	3,957,806	4,304,778	2,431,224
- Q3	4,065,314	4,848,020	2,677,777
- Q4	3,571,870	4,161,167	2,462,187
Total 2011	16,052,686	18,969,504	10,675,988

A sample of customer bills from each quarter was selected and the Rider AER charge was manually recalculated. These amounts were verified via FirstEnergy's Bill Verification Tool. This verified that the correct tariff rates were in effect for each quarter. The revenue was then traced to the monthly billing reports. These monthly billing reports were traced to the appropriate Operating Company's General Ledger by revenue account[8]. All amounts were verified with no notable exceptions.

[7] W/P RMP-1
[8] W/P RMP-2 and GS Set-1 INT-11.

C. Summary of Rider AER Compliance Expenses[9]

2009 Expenses (000's)

Description	OE	CEI	TE
3Q			
REC Expense			
RFP Costs	$31	$31	$31
Carrying Costs	$0	$0	$0
Subtotal	$31	$31	$31
4Q			
REC Expense			
RFP Costs	$157	$159	$149
Carrying Costs	($19)	($11)	($6)
Subtotal	$138	$148	$143
Total 2009	$169	$179	$174

2010 Expenses (000's)

Description	OE	CEI	TE
1Q			
REC Expense	$17,882	$14,474	$7,647
RFP Costs	$3	$3	$3
Carrying Costs	($92)	($56)	($24)
Subtotal	$17,793	$14,421	$7,626
2Q			
REC Expense	$20,094	$16,260	$8,648
RFP Costs	$147	$85	($41)
Carrying Costs	$257	$238	$140
Subtotal	$20,498	$16,583	$8,747
3Q			
REC Expense			
RFP Costs	$95	$78	$42
Carrying Costs	$311	$296	$175
Subtotal	$406	$374	$217
4Q			
REC Expense	$3,339	$2,664	$1,416
RFP Costs	$2	$1	$1
Carrying Costs	$193	$200	$119
Subtotal	$3,534	$2,865	$1,536
Total 2010	$42,231	$34,243	$18,126

[9] With the exception of December 2011, the cost of RECs was recorded as an expense in the month retired. Carrying costs can be negative in periods where revenues exceeded expenses. There were corrections in allocations of RFP costs which caused TE to have negative costs for 2010 Q2.

2011 Expenses (000's)

Description	OE	CEI	TE
1Q			
REC Expense			
RFP Costs	$44	$35	$18
Carrying Costs	$127	$136	$74
Subtotal	$171	$171	$92
2Q			
REC Expense	$4,054	$3,235	$1,720
RFP Costs	$26	$19	$9
Carrying Costs	$100	$109	$50
Subtotal	$4,180	$3,363	$1,779
3Q			
REC Expense			
RFP Costs	$29	$21	$11
Carrying Costs	$17	$36	$3
Subtotal	$46	$57	$14
4Q			
REC Expense	$24,942	$19,236	$10,161
RFP Costs	$99	$72	$36
Carrying Costs	$15	$26	$(14)
Subtotal	$25,056	$19,334	$10,183
Total 2011	$29,453	$22,925	$12,068

D. Clerical Accuracy of Rider AER Filings

FirstEnergy calculated Rider AER quarterly from the fourth quarter of 2009 through the second quarter of 2011. The following minor clerical errors were identified.[10]

- 2010 Q1, page 7 of 8 – line 4 should be October revenues.
- 2010 Q2, page 4 of 6 – used November and December 2009 estimate rather than February and March 2010.
- 2010 Q2, page 5 of 6 – lines 4 – 6 should be replaced by October through December 2009 actual revenues.
- 2010 Q2, page 2 of 5 – TE's rate by rate schedule is incorrectly rounded for RS, GS, GP and Lighting.

[10] References are to GS Set-1 INT-13.

- From 2010 Q2 through 2011 Q2, the allocation percentages used to allocate costs to the Operating Companies on page 1 are not rounded to the percentages stated.
- 2010 Q3, page 3 of 6 – could not trace estimated non-shopping kWh other than for rate RS.
- 2010 Q4, page 3 of 4 – could not trace OE's Lighting kWh for August and September.
- 2010 Q4, page 4 of 4 – calculation on line 15 is incorrect. The revenues on line 13 should be subtracted after the gross-up calculation.
- 2011 Q1 and Q2, page 5 of 5 – the calculation of 2011 REC expense estimate is not logical. The calculation is using the Rider AER rate used to recover remaining 2010 costs times the July through December 2011 estimated kWh to determine the 2011 REC expense estimate.

In addition to these minor clerical errors, the following substantial issues were found relating to rider calculation caused by other than clerical accuracy.

1. The Stipulation and Recommendation approved by the Commission in Case No. 08-935-EL-SSO provides for Rider AER to recover, on a quarterly basis, the prudently incurred cost of RECs including RFP costs and carrying charges. FirstEnergy has decided that the rider should be calculated to recover costs over periods longer than a quarter. The initial filing for the fourth quarter of 2009 was calculated to recover the 2009 costs over a nine month period from October 2009 through June 2010. The first quarterly calculation for 2010 was to recover the remaining 2009 costs and all 2010 costs over the calendar year 2010. Subsequent 2010 quarterly calculations spread the cost recovery over periods of nine months. Similarly, the 2011 rider calculations were to recover prior unrecovered costs plus the 2011 costs over the calendar year 2011 and possibly beyond 2011. FirstEnergy explains these long term calculations as an attempt to levelize the rate and avoid large swings in the Rider AER rate. We recommend the quarterly calculations follow the Stipulation and each should attempt to recover the estimated costs to be incurred in that particular quarter. The Operating Companies received approval to recover REC costs as incurred rather than waiting for the annual REC retirement and expense recognition. The RECs are purchased throughout the year so the costs should be incurred somewhat regularly throughout the year. This will have the effect of levelizing the rider rate.

2. The Stipulation and Recommendation also states the rider shall be reconciled quarterly. FirstEnergy has not shown that it attempted to reconcile the rider for any period to date. In fact, costs from 2009 remain in the Rider AER calculation for periods in 2011. FirstEnergy states it reviews the Regulatory Asset balance and as that balance nears zero, the rider becomes reconciled. We recommend the Company reconcile each year's actual recoverable expenditures (including carrying costs) to billed revenue and determine any

remaining 2011 over or under recovery balance. Going forward, the quarterly rider calculation should be reconciled and trued-up in the second quarter following the initial estimated calculation.

3. The Stipulation and Recommendation in Case No. 08-935-EL-SSO, reinforced by the approved Stipulation and Recommendation in Case No. 10-388-EL-SSO, allows the Operating Companies to recover the costs of RECs as purchased rather than waiting until the RECs are retired to meet the Operating Companies compliance obligation under ORC Sec. 4928.64 and 4928.65. In the Rider AER calculations, FirstEnergy attempted to recover the estimated annual compliance obligation rather than the estimated cost of RECs, other administrative costs and carrying costs to be incurred during the ensuing quarter. We recommend the quarterly Rider AER calculation attempt to recover only the estimated costs to be incurred during that quarter, but all of those expected costs, including administrative costs and carrying costs.

4. In 2011, the Company calculated Rider AER rates for the first and second quarters only. For quarters three and four, they said the rate would remain the same because it would not change materially if they recalculated it. We recommend the Rider must be calculated each quarter. It is nearly impossible for the rate to remain constant from quarter to quarter with costs and billing statistics changing all the time. In addition, if the rider is reconciled and trued-up each quarter, there will always be over or under recoveries to be included in the quarterly rider calculations.

5. See Section I. below for a discussion of the estimated REC expenditures and administrative costs to be recovered.

E. Individual Components Included in Rider AER for Recovery

The Stipulation and Recommendation in Case No. 08-935-EL-SSO allows FirstEnergy's Operating Companies to recover all of their prudently incurred costs related to REC purchases plus carrying costs on the unrecovered balance. Below are the exceptions we found to the recovery of these costs.

1. One of the costs to be recovered via Rider AER is carrying costs on the unrecovered balance of REC expenditures and other allowable costs. FirstEnergy performed a calculation of estimated carrying costs for the year 2010 in conjunction with its 2010 Q1 Rider AER calculation. This calculation provided an estimated carrying cost amount of $246,766 for year 2010[11]. The Company chose not to include this amount in its Rider AER calculation and did not recalculate a carrying cost estimate through the remainder of the audit period. Their reasoning was the amount was "nominal" so it was not included

[11] GS Set-1 INT-13, Attachment 2, page 6 of 8.

in the recovery calculation. FirstEnergy's own calculation of carrying costs on its Regulatory Asset provides a consolidated total of $2,400,132 for the twenty seven months of the audit period. Our calculation (discussed later) provides a much greater carrying cost amount to be recovered. We recommend some reasonable amount of carrying costs be included in the Rider AER calculation each quarter. This amount can be a budget estimate, a calculated amount or the prior quarter's actual, but it should be included in the calculation.

2. FirstEnergy was authorized to recover other administrative costs such as the costs of its RFPs through Rider AER. In its 2010 Q1 calculation, the Company included $101,604 of costs for Navigant (its RFP consultant) that had not been expensed. These costs remained in the calculation through the audit period and no additional administrative expenses were included. Our calculation provides a total amount of $1,376,909 of administrative costs on a consolidated basis to be recovered by the Operating Companies through Rider AER[12]. An estimate of these costs should be included quarterly and actual costs included in the true-up to recover these costs on a timely basis.

F. Calculation of Carrying Costs

FirstEnergy calculates carrying costs each month on each Operating Company's Regulatory Asset account using the approved interest rate of 0.7066% per month. The Regulatory Asset account is debited or credited each month with the net of Rider AER revenues less REC cost and administrative costs expensed. Carrying costs have also been recorded in this account. Based on our review of the work papers supporting the Regulatory Asset activity and the calculation of carrying costs thereon, it appears that Regulatory Asset is being properly adjusted by the net of revenues and expenses. However, we do not agree with the calculation of carrying costs.

Carrying costs are intended to make the Company whole for the interest cost of money expended to comply with regulatory requirements. In this case, that is the purchase of RECs and the related administrative costs as compared to the recovery of Rider AER revenues. We recommend FirstEnergy calculate carrying costs based on the cost of RECs when purchased rather than when the RECs are expensed. This is in line with the REC cost recovery authorized by the Commission in Case No. 08-935-EL-SSO. As calculated by FirstEnergy, consolidated carrying costs for the audit period were $2,400,132. If they were calculated based on REC expenditures, the consolidated Carrying Costs would be $6,592,378[13].

As discussed in section E.1. above, the Stipulation and Recommendation states that the quarterly Rider AER calculation should include carrying costs on any unrecovered balance of prudently incurred costs of RECs. This is not being included in the quarterly rider calculation. An estimate of the carrying costs for the period November 2009

[12] W/P RMP-4, total of lines 2, 5, 6, 9 and 10.
[13] W/P RMP-3.

through December 2010 was calculated for the first quarter 2010 Rider AER calculation. This estimate was included in the rider rate for the first quarter of 2010 but was not included subsequent to that calculation. FirstEnergy's reason for this omission was that the amount determined for 2010 ($246,766) was "nominal" and they decided not to include any amount in future calculations. We recommend FirstEnergy should calculate a carrying cost estimate for each quarterly filing as set forth in the Stipulation. In some cases, the carrying cost could be a negative amount which would reduce the amount of costs to be recovered from customers and thereby reduce the rider rate.

G. Comparison of Costs Recovered to Costs Incurred

Throughout the audit period, the Operating Companies' Rider AER calculations were aimed at recovering the cost of RECs delivered plus prudently incurred administrative costs. The total consolidated REC expenditures and administrative expenses for the audit period were $166,100,451[14]. This amount does not include carrying costs that FirstEnergy calculated in the amount of $2,400,132. Rider AER revenues booked for the audit period, excluding CAT, totaled $118,060,433[15] on a consolidated basis. Based on these amounts, FirstEnergy has under collected $50,440,151 as of December 31, 2011.

If the Rider AER calculation had been performed for recovery of costs on a quarterly basis, and included some estimate of administrative costs and carrying costs, the rider would have recovered considerably more of the incurred costs. If reconciliations had been performed quarterly, the over/under recovery could have been included within two quarters for recovery or return to customers. Our recalculation of the Rider, including RECs purchased, administrative costs, carrying costs and quarterly reconciliations, resulted in an under collection of $23,431,795[16] as of December 31, 2011. We recommend one fourth of the balance of the 2009 – 2011 under recovery be included in the next four quarterly Rider AER calculations.

H. Accounting Treatment Related to Rider AER

As part of the audit, we reviewed FirstEnergy's Sarbanes Oxley policy and procedures specific to accounting for RECs and Rider AER. FirstEnergy began including Rider AER's Regulatory Asset in its review in the third quarter of 2009, coincidental with the initial costs of the REC program being incurred. We reviewed the Accounting Guidance Memo and the Interpretation Memo for Rider AER[17] and several quarterly review write-ups of the Rider AER Regulatory Asset reconciliation. Based on our review, we conclude that FirstEnergy has controls in place to properly record Rider AER revenues and expenses and to record and reconcile the Regulatory Asset balance.

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[14] W/P RMP-4, line 12.

[15] W/P RMP-4, line 22.

[16] W/P RMP-5 through RMP-13. This recalculation was performed using data available at the time the original calculation was performed however, some assumptions were made. For example, a constant of $100,000 was used each quarter for administrative expenses and beginning with 2010 Q2, the actual carrying costs for the prior quarter was included.

[17] GS Set-9 INT-4, Attachments 1 and 2.

There are several different types of transactions that must be recorded in connection with Rider AER. These include:

- Record Rider AER revenues.
- Record the purchase of RECs.
- Record the retirement of RECs.
- Record expenses related to the purchase and retirement of RECs (i.e. Navigant RFP costs, broker fees and GATS costs).
- Record the deferral of the difference between revenues and expenses.
- Record carrying costs.

Record Rider AER revenues

The billed Rider AER revenues are recorded each month in specific subaccounts of FERC Account 440 - Residential Sales; Account 442 - Commercial and Industrial Sales; and Account 444 - Public Street and Highway Lighting. Subaccount 440083 is used for recovery of Rider AER from residential customers. Subaccount 442121 is used for recovery of Rider AER from commercial customers. Subaccount 442126 is used for recovery of Rider AER from company use customers. Subaccount 442221 is used for recovery of Rider AER from industrial customers. Subaccount 444082 is used for recovery of Rider AER from public street and highway lighting customers.

As part of our bill verification testing, a sample of bills for each quarter in the audit period was selected. The Rider AER charge was manually recalculated and verified using FirstEnergy's Bill Verification Tool. A number of the bills were then selected and traced to the monthly revenue report and then to the General Ledger activity for that month. No exceptions were noted.

Each month, the Operating Companies record an amount in each revenue account for unbilled revenues. This is reversed the following month when a new unbilled amount is recorded. Also, several large industrial customers request to be billed on a calendar month basis. FirstEnergy manually prepares bills for these customers each month and makes an adjustment to the revenue account for the billing difference. Finally, adjustments are made in the revenue accounts to reclassify some customers between rate classes[18]. A sample of these adjustments was reviewed with no exceptions noted. Based on this review, we conclude that FirstEnergy is recording Rider AER revenues accurately and in the proper accounts.

Record Purchase of RECs

Forty-seven S-RECs were purchased from eight customers under the Residential Renewable Energy Credit Program in 2010 and 2011[19].

[18] W/P RMP-2.
[19] W/P DLS-9.

The Companies retained Navigant Consulting, Inc. to administer six Requests for Proposals (RFP), establishing the right to purchase Renewable Energy Credits (RECs).

- 7-15-09 – Purchase Ohio solar RECs, all-states solar RECs, Ohio all renewable RECs and all-state all renewable RECs for 2009 and/or 2010 and/or 2011.
- 9-23-09 – Purchase Ohio solar RECs, all-states solar RECs and Ohio all renewable RECs for 2009 and/or 2010 and/or 2011.
- 7-1-10 – Purchase Ohio solar RECs, all-states solar RECs, Ohio all renewable RECs and all-state all renewable RECs for 2010 and/or 2011.
- 3-8-11 – Purchase Ohio solar RECs for 2010.
- 8-1-11 – Purchase Ohio solar RECs and all-states solar RECs for 2009 and/or 2010 and/or 2011.
- 9-13-11 – Purchase Ohio solar RECs and Ohio all renewable RECs in equal amounts annually for 2011 through 2020.

The results of the RFP's are shown in GS Set-1 INT-16.

Once a bid is accepted, FirstEnergy enters into a contract with the bidder that specifies the quantity, cost and attributes (i.e. solar, non-solar, in-state and all states) of the RECs to be purchased. When the RECs are ready to be transferred to FirstEnergy, the owner must release the RECs to the Load Serving Entity (LSE) via Generation Attribute Tracking System (GATS). The LSE must then accept the RECs via GATS for the transfer to be completed to the LSE's Clean Energy Portfolio Standard (CEPS) subaccount.

PJM's Environmental Services owns and operates GATS. GATS is a regional information system that tracks the environmental attributes of generation, and will support reporting, compliance and verification requirements related to environmental compliance and related markets. GATS provides for:

- Banking certificates to accommodate varying certificate life spans as determined by state policy or state regulation.
- Enabling various state programs and their definitions of preferred attributes.
- Moving certificates to non-utilities (i.e. direct sales to retail entities).
- A bulletin board to facilitate bilateral trades.

FirstEnergy maintains one GATS account for all three Operating Companies. Within this account there can be four types of subaccounts:

- Active. This subaccount is the initial point of deposit for any REC into GATS.
- Clean Energy Portfolio Standard (CEPS). This subaccount holds RECs meeting the state's renewable portfolio standard requirements. It allows the RECs to be retained after the trading period ends.

- Retail LSE. This subaccount is used by retail Load Serving Entities to designate certificates to be used for disclosure label purposes or renewable portfolio standard purposes.
- Reserve subaccount. This subaccount is a repository for RECs withdrawn from GATS. Once in the reserve subaccount, the REC cannot be removed from that account.

The four largest bidders (identified here as Bidder #1, #2, #5 and #82) which represented 98.5% of the dollar volume of RECs purchased were selected for more detailed investigation[20]. Additionally, every 8th bidder was selected to get a larger sampling of vendors. The invoices were compared to the contract to verify that the terms and conditions of the contracts were being followed. We then verified the cost of such purchases were included in inventory. The following exceptions were noted:

- We were able to verify the invoices of Bidder 1 (12-15-09, 1-26-10, 2-17-10 and 3-31-10) to the contracts although the invoices did not have quantity, price and attribute information.
- Bidder 20 had a contract for 50 SRECs yet only 32 were delivered during 2011.

FirstEnergy provided a one page procedure that was in place for accounting for RECs from 2009 through November 2011. A new and more comprehensive procedure became effective on December 31, 2011[21]. The original and revised policies were included in response to GS Set-1 INT-5.

The Operating Companies' REC inventory was reflected in account 158500 (a subaccount of FERC account 158.1 - Allowance Inventory) from 2009 through February 2010. In March 2010, the balance of the 158500 account was transferred to account 174010 (a subaccount of FERC account 174 -Miscellaneous Current and Accrued Assets). We agree with this change in accounting as FERC Account 158.1 is for emission allowances.

The purchase price of RECs is allocated among the Operating Companies based on the three-year average of each Company's SSO retail electric sales as a percentage of all Operating Companies' three-year average of SSO retail electric sales as shown below. These percentages are calculated by FirstEnergy's Rates Department.

[20] W/P DLS-1

[21] Goldenberg supports the new procedure.

Year	OE	CEI	TE	Total
2006	20,273,176	16,936,804	8,977,204	
2007	21,354,818	17,403,753	9,228,709	
2008	21,040,189	17,157,556	9,006,924	
Average	20,889,394	17,166,038	9,070,946	47,126,378
% for 2009	44.33%	36.42%	19.25%	100.00%
% used[22]	46%	35%	19%	
2007	21,354,818	17,403,753	9,228,709	
2008	21,040,189	17,157,556	9,006,924	
2009	19,043,752	14,450,199	7,815,831	
Average	20,479,586	16,337,169	8,683,821	45,500,576
% for 2010	45.00%	35.91%	19.09%	100.00%
% used	45.00%	35.91%	19.09%	
2008	21,040,189	17,157,556	9,006,924	
2009	19,043,752	14,450,199	7,815,831	
2010	9,928,843	6,981,963	3,537,132	
Average	16,670,928	12,863,239	6,786,629	36,320,796
% for 2011	45.90%	35.42%	18.68%	100.00%
% used	45.90%	35.40%	18.70%	100.00%

A review of the allocation of costs of all invoices revealed the following exceptions from the allocation factors shown above.[23] These exceptions were brought to FirstEnergy's attention as we were unable to determine if there were subsequent corrections.

- The 2009 invoices used an incorrect allocation percentage. These were later corrected to the correct allocation percentage.
- In March 2010, Bidder 50's costs were allocated 44.70% to OE, 36.19% to CEI and 19.11% to TE.
- In May 2010, Bidder 6's costs were allocated 44.32% to OE, 36.43% to CEI and 19.25% to TE.
- In October 2010, Bidder 5's costs were allocated 23.12% to OE, 50.20% to CEI and 26.69% to TE.
- In March 2011, Bidder 1's costs were allocated 45.00% to OE, 35.91% to CEI and 19.09% to TE.
- In June 2011, Bidders 8, 5, 1 and 10's costs were allocated 45.00% to OE, 35.91% to CEI and 19.09% to TE.
- The remainder of the 2011 invoices did not provide an allocation of the purchase cost.

[22] % used is the actual percentage allocation among the Operating Companies applied in that year.
[23] W/P DLS-7

When RECs are purchased, the cost of the RECs is charged to the general ledger inventory account. The company uses Aligne as the deal capture system to keep track of the cost, quantity and attributes of each REC in inventory. Each month, the quantity of RECs in the Aligne system is reconciled to GATS and the value of RECs in the Aligne system is reconciled to the consolidated total general ledger inventory account.

Record Retirement of RECs

In accordance with the original policy (2009 through November 2011), RECs were expensed at the time they were identified for compliance and retired, generally in April of the following year. The revised policy allows the Companies to record an estimated REC expense each month based on the actual or forecasted sales and the carrying value of RECs within the Aligne system. When RECs are actually retired and the final compliance cost for the year is determined, any necessary true-up is recorded. We agree with the revised policy.

The basis for selecting RECs to be retired is as follows:

- In 2009, RECs delivered earliest were retired first in GATS up to the individual required RECs category quantities needed for 2009 (FIFO). RECs in excess of those needed for 2009 compliance were maintained in FirstEnergy's GATS CEPS account for eligibility for future year(s) compliance.
- In 2010, some RECs delivered were retired using the FIFO methodology utilized in 2009; however, FirstEnergy changed the process to retire the older vintage RECs before retiring new vintage RECs. RECs in excess of those needed for 2010 compliance were maintained in FirstEnergy's GATS CEPS account for eligibility for future year(s) compliance.
- In 2011, RECs were retired in the following order:
    - Residential SREC program purchases
    - Long Term RFP RECs and SRECs; and
    - By price from lowest to highest

Having three different REC retirement policies in three years creates REC inventory valuation and annual compliance expense that is not comparable on a year to year basis. We recommend FirstEnergy continue its 2011 REC retirement policy but change the third tier to retire the highest costs RECs first to reduce future carrying costs, recognizing necessarily that any RECs expiring first, regardless of price, will need to be retired first. It should also be acknowledged that the Companies are currently required by the Commission to retire Residential REC Program and 10-year RFP RECs prior to RECs obtained from other sources. The revised retirement policy will provide for a consistent, logical and orderly means to value inventory and reflect the expense of compliance.

The cost of RECs retired are charged to subaccount 506819 - Residential Renewable Energy Credits, subaccount 506821 - Renewable Energy Credits and subaccount 506835 - Associated Company Renewable Energy Credits. All of these accounts are subaccounts of FERC Account 506 - Miscellaneous Steam Power Expenses (Major Only).

When a REC is used to meet Ohio's alternative energy portfolio standard, the REC is transferred from the GATS CEPS subaccount to the GATS reserve subaccount. It is also retired in the Aligne system.

FirstEnergy inadvertently moved 4,138 RECs to its GATS reserve account in 2011 for calendar year 2010 requirements. As the Commission allowed FirstEnergy to use these RECs to satisfy future compliance requirements, there were no financial impacts to customers as a result of this issue. We recommend FirstEnergy review its procedures for retirement of RECs to ensure the right quantity of RECs are moved to the reserve account each year.

Record expenses related to the purchase and retirement of RECs (i.e. Navigant RFP costs, broker fees and GATS costs).

The Navigant RFP costs, broker fees and GATS costs are charged to subaccount 557014 (a subaccount of FERC account 557 - Other Expenses). This account is used for each Operating Company. In 2009 these costs were split equally between the Companies. In 2010, entries were made to change the allocation on a cumulative basis as if the allocation percentages were based on three-year average SSO sales levels.[24] We agree with this methodology for all administrative expenses.

Record the deferral of the difference between revenues and expenses.

In Case No. 08-935-EL-SSO, Item 9 of the stipulation states "A generation rider will be established to recover, on a quarterly basis, the prudently incurred cost of such credits pursuant to R.C. § 4928.64 including the cost of administering the RFP and carrying charges on any unrecovered balances including accumulated deferred interest."

The Operating Companies calculate monthly the amount to be deferred. This is done by calculating the Rider AER revenues booked less the costs of the program (retirement of RECs, Navigant RFP costs, broker fees and GATS costs). This balance is divided by 2 to reflect an average activity for the month. The interest rate is then applied to the sum of the average activity plus prior accumulated deferred principal and interest to determine the current month interest deferral. The monthly interest rate of 0.7066% was approved by the Commission in Case 08-935-EL-SSO. We verified the calculation of the Regulatory Asset and carrying costs booked by the Operating Companies for the audit period. Certain allocation errors were encountered in the early months but corrections were made to true-up the balance on each Operating Companies' books.

During 2009 through November 2011, retirement costs were recorded when the RECs were moved to the reserve account. This means that the Companies have incurred costs for the purchase of RECs during the year that are not reflected in the carrying cost calculation until such RECs are moved to the reserve account. If the intent of the carrying cost mechanism is to recover the interest cost of compliance expenditures, then

[24] W/P DLS-10

the carrying cost calculation should be revised to reflect the cost of RECs when purchased versus expensed.

This is less of an issue for December 2011 and thereafter as an estimated REC retirement cost is now being reflected monthly on the Operating Companies' financial statements.

The balance of each Operating Companies' Regulatory Asset is greater than it should be due in large part to the process FirstEnergy has used to calculate Rider AER. The effect of spreading the recovery of expenditures over longer periods, poor forecasting of non-shopping sales volumes, excluding administrative costs and carrying costs from the calculation and failure to reconcile the calculation on a regular basis have all contributed to the under recovery of allowed costs and therefore, an increased Regulatory Asset balance.

The difference between Rider AER revenues booked less the costs of the program (retirement of RECs, Navigant RFP costs, broker fees and GATS costs) is charged to subaccount 407710 (a subaccount of FERC account 407.3 - Other Regulatory Debits) with the offsetting entry reflected as a Regulatory Asset in subaccount 182387 (a subaccount of FERC account 182.3 - Other Regulatory Assets).

Record carrying costs.

Carrying costs are calculated monthly and recorded as a Regulatory Asset in subaccount 182387 and as a contra expense in subaccount 407715 (a subaccount of FERC account 407.3 - Other Regulatory Debits).

I. Accuracy of Projected Costs and Sales Volumes

FirstEnergy did not include an appropriate estimate of the REC expenditures to be recovered in its quarterly Rider AER calculations. Throughout the nine quarters of the audit period, a variety of methods was used to estimate the costs to be recovered. For year 2010, the REC estimate was calculated as 3% of the Company's estimated generation cost[25]. The 2011 estimate was based on the Rider AER rate to recover remaining 2010 costs times the July through December 2011 projected sales volumes.[26] We recommend there be communication between the Regulated Commodity Sourcing group and the Rate Strategy group to provide an estimate of the REC expense expected to be recorded during the following quarter for recovery.

Sales volumes used in the Rider AER calculation on the other hand were projected. The volumes used were the non-shopping kWh projected to be delivered during the period for which the rider rate was being calculated. These projections were from FirstEnergy's Load Forecast which is prepared annually. The Load Forecast is based on past trends and other economic information. We reviewed these projected volumes compared to the actual sales volumes realized by quarter. The result of our analysis showed the Companies did not do a good job of estimating these volumes. In eight of the nine

[25] See GS Set-3 INT-15, Attachment 3.
[26] See GS Set-1 INT-13, Attachments 6 and 7, page 5 of 5.

quarters of the audit period, actual sales volumes were from 7% to 36% less than forecasted volumes. Only in the fourth quarter of 2010 were actual sales in excess of forecasted sales, by 10%[27]. Many factors could contribute to these variances including weather, economic conditions and additional shopping by customers.

Since FirstEnergy is determining the Rider AER rate based on forecasted sales, if actual sales are consistently less than forecasted, the Operating Companies will not recover all of their allowable REC costs. We recommend the Load Forecast be reviewed regularly to provide more current information for calculation of this rider.

J. Allocations Among The Operating Companies

FirstEnergy acquires all of the RECs for compliance and incurs other expenses in connection with the RFPs and other administrative costs. These costs are allocated to the Operating Companies via several allocation methods. Since the primary purpose of Rider AER is to recover the costs associated with complying with the AEPS, we recommend a single allocation be calculated at the beginning of each year and applied to all costs incurred for AEPS compliance in that year. The allocation should be based on the non-shopping MWh baseline used to determine each Operating Company's AEPS compliance obligation. The allocation should be calculated as soon as the information is available after the beginning of the year and used for all cost allocated during that year. Adjustments and true-ups for prior years should be allocated using the percentages calculated for the appropriate year.

VII. STATUS RELATIVE TO 3% PROVISION OF O.R.C. 4928.64(C)(3) AND AS FURTHER DETAILED IN O.A.C. 4901:1-40-07

A. RFP Requirement

The RFP for the financial audit of the FirstEnergy Ohio Utilities Rider AER has specific requirements related to the statutory 3% cost provision. These include:

- Attachment 2, The Financial Audit Program Standards item #4 states: "A review of the Companies' status relative to the 3% provision contained within Ohio Revised Code, 4928.64(C)(3) and as further detailed in Ohio Administrative Code, 4901:1-40-07;"
- The Public Utilities Commission of Ohio ("Commission") Entry #(4) of its January 18, 2012 order in Case No. 11-5201-EL-RDR states: "Additionally, as this is a case of first impression, the Commission directs the Staff to work with the auditor to develop and incorporate into the audit report a range of alternative methodologies to determine the Companies' status relative to the 3% provision contained within Section 4928.64(C)(3), Revised Code, including an analysis of the impact of renewable generation on market prices and the electric distribution utilities' renewable procurement costs. Staff will not be bound, however, by the auditor's choice of methodology".

[27] W/P RMP-14.

B. The Ohio Revised Code

The Ohio Revised Code Section 4928.64(C)(3), states: "An electric distribution utility or an electric services company need not comply with a benchmark under division (B)(1) or (2) of this section to the extent that its reasonably expected cost of that compliance exceeds its reasonably expected cost of otherwise producing or acquiring the requisite electricity by three per cent or more. The cost of compliance shall be calculated as though any exemption from taxes and assessments had not been granted under section 5727.75 of the revised code."

C. The Ohio Administrative Code

The Ohio Administrative Code Rule 4901:1-40-07 Cost Cap, states:

(B) An electric utility or electric services company may file an application requesting a determination from the commission that its reasonably expected cost of compliance with a renewable energy resource benchmark, including a solar energy resource benchmark, would exceed its reasonably expected cost of generation to customers by three per cent or more. The process and timeframes for such a determination shall be set by entry of the commission, the legal director, deputy legal director, or attorney examiner.

(1) The burden of proof for substantiating such a claim shall remain with the electric utility or electric services company.

(2) An electric utility or electric services company shall pursue all reasonable compliance options prior to requesting such a determination from the commission.

(3) In the case that the commission makes such a determination, the electric utility or electric services company may not be required to fully comply with that specific benchmark.

(C) Calculations involving a three per cent cost cap shall consist of comparing the total expected cost of generation to customers of an electric utility or electric services company, while satisfying an alternative energy portfolio standard requirement, to the total expected cost of generation to customers of the electric utility or electric services company without satisfying that alternative energy portfolio standard requirement.

(D) Any costs included in a commission-approved unavoidable surcharge for construction or environmental expenditures of generation resources shall be excluded from consideration as a cost of compliance under the terms of the alternative energy portfolio standard and therefore, would not count against the applicable cost cap. Such costs should, however, be included in the calculation of the total expected cost of generation to customers described in paragraph (C) of this rule.

(E) If the commission makes a determination that a three per cent provision is triggered, the electric utility or electric services company shall comply with each benchmark up to the point that the three per cent increment would be reached for each benchmark.

D. Analysis

In developing alternative methodologies to determine the Companies' status relative to the 3% provision, the auditor assumes such methodologies must be compliant with the Ohio Revised Code Section 4928.64(C)(3) and the Ohio Administrative Code Rule 4901:1-40-07. However, several alternatives will be offered that are not required by the current law, but can assist the Commission in evaluating the 3% provision. The Ohio Revised Code and the Ohio Administrative Code provide criteria for the components of the calculation as follows:

- The baseline kWh shall be the average of the three previous calendar year sales. Therefore, it seems reasonable to use the same period to develop the generation cost. Using any other period can be problematic as this baseline can vary significantly from the current year sales due to customer switching.
- The renewable energy resource benchmarks are defined for future periods.
- The calculation is based on "reasonably expected costs".
- The cost of compliance shall be calculated as though any exemption from taxes and assessments had not been granted under section 5727.75 of the Ohio Revised Code. This section deals with the exemption on tangible personal property and real property of certain qualified energy projects. This auditor is not aware of any such qualified energy projects for the Operating Companies, thus it does not currently apply.

The Ohio Revised Code and the Ohio Administrative Code do not provide specific guidance for certain components of the calculation.

- The timeframe for the calculation is not defined.
- The term "reasonably expected cost of compliance" is not defined.
- The term "reasonably expected cost of otherwise producing or acquiring the requisite electricity" is not defined.

The timeframe for the calculation is not defined. Since the costs are expected costs, the timeframe must be a future period where the costs of compliance and acquiring electricity can be reasonably estimated for the calculation to be relevant.

The "reasonably expected cost of compliance" raises several issues.

- To forecast the reasonably expected cost of compliance requires assumptions to be made on future sales. Given the volatile state of customer switching, it is difficult to project kWh sales levels very far into the future.
- Another issue is defining the reasonable cost of compliance in the future. One may expect this to include the lowest cost of compliance, but this may not be

the case. Should RECs costing more than the compliance payments provided for in Ohio Administrative Rule 4901:1-40-08 be included in the 3% calculation?

- Another issue is defining the period of time costs can be reasonably estimated. The longer the time period usually reduces the accuracy of the projection. Long-term contracts for the purchase of RECs will typically lock in a price for RECs. Therefore, these costs are known. As long as there is a liquid market for the purchase and sale of RECs, prices can be reasonably estimated. Therefore, the contract purchases and the liquidity of the market will determine how long the cost of compliance can be reasonably projected.
- Should the cost of compliance include the costs related to prior periods? The Commission granted force majeure to the Operating Companies on a portion of the S-REC benchmark in 2009 and 2010. It added the shortfalls to the subsequent year(s). For purposes of performing the 3% calculation, these costs could be moved to the original compliance year for the 3% calculation to have a better matching of costs with the applicable compliance year.

The term "reasonably expected cost of otherwise producing or acquiring the requisite electricity" also raises several issues.

- The baseline kWh is developed using a three-year historical average and the projected cost of compliance is based on that sales volume. The future cost of electricity should also be based on the same sales volume to ensure there is not a mismatch of sales volumes that can cause a companies' 3% calculation to be misleading.
- The future price of electricity can be estimated depending on the timeframe for which it has procurement contracts. If an electric distribution utility wishes to estimate its electricity costs beyond that, there must be a liquid market for wholesale electricity. Therefore, the wholesale electric purchase contracts and the liquidity of the wholesale electric markets will determine how long the cost of electricity can be reasonably projected.
- The renewable energy generating resources within the PJM often displace higher cost traditional generating resources. Therefore, the Ohio electric utilities' customers benefit from these renewable electric generating resources through lower prices obtained from the wholesale energy market. It may be difficult to calculate this benefit precisely, but the Commission may want to consider adjusting the cost of electricity to reflect this benefit.

E. Alternative Methodologies

As stated previously, the Commission directed the Staff to work with the auditor to develop and incorporate into the audit report a range of alternative methodologies to determine the Companies' status relative to the 3% provision contained within Section 4928.64(C)(3). The formula for such calculation is relatively straight forward. Determine the reasonably expected cost of compliance with the renewable energy resource benchmark and divide it by the reasonably expected cost of generation to customers. There are only three components in this calculation; timeframe, the

reasonable expected cost of compliance with the renewable energy resource benchmark and the reasonably expected cost of generation to customers. Below is a discussion of these three components and alternative ways of calculating each.

Timeframe - The Ohio Revised Code and the Ohio Administrative Code imply the timeframe must be a forecasted period. The forecasted period should not be longer than the utility can reasonably estimate its cost of compliance and generation. The alternatives include:

- Historical calendar year. While this is not required to calculate the 3% provision, it may be useful for the Commission to request such a calculation. Under this alternative, the Companies will compare the cost of compliance for a calendar year to the cost of electricity for the volume of sales included in the three-year benchmark.

  Using a historical calendar year can be helpful in evaluating the Operating Companies situation as recoveries under Rider AER began on October 1, 2009 and continued for an extended period. It may be useful to compare the final cost of compliance with the generation cost for 2009 benchmark. The final cost of compliance could be adjusted for S-RECs purchased in subsequent years as a result of the force majeure filing.

  This timeframe will allow the Commission to see how the utility actually performed and give the Commission a basis to view the projected calculations. It may also be useful to the Commission in its mandated filings with the Ohio Legislature.

  It may be useful to calculate the compliance cost using the Rider AER revenues as a proxy for the compliance cost as well as the actual compliance cost when finalized. Theoretically, these per cents should be close. If not, it could indicate issues the Commission may want to investigate.

- Balance of the current calendar year. This timeframe will allow the Commission and utility to view expected performance for the balance of the year. Since most, if not all of the RECs and generation will have already been obtained; the forecast should be reasonably accurate. It will allow time to adjust course if desirable.
- The next calendar year. This timeframe will allow the Commission and utility to view expected performance for the balance of the year. Since many, if not all of the RECs and generation may have already been obtained; the forecast should be reasonably accurate. It will allow time to adjust course if desirable. The Commission may wish to require each Ohio electric utility to make this calculation annually to ensure it understands the expected impact of the Alternative Energy Portfolio Standard.
- The balance of the SSO period. This timeframe will allow the Commission and utility to view expected performance for the balance of SSO period. Since some of the RECs and generation will have already been obtained, the forecast should be reasonable accurate. It will allow time to adjust course if desirable.

Compliance Cost Forecasted - The Ohio Revised Code and the Ohio Administrative Code imply the reasonably expected cost of compliance must be forecasted. The forecasted period should not be longer than the utility can reasonably estimate its cost of compliance and generation to be relevant. The alternatives include:

- Move compliance costs related to prior periods (i.e. resulting from force majeure filings) to the period covered by the force majeure filing. This will delay any historical calculations. As an alternative, the benchmark sales can be adjusted accordingly.
- The reasonably expected cost of compliance could include REC purchases and other reasonably incurred costs required to meet its benchmark, regardless of cost. An estimate would be used to purchase additional RECs to meet any shortfalls. The estimate could be based on the current market or other contracts.
- The reasonably expected cost of compliance could exclude REC purchases that cost more than the applicable renewable compliance payment per REC. An estimate would be used to purchase additional RECs to meet any shortfalls. The estimate could be based on the current market or other contracts. If there is still a REC shortfall, the utility may wish to prepare a force majeure filing before the Commission.

Cost of Generation Forecasted - The Ohio Revised Code and the Ohio Administrative Code imply the reasonably expected cost of generation must be forecasted. The forecasted period should not be longer than the utility can reasonably estimate its cost of compliance and generation. The alternatives include:

- The reasonably expected cost of generation would consist of the SSO generation price to customers (i.e. the auction results).
- The reasonably expected cost of generation would include the SSO generation price to customers adjusted for the benefits of the renewable generation. It is possible that renewable energy generating resources, to the extent that they displace higher cost traditional generating resources, can exert downward pressure on PJM wholesale market clearing prices, as these prices are based upon variable production costs rather than the full cost of capital investment. Therefore, Ohio electric utilities' customers benefit from these renewable electric generating resources indirectly through lower prices obtained through the wholesale energy market. An estimate of the approximate magnitude of this benefit can be achieved through use of nodal production cost simulation software or other modeling techniques, although it will always be difficult to calculate precisely. However, the Commission should be aware that the cost of electricity in wholesale markets is influenced by the existence of renewable resources with low marginal costs of production.

F. 3% Provision Calculation

To assist the Commission in evaluating alternative methodologies to calculate the 3% provision, we recommend the Commission require each Operating Company to develop 3% provision calculations for the calendar year 2013 and the balance of the SSO period.

FirstEnergy provided its 3% provision calculation which reflects the final cost of compliance for the calendar year and the current year generation cost applied to the three-year average SSO sales.[28] We recommend the Commission have each Operating Company prepare this calculation annually to assist the Commission with its evaluation of the 3% provision.

2011	**FirstEnergy**
Cost of Compliance	$54,507,928
Cost of Generation, Excluding Compliance	$2,217,042,022
% Cost of Compliance	2.46%
2010	
Cost of Compliance	$60,749,428
Cost of Generation, Excluding Compliance	$2,940,669,478
% Cost of Compliance	2.07%
2009	
Cost of Compliance	$40,632,355
Cost of Generation, Excluding Compliance	$3,158,985,955
% Cost of Compliance	1.29%

[28] See GS Set-2 INT-4.

VII. LIST OF RECOMMENDATIONS

1. The overall Rider AER rate calculated for each Operating Company should be used rather than allocating to rate schedule based on Loss Factors.
2. Rider AER calculations should recover the estimated costs to be incurred during the ensuing quarter over the non-shopping sales for that quarter.
3. Rider AER should include estimated carrying costs for recovery each quarter.
4. Rider AER should be reconciled each quarter and any over or under recovery included in the calculation in the second subsequent quarter.
5. Rider AER should be calculated every quarter.
6. Estimated administrative costs should be included in each quarterly calculation.
7. One-fourth of the under recovered balance as of December 31, 2011, should be included in the next four quarterly Rider AER calculations for recovery.
8. The Operating Company allocation should be clearly listed on all invoices to provide better support for future audits.
9. The purchase price of RECs should be allocated among the Operating Companies based on the three-year average of each Operating Companies' SSO retail electric sales as a percentage of all Companies' three-year average of SSO retail electric sales. Prior errors should be corrected.
10. We recommend the carrying cost calculation be revised to reflect the difference between actual revenues booked and actual cash expenditures.
11. FirstEnergy's procedures for retirement of RECs should be reviewed to ensure the right quantity of RECs is moved to the reserve account each year.
12. FirstEnergy's REC retirement policy should remain consistent to provide for a consistent, logical and orderly means to value inventory and reflect the expense of compliance.
13. We recommend improved communication between the Regulated Commodity Sourcing group and Rate Strategy group to provide an estimate of REC expense expected to be recorded in the following quarter.
14. Each Operating Company's Load Forecast should be reviewed regularly to provide more current estimated sales information for the calculation of Rider AER.
15. A single Operating Company allocation should be calculated at the beginning of each year and applied to all costs incurred that year for REC compliance.
16. FirstEnergy has had a different method for selecting RECs to be retired in each of the years 2009 – 2011. We recommend the 2011 policy be used in the future with except in the third tier, the highest cost RECs should be retired first to reduce future carrying costs.
17. To assist the Commission in evaluating alternative methodologies to calculate the 3% provision, we recommend the Commission require each Operating Company to develop 3% provision calculations for the calendar year 2013 and the balance of the SSO period. Additionally, we recommend the Commission consider requiring the Operating Companies to provide a historical 3% calculation to determine the Companies' status with the three percent provision.

Summary: Application Application for Rehearing by the Office of the Ohio Consumers' Counsel and Citizen Power electronically filed by Patti Mallarnee on behalf of Sauer, Larry S.