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 Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of and Electric Security Plan.	)))))))	Case No. 14-1297-EL-SSO

INITIAL BRIEF OF THE ENVIRONMENTAL LAW AND POLICY CENTER, ENVIRONMENTAL DEFENSE FUND, AND OHIO ENVIRONMENTAL COUNCIL

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I. INTRODUCTION

Less than 12 months ago, the Public Utilities Commission of Ohio ("PUCO" or "Commission") decided the main issue in this case in a similar proceeding involving the Ohio Power Company ("AEP"). The Commission ruled that it could not approve a proposal by AEP to pass on the costs of its own uneconomic coal plants to customers in light of the lack of certainty about both the costs and any potential benefits from such a deal. Case Nos. 13-2385-EL-SSO *et al.*, Opinion and Order (Feb. 25, 2015) ("*AEP ESP 3 Case*") at 25. The Ohio Edison Company, the Cleveland Electric Illuminating Company, and the Toledo Edison Company (collectively "FirstEnergy Utilities" or "Companies") have now approached the Commission for approval of a proposal that would similarly shift the risks of ownership of approximately 3200 MW of coal and nuclear generation from their affiliate FirstEnergy Solutions ("FES") onto the FirstEnergy Utilities' distribution customers through a non-bypassable rider. This deal would be based on a power purchase agreement ("PPA") structure under which customers would bear the costs of this generation through the Retail Rate Stability Rider ("Rider RRS"), along with a guaranteed profit for FES, and in return would receive only the uncertain market revenues from these units. The Companies have not presented any evidence suggesting that the enormous risks for customers posed by this arrangement are any different than the risks AEP customers faced in the PPA proposal rejected by the Commission in February 2015.

If anything, the picture is significantly worse. The Companies themselves estimate that Rider RRS is likely to cost customers $363 million by 2018,[1] and market prices have only fallen since the Companies prepared that projection, so costs to consumers will likely be much higher. In fact, in light of more current market expectations, intervenor experts estimate that Rider RRS

[1] Unless otherwise indicated, all dollar figures in this brief are presented in net present value rather than nominal dollars.

could cost the FirstEnergy Utilities' customers well over $2 billion by 2024. That includes a projected cost of over $1 billion (nominal dollars) in just the first eighteen months of the rider term based on updated market data of the same type utilized by the Companies in preparing their projection. The Companies admit that such near-term estimates are relatively reliable, but make their case that Rider RRS offers net benefits based on projections of credits in later years that lack any such certainty.

These likely high costs for customers are the result of a deal that is simply inconsistent with Ohio law. The state legislature made the decision years ago to pursue deregulation so that the competitive market would drive out uneconomic generation and provide retail customers with cheaper electric service. But now the FirstEnergy Utilities seek to reverse course and require customers to once again bear the costs of guaranteeing shareholders a profit from their utility's generation affiliate while shielding generation assets from the rigors of the market. Unaccompanied by any evidence that the proposed PPA is a "just and reasonable" deal that does not pass on unnecessary costs to customers for the benefit of FES, this arrangement is inconsistent with Ohio legal protections for customers against such affiliate transactions.

What will the Companies' customers get in return? A hedge that the FirstEnergy Utilities have failed to show customers either want or need, and that would deprive customers of access to low electricity prices in return for only minor relief at times of high prices. They will also receive the dubious benefit of financially supporting units to prevent retirement without any legitimate estimate of what the financial consequences would be if they did shut down. This dubious value is far overshadowed by the clear and significant risks of the PPA proposal.

The Companies include Rider RRS as a part of a settlement package for an Electric Security Plan ("ESP") that may offer customer some limited benefits, such as funding for low income programs. However, the FirstEnergy Utilities have not submitted any evidence that supports either the extent or likelihood of such benefits. Meanwhile, other aspects of the proposed settlement have the potentially to significantly harm customers. As a whole, the settlement provisions do not outweigh – and may even add to – the substantial and likely environmental and public health harms posed by Rider RRS's subsidy of polluting coal plants, as well as the financial costs that the rider would impose on Ohio customers who could otherwise benefit from a competitive generation market. The FirstEnergy Utilities bear the burden of demonstrating that the proposed ESP is reasonable and meets the statutory standard of being better in the aggregate than a market-based offer. The Environmental Law & Policy Center, Environmental Defense Fund, and Ohio Environmental Council ("Environmental Intervenors") urge the Commission to conclude that the Companies have not met this burden.

II. FACTS

A. The Rider RRS Proposal

The Companies filed their ESP 4 Application on August 4, 2014, and amended that Application through a stipulation and supplemental stipulations filed on December 22, 2014, May 28, 2015, June 4, 2015, and December 1, 2015 (collectively, "Stipulations"). As a central part of the proposed ESP, the FirstEnergy Utilities seek cost recovery through Rider RRS for the purchase of electricity generated from the W.H. Sammis Plant ("Sammis"), a coal plant with a 2220 MW nameplate capacity; Davis-Besse Nuclear Power Station ("Davis-Besse"), a nuclear plant rated at 908 MW; and a 4.85% interest in the Kyger Creek and Clifty Creek Plants of the Ohio Valley Electric Corporation ("OVEC") (equivalent to 115.9 MW based on nameplate capacity). Co. Ex. 33 at 3; Co. Ex. 32 at 2, 5, 8. The Companies' generation affiliate FES owns Sammis and Davis-Besse, and has a contractual entitlement to the OVEC output. Co. Ex. 33 at 3.

In total, these plants (collectively, "PPA Plants") represent over 3200 MW of FES generation that the Companies propose to – for all intents and purposes – make the financial responsibility of FirstEnergy Utilities' distribution customers for the next eight years, from June 1, 2016 through May 31, 2024. Co. Ex. 7 at 14; Co. Ex. 155 at 3.

The FirstEnergy Utilities seek to include in Rider RRS the net of the Companies' costs and revenues under a PPA with FES, currently before the Commission in the form of a final draft term sheet ("Affiliate PPA Term Sheet"). Co. Ex. 156; Co. Ex. 33 at 3. This arrangement would make the Companies' customers responsible for covering all costs of the PPA Plants, as well as for providing a consistent return to FES of 10.38% on all past and future capital investments in Sammis and Davis-Besse. Co. Ex. 156 at 4-6, 13; Co. Ex. 33 at 3. Customers will then receive the market revenues from selling the output of the PPA Plants. Thus, the Rider RRS proposal shifts the risk of market price fluctuations from shareholders of the Companies' parent FirstEnergy Corp. ("FirstEnergy") to the FirstEnergy Utilities' customers.

In addition to this core buy-back provision, the Stipulations also provide for a maximum credit to the Companies' customers of up to $100 million (in nominal terms) in 2020 through 2024 if the rider produces a charge in those years or delivers less than a threshold credit amount ($10 million in Year 5 of the ESP, escalating to $40 million in Year 8). Co. Ex. 154 at 7-8. The credit provision does not apply in the first four years of the PPA rider. *Id.* It also does not guarantee any absolute limit on losses or any minimum credit over the life of the PPA. Tr. XXXVI at 7523:17-7524:2.

The record contains projections of the charges and credits that will flow through Rider RRS through 2024 from several parties. The Companies offer a projection, based on a 2014 forecast of wholesale energy and capacity prices by consultant Judah Rose from ICF

International ("2014 ICF Forecast"), that Rider RRS will result in net credits of $260 million to customers through May 31, 2024 – the result of about $360 million of charges in 2016-2018 followed by net credits in 2019-2024. Co. Ex. 155 at 14; Sierra Club Ex. 89. Ohio Consumers' Counsel ("OCC") witness Wilson, on the other hand, uses alternative natural gas forecasts from 2015 to estimate that Rider RRS will *cost* customers up to $2.7 billion over the same time period, with a total cost of around $800 (nominal dollars) for an average residential customer. OCC/NOPEC Ex. 9 at 12-13 & Tbl. 2. Similarly, P3/EPSA witness Kalt projects customers will pay between $793 and $858 million given up-to-date outlooks for natural gas prices. P3/EPSA Ex. 5 at 16-17, Att. JPK-SS-2, JPK-SS-3. Finally, Sierra Club witness Comings prepared a projection of Rider RRS's customer impact based on FES's own internal market forecast that predicts [redacted] by 2018, improving only to [redacted] by 2024 [redacted]. Sierra Club Ex. 96C at 2, 4 Fig. 1.

B. Stipulation Provisions

In addition to Rider RRS, the FirstEnergy Utilities' Application and the proposed Stipulations also address a number of other elements of the Companies' ESP for 2016 through 2024, including the following:

- The Companies will file a case by April 3, 2017, to change residential customers' base distribution rates to a straight fixed variable design. This rate structure will phase in over three years, starting with an allocation of 25% fixed costs and 75% variable costs in Year 1 and moving to an allocation of 75% fixed costs and 25% variable costs in Year 3. Co. Ex. 154 at 12-13.
- The Companies will file a "grid modernization business plan highlighting future initiatives for Commission consideration and approval," which will address topics such as Advanced Metering Infrastructure, VOLT/VAR, and distributed generation. Co. Ex. 154 at 9. The FirstEnergy Utilities will earn a return on equity ("ROE") set at the ATSI ROE (currently 10.38%) plus a 50 basis point adder for any grid modernization project approved under this plan. *Id.* at 10.

- The Companies will "strive to achieve" 800,000 MWh of energy savings annually in their energy efficiency and peak demand reduction ("EE/PDR") portfolio plan through May 31, 2024. They also agree to reactivate energy efficiency programs previously suspended at their request in Case No. 12-2190-EL-POR and begin implementing "best practice ideas" for additional programs. Co. Ex. 154 at 11. Energy savings from "all cost effective energy efficiency programs" in the Companies' EE/PDR plan "shall be eligible for shared savings" and the annual shared savings cap "shall be increased from $10 million to $25 million." *Id*. at 11-12.
- The Companies commit to paying up to $3.2 million to the Council of Smaller Enterprises ("COSE"), the Association of Independent Colleges and Universities of Ohio ("AICUO"), and the City of Akron for energy efficiency efforts during the ESP, including approximately $1.2 million not tied to energy savings achievements. Co. Ex. 2 at 10-13; Co. Ex. 154 at 15. Most of these payments will be recovered from customers. Co. Ex. 2 at 10-13; Co. Ex. 154 at 15; Tr. XXXVII at 7788-7794.
- Under certain conditions PUCO Staff may request that the Companies procure "100 MW of new Ohio wind or solar resources" for the remaining term of the ESP. Co. Ex. 154 at 12.

III. STANDARD OF REVIEW

In reviewing a proposed stipulation, "[t]he ultimate issue for the Commission's consideration is whether the agreement . . . is reasonable and should be adopted." *In re Columbus S. Power Co.* ("*AEP ESP 2 Case*"), Case No. 11-346-EL-SSO, *et al.*, Opinion and Order (Dec. 14, 2011) at 27. In conducting this inquiry, the Commission has traditionally considered three criteria:

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

Id.

The Stipulations cannot substitute for record evidence in this case. The Commission concluded as much when it rejected a stipulation filed in the *AEP ESP 2 Case* based on a finding that the signatory parties had in fact failed to demonstrate in the record that certain stipulation provisions would satisfy the requirements of R.C. 4928.143 and the overall reasonableness review standard. *AEP ESP 2 Case*, Entry on Rehearing (Feb. 23, 2012) at 10. Similarly, in *Monongahela Power Co. v. Public Utilities Commission*, the Ohio Supreme Court held that the Commission had erroneously approved a stipulation shortening a utility's "market development period" during which its rates were capped and frozen. 104 Ohio St. 3d 571, 2004-Ohio-6896, 820 N.E.2d 921, ¶¶ 7, 24-27. The key issue in that case was whether the stipulation could have the effect of shortening the applicable market development period under R.C. 4928.40, which provides for early termination of the market development period for a utility only under specific factual circumstances showing the existence of a competitive retail electricity market. *Id.* ¶ 17. The Supreme Court concluded that the in the absence of any record evidence satisfying that test, the Commission could not approve the shortening of the market development period based on the stipulation alone. *Id.* ¶ 26. Similarly, the FirstEnergy Utilities must support their arguments with record evidence here.

The existence of the Stipulations also does not alter the fact that the Companies bear the burden of proof in this case in all respects. Under R.C. 4928.143, the statute governing ESPs, the Commission may approve the proposed ESP only if the FirstEnergy Utilities prove that it is "more favorable in the aggregate" than a market-rate offer. R.C. 4928.143(C)(1). Additionally, the burden is on the FirstEnergy Utilities to show that the elements of the ESP are "just and reasonable and are consistent with the policy of the state as delineated in" R.C. 4928.02. Ohio Adm. Code 4901:1-35-06(A). The Commission concluded that both R.C. 4928.143 and R.C. 4928.02 continue to apply to a proposed stipulated ESP in the *AEP ESP 2 Case.* Opinion and Order (Dec. 14, 2011) at 17; *see also id.* at 27. The Companies must also specifically justify the Rider RRS proposal, consistent with the Commission's directive in the *AEP ESP 3 Case* that "AEP will be required, in a future filing, to justify any requested cost recovery" under a placeholder PPA rider. *AEP ESP 3 Case*, Opinion and Order (Feb. 25, 2015) at 25. More generally, the burden is on the signatory parties to the Stipulations to show that they meet the stipulation standard. *AEP ESP 2 Case*, Entry on Rehearing (Feb. 23, 2012) at 8.

Finally, the Commission laid out considerations specific to the review of the type of PPA rider proposed by the Companies in the *AEP ESP 3 Case*. The Commission directed that any filing seeking cost recovery for a PPA under such a rider "should, at a minimum, address" several factors:

1) "financial need of the generating plant";

2) "necessity of the generating facility, in light of future reliability concerns, including supply diversity";

3) "description of how the generating plant is compliant with all pertinent environmental regulations and its plan for compliance with pending environmental regulations"; and

4) "the impact that a closure of the generating plant would have on electric prices and the resulting effect on economic development within the state."

AEP ESP 3 Case, Opinion and Order (Feb. 25, 2015) at 25. The Commission also directed that any PPA rider proposal must "include an alternative plan to allocate the rider's financial risk between both the Company and its ratepayers." *Id.* In rejecting AEP's PPA rider proposal in that case, the Commission ultimately faulted AEP for making a showing that the proposal "would provide customers with sufficient benefit from the rider's financial hedging mechanism or any other benefit that is commensurate with the rider's potential cost." *AEP ESP 3 Case*, Opinion and Order (Feb. 25, 2015) at 25. The Commission should focus on that same issue in its consideration of the Rider RRS element of the Companies' ESP proposal here.

IV. ARGUMENT

Rider RRS, a central component of the Companies' proposed ESP 4, is essentially a gamble with customers' money. The FirstEnergy Utilities' contract with affiliate FES may result in a net credit under Rider RRS if the market price of electricity increases significantly, but it puts customers at risk for paying well over $2 billion in additional electricity costs if market prices do not rise consistent with the Companies' forecast. That risk is real and substantial, and accompanied by only uncertain and tenuous evaluations of potential offsetting benefits.

While the FirstEnergy Utilities project that customers will in fact get a net credit under Rider RRS through 2024, that projection is based on a stale forecast that projects higher power prices than can reasonably be expected given current market outlooks. That is particularly true in the early years of the rider, when more recent market information offers significant certainty that the Companies have overestimated PPA Plant revenues. Moreover, the Companies' failure to evaluate any alternatives to the PPA Plants, or seek competing offers in developing its proposal, leaves the Commission with any objective reference point in considering whether the PPA offers an unwarranted subsidy to the Companies' affiliate in the form of unjust and unreasonable contract terms (including, but not limited to, price). Meanwhile, the Companies have offered a flawed assessment of the benefits of Rider RRS that does not show they are "commensurate with" the potential costs of the rider. Finally, the Companies provide little to no evidence of any value for customers in the Stipulations that might outweigh the significant risks of Rider RRS.

Accordingly, the Commission should reject Rider RRS along with certain stipulation provisions discussed below.[2]

A. The Companies Have Failed to Show That Rider RRS or the Stipulation as a Whole Will Benefit Ratepayers or the Public Interest.

It is indisputable that Rider RRS creates risk for customers. If the Companies' projections are wrong, customers will pay substantially more under the rider – potentially over $2 billion according to some witnesses' forecasts. Addressing nearly identical circumstances in the *AEP ESP 3 Case*, the Commission rejected AEP's PPA proposal based in large part on "the uncertainty and speculation inherent in the process of projecting the net impact of the proposed PPA rider." *AEP ESP 3 Case*, Opinion and Order (Feb. 25, 2015) at 24. The Companies have significantly underestimated that uncertainty and the resulting risk in this case by relying on a flawed, out-of-date market price forecast that is not consistent with current market realities and that is unaccompanied by any analysis of potential alternative scenarios. In fact, significant decreases in natural gas prices and PJM load forecasts since 2014 mean that customers are likely to face substantial charges under Rider RRS, particularly over the next few years when there is the most certainty about likely outcomes. This inconsistency with the most recent evidence of market conditions undercuts the reliability of the Companies' rider projection as any safeguard against the risks of betting ratepayers' money on currently uneconomic coal plants. That lack of reliability holds especially true in the absence of any attempt by the FirstEnergy Utilities to find a better deal from the market. By doing so, the Companies would have created a competitive benchmark for evaluating the reasonableness of their Rider RRS projections and the proposed

[2] We have additional legal objections to the basic concept of a non-bypassable PPA rider that we will not seek to re-open here because they are currently pending decision on rehearing in the *AEP ESP 3 Case*. *See AEP ESP 3 Case*, Application for Rehearing by the Environmental Law & Policy Center, Ohio Environmental Council, and Environmental Defense Fund (Mar. 27, 2015).

terms of the underlying PPA – a test of particular importance given the undeniable possibility that the Companies might be acting to benefit their affiliate FES and FirstEnergy shareholders more than their customers.

Accordingly, the key question is whether the Companies have met their burden to show that the proposed rider, along with the other ESP elements and the Stipulations, offer benefits that outweigh these significant risks. They have not. On every critical issue, the Companies have failed to back up their assertions about the value of Rider RRS – as a hedge against market prices, in providing fuel diversity, in avoiding transmission costs, or in preserving jobs – with credible record evidence. At the same time, Rider RRS creates economic roadblocks to pursuing energy efficiency measures that might themselves provide important price-stabilizing value or otherwise benefit customers. Furthermore, the Stipulations contain other flawed provisions that undermine state policy and customer welfare. To the extent some stipulation provisions do offer potential benefits, they are highly contingent on future events or simply unenforceable. Thus, the record shows that the benefits of the Companies' Application and accompanying Stipulations do not outweigh the fact that they would likely result in charges of at least hundreds of millions, if not billions, of dollars to FirstEnergy ratepayers over the next eight years.

1. The Commission Ruled in the *AEP ESP 3 Case* That a PPA Rider Proposal Must Address Whether the Potential Benefits of the Rider Are "Commensurate With" Its Potential Costs.

The *AEP ESP 3 Case* decision plainly describes the Commission's concerns regarding the type of PPA rider proposal presented here. In that case, the Commission rejected AEP's PPA proposal because the utility had not shown that it "would provide customers with sufficient benefit from the rider's financial hedging mechanism or any other benefit that is commensurate with the rider's potential cost." *AEP ESP 3 Case*, Opinion and Order (Feb. 25, 2015) at 25. In reaching this holding, the Commission considered the widely varying projections from the parties, and even from AEP itself, showing everything from a net cost of $116 million to a net benefit of $8.4 million over the term of AEP's ESP III. *Id.* at 23. The Commission cited this range of projections in concluding that "all of these projections are based on data assumptions [regarding plant costs and market prices]" and that it could not "reasonably determine the rate impact of the rider" given "the uncertainty and speculation inherent in the process of projecting the net impact of the proposed PPA rider." *Id.* at 24.

The Commission concurrently held that there might be "little offsetting benefit from the rider's intended purpose as a hedge against volatility," especially given that "there are already existing means, such as the laddering and staggering of SSO [Standard Service Offer] auction products and the availability of fixed price contracts in the market, that provide a significant hedge against price volatility." *Id.* The Commission accordingly determined that it was "unclear . . . whether customers would even benefit from the financial hedge." *Id.* at 23. In order to address these key concerns identified by the Commission with respect to their parallel proposal, the Companies must carry their burden to show that Rider RRS would offer more than exposure to potentially significant costs for the sake of speculative benefits. As described below, they cannot.

2. Rider RRS Presents a Significant Risk of High Costs to Ratepayers.

The Companies assert that Rider RRS will provide their customers with a net benefit of $260 million by May 31, 2024. Co. Ex. 155 at 12. This outcome results from a projection of high net revenues starting in 2019 after losses of more than $360 million in 2016-2018. Sierra Club Ex. 89. However, the FirstEnergy Utilities' projection is outdated and incomplete. A shift in expectations regarding demand and natural gas prices over the next several years means that the near-term losses under the Companies' own projection are likely to be much worse than predicted, up to *$1 billion*. Meanwhile, the long-term upside on which the Companies rely is uncertain at best in light of these same market trends.

The Companies originally proposed a PPA and accompanying rider extending into 2031, supported by a projection of the revenues and costs under Rider RRS from June 1, 2016 through May 31, 2031. Co. Ex. 33, Att. JAR-1. This projection was based on FES estimates of PPA Plant costs and a PJM energy and capacity price forecast from 2014 provided by Company witness Rose. Co. Ex. 33 at 6; Co. Ex. 21 at 2. In support of the Third Supplemental Stipulation filed on December 1, 2015, Company witness Mikkelsen adopted this original projection, but modified it to reflect the revised 10.38% ROE for FES (lowered from 11.15% in the original proposal) and revised PPA term. Co. Ex. 155 at 7; Tr. XXXVI at 7510-7513.

The Companies' rider projection rests on three key sets of variables: the costs of the PPA Plants; the market prices for capacity and energy that would be the main source of the PPA Plants' revenue; and the frequency of outages that will prevent the PPA Plants from running and earning those market revenues, and that could result in non-performance penalties. Company witness Lisowski utilized FirstEnergy forecasts of each of these variables, including market price forecast commissioned from Company witness Rose, to project the annual amount of the Rider RRS credit or charge through December 2024. Co. Ex. 21 at 2, 4-5.

The Commission cannot reasonably rest its view of the merits of the PPA rider proposal on Witness Mikkelsen's projection. At every turn, the record evidence undermines the credibility of that projection and indicates that the Companies have significantly underestimated the probable costs of Rider RRS. Eighteen months after Company witness Rose prepared his market price forecast, more recent market information shows a steep drop in natural gas prices that is likely to result in much worse outcomes than the Companies projected, particularly over the next few years. PJM's recent significant decreases in the load forecast underlying Witness Rose's modeling also undermine a key basis for his analysis of future market prices.

Even ignoring these developments over the last year and a half, rider projections produced from FES's own 2014 market price forecast show [redacted] than the Companies projected using Witness Rose's analysis. This comparison highlights the [redacted] in potential outcomes for customers under Rider RRS based on plausible alternative market scenarios that the Companies failed to analyze themselves, and must [redacted] the wisdom of crediting a single rider projection prepared by the FirstEnergy Utilities to support a deal that will admittedly offer important benefits to its affiliate FES and FirstEnergy shareholders.

a. The Companies' Rider Projection Is Inconsistent with Current Market Realities.

Sine Company witness Rose prepared his market price forecast in the summer of 2014, natural gas prices – a significant driver of energy prices (OCC/NOPEC Ex. 4 at 20; Co. Ex. 17 at 23 Fig. 4, 36) – have dropped dramatically. The average Henry Hub price in 2015 was $2.69 per MMBtu based on actual and futures data, compared to the 2015 price of $4.34 per MMBtu used by the Companies in their rider projection here – an overestimate of 61%. Sierra Club Ex. 95 at 9, Tbl. 1. Similarly, the Companies' projection rests on a 2016 natural gas futures price of $4.28 that now stands at $2.51 – an overestimate of 70%. *Id.* The FirstEnergy Utilities have not attempted to calculate the effect of those changed market expectations on the likely impacts of Rider RRS, but OCC witness Wilson calculates that given current natural gas futures prices the rider is likely cost customers dearly, up to $2.7 billion. OCC/NOPEC Ex. 9 at 12.

While the Companies are likely to criticize this aspect of Witness Wilson's testimony because of its reliance on futures prices, Company witness Rose himself relied entirely on those same futures prices for the first two years past his 2014 forecast, 2015 and 2016. Co. Ex. 17 at 46. Over that same two-year timeframe OCC witness Wilson projects a Rider RRS charge of more than $1 billion in nominal dollars for 2016 and 2017. OCC/NOPEC Ex. 9 at 8, Tbl. 1. That is more than *triple* the $330 million (nominal dollar) loss that even the Companies predict over that time period, and is enough on its own to wipe out the Companies' projected net benefit of $892 million in nominal dollars over the remaining years of Rider RRS, resulting in a nominal dollar net charge to FirstEnergy Utilities' customers of more than $100 million.[3] Sierra Club. Ex. 89. These near-term losses must weigh particularly heavily in the Commission's assessment of the Rider RRS proposal because that is the horizon in which even Company witness Rose concedes there is better information available about "what's likely to happen" in the markets.[4] Tr. VI at 1145:13-18. Furthermore, even if the Commission feels that for some reason it must ignore this most up-to-date information, Sierra Club witness Comings testified the Companies' rider projection is also [redacted] the expectations of the actual owner of

[3] Although OCC witness Wilson did not provide net present value equivalents for his 2016 and 2017 rider projections, the net present value of the rider incorporating those values is likely to be worse than the impact in nominal dollars. Since the rider credits underlying the Companies' projection of a net rider benefit occur solely in the later years of Rider RRS, 2019 through 2024, they are significantly discounted in net present value terms from $976 million in nominal dollars to just $623 million. Meanwhile, early losses under the rider are not discounted nearly as much. Accordingly, if translated to net present value the near term charges projected by Witness Wilson would likely outweigh credits far in the future by much more than $100 million.

[4] Furthermore, these near-term costs may be unrecoverable in the event that approval of Rider RRS or the underlying PPA is later invalidated as unreasonable or illegal. The Third Supplemental Stipulation includes a severability provision to address such a situation but states: "This commitment on severability is not intended and shall not be construed to affect the prohibition against retroactive ratemaking. No amounts collected shall be refunded as a result of this severability provision." Co. Ex. 154 at 9.

the PPA Plants, FES, as of 2014. These alternative assessments indicate that customers may well pay over $2 billion under the Rider RRS proposal, and at the least face costs of [redacted] in the next three years.

This significant decrease in futures prices since 2014 likely represents more than just a short-term swing. Company witness Rose's organization, ICF, itself produced an August 2015 forecast of natural gas prices using the same modeling tools employed by Rose that projects long-term natural gas prices "[redacted] in every year than the ICF forecast used in the Companies' filing." Sierra Club. Ex. 78C at 10. The Companies cannot reasonably disavow what even its own expert's organization views as a lasting drop in future natural gas prices.

Additionally, another fundamental input into Company witness Rose's 2014 analysis – his assumptions regarding load in PJM – has also lost credibility in light of recent developments. Witness Rose testified that he relied exclusively on the 2014 load forecast prepared by PJM as the basis for his assumptions about demand growth in the region. Tr. VI at 1188:21-1189:19. However, he acknowledged that PJM itself characterized that forecast as not adequately accounting for the effects of future energy efficiency measures, and that PJM's 2015 load forecast incorporated additional load reductions to better reflect such developments. Tr. VI at 1264:10-14; Sierra Club Ex. 15 at 1 (2015 PJM load report noting change in forecasting methodology from 2014 "as a short-term solution as it [PJM] pursues its announced intention to better reflect usage trends such as adoption of more energy efficient end uses and behind the meter generation which are not currently captured in the forecast model"). That change in methodology resulted in a significant reduction in projected peak demand between the 2014 and 2015 PJM load forecasts, in the range of 2.5% to 2.9%, and even larger reductions from the 2015 to the 2016 PJM load forecast, with projected load 3.7% lower in 2016 and 5.7% lower in 2024. Sierra Club Ex. 15 at 2, 41; Co. Ex. 171 at 2, 20; Sierra Club Ex. 95 at 17-18 & Fig. 5.

This trend of significant decreases in demand holds true even accounting for the fact that PJM's 2015 Capacity Performance rules now restrict the participation of demand response resources (also known as "load management") in the PJM capacity market to reduce peak demand. PJM now projects fewer demand resources to be available to reduce peak demand in future years, especially once the rules go into full effect in 2020. *Compare* Co. Ex. 171 at 70 *with* Sierra Club Ex. 15 at 68. However, that reduction in expected demand resources does not change the fact that overall peak load projected by PJM is now much lower than the forecast levels utilized by Company witness Rose. For example, Company witness Rose adopted PJM's 2014 forecast of 171,216 MW of unrestricted summer peak load in the PJM RTO in 2022, and applied his own projection of 11,144 MW of demand response in that year, for a "restricted" peak load forecast of 159,772 MW. Co. Ex. 20 at 1-2. PJM's 2016 forecast predicts unrestricted peak load of 157,986 MW in 2022, and demand resources of 3,436 MW, for a restricted peak load of 154,551. Co. Ex. 171 at 70, 73. That is still a decrease of over 3,400 MW, or more than 3%. Meanwhile, in prior years when demand response is still participating in the PJM capacity market at levels of 8,000-9,000 MW, Co. Ex. 171 at 70, the comparable differences are even greater – for example, Company witness Rose projected restricted peak load of 155,742 MW for 2019, almost 8,000 MW, or 5%, more than PJM's 2016 restricted peak forecast of 147,923. Co. Ex. 171 at 3.

Even looking at the difference between the 2014 and 2016 PJM forecasts may understate the flawed nature of Company witness Rose's load assumptions, since the change in modeling for the 2016 PJM load forecast was meant to reflect existing "trends in . . . [energy] efficiency," but not “accelerated energy efficiency” beyond those trends. Co. Ex. 171 at 1 (numbered page), 5 (definition of “unrestricted peak”). This is the same approach as Witness Rose took when he projected a constant level of energy efficiency of 0.8% energy savings per year through 2024. Co. Ex. 20 at 2. In both instances, the failure to capture increasing levels of energy efficiency is likely to understate future load reductions in light of existing Ohio law that requires specific energy savings achievements through 2027 that may be greater than historic trends, as well as federal policy in the form of the Clean Power Plan that may drive even more “accelerated” energy efficiency deployment. R.C. 4928.66(A); Tr. VI at 1267:23-1268:2. Looking only at existing law, for example, Company witness Rose’s assumption of 0.8% energy savings per year across PJM is inconsistent with Ohio’s current energy efficiency standard, which requires utilities to achieve energy savings of 1% per year through 2020 and 2% per year in 2021 through 2027. R.C. 4928.66(A).

These flaws in Company witness Rose’s load assumptions are key because, as he recognized, “lower demand generally would have a downward effect on energy prices [and] . . . on capacity prices.” Tr. VI at 1141:21-1142:2. Although Witness Rose suggested on rebuttal that a several percentage point reduction in demand in PJM might not significantly affect his market price projections, he has not actually modeled the effects of such a change, and at the time of his original hearing testimony stated that lower demand than expected *is* “a significant factor obviously in supply and demand analysis.” Tr. VI at 1196-1197; 1141:19-20. Moreover, Witness Rose explained that his assertion on rebuttal was based on his observation that existing levels of demand are in fact driving wholesale price increases consistent with his forecast, a premise that is not supported by the record. *Id.* at 1196. He referred to observed capacity price increases in 2014 PJM auctions for 2017/2018 and 2018/2019, [redacted]

[redacted]. For example, Company witness Rose predicted a [redacted]. Sierra Club Ex. 96C at 15-16 & Fig. 4. Meanwhile, at the time of Witness Rose's hearing testimony, 2015 energy prices were running 10-15 percent lower than he had forecast. Tr. VI at 1188. Finally, Company witness Rose did not address the important question of whether current levels of demand could *continue* to result in the [redacted] he projects over the full eight years of Rider RRS. In all, there is no reason to doubt Witness Rose's own testimony that lower demand tends to result in lower wholesale electricity prices, resulting in another driver of worse outcomes for customers under Rider RRS than the Companies have projected.

This record closely resembles that in the *AEP ESP 3 Case*, where the Commission concluded that:

> [i]n light of the uncertainty and speculation inherent in the process of projecting the net impact of the proposed PPA rider, which is evident in AEP's own projections ranging from a $52 million net cost to an $8.4 million net benefit, the Commission is unable to reasonably determine the rate impact of the rider.

AEP ESP 3 Case, Opinion and Order (Feb. 25, 2015) at 24. If anything, the current FirstEnergy proposal is far worse given that the quantitative risks are significantly higher and the Companies' rider projections rest on flawed, out-of-date market assumptions. Overall, the Companies have failed to meet the burden of providing a reliable estimate of the potential Rider RRS impacts that would allow the Commission to determine whether the Rider RRS proposal "would provide customers with . . . benefit that is commensurate with the rider's potential cost." *AEP ESP 3 Case*, Opinion and Order (Feb. 25, 2015) at 25.

b. The FirstEnergy Utilities' Rider Projection Lacks Any Reference Points for Evaluating the Magnitude of Customer Risk or the Reasonableness of the Proposed PPA Terms.

The Companies' failure to conduct any competitive or market procurement, or even any evaluation of alternative resources on its own, further undermines the reasonableness of the PPA proposal. This is a deal with an unregulated affiliate that was arrived at based on conversations exclusively between the FirstEnergy Utilities and FES; involved no evaluation of alternative units or competitive process to identify alternative resources; and includes no benchmark comparison to similar transactions in the market. Tr. XIII at 2745-2750; Co. Ex. 33 at 4-5. Hence, the Companies provides no evidence in the record for the Commission to judge whether the proposed contract with FES represents a reasonable or prudent price for the alleged benefits it will provide. If anything, the Companies' conduct and explanation indicates it may well have unreasonably sought to benefit its affiliate FES at the expense of customers.

As the Federal Energy Regulatory Commission ("FERC") has articulated in reviewing contracts for justness and reasonableness at the wholesale level, an affiliate deal untested by the competitive market raises the prospect that a purchaser like the Companies "might agree to pay a higher price than it would otherwise agree to pay because the purchaser [in the form of the affiliate parent company and its shareholders] would financially profit from the transaction." *In re Ocean State Power*, 44 F.E.R.C. ¶ 61,261, 61,983 (1988). This view applies to cost-based as well as market price wholesale contracts. *S. California Edison Co.*, 109 F.E.R.C. ¶ 61,086, 61,356 (2004). The concern regarding such affiliate abuse leading to an unreasonable deal is substantiated here by the fact that the Companies failed to seek out any alternatives to this purchase from their own affiliate and offered no credible justification for that approach.

i. The Companies Unreasonably Declined to Even Consider Alternative Resources for Inclusion in the PPA.

The FirstEnergy Utilities simply never looked at any other "solution" besides a contract with FES for the PPA Plants, other than rejecting an initial FES offer that included a broader set of FES plants. Tr. XIII at 2745-2750. They certainly did not seek a deal on the broader market, for example by issuing a request for procurement to non-affiliate generation companies. *Id.* In the after-the-fact explanation of their approach, the Companies take an arbitrarily narrow view of what resources could help address their alleged concerns about resource diversity, price stabilization, economic development, and transmission costs.

Other generation or demand-side resources could potentially accomplish the Companies' goals at lower cost or under contract terms that more effectively shielded ratepayers from market risk. This basic concept is easily illustrated by the fact that intervenor Exelon has represented it will bid into a competitive procurement process at a price offering the Companies' customers $2 billion in savings over the next eight years. Exelon Ex. 4 at 2. Additionally, the Companies might have been able to use a truly arms-length negotiation process to seek more favorable terms in a proposed PPA, such as the sort of protection against market risk through a fixed price that is offered by Exelon. *Id.* at 6, 8. The FirstEnergy Utilities may argue that the Exelon offer is a self-interested attempt at a subsidy for its own generation. However, as the Companies' own behavior illustrates, any company will act in the interests of itself and its shareholders and will only offer a deal if it expects to profit off that deal. The point of a competitive process is to provide an incentive for such a company to offer the best deal possible in order to beat out the competition, and to provide sufficient information for the parties and the Commission to evaluate the best option for customers on a transparent record about comparative tradeoffs among different resources. FirstEnergy's self-dealing prevented any such process here.

For example, both renewable and natural gas generation are cleaner power sources than coal plants and therefore do not face the same significant risks and economic burden entailed in controlling emissions of substances such as mercury, sulfur dioxide, nitrogen oxides, and particulate matter. Sierra Club Ex. 70C at 30-43; OEC/EDF Ex. 1 at 17-18. Sammis, for example, incurred $1.8 billion in capital investment costs to comply with recent federal mercury regulation that even FirstEnergy admits is a significant driver of the high costs and poor economics of the plant. Co. Ex. 32 at 10; Co. Ex. 143 at 4; Tr. XI at 2280:16-2282:2. Absent the need to incur such environmental compliance costs or to cover the expense of such past investments, both natural gas and renewables may offer cheaper and less risky generation resources over the long run. Moreover, the Companies never acknowledge that shifting toward such cleaner resources could offer the state valuable public health and economic benefits in reducing impacts from coal pollution. *See, e.g.*, ELPC Ex. 25 at 2-13, ELPC Ex. 26 at ES-3 to ES-13 (regulatory impact analyses for federal air pollution rules describing public health benefits of pollution reduction).[5] Promoting renewable and natural gas generation may also help position Ohio well for future compliance with pending federal carbon regulation, namely the Clean Power Plan issued by the U.S. Environmental Protection Agency ("U.S. EPA") in 2015. OEC/EDF Ex. 1 at 14.

As Mid-Atlantic Renewable Energy Coalition ("MAREC") witness Burcat testified, renewable generation offers the unique benefit of eliminating risk from fuel price volatility, facilitating the sort of fixed price contract offer that FES has declined to make and mitigating overall wholesale price volatility. MAREC Ex. 1 at 11-12. Renewable resources can also offer significant local economic development benefits. MAREC Ex. 1 at 13. Furthermore, a

[5] The Attorney Examiner took administrative notice of these documents, Tr. XXXV at 7482:12-17, which are docketed in this case as attachments to a Notice filed on October 30, 2015.

procurement process could be structured to ensure construction of new resources of these types in Ohio, as contemplated in the Third Supplemental Stipulation provision regarding renewable energy. Co. Ex. 154 at 12. That would provide the same benefits of in-state generation touted by the Companies, and could even allow tailored targeting of new generation construction to alleviate transmission issues that the FirstEnergy Utilities contend will result from retirement of the PPA Units. *See* OCC/NOPEC Ex. 4 at 64 (proposing a competitive procurement process to consider the value of different types of generation across multiple metrics).

The Companies dismiss such potential advantages with arguments about the lack of reliability of renewables and natural gas. Co. Ex. 28 at 7-8. However, their witnesses were unable to back up these concerns with any quantitative analysis of the costs and benefits of different proportions of coal, natural gas, and other types of resources. Tr. XI at 2254:15-2255:23; P3/EPSA Ex. 5 at 17-20. They also offered a notably one-sided assessment of reliability issues, ignoring the fact that their arguments about the poor performance of natural gas generation in extreme cold weather apply to coal generation as well, as illustrated by the 13,658 MW of coal outages in PJM during the "Polar Vortex" of January 7, 2014 and 10,224 MW of coal outages during similarly cold weather in February 2015. IGS Ex. 1 at 21. Finally, the Companies never addressed the fact that PJM's rules to ensure reliability, particularly the recent Capacity Performance market reforms, would avoid the sort of grid reliability problems that the FirstEnergy Utilities attribute solely to sources like natural gas. IMM Ex. 2 at 3-4 (describing Capacity Performance rules); Tr. X at 2215:3-2218:13. Despite these ready counterarguments, the Companies dismissed these alternatives out of hand. That truncated process prevents the Commission from being able to assume its proper role of balancing the advantages and disadvantages of each of these types of generation and determining whether it is reasonable to subsidize FES's existing generation assets rather than seeking a shift to other generation resources.

The FirstEnergy Utilities also excluded demand-side resources from their discussion of what resources can provide the alleged benefits of a PPA rider. Tr. XI at 2245:22-2246:8, 2250:15-19. At the same time, the Companies' witnesses acknowledge that resources such as energy efficiency can protect customers against rising energy costs and provide resource diversity. Tr. III at 516:7-20; Tr. XI at 2251:22-2252:11. The FirstEnergy Utilities' own energy efficiency plans for 2013-2015 projected those programs would result in cost-effective energy savings of over 650,000 MWh on average in each year based on annual expenditures of approximately $83 million, resulting in lifetime net savings of over $235 million for customers while producing jobs and potentially delaying the need to build new generation. *In the Matter of the Application of FirstEnergy for Approval of Energy Efficiency and Peak Demand Reduction Program Plans for 2013 Through 2015*, Case Nos. 12-2190-EL-POR *et al.*, Application Atts. A, B, C at 4, 92, Appx. C-3, Tbls. PUCO 1, PUCO 2, PUCO 3 (July 31, 2012) ("*FirstEnergy 2013-2015 EE/PDR Plan Case*").[6] For comparison, those yearly energy savings are equivalent to the annual energy output of a 74 MW generation resource operating at 100% capacity. The Companies also projected that the same programs would result in annual peak demand reduction of 617 MW across its service territories, reducing the need to build new generation. *Id.* at 53-54, Appx. C-3, Tbl. PUCO 2. Moreover, as OMAEG witness Seryak and ELPC witness Rábago explain, these energy savings and peak demand reductions result in lower wholesale power prices across the whole system in addition to shielding individual program participants from high electricity costs. OMAEG Ex. 22 at 12; ELPC Ex. 28 at 22.

[6] The Attorney Examiner took administrative notice of the energy efficiency plans for each of the FirstEnergy Utilities. Tr. XI at 2485-2486.

There are readily available examples of utilizing such demand-side resources to meet the types of needs described by Company witness Moul, such as preserving resource diversity and mitigating upward pressure on electricity costs or price volatility. In 2005 the Montana Public Utilities Commission specifically commended a utility's procurement of 100 MW of cost-effective energy efficiency resources as part of its supply portfolio, noting that "acquiring energy efficiency mitigates upward pressure on long-term portfolio costs, . . . contributes to portfolio diversity, mitigates risk related to volatile fuel prices and wholesale electricity prices and is environmentally responsible, thereby mitigating risk related to future environmental regulation." *In the Matter of the Application of North Western Energy's Electric Default Supply Tracker Filing*, Docket No. D2003.6.77 *et al.*, 2005 Mont. PUC LEXIS 112, at 94 (Dec. 14, 2005). Connecticut's public utilities agency likewise approved a utility's competitive procurement process for new generation or demand-side resources to address capacity constraints that resulted in a resource portfolio including a 5 MW energy efficiency program as one cost-effective capacity resource. *DPUC Investigation of Measures to Reduce Federally Mandated Congestion Charges (Long Term Measures),* Docket No. 05-07-14PH02, 2007 Conn. PUC LEXIS 108 at 4-6 (May 3, 2007). One of the Company's witnesses was even aware of this latter example at the time he prepared his testimony for this case. Tr. IV at 819-820. Yet the Companies have not been able to offer a coherent explanation why they did not even consider demand-side measures as part of a package to address their resource concerns here.

Moreover, it is telling that just as the Companies were voicing concern about customer exposure to volatile and high prices in this case, they made the decision to suspend the majority of their energy efficiency programs for 2015 and 2016. *FirstEnergy 2013-2015 EE/PDR Plan Case*, Finding and Order (Nov. 20, 2014) at 1-3.The Companies have only committed to reinstate these programs as part of the Third Supplemental Stipulation, as a bargaining chip for approval of Rider RRS. This belated articulation of a rationale for the PPA and the FirstEnergy Utilities' inconsistent behavior with respect to energy efficiency belies their position that they offer an objective assessment of the merits of Rider RRS.

ii. The Companies' Assessment of the Merits of the PPA Proposal Does Not Stand on Its Own.

The FirstEnergy Utilities may suggest that the Commission can still evaluate the reasonableness of Rider RRS based solely on their narrow assessment of the FES plants standing alone. However, the Companies' evaluation of this affiliate deal is seriously lacking as an objective assessment of the magnitude of costs that it might impose on the FirstEnergy Utilities' customers.

In addition to the outdated nature of the Companies' rider projection discussed above, the FirstEnergy Utilities failed to do any sensitivity analyses to consider alternative scenarios to Company witness Rose's market forecast. Sierra Club Ex. 69 at 9-10. This leaves the Commission without the ability to weigh whether other outcomes besides the Companies' forecast of a net credit of $260 million are likely, and if so what costs they might impose on customers. By contrast, Company witness Strah acknowledged that he was aware of a resource procurement effort overseen by the Connecticut Department of Public Utility Control in which the final selection of resources to help meet local capacity constraints was "based on the results of nine different market scenarios, with differing supply-demand conditions, environmental regulations, and fuel prices," producing a "range in net benefits . . . from $-66 to $1,679 million." *DPUC Investigation of Measures to Reduce Federally Mandated Congestion Charges (Long Term Measures)*, Docket No. 05-07-14PH02, 2007 Conn. PUC LEXIS 108 at 6 n.1 (May 3, 2007). Similarly, Company witness Moul testified that in his experience at FES, the FirstEnergy business development group would produce an asset valuation in the form of a range rather than a single value when considering an asset purchase. Tr. X at 2227:2-2231:5. Under these circumstances, where the Rider RRS proposal would effectively make FirstEnergy customers the owners of the PPA Plants for the next eight years, the Companies should have done no less.

Company witness Rose asserts that ICF has not conducted sensitivity analyses even in connection with assessing compliance costs for the federal Clean Power Plan rulemaking. However, that statement ignores the fact that the U.S. Environmental Protection Agency ("U.S. EPA") *did* provide detailed information on sensitivity analyses with respect to the ultimate question of the overall environmental and health benefits of the rule. ELPC Ex. 24 at 4-37. This approach reflects U.S. EPA's recognition that "[i]n any complex analysis using estimated parameters and inputs from numerous models, there are likely to be many sources of uncertainty." *Id.* at 4-36. The agency also presented a range of monetized benefit forecasts under different discount rate and health benefit assumptions, *id.* at 4-44 to 4-46, but cautioned that "the estimates of co-benefits in each analysis year should be viewed as representative of the general magnitude of co-benefits of the illustrative plan approach, rather than the actual co-benefits anticipated from implementing the final emission guidelines." *Id.* at 4-37. Similarly, in the regulatory impact analysis for the Cross-State Air Pollution Rule (also cited by Rose for lacking an economic sensitivity analysis, rebuttal test. at 12-13), U.S. EPA gave only limited weight to specific quantitative projections of the benefits of the rule. Instead, the agency focused on the fact that the full range of potential benefit projections showed that "[t]he benefits outweigh social costs from 150 up to 350 to 1, or from 110 up to 335 to 1," making it "clear that [even under different sets of assumptions] the benefits of the Transport Rule are substantial and far outweigh the costs." ELPC Ex. 25 at 1; *see also* ELPC Ex. 26 at ES-1 (similar discussion in regulatory impact analysis for Mercury and Air Toxics Standard). By contrast, in this case the Companies and Witness Rose ask the Commission to credit the Rider RRS projection without any context as to the likelihood and potential impacts of alternative assumptions.

There is one alternative market price forecast produced by FES in discovery that suggests the Commission could reasonably expect [redacted] under Rider RRS. As explained by Sierra Club witness Comings based on the Companies' own application of the FES forecast to the PPA Plants, the [redacted] the prices projected by Company witness Rose would result in [redacted] by 2024. Sierra Club Ex. 96C at 2, 4 Fig. 1. [redacted] under Rider RRS by 2018, over the near-term years when Witness Rose believes such forecasts rest on the best knowledge about what is likely to happen. Tr. VI at 1145:13-18. With a [redacted] between the Companies' rider projection and that of its own affiliate, the Commission must consider whether further comparison scenarios altering variables such as the underlying load forecast could result in [redacted] between the Companies' expectations and other plausible rider impacts. Not only did the FirstEnergy Utilities fail to consider resources besides FES generation, but they also did not meet their burden to provide the Commission with enough information to verify the credibility of the Companies' evaluation of the potential costs of that affiliate deal.

iii. The Commission Should Reject Rider RRS Because of the Lack of Any Objective Reference Point for Judging Whether the Rider or the Underlying PPA Is Reasonable.

As noted above, FERC has articulated strong concern that an affiliate deal such as the PPA here may impose unjust and unreasonable rates on captive customers in order to benefit a utility's affiliate. Therefore, FERC requires a utility to affirmatively demonstrate that no affiliate abuse of this sort has occurred before FERC will conclude that an affiliate transaction is just and reasonable. *Boston Edison Co. Re: Edgar Electric Energy Co.*, 55 F.E.R.C. ¶ 61,382, 62,167 (1991). Such a demonstration may consist of "evidence of direct head-to-head competition between . . . [the affiliate] and competing unaffiliated suppliers either in a formal solicitation or in an informal negotiation process," along with assurance that the process did not unduly favor the affiliate, or evidence regarding "benchmark evidence which shows the prices, and terms and conditions of sales made by nonaffiliated sellers." *Id.* ¶¶ 62,168-62,169.

Environmental Intervenors do not suggest that the Commission must apply FERC precedent here, but the *Edgar* approach is consistent with the standards the Commission has previously applied in considering the reasonableness of an affiliate transaction. For example, the Commission has allowed affiliates to supply power to their sister distribution companies only through a competitive auction process that ensures affiliates participate "in the same fair and nondiscriminatory manner as all other participants" without any "competitive advantage." *In re Application of the Dayton Power and Light Company for Approval of Its Electric Security Plan*, Case Nos. 12-426-EL-SSO *et al.*, Opinion and Order (Sept. 4, 2013) at 16; *In re Application of Duke Energy Ohio, Inc. for Authority to Establish a Standard Service Offer*, Case Nos. 11-3549-EL-SSO *et al.*, Opinion and Order (Nov. 22, 2011) at 13. The Commission has approved one contract for AEP's generation affiliate to supply it with capacity outside a competitive auction process, but did so only upon modifying the utility's ESP proposal, which provided for passing through the contract rate of $255 per MW-day, to preclude AEP from collecting capacity charges in excess of the benchmark state compensation capacity charge of $188.88 per MW-day. *AEP ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 59. Moreover, the *AEP ESP 3 Case* opinion echoed FERC's concern about finding some objective reference point for judging the reasonableness of cost estimates for an affiliate deal, reserving the Commission's right to "require a study by an independent third party, selected by the Commission, of . . . pricing issues as they relate to the [PPA rider] application." Opinion and Order (Feb. 25, 2015) at 25. Finally, the fundamental standard for review of an ESP – that it be "more favorable in the aggregate" than a market-rate offer under R.C. 4928.142 – suggests that the Commission must evaluate what alternatives the market might provide before approving Rider RRS based on an affiliate deal. R.C. 4928.143(C)(1).

In this case, the Commission lacks the sort of reassurances, such as competitive procurement or some objective benchmark price, that would allow it to adequately evaluate whether this affiliate transaction is "just and reasonable" or "more favorable in the aggregate" than a market-rate offer. Ohio Adm. Code 4901:1-35-06(A); R.C. 4928.143(C)(1). At the same time, the Commission cannot rely on FERC's own review process for wholesale power contracts to ensure that the PPA terms are a just and reasonable rate for which retail recovery is warranted, as it has done in the past. In AEP's second ESP case, the Commission considered an affiliate contract between AEP and its generation affiliate to procure capacity for the seventeen months spanning AEP's transition to full corporate separation and full participation in the PJM capacity market. Responding to intervenor concerns regarding potential affiliate subsidies, the Commission indicated that such FERC review should apply to that contract. *AEP ESP 2 Case*, Opinion and Order (Aug. 8, 2012) at 57. Although the Commission allowed that contract to stand, it did so based on its recognition "that the contract between AEP-Ohio and GenResources is subject to prior FERC approval" and specifically declined to "make . . . any expressed or implied endorsement of the terms or conditions of the AEP-Ohio contract with GenResources, as presented in this case." *Id.* at 60.

FERC subsequently reviewed that contract under the *Edgar* standard, and approved the contract as just and reasonable at the $188.88 per MW-day capacity rate given that the transaction would occur "during a specified transition period for what would have been retail transactions if the Ohio Commission had not implemented a restructuring plan, ... after which the [contract] will end and all of Ohio Power's SSO customers' capacity and energy requirements will be procured *through a competitive bidding process*." *AEP Generation Res. Inc.*, 145 F.E.R.C. ¶ 61,275, 62,546 (2013) (emphasis added). In addressing *Edgar*, FERC again emphasized that the affiliate contract "is a short-term agreement for a transition period that supports the Ohio Commission's restructuring efforts[,]" which "will enable customers to obtain energy and capacity *through competitive market mechanisms*." *Id.* (emphasis added).

The Commission cannot likewise leave FERC to review this affiliate deal, since the Companies take the position that they will seek to execute the proposed PPA under their market rate authority rather than subjecting it to substantive FERC review under the "just and reasonable" standard.[7] Tr. III at 660:23-661:2. Ultimately, the FirstEnergy Utilities seek review of the PPA proposal through the Commission rather than FERC, but have failed to provide the Commission with the sort of evidence that would support a finding that an affiliate deal is either just and reasonable or better than a market-rate offer. The PPA price is not based on any objectively reasonable rate for the service being provided or a market procurement, and the Companies propose an eight-year deal that they may seek to extend even further into the future

[7] The Environmental Intervenors do not seek any Commission determination of whether the PPA does in fact fall within the scope of the Companies' market-based tariff and if so whether it would fail under the *Edgar* standard. Parties to this case are in the process of requesting FERC review of that question. *See* FERC Docket No. EL16-34-000, Complaint Requesting Fast Track Processing (filed Jan. 27, 2016). However, it is certainly important to the Commission's consideration of whether Rider RRS is reasonable to be aware that approving the rider may result in wholesale prices being passed through to retail customers without any review of the reasonableness of that contract at the federal level.

without ever opening the door to market-based or competitive proposals. Tr. XXXVI at 7526:23-7527:1.

With their sole focus on FES plants, the Companies may have deprived customers of reasonably priced alternatives that would provide real benefits without the substantial risks detailed above. Ultimately, since the Companies did not conduct *any* competitive process or present the Commission with *any* alternative options for comparison, they provide no basis for the Commission to conclude that this deal is one that benefits customers as well as the Company's generation affiliate and their mutual shareholders. The Companies have not met their burden of proof of demonstrating the reasonableness of the Rider RRS proposal.

c. The PPA Plant Costs Are Likely to Be Higher Than Projected.

The Commission's Opinion and Order in the *AEP ESP 3 Case* rightly zeroed in on one significant area of risk for coal plants such as Sammis and the OVEC plants: the costs of controlling the significant pollution associated with coal generation. *AEP ESP 3 Case*, Opinion and Order (Feb. 25. 2015) at 25. Accordingly, the Commission expressly ordered that a PPA proposal such as this one must include a "description of how the generating plant is compliant with all pertinent environmental regulations and its plan for compliance with pending environmental regulations." *Id.* The Companies did not adequately address that issue in the pending application.

For example, Company witnesses Harden and Evans acknowledged that, at the time of the September hearing in this case, the U.S. EPA had proposed and would soon finalize Steam Electric Effluent Limitation Guidelines ("Steam Electric ELG") regulating wastewater discharges from coal plants. Tr. XIX at 3803-3806. Yet the Companies did not provide any capital cost estimate relating to compliance with this pending rule. Tr. XII (Confidential) at 2635:15-23; Tr. XIX at 3806-3807.

Additionally, Company witness Evans failed to address potential costs of compliance for the OVEC plants under a 2014 U.S. EPA proposal to lower the national ozone standard from 75 parts per billion ("ppb") to somewhere in the range of 65-70 ppb. Sierra Club Ex. 69 at 39-40. This is a glaring omission considering that counties neighboring the Kyger Creek and Clifty Creek plants have ozone levels above 70 ppb or even the 2008 standard of 75 ppb. *Id.* at 40-41. Thus, the Commission has no way to know whether these plants will need to install additional control measures or curtail operating time in order to comply with the new ozone standard. It is clear that in the former situation the plants could require significant capital investment not accounted for in the Companies' analysis. *Id.* at 41-42.

Finally, the Companies offer only an incomplete evaluation of potential compliance costs under the federal Cross State Air Pollution Rule ("CSAPR"), regulating compliance with national ozone and fine particulate pollution standards across state lines. Co. Ex. 46 at 8-9. Company witness Evans testified that regarding the existing "Phase 1" and "Phase 2" requirements under CSAPR, which begin in 2015 and 2017 respectively. *Id.* The Companies relied on modeling by the Ohio Environmental Protection Agency regarding these existing CSAPR requirements as the basis for asserting that Sammis and OVEC are able to comply with the rule. Tr. XII at 2548:20-2549:12. However, as Sierra Club witness Comings testified, this current iteration of CSAPR implements outdated air quality standards and is likely to be revised in the future to reflect current, more stringent federal standards. Sierra Club Ex. 69 at 42 & n.80, 43. The Companies have not addressed the potential costs of compliance under such a future iteration of CSAPR.

These holes in the Companies' evaluation are conspicuous given the Commission's specific direction to address the important issue of environmental compliance. Moreover, even if the resulting increases in costs due to compliance with future environmental regulations are not enormous, they could still have an outsized effect on the PPA rider to the extent that the PPA Units are marginal units near the top of the dispatch stack. *See* Co. Ex. 151 at 16 (Rose testimony noting that currently coal units are marginal units for setting energy prices in PJM). In that case, even a relatively small increase in costs per megawatt-hour could cause the unit not to be dispatched and to lose out on energy revenues for that time period. At the same time, the PPA will ensure that FirstEnergy is able to recover such costs (along with a healthy profit) regardless of their magnitude. This will prevent retirement of the PPA Units even where it makes economic sense for these polluting plants to retire in favor of cleaner, and therefore less costly, generation sources.

Environmental compliance costs that the Companies have failed to anticipate could directly offset the net PPA revenues flowing to customers, and could also render the plants less economic in the PJM supply stack, reducing their potential market revenues. With costs eating away either directly or indirectly at PPA revenues, Rider RRS might no longer offer revenues offsetting rising market prices even if they do occur, decreasing its value as a hedge. Despite the Commission's specific directive to do so, the Companies have offered at best an incomplete picture of these potential costs, rendering Rider RRS an even riskier proposition.

3. The Companies Have Not Offered Record Evidence Supporting Their Assertions Regarding the Benefits of the PPA Rider.

The Commission approved a placeholder PPA rider in the *AEP ESP 3 Case* primarily because of its conclusion that "there may be value for consumers in a reasonable PPA rider proposal that provides for a significant financial hedge that truly stabilizes rates, particularly during periods of extreme weather." *AEP ESP 3 Case*, Opinion and Order (Feb. 25, 2015) at 25. The FirstEnergy Utilities have pointed to this hedging rationale as one important benefit of their proposal, framing Rider RRS as a cure to long-term price volatility. Co. Ex. 13 at 3. However, the Companies' evidence regarding alleged volatility does not meet their burden to demonstrate that the Rider RRS proposal is necessary or useful in protecting customers. They fail to show that customers are actually exposed to that volatility or that, if so, customers lack adequate tools to address it. As for the other alleged benefits of Rider RRS resulting from keeping the PPA Plants from retiring, those primarily consist of an unrealistic estimate of transmission costs avoided by keeping the plants open, and an incomplete economic development analysis that focuses on lost jobs and revenue if the PPA Plants close without considering potential broader economic effects of Rider RRS. Ultimately, the Companies fail to demonstrate that Rider RRS and the Stipulation offer value that outweighs the likely costs for their customers.

a. The Companies Have Not Shown that Retail Customers Are Exposed to Significant Unwanted Price Volatility.

The Companies have offered no examples of *retail* customers actually experiencing unwanted price volatility. P3/EPSA Ex. 5 at 24. At best, Company witness Mikkelsen pointed to variation in wholesale energy prices that might be experienced by customers with variable price contracts through a CRES provider, in particular during the Polar Vortex. Co. Ex. 146 at 2-3. But that cursory evidence does not show that Rider RRS will offer a hedge that is "commensurate with" the significant risk of customers paying hundreds of millions or billions of dollars as outlined above. *AEP ESP 3 Case*, Opinion and Order (Feb. 25, 2015) at 25.

Company witness Strah's own testimony demonstrates the relatively minor stabilizing effects of the rider even if it produces the credits projected by the FirstEnergy Utilities. He testified that at its peak projected credit level of $351 million in 2029, Rider RRS would provide a $4.97 credit each month for a typical residential customer using 750 kwh per month, offsetting about 6% of a projected monthly generation bill of about $83. Co. Ex. 13 at 12. Under Company witness Mikkelsen's revised projection, the maximum projected credit over the term of Rider RRS is $216 million in 2021. Sierra Club Ex. 89. Witness Strah originally calculated that a similar level of credit in 2025 (about $229 million[8]) would reduce a monthly bill by just over 0.4 cents/kwh, or less than $3.75 for a typical residential customer. Co. Ex. 13 at 15 Fig. 2; Co. Ex. 33, Att. JAR-1 (original rider projections). Thus, the maximum monthly savings for a customer through Rider RRS will be under $4, and sometimes much less – for example, Witness Strah calculated that a $132 million credit (originally projected in 2024) would offer a credit of under 0.3 cents/kwh, or less than $2.25 per month on a bill of 750 kwh. Co. Ex. 13 at 15, Fig. 2; Co. Ex. 33, Att. JAR-1 (original rider projections). Meanwhile, OCC witness Wilson testified that Rider RRS would put a customer at risk of paying more than $8 a month as of 2017, or nearly *18%* of an estimated monthly generation bill of around $45. OCC/NOPEC Ex. 9 at 13, Tbl. 2;[9] Co. Ex. 13 at 14, Fig. 1. Thus, Rider RRS would offer an upside hedge of 6% at the absolute maximum but potentially impose a 17% downside in years with low plant revenues and electricity costs. The Companies have done nothing to show that any of its customers would accept that tradeoff, let alone that the Commission should *force* all of its customers to do so through a non-bypassable charge.[10]

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[8] This projected credit was subsequently revised down to $222 million due to an error in the Companies' calculations. *See* Co. Ex. 34.

[9] This represents an annual charge of $135.70 for a customer using 1000 kwh per month, adjusted downward by 25% to reflect the charge for a 750 kwh/month customer and divided by 12 to provide a monthly charge amount.

[10] The Environmental Intervenors, among other parties, have challenged on rehearing in the *AEP ESP 3 Case* whether imposing a PPA rider as a non-bypassable charge is in fact illegal because it violates R.C. 4928.02(H). *Supra* at 10 n.2.

In addition to failing to demonstrate the PPA provides a reasonable hedge, the Companies ignore the fact that there are a number of existing hedging mechanisms already available for customers who prefer to lock in stable rates. As the Commission has noted, both the SSO price and fixed price contracts from Competitive Retail Electric Service ("CRES") providers offer a viable route for customers to reduce their exposure to the ups and downs of wholesale market prices. *AEP ESP 3 Case*, Opinion and Order (Feb. 25, 2015) at 24; *see, e.g.*, Sierra Club Ex. 84 (October 23, 2015 Apples to Apples website for FirstEnergy customers showing a number of fixed price offers up to 36 months). SSO service likewise offers customers a fixed price over a three year timeframe. The Companies have not offered any record evidence regarding the proportion of its customers that in fact take service under a variable rate contract that would expose them to short-term price volatility, rather than relying on such tools as SSO service and fixed price contracts.

The Companies have also failed to show that Rider RRS is a beneficial mechanism to address potential long-term increases in market electricity prices. OCC witness Wilson has criticized much of the basis for Company witness Rose's testimony about the future conditions that would produce steep future price increases. OCC/NOPEC Ex. 6 at 32-43. Additionally, the PJM reductions in projected demand growth described above, *supra* at 16-17 – driven in large part by a better understanding of the significant role of efficiency improvements in mitigating demand growth – have undermined one of the key drivers of higher energy prices identified by Company witness Rose, yet he has not explained how that changing reality might affect his forecast. Co. Ex. 17 at 62. There are also tools currently available to manage price volatility over a several-year time horizon that the Companies have ignored. For example, large Ohio communities in FirstEnergy service territory have procured a community aggregation contract of more than five years, and presumably through a negotiation or procurement process that provides some reassurance about the legitimate value of such a contract. OCC/NOPEC Ex. 4 at 52.

Moreover, the Companies have never addressed the implementation of energy efficiency measures or the installation of behind-the-meter generation as alternatives to Rider RRS that could reduce exposure to increasing market prices. As acknowledged in the Companies' documentation regarding their energy efficiency programs, energy efficiency programs can help customers avoid significant electricity costs. *See FirstEnergy 2013-2015 EE/PDR Plan Case*, Application Atts. A, B, C at 4, Appx. C-3 Tbl. PUCO 1 (lifetime savings of hundreds of millions of dollars in avoided costs). Ohio law recognizes that behind-the-meter generation such as combined heat and power can likewise provide energy savings by reducing purchases from the grid. R.C. 4928.66(A)(1)(a); *see also In the Matter of the Applications of Solvay Advanced Polymers, L.L.C., dba Solvay Specialty Polymers; and Kraton Polymers U.S. LLC*, Case Nos. 14-2296-EL-EEC and 14-2304-EL-EEC, Finding and Order (Nov. 18, 2015) at 4-5 (projected net savings from installation of two industrial combined heat and power projects). Such tools are at their most useful when electricity prices are at consistently high levels, as the Companies assert they will be within a few years. Yet the Companies ignored the potential of demand-side measures when arranging its affiliate deal, and have agreed to reinstate their energy efficiency programs only if the Commission approves Rider RRS. Most importantly, the Companies never consider whether customers may prefer demand-side measures as a way to counter whatever price increases do occur over the next eight years. The market is already providing energy efficiency measures as one mechanism to manage energy bills, an approach that will offer at least some customers an environmentally friendly and cost-effective option to address future electricity prices increases if they do occur. *See, e.g.*, Sierra Club Ex. 84 (listing CRES fixed-price offers that include a free "learning thermostat" to "help you save up to 10-12% on heating bills and 15% on cooling bills"). Given this gap in the Companies' arguments, the Commission lacks justification to force customers to choose the risky hedge proposed in Rider RRS over other, potentially preferable options.

b. The PPA Rider Reduces the Benefits of Efficiency and Demand Reduction for AEP Customers and the General Public.

Not only did the Companies fail to consider the potential benefits of energy efficiency as an alternative hedging mechanism for customers, but they also do not acknowledge that Rider RRS may actually handicap the Commission and FirstEnergy EDU customers with respect to future energy efficiency and peak demand reduction efforts. As discussed by multiple witnesses, one benefit of energy efficiency and demand response resources is to lower wholesale market prices by reducing peak loads. OMAEG Ex. 22 at 12; ELPC Ex. 28 at 22. However, if the Commission approves the Rider RRS proposal, energy efficiency or demand response programs that would thus benefit customers may instead *harm* them by lowering the revenues of the PPA Units. ELPC Ex. 28 at 22. When the PPA revenues decrease, customers pay increased charges (or at best receive reduced credits) under the rider. *Id.* The Commission must consider the fact that Rider RRS will thus reduce the benefits of energy efficiency and peak demand reduction measures in deciding whether the benefits of the Companies' proposal outweigh the cost.

c. There Is No Evidence that Reliability in PJM Is at Risk.

The Companies heavily emphasize the "future reliability concerns" that the Commission discussed as one factor in considering a proposed PPA to prevent unit retirement in the *AEP ESP 3 Case*. Opinion and Order (Feb. 25, 2015) at 25. Fundamentally, the task of ensuring reliable transmission of electricity across the region belongs to PJM, which has mechanisms for doing so.

RESA Ex. 1 at 5-6. Moreover, in this case it appears that PJM is doing its job well. The Companies' invocation of massive retirements unmitigated by replacement resources does not match reality. Multiple intervenor witnesses have explained that new generation is coming online in significant amounts across PJM, including in Ohio. *E.g.*, Sierra Club Ex. 95 at 11; OCC/NOPEC Ex. 5 at 8-11. And as PJM itself noted in its most recent Base Residual Auction results for 2018/2019, those results show "a continuation of strong participation by new Generation Capacity Resources mostly in the form of new (or uprates to existing) gas-fired combustion turbine and combined cycle generation units." IGS Ex. 5 at 8.[11] As the new Capacity Performance rules take effect, all of this generation will have to perform reliably or face significant penalties. IMM Ex. 2 at 3-4.

The record also shows that a significant amount of this new capacity is being developed in Ohio, including five new natural gas plants amounting to nearly 4000 MW of new generation. Sierra Club Ex. 95 at 11. In light of this present-day evidence that market conditions are fostering the construction of new generation in Ohio as well as across PJM, the Companies' suggestion that historic trends in generation construction under different economic conditions and across may different areas of PJM should carry no weight. Co. Ex. 39 at 7.

d. The Companies' Projection Transmission Costs in the Event of Retirement of the PPA Units Is Unlikely to Prove True.

The Companies suggest that retirement of the PPA Plants could result in transmission costs for their customers of between $400 million and $1 billion. Co. Ex. 39 at 8. However, this prediction is based on an outdated load forecast that simply fails to take account of current conditions. As discussed above, the 2014 PJM load forecast on which the Companies'

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[11] Although this exhibit is designated as confidential in the record index, the Companies indicated at hearing that they did not object to it being treated as public. Tr. VIII at 1552.

transmission cost analysis is based has been revised significantly downward in recent years. *Supra* at 16-17; Sierra Club Ex. 95 at 17-18 & Fig. 5. Moreover, the Companies' analysis rested on then-current PJM generation scenarios that omitted at least some new generation currently being constructed in Ohio. Tr. XV at 3229-3232.The Companies chose not to update their transmission cost projections to account for these developments. They have not even provided the Commission with any qualitative assessment of how much significantly reduced load or new generation in Ohio would mitigate potential transmission costs if any of the PPA Plants retire. The burden is on the Companies to substantiate this element of their argument as to the benefits of customers in assuming the significant risks posted by Rider RRS, and they have not done so.

e. The Companies' Analysis of the Economic Development Benefits of Rider RRS Is Inadequate.

The Commission's decision in the *AEP ESP 3 Case* did consider that a PPA might have economic development benefits if it prevented unit retirements that would otherwise occur, and explained how to analyze those benefits. The Commission stated that such an analysis should provide evidence of "the impact that a closure of the generating plant would have on electric prices and the resulting effect on economic development within the state." *AEP ESP 3 Case*, Opinion and Order (Feb. 25, 2015) at 25. Requiring a comprehensive evaluation of potential ramifications for the state as a whole is consistent with the Commission's approach in the context of evaluating "reasonable arrangements" to promote economic development by offering businesses a special discount on electricity rates. In such cases the Commission looks at not only "the benefits received by the parties to the arrangement," but also benefits to "the electric utility's ratepayers, and the state of Ohio." *In re Ohio Edison Company and V&M Star*, Case No. 09-80-EL-AEC, Opinion and Order (Mar. 4, 2009) at 7. The Companies fail to provide the information necessary to conduct such a holistic evaluation, and thus have not satisfied the Commission's clear directive in the *AEP ESP 3 Case*.

The Companies do offer an analysis of how many jobs Sammis and Davis-Besse support and what tax revenues they produce, with the presumption that those jobs and revenues would be lost without recourse should the units retire. Co. Ex. 36 at 6, 10. However, the Companies do not address what effect such retirements might have on electricity prices – the exact issue highlighted by the Commission. Tr. XV at 3090-3091. Accordingly, it is unknown whether the shutdown of these uneconomic plants might actually reduce electricity prices within the state by making way for cheaper new generation (such as new natural gas plants currently being constructed as described above) or expanded investments in energy efficiency. OMAEG Ex. 18 at 10-13. If that were the case, those new generation sources or energy efficiency investments could directly provide employment and economic stimulus, and the additional revenue available to customers across the state as a result of savings on electricity bills could spur economic development sufficient as well. *Id.* Since the Companies never considered these possibilities, there is no way to know such effects could offset or even outweigh the effects of retirement of Sammis or Davis-Besse.

Moreover, if Rider RRS does cause customers to pay more for their electricity, this translates to customers spending less on other goods and services. It also puts businesses at a competitive disadvantage with respect to businesses in other service territories or states that are able to fully take advantage of low market prices. OMAEG Ex. 18 at 15. The Company did not consider this possibility either. Finally, the Companies' economic development analysis does not include any consideration of whether out-of-market payments to certain generators may discourage competitors from building new and cheaper generation in Ohio, potentially resulting in higher prices over the long run. OMAEG Ex. 17 at 21. The Companies' failure to consider these potential consequences precludes the Commission from determining the economic development benefits of subsidizing the PPA Plants.

As described above, the PPA rider could end up costing customers well over $2 billion. The Companies fail to justify preservation of the jobs and tax revenue attributable to the PPA Plants at such high costs to its customers. Keeping the units open is not an unalloyed economic development benefit – it involves potential tradeoffs that the Commission simply does not have enough information to consider. The burden lies on the Companies to analyze both the benefits *and* potential costs of the Stipulations of Rider RRS in order to give the Commission evidence it needs to conduct a proper evaluation. The Companies have failed to meet this burden.

4. The Provisions Added to This Proposal in the Stipulations Do Not Merit Any Significant Weight in the Commission's Determination of Benefits of the Package.

The Companies have failed to demonstrate the actual value of the many provisions in the proposed Stipulations, and that on balance they outweigh the costs of the main element of the FirstEnergy ESP proposal – Rider RRS. The Stipulations, particularly the Third Supplemental Stipulation, are not supported by record evidence that would allow the Commission to evaluate the merits of the Companies' assertion that they would benefit the public interest. Moreover, certain specific provisions of the Stipulations could harm customers in significant ways. The Commission must consider such potential adverse effects just as seriously as any potential benefits.

a. The Stipulations May Actually Harm Customer Interests.

Some provisions of the Stipulations may in fact harm customers. For example, approval of the Stipulations would preclude the Commission from terminating the Rider RRS and Rider

DCR before 2024 to protect customer interests even though R.C. 4928.143 provides for a review and potential termination of an extended ESP in its fourth year. Co. Ex. 154 at 18. Additionally, in return for the Companies' commitment merely to file a grid modernization business plan, the Commission must approve an incentive ROE on grid modernization investments without any evidence showing that it will not provide windfall profits to the Companies. ELPC Ex. 28 at 13-14. Similarly, as discussed further below, the energy efficiency provisions commit the Commission to allow incentive payments to the Companies at levels that may well be unreasonable; and for programs that may have no merit.

b. The Commission Should Not Make Any Preliminary Findings on Straight Fixed Variable Rates Without a Full Record.

In section F of the Third Supplemental Stipulation, the FirstEnergy Utilities ask the Commission to pre-approve a shift to straight fixed variable residential rates, an issue never raised in the Companies' testimony prior to the stipulation. The Companies never explain why they include this issue in the Stipulation, how it benefits customers, or why this rate design issue should be considered outside of a rate case. Co. Ex. 155. This issue has broad policy ramifications for FirstEnergy distribution customers, and the Commission should not approve inclusion of it in this settlement.

The Third Supplemental Stipulation states, "The Companies agree to file a case before the Commission by April 3, 2017, to transition to the proposed straight fixed variable cost recovery mechanism for residential customers' base distribution rates." Co. Ex. 154 at 12. The Companies further state:

> Cost recovery shall be based on an allocation of 75 percent fixed costs and 25 percent variable costs. The phase in will occur as follows:
>
> i. Year 1: 25% fixed costs and 75% variable costs
> ii. Year 2: 50% fixed costs and 50% variable costs

iii. Year 3: 75% fixed costs and 25% variable costs

Id. The Companies fail to explain why the Commission should pre-approve a filing of such a case, and more importantly, why it should pre-judge any levels for recovery of fixed costs even as a starting point for a future filing. As ELPC Witness Rábago explains regarding this provision, "the Commission lacks any evidentiary basis to evaluate its merits or its potential consequences." ELPC Ex. 28 at 18.

Utilities have the option of recovering distribution revenues through either a fixed monthly customer charge or through volumetric charges. When utilities recover a high percentage of the distribution costs through fixed monthly charges, it has a significant effect on consumers. Most importantly, low usage customers pay more than they would under a balanced rate structure, and customers who invest in efficiency receive diminished returns. As Witness Rábago notes:

> Increased fixed cost recovery for what are identified as fixed costs reduces the payback value of energy efficiency investments. Customers who reduce energy use can't avoid fixed cost charges, so they act as a regressive tax on customers, especially low use customers, who include the elderly, those on fixed incomes, and the poor.

ELPC Ex. 28 at 18. The Companies fail to even mention these issues outside of the conclusory description of the issues in the Third Supplemental Stipulation, much less adequately address them. Co. Ex. 155. When pressed on the issue, the Companies admit their only justification for the shift is that "it was part of a negotiated settlement." ELPC Ex. 28, Ex. KRR-4, ELPC Set 7-INT-012. Moreover, such a change directly undermines the benefits that the Companies allege customers will receive from their new energy efficiency offerings under Section E of the Third Supplemental Stipulation. The Companies tout their renewed efforts on efficiency as "Robust

Comprehensive Energy Efficiency Offerings," at the same time as they commit to seeking a rate design change that reduces the benefits of efficiency to their customers.

In addition to requesting pre-approval of a shift, the Companies request pre-approval of the exact percentages of revenue recovered through fixed charges. Any such approval of the shift to recovering 75% of its costs in a fixed charge violates fundamental principles of ratemaking. "The predetermination of the percentages for recovery of costs through fixed or variable charges in the Stipulation violates standard ratemaking principles requiring evidence-based determinations of cost-causation, cost allocation, and fair rate design." ELPC Ex. 28 at 18. While indicating its interest in seeing Ohio move in this direction, the Ohio Commission itself stated, "The appropriate time to implement an SFV rate design is during an electric utility's rate case." *In the Matter of Aligning Electric Distribution Utility Rate Structure with Ohio's Public Policies to Promote Competition, Energy Efficiency, and Distributed Generation,* Case No. 10-3126-EL-UNC, Finding and Order (Aug. 21, 2013) at 20. This principle is especially applicable here since there no basis in the record for these percentages. Tr. XXXVII at 7856-7857. Company witness Mikkelsen would not even attest in hearing that the FirstEnergy Utilities would offer any explanation of the basis for that allocation in a future rate case. *Id.*

The Commission should note that a number of state commissions have recently rejected proposals to increase customer charges, siding with consumer and environmental intervenors that had very different perspectives on customer charges and rate design. In the recent Detroit Edison rate case, for example, the Michigan Commission rejected DTE's attempt to raise the residential fixed customer charge from $6.00 to $10.00, explaining that DTE had failed to convince the Commission that delivery costs are fixed costs. *In the matter of the application of DTE Electric*

Company for Authority to Increase Its Rates, Docket No. U-17767, 2015 Mich. PSC LEXIS 344 at 196-197 (Dec. 11, 2015).

Given the importance of this issue, and the Companies' failure to submit any evidence in support of this aspect of its proposal, Environmental Intervenors urge the Commission to reject this Section of the Stipulation. The Companies are free to come in for a rate case at any time, and alternatively the Commission can open a generic proceeding on rate design where it can ensure the development of a comprehensive record.

c. The Energy Efficiency Provisions May Not Provide Significant Benefits, Yet Would Require Significant Concessions.

Page 11 of the Third Supplemental Stipulation purports to commit the Companies to provide "robust comprehensive energy efficiency offerings." However, the "robustness" of this provision is dubious.

As an initial matter, the 800,000 MWh target is not binding, stating only that the FirstEnergy Utilities will "strive to achieve" that goal. Co. Ex. 154 at 11. While the Companies may have good intentions, the lack of enforceability of this target must lessen the weight that the Commission can place on it as a potential benefit. The target is also subject to customer opt-outs, meaning that where customer opt-outs from the Companies' energy efficiency programs lessen the FirstEnergy Utilities' baseline energy load, they will adjust the 800,000 MWh goal accordingly. Such customer opt-outs are already available to the Companies' large customers pursuant to R.C. 4928.6611 and S.B. 310, Section 8, and will continue to be available throughout the ESP period. The FirstEnergy Utilities have not offered any evidence of the amount of existing or projected future opt-outs, so there is no way to know how far this 800,000 MWh may already be reduced or may be further reduced in the future.

The Commission must also understand what savings will "count" toward meeting this 800,000 MWh goal. R.C. 4928.662, enacted in 2014, provides that a utility must count not only savings from utility energy efficiency programs toward its statutory targets, but also energy savings resulting from customer actions outside those programs, as when a customer replaces an incandescent lightbulb that fails with a more efficient CFL bulb. R.C. 4928.662(A). Under the same provision, utilities also count savings from measures incentivized under its programs on a "gross" basis, *i.e.*, even if they would have happened without the utility paying for customer incentives. R.C. 4928.662(D). Company witness Mikkelsen indicated that the FirstEnergy Utilities would apply this statutory provision in measuring its progress toward the Stipulation goal. Tr. XXXVII at 7865. Moreover, the Companies already have a "Customer Action Program" designed to measure such savings that it has indicated it may include in its EE/PDR portfolio plan. Tr. XXXVII at 7860-7865. Thus, all of these savings could come from normal customer behavior and business as usual, rather than any new beneficial action by the Companies to promote implementation of cost-effective energy efficiency.

At the same time, approval of this provision would automatically authorize the Companies to collect up to $25 million in "shared savings" as incentive payments for savings above statutory efficiency requirements from any "cost effective energy efficiency programs." This constitutes a 150% increase in the Companies' shared savings cap, with absolutely no explanation in the record of the basis for that increase. ELPC Ex. 27. Moreover, according to Company witness Mikkelsen, since the Companies take the position that their Customer Action

Program is cost-effective, these incentive payments would be paid on energy savings from customer action that the Companies had done nothing to cause. Tr. XXXVII at 7866.

As the Commission has recently noted, the purpose of a shared savings mechanism is to provide a utility the motivation to "continue to find ways to encourage energy efficiency." *In the Matter of the Application of Duke Energy Ohio, Inc. for Recovery of Program Costs, Lost Distribution Revenue, and Performance Incentives Related to its Energy Efficiency and Demand Response Programs*, Case No. 14-457-EL-RDR, Finding and Order (May 20, 2015) at 5. The Companies have not demonstrated that this shared savings provision does anything more than offer generous profits to the FirstEnergy Utilities at customer expense.

d. The Companies Have Not Provided Evidence that Several Provisions of the Third Supplemental Stipulation Will Provide Any Benefits.

A number of provisions in the Stipulations, particularly the Third Supplemental Stipulation, may be window dressing at best. For example the carbon reduction on page 11 is not binding. It is also unsupported by any evidence of feasible plans for FirstEnergy to achieve that goal, particularly if Rider RRS forestalls retirement of the carbon-polluting Sammis and OVEC plants. The Companies will not file any report on its plans until 2021, and the Commission will not know if the goal has been met for more than three decades.

Similarly, the Companies have not shown that the renewable provision on page 12 is likely to provide any benefits. That provision is triggered when there is some new law or rule for which new renewables would be helpful for compliance, but only where PUCO Staff determines that law or rule has not fostered any development of renewable resources. The Companies have not offered any criteria for Staff to apply in making this determination, and as a matter of common sense it seems unlikely that a law or rule would be so completely ineffective.

Even if the renewables provision is triggered, it may not be effective. The Third Supplemental Stipulation limits the Companies to seeking a renewables PPA for the duration of ESP 4, without any evaluation of whether a PPA of that term would be sufficient to support development of a significant renewables project. As MAREC witness Burcat has testified, a large-scale capital investment for a generation project "require[s] large-scale financing" that provides "some meaningful degree of certainty that adequate returns can be achieved." MAREC Ex. 1 at 5. Such adequate terms may not be available under a PPA limited to the duration of ESP 4, especially if the triggering event does not occur early in the ESP period – certainly a significant possibility since state laws or rules to implement the Clean Power Plan, the most obvious candidate for a trigger, would not need to take effect until 2022.

Rejecting the stipulation package does not preclude the Companies or the Commission from pursuing ideas in the Stipulations that are potentially meritorious but unsupported by any record evidence. As Witness Rábago testified, the Commission has the authority to open these issues in separate dockets and independently evaluate such benefits in a setting where they can be appropriately considered on a full and open record. Tr. XXXVIII at 8205. That will allow decisions free of harmful giveaways to the Companies and without pre-committing the Commission to piecemeal approval of any aspects of these untested proposals.

C. Commission Approval of a Backroom Affiliate Deal Is Not Consistent with Applicable Regulatory Principles or Practices.

1. The Rider RRS Proposal Contravenes Legal Protections Against Abuse of Affiliate Power.

More than 15 years ago, Ohio deregulated its utility industry shifting from cost-based rates to market competition for generation. This change meant that customers would benefit from competition between power producers with uneconomic plants retiring in favor of more efficient lower priced producers. In order to ensure that even utility generation affiliates would be subject to the discipline of market forces, the legislature required corporate separation between monopoly electric distribution companies and their unregulated affiliates. Thus, Ohio law clearly states that an electric utility must operate under a corporate separation plan "sufficient to ensure that the utility will not extend any undue preference or advantage to any affiliate, division, or part of its own business engaged in the business of supplying the competitive retail electric service or nonelectric product or service." R.C. 4928.17(A)(3). Similarly, R.C. 4928.02(H) provides that it is state policy to "[e]nsure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa . . . ." As explained in the Commission rules implementing these corporate separation requirements, their purpose is to ensure that "a competitive advantage is not gained solely because of corporate affiliation" and "to create competitive equality, prevent unfair competitive advantage, prohibit the abuse of market power and effectuate" R.C. 4928.02. Accordingly, Ohio Adm. Code 4901:1-37-04(A)(3) bars "cross-subsidies" between an electric utility and its affiliate.

Even prior to deregulation, Commission precedent incorporated similar precepts, as in cases requiring heightened scrutiny of affiliate fuel purchases under (now-defunct) R.C. 4905.01(F). *In re Electric Fuel Component*, No. 86-01-EL-EFC, Opinion and Order (Nov. 12, 1986). As discussed above, FERC likewise will not approve an affiliate deal that is not supported by some objective reference point for its costs and benefits such as a showing that there was competition between an affiliate and competing suppliers on a level playing field, or that the affiliate deal is consistent with benchmark evidence of similar transactions with non-affiliates. *Boston Edison Co. Re: Edgar Electric Energy Co.*, 55 F.E.R.C. ¶ 61,382, 62,168-62,169 (1991). Otherwise, FERC presumes that the transaction is not just and reasonable. Other state utility commissions have also applied such a heightened standard of review in considering whether to approve affiliate transactions. *See, e.g.*, *Entergy Louisiana*, Docket No U-27136, 2006 La. PUC LEXIS 281, at 102-103 (Aug. 29, 2006) (noting that "heightened scrutiny" applies to affiliate transactions given concerns about protecting ratepayers and "caus[ing] long-term harm to the wholesale competitive market" by "discourag[ing] non-affiliates from adding supply in the local area").

The PPA rider as proposed by the Company is inconsistent with Ohio laws and policies barring affiliate subsidies, and their purpose of promoting effective competition in the retail electricity market. The Companies have failed to show that the affiliate transaction proposed here does not provide an anti-competitive advantage or financial subsidy. The Companies arrived at the proposed PPA with FES without any evaluation of other options, providing its affiliate with the exclusive opportunity to provide the desired generation resources at a guaranteed rate of return that it has been unable to obtain in the market. *Supra* at 20-25. Thus, the PPA proposal will effectively ensure greater profits and lower risk for FirstEnergy shareholders than the Companies could obtain otherwise. Moreover, the Companies have failed to substantiate the reasonableness of this approach. *Id.*

Whether one terms this "undue advantage" or a "subsidy," the PPA proposal is clearly a transaction that offers FES significant benefits without any safeguards such as those described in

Edgar, designed to ensure that the Company's customers receive the best deal or even a reasonably good deal with sufficient protections against market risk. Yet if the Commission approves the Stipulation, FirstEnergy customers will be stuck with the PPA rider for the next eight years ely without the Commission ever evaluating it against other options, at a potential cost of more than $2 billion. That outcome is inconsistent with Ohio law and effective policy, and therefore the Companies have not met its burden of proof in demonstrating that Rider RRS satisfies this prong of the stipulation review standard.

2. The Stipulation Commitments to Provide Specified Energy Efficiency Funding Without Any Evidence that the Funding Will Result in Cost-Effective Energy Savings Are Inconsistent with Ohio Administrative Code 4901:1-39-03 and 4901:1-39-04.

Several of the stipulation provisions commit the Companies to give significant funding to particular parties as part of its energy efficiency and peak demand reduction ("EE/PDR") portfolio plan. However, the Companies fail to provide any evidence that such funding meets the standards that the Commission has established for approval of a such a portfolio plan in Ohio Administrative Code 4901:1-39-03 and 4901:1-39-04. This problem does not constitute merely a technical violation of formalistic procedural rules. Rather, it represents a troubling practice of circumventing a Commission process designed to achieve an important substantive outcome: a well-designed EE/PDR portfolio plan that uses customer funds wisely to produce cost-effective energy savings across all customer classes. The Commission should not approve such an approach.

Commission rules regarding approval of a utility's EE/PDR portfolio plan set forth specific requirements for that process, with the purpose of developing programs "that will encourage innovation and market access for cost-effective energy efficiency and peak-demand reduction, achieve the statutory benchmark for peak-demand reduction, meet or exceed the statutory benchmark for energy efficiency, and provide for the participation of stakeholders in developing energy efficiency and peak-demand reduction programs for the benefit of the state of Ohio." Ohio Adm. Code 4901:1-39-02(A). First, the utility must "conduct an assessment of potential energy savings and peak-demand reduction from adoption of energy efficiency and demand-response measures within its certified territory." Ohio Adm. Code 4901:1-39-03(A). In considering the assessed measures for inclusion in a portfolio plan, the utility must consider criteria including:

> (1) Relative cost-effectiveness.
>
> (2) Benefit to all members of a customer class, including nonparticipants.
>
> (3) Potential for broad participation within the targeted customer class.
>
> (4) Likely magnitude of aggregate energy savings or peak-demand reduction.
>
> (5) Nonenergy benefits.
>
> (6) Equity among customer classes. . . .
>
> (11) The degree to which the program successfully addresses market barriers or market failures.
>
> (12) The degree to which the program leverages knowledge gained from existing program successes and failures [and]
>
> (13) The degree to which the program promotes market transformation.

Ohio Adm. Code 4901:1-39-03(B).

Ultimately, the utility must "propose a comprehensive energy efficiency and peak-demand reduction program portfolio, including a range of programs that encourage innovation and market access for cost-effective energy efficiency and peak-demand reduction for all customer classes." Ohio Adm. Code 4901:1-39-04(A). "In general, each program proposed within a program portfolio plan must . . . be cost-effective," unless "that program provides substantial nonenergy benefits." Ohio Adm. Code 4901:1-39-04(B). The utility must support its proposed plan with "[a] narrative describing why the program is recommended pursuant to the program design criteria in this chapter"; "projections and basis for calculating energy savings and/or peak-demand reduction resulting from the program"; "[a]n estimate of the level of program participation"; and "[a] description of the marketing approach to be employed, including rebates or incentives offered through each program, and how it is expected to influence consumer choice or behavior." Ohio Adm. Code 4901:1-39-04(B)(5).

The Companies complied with none of these requirements. They did not conduct any assessment of measures that COSE or AICUO might implement with the funding provided under the Third Supplemental Stipulation. Tr. III at 563-569. Nor did they provide any evidence that they considered the criteria in Ohio Adm. Code 4901:1-39-03(B) in deciding to commit funding to these entities. The Companies did not even require that the funding produce cost-effective savings, or that it be spent on FirstEnergy customers. Tr. III at 563-569. As a result, the FirstEnergy Utilities may be spending customer money on parties in return for their support for the Stipulations without credible evidence of the type required by the Commission to show that the money will benefit customers.

Even if the Commission credits the unsupported assertion that COSE and AICUO will implement beneficial energy efficiency programs, the above criteria require the FirstEnergy Utilities to consider not just whether a program does result in cost-effective savings but also whether it promotes a host of other considerations. Those considerations include a program's value relative to other programs that might offer more innovative approaches, more progress in developing energy efficiency markets, better customer engagement, or simply more cost-effective savings. In this case, the Companies committed funding toward COSE and AICUO that might be more valuably employed elsewhere, inconsistent with the Commission's carefully crafted rules.

3. The Stipulations Allow Customers that Have Opted Out of Paying the Companies' Energy Efficiency and Peak Demand Reduction Programs to Continue to Receive Payments for Peak Demand Reduction in Violation of R.C. 4928.6613.

The original Stipulation filed in this case on December 22, 2015 contains a provision unrelated to the PPA proposal that is inconsistent with R.C. 4928.6613. This statute, along with R.C. 4928.6611 and R.C. 4928.6612, provides that certain utility customers may "opt out" of a utility's energy efficiency and peak-demand reduction portfolio plan. The effect of that opt out is that

> no account properly identified in the customer's verified [opt-out] notice under division (C) of section 4928.6612 of the Revised Code shall be subject to any cost recovery mechanism under section 4928.66 of the Revised Code or eligible to participate in, or directly benefit from, programs arising from electric distribution utility portfolio plans approved by the public utilities commission.

R.C. 4928.6613. In other words, the customer gives up the ability to participate in the utility's energy efficiency and peak demand reduction programs in return for being exempted from paying for those programs.

The Stipulation contravenes this provision in Section A.1.6, which relates to customers participating in Rider ELR. Co. Ex. 2 at 8. Rider ELR provides for the Companies to pay eligible customers monthly customers a credit in return for each kilowatt-month of interruptible load – an amount by which the customer will reduce its demand if called upon under the terms of the ELR tariff. The Stipulation states that "ELR customers may opt out of the opportunity and ability to obtain direct benefits from the Companies' EE/PDR Portfolio Plans as provided in S.B. 310." Co. Ex. 2 at 8. This sentence would apparently allow customers to opt out of paying for the

Companies EE/PDR programs (through Rider DSE) while still participating in its interruptible tariff.

However, the Companies' interruptible program is part of their portfolio plan, and they counts demand response resources from that program toward compliance with their demand reduction targets under R.C. 4928.66. *FirstEnergy 2013-2015 EE/PDR Plan Case,* Application Atts. A, B, C at 13. Moreover, the Commission itself has recently stated that it views utility interruptible programs as related to compliance with statutory peak demand requirements, and that in fact demand reductions are the "primary benefit" of such programs. *In the Matter of the Amendment of Chapters 4901:1-10 and 4901:1-21*, Case No. 14-1411-EL-ORD, Third Entry on Rehearing (Aug. 26, 2015) at 4. It would therefore violate the plain language of R.C. 4928.6613 to allow interruptible customers a piecemeal opt-out whereby they receive the benefit of the Companies' peak demand reduction programs (in the form of a monetary credit) but do not have to pay their share of the costs of the overall program portfolio.

4. Granting the Companies Lost Distribution Revenues for Their Customer Action Program Would Be Inconsistent with Commission Precedent.

As part of the ESP 4 Application, the Companies seek authorization to recover lost distribution revenues for their energy efficiency programs, including their "Customer Action Program" described above. When the FirstEnergy Utilities originally proposed this program, several parties argued that they should not be able to receive lost distribution revenues for a program that reflects baseline efficiency improvements rather than the effects of a utility program. *FirstEnergy 2013-2015 EE/PDR Plan Case,* Finding and Order (Nov. 20, 2014) at 18. At that time, the Commission indicated it would resolve this issue in this case. *Id.* at 18-19.

The Commission should bar the Companies from seeking lost distribution revenues based on efficiency improvements measured through the Customer Action Program. The Commission has already made clear in the context of smart grid deployment that "approval of lost distribution revenues is limited to those lost revenues which can be demonstrated to be the result of FirstEnergy's proposed alternative pricing program." *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Approval of Ohio Site Deployment of the Smart Grid Modernization Initiative*, Case Nos. 09-1820-EL-ATA *et al.*, Finding and Order (June 30, 2010) at 10. Similarly, the Commission has previously stated with respect to a FirstEnergy efficiency program that lost distribution revenues are meant to reflect "the actual impact of [a utility's efficiency programs] . . . upon energy savings." *In the Matter of the Application of The Cleveland Electric Illuminating Company, Ohio Edison Company, and The Toledo Edison Company for Approval of Their EE/PDR Program Portfolio Plans for 2010 through 2012*, Case Nos. 09-1947-EL-POR *et al.*, Opinion and Order (Mar. 23, 2011) at 18. The same regulatory principle applies here. The Companies cannot recover lost distribution revenues related to the Customer Action Program since that program does not actually cause or impact customer behavior, merely measuring independent customer action.

VI. CONCLUSION

The FirstEnergy Utilities bear the burden to demonstrate that the proposed Stipulations, including Rider RRS and ESP 4 as a whole, are reasonable and merit Commission approval. The record demonstrates the Companies' failure to satisfy this burden across the board. They have provided a flawed projection of the impacts of Rider RRS that is inconsistent with recent market information showing that this proposal puts customers at risk to pay more than $2 billion. The

Companies' process for developing the PPA , considering only FES plants without going to the market or considering any other resources, provides no reassurance that this affiliate deal represents a reasonable price in return for a value that could not be obtained on better terms elsewhere. Approval of the proposed Rider RRS would also contravene Ohio law barring such affiliate deals. Finally, the Companies have not shown that the Stipulations offer concrete benefits to customers that justify the significant risks of Rider RRS. In fact, some provisions of the Stipulation would harm customers or violate Ohio law and policy. For these reasons, the Commission should reject Rider RRS and the proposed Stipulation provisions discussed above.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The Public Utilities Commission of Ohio's e-filing system will electronically serve notice of the filing of this Initial Brief on the parties referenced on the service list of the docket card who have electronically subscribed to the case. In addition, the undersigned certifies that a courtesy copy of the foregoing document is also being served (via electronic mail) on February 16, 2016 upon all persons/entities listed below.

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