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 An Electric Security Plan	**)))))))**	**Case No. 14-1297-EL-SSO**

INITIAL POST-HEARING BRIEF OF THE SIERRA CLUB

Public Version

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In this case, the witnesses for the Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, "FirstEnergy" or "Companies") have talked at length about "stability." This word is pervasive in the Companies' filings, and indeed, it crops up twice in the most consequential provision of the eight-year electric security plan ("ESP") the Companies have submitted for Commission approval.[1] At the heart of this case is what FirstEnergy has deemed a Retail Rate Stability Rider ("Rider RRS"), which is the central component of the so-called "Economic Stability Program." Under FirstEnergy's telling, Rider RRS will provide stability to the Companies' customers, as well as a host of other benefits.

While FirstEnergy is correct that its proposal would provide stability, it would be First Energy Solutions Corp. ("FES"), *not* the Companies' customers, who would be receiving such stability. In particular, Rider RRS, together with a related power purchase agreement ("PPA"), would provide a stable, risk-free source of income for FES, a lateral affiliate of the Companies that owns a number of generating plants. Through FirstEnergy's proposal, the Companies and, ultimately, their customers, would ensure that FES covers a projected $11.616 billion in costs for several of these plants over eight years, and provides FES with a locked-in return on equity that is projected to total [redacted] over the term of the rider.[2] In short, FES would have freed itself of all of the financial risks that are typically part of being a merchant generator competing in PJM's wholesale markets, and ensure that it will cover its costs and receive a profit.

[1] The Companies' proposed ESP, which was initially submitted in August 2014, has been modified by subsequent stipulations, the most recent of which was filed on December 1, 2015. *See* Third Supplemental Stipulation and Recommendation. Because this brief does not discuss any previous stipulations that were filed in this case, any mention of the "Stipulation" in either the text or footnotes is referring to the Third Supplemental Stipulation, admitted as Co. Ex. 154.

[2] SC Ex. 89; SC Ex. 90c (sum of amounts listed in line 24, "Equity Return," in attachments JJL-1 and JJL-2). These figures are in nominal dollars.

The Companies' customers, by contrast, would find themselves in the opposite situation: under Rider RRS, they would be forced to bear the financial risks of FES's generating plants. And the risks of this proposal are enormous. While even FirstEnergy admits that customers would lose $363 million over the first 31 months of Rider RRS,[3] the evidence in this case strongly establishes that the cost to customers will almost certainly be significantly higher. Moreover, although FirstEnergy has projected that customers would receive a credit during the later years of Rider RRS, that projection is built on unreasonable and outdated assumptions.

Rider RRS, and the Stipulation that includes this proposed rider, should be rejected because it is unlawful, and because FirstEnergy has utterly failed to meet its burden of showing that the rider is just and reasonable, or that the ESP would be more favorable in the aggregate than a market rate offer. As explained below, Rider RRS is not authorized by R.C. 4928.143. And even if this rider were legally permissible, it should be rejected as unjust and unreasonable. FirstEnergy's projection of charges and credits under Rider RRS is based on inaccurate and outdated market price forecasts that are already proving to be wrong, and was generating with only a single, flawed modeling run. The projection also fails to account for potentially costly environmental compliance risks. Put simply, customers would face significant financial risks if Rider RRS were approved. And these risks are compounded by the structure of FirstEnergy's proposal, which further allocates risk away from FES and onto customers. Rider RRS should also be rejected because the other purported benefits of this rider – such as avoiding transmission upgrades and providing fuel diversity – are illusory. These benefits are premised on the empty threat that FES's plants would suddenly retire in the absence of Rider RRS. Moreover,

[3] SC Ex. 89. This figure represents the net present value of projected customer losses during that time period.

FirstEnergy's characterization of these benefits is otherwise flawed. For all of these reasons, and for the additional reasons discussed below, the Commission should reject Rider RRS.

LEGAL STANDARD

R.C. 4928 establishes a comprehensive scheme for regulating retail electric service.[4] Among other things, the statutory scheme requires electric distribution utilities to provide a standard service offer, and directs utilities to submit an application for either a market rate offer or an electric security plan ("ESP").[5] Where, as here, a utility has proposed an ESP for its standard service offer ("SSO"), the utility bears the burden of demonstrating that the application satisfies R.C. 4928.143. The Commission may approve, or modify and approve, an electric security plan only if it finds that the utility has met its burden of demonstrating that the ESP, "including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under section 4928.142."[6]

The specific components of an ESP, such as the Retail Rate Stability Rider proposed by the Companies, are also governed by R.C. 4928.143. To be approved as part of an ESP, a proposed rider must qualify as a "permissible provision of an ESP, in accordance with R.C. 4928.143(B)(1) or (B)(2)."[7] If a provision does not fall within one of the enumerated categories set forth in (B)(1) or (B)(2), it cannot be approved as part of an ESP.[8]

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[4] *See generally* R.C. 4928.

[5] R.C. 4928.141-.143.

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

[7] *In re Ohio Power Co.*, Case No. 13-2385-EL-SSO, et al., Opinion and Order, at 20 (Feb. 25, 2015) (hereinafter, "AEP ESP III Order").

[8] *See, e.g.*, *In re Application of Columbus S. Power Co.*, 128 Ohio St.3d 512, 2011-Ohio-1788, 947 N.E.2d 655, ¶ 33.

If a proposed rider does qualify as a permissible ESP provision, the Commission should review the record to determine whether the proposal is "just and reasonable" and whether customers would, in fact, sufficiently benefit from it.[9] In reviewing such proposals, the Commission should be "guided by the policies of the state as established by the General Assembly in R.C. 4928.02, as amended by Amended Substitute Senate Bill 221 (SB 221)."[10] In the Commission's review of proposed riders, such as Rider RRS, the utility carries "the burden of proof to show that the proposals in the application are just and reasonable and are consistent with the policy of the state as delineated in divisions (A) to (N) of section 4928.02 of the Revised Code."[11]

Additionally, because the Companies' ESP Application has been modified by a stipulation entered into by several parties,[12] the Commission will typically evaluate whether: 1) the settlement is a product of serious bargaining among capable, knowledgeable parties; 2) the settlement, as a package, benefits ratepayers and the public interest; and 3) the settlement package violates any important regulatory principle or practice.[13] However, a stipulation is not,

[9] *See, e.g.*, O.A.C. 4901:1-35-06(A); AEP ESP III Order at 23 (considering, based on the record whether AEP Ohio's "PPA rider proposal is reasonable and whether customers would, in fact, sufficiently benefit from the rider's financial hedging mechanism").

[10] AEP ESP III Order at 7. *See also, e.g.*, *In re Application of Columbus S. Power Co.*, 128 Ohio St.3d 512, 2011-Ohio-1788, 947 N.E.2d 655, ¶ 62 (discussing R.C. 4928.02(D), and noting "such policy statements are guidelines for the commission to weigh in evaluating utility proposals to further state policy goals") (quotation marks, citation, and alterations omitted). R.C. 4928.06(A) directs the Commission to "ensure that the policy specified in section 4928.02 of the Revised Code is effectuated."

[11] O.A.C. 4901:1-35-06(A); R.C. 4928.143(C)(1); *see also, e.g.*, *Re Duke Energy Ohio, Inc.*, Case No. Case No. 12-2400-EL-UNC, 2014 WL 1385220 (Feb. 13, 2014) (rejecting Duke's application where the utility had not sustained its burden of proof).

[12] *See generally* Stipulation.

[13] *In the Matter 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 Section 4928.143, Revised Code, in the Form of an Electric Security Plan*, Case No. 12-1230-EL-SSO, Opinion and Order, at 24 (July 18, 2012) (hereinafter, "FE ESP III Order").

in itself, sufficient to satisfy the Companies' burden in this proceeding.[14] Rather, the Commission still "must determine, from the evidence, what is just and reasonable."[15] Moreover, the existence of a stipulation does not affect the Commission's review of the legality of the proposed ESP provisions.[16] Instead, the stipulation is only a recommendation to the Commission which the Companies would still have to demonstrate is lawful and supported by evidence in the record.[17]

ARGUMENT

I. Rider RRS is not authorized under Ohio law.

A. Rider RRS

As part of their ESP filing, the Companies have requested that the Commission approve Rider RRS, a non-bypassable rider that would add on to their customers' bills a charge or credit that is tied to the economic fortunes of four generating facilities owned wholly or partly by FES: the W.H. Sammis, Kyger Creek, and Clifty Creek coal plants, and the Davis-Besse nuclear plant.[18]

As currently proposed, the Companies would enter into an eight-year purchase power agreement ("PPA") with FirstEnergy Solutions Corp. ("FES") (hereinafter, the "proposed

[14] *Indus. Energy Consumers of Ohio Power Co. v. Pub. Utils. Comm'n of Ohio*, 68 Ohio St.3d 559, 562-63, 629 N.E.2d 423 (1994).

[15] *In re Application of Columbus S. Power Co.*, 129 Ohio St.3d 46, 2011-Ohio-2383, 950 N.E.2d 164, ¶ 19 (citation omitted) (emphasis removed).

[16] *See, e.g., Indus. Energy Consumers*, 68 Ohio St.3d at 563, 629 N.E.2d 423 (in an appeal of Commission-approved stipulation, reviewing court "has complete and independent power of review" as to questions of law); *see also In re Application of Columbus S. Power Co.*, 129 Ohio St.3d 46, 2011-Ohio-2383, 950 N.E.2d 164, ¶ 12 (resolving appellant's claim that statute required a cost-of-service study without reference to three-part stipulation test).

[17] *Indus. Energy Consumers*, 68 Ohio St.3d at 562-563, 629 N.E.2d 423.

[18] The Companies initially requested Rider RRS in the ESP Application they filed on August 4, 2014. The length of this proposed rider was changed from 15 to 8 years in the Stipulation. *See* Stipulation at 7.

transaction"). Under the proposed transaction, the Companies would pay all of FES's costs for Sammis, Davis-Besse, and FES's 4.85% ownership share of Clifty Creek and Kyger Creek (hereinafter, the "OVEC entitlement") over the eight-year term.[19] The Companies would also pay a return on equity for FES's invested capital in the Sammis and Davis-Besse plants.[20] According to the Companies' projection, the equity return for these plants over the eight-year term would total [redacted].[21] In return, the Companies would receive the energy, capacity, and ancillary services from those plants, which they would then sell into the PJM market.[22] Under Rider RRS, the Companies would then pass through to their customers a charge or credit reflecting the difference between the Companies' payments to FES and the revenues from the sales of energy, capacity, and ancillary services into the market.[23] Thus, the bills paid by the Companies' customers over this eight-year period would be directly linked to the financial performance of these four power plants.

Although there is considerable uncertainty regarding the financial impact of this proposal,[24] the Companies' own projections estimate that customers would incur, on a net present value basis, $363 million in costs in 2016-18 if Rider RRS were approved.[25] Meanwhile,

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[19] *See* Co. Ex. 156 § 13 (revised term sheet for the proposed transaction) (hereinafter, "Term Sheet"). The original term sheet, which was admitted as SC Ex. 1, was finalized in July 2014. Tr. XI at 2293; Tr. XIII at 2751. On November 18, 2015, the Companies and FES modified two provisions of the term sheet: shortening the length of the proposed transaction and reducing FES's return on equity from 11.15% to 10.38%. *See* Co. Ex. 155, Mikkelsen Fifth Suppl. at 7 (describing changes).

[20] Term Sheet § 13(1)(iv).

[21] SC Ex. 90c (sum of amounts listed in line 24, "Equity Return," in attachments JJL-1 and JJL-2).

[22] *See* Term Sheet. The terms of the proposed transaction are discussed in more detail in Section III.A below.

[23] Co. Ex. 33, Ruberto Direct at 3.

[24] *See generally infra* at Section II; *see also* SC Ex. 69, Comings Direct at 8-11, 26-35, 52. The confidential version of Comings' Direct Testimony is admitted as SC Ex. 70c.

[25] *See* SC Ex. 89 (Mikkelsen Workpaper, dated Nov. 30, 2015) (projecting a net present cost to ratepayers of $144 million in 2016, $152 million in 2017, and $67 million in 2018). Note: Sierra Club Exhibits 89

under the terms of the proposed transaction, FES would be provided a return on equity for its Sammis and Davis-Besse plants, and full recovery of costs for its ownership share of the Clifty Creek and Kyger Creek plants.[26]

B. Rider RRS is not legally permissible under R.C. 4928.143.

As explained above, a proposed rider can be included in an ESP only if it falls within one of the categories set forth in R.C. 4928.143(B)(1) or (B)(2). Because Rider RRS falls within neither of these categories, it is legally impermissible, and cannot be approved as part of this ESP.

FirstEnergy may argue that Rider RRS is authorized by R.C. 4928.143(B)(2)(d). But neither this provision, nor any other provision under (B)(1) or (B)(2), provides authority for Rider RRS.

R.C. 4928.143(B)(2)(d) authorizes an ESP to include "terms, conditions, or charges" that:

- Relate to "limitations on customer shopping for retail electric generation service, bypassability, standby, back-up, or supplemental power service, default service, carrying costs, amortization periods, and accounting or deferrals, including future recovery of such deferrals"; and

- "would have the effect of stabilizing or providing certainty regarding retail electric service."

Although it would be a "term[], condition[], or charge[]," Rider RRS would not limit "customer shopping for retail electric generation service," nor would it "have the effect of stabilizing or providing certainty regarding retail electric service." Rider RRS is not authorized by R.C.

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and 90c are modified versions of exhibits that were originally attached to the testimony of FirstEnergy witnesses Jay Ruberto and Jason Lisowski. SC Exhibit 89 includes a modified version of Attachment JAR-1 revised, reflecting the changes to Rider RRS made in the Stipulation. Similarly, SC Exhibit 90c includes a modified version of attachments JJL-1, -2, and -3 revised, again reflecting the Stipulation.

[26] Term Sheet § 13.

4928.143(B)(2)(d) and cannot be approved in FirstEnergy's ESP for at least three independent reasons.

First, the Rider RRS mechanism has nothing to do with retail electric service. As defined by Ohio law, "[r]etail electric service" means "any service involved in supplying or arranging for the supply of electricity to ultimate consumers in this state, from the point of generation to the point of consumption."[27] In other words, "retail electric service" refers to the Companies' supplying of electricity to their customers in Ohio such as, for example, the purchasing through an auction of electricity to satisfy the energy needs of the Companies' ratepayers.[28] Yet the record is undisputed that the energy that FirstEnergy's customers would be paying for under Rider RRS would not be used to serve those customers.[29] Instead, under FirstEnergy's proposal the Companies would sell the output from Sammis, Davis-Besse, and the OVEC entitlement into the wholesale PJM markets.[30] FirstEnergy's proposal has nothing to do with "the supply of electricity to ultimate consumers"[31] because if Rider RRS goes into effect, FirstEnergy's non-shopping customers would still receive their own energy supply through an SSO auction process.[32]

Rather than involving retail electric service, FirstEnergy's proposal would require customers to effectively become merchant generators, paying for all of the costs of producing energy for sale into the wholesale energy market and receiving whatever revenue might accrue

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[27] R.C. 4928.01(27).

[28] *Cf. In re Application of Columbus S. Power Co.*, 138 Ohio St.3d 448, 2014-Ohio-462, 8 N.E.3d 863, ¶ 34 (upholding inclusion in ESP of environmental investment carrying charges for retrofitted coal units "because AEP generally uses its own generating units to serve its customers.").

[29] Tr. I at 37-38, 39.

[30] Ruberto Direct at 3; Tr. I at 36-37; Tr. XIII at 2808.

[31] R.C. 4928.01(27).

[32] Tr. I at 38, 107-08.

from such sales. While the RRS charge would appear on customer bills, the wholesale energy market transactions associated with the Companies' proposal are not related to "retail electric service" as that phrase is defined under Ohio law.[33] Indeed, the price of energy received by SSO customers would not be impacted at all by Rider RRS; the rider is a separate generation-related rider unrelated to customers' own electricity.[34]

Second, Rider RRS is not authorized under (B)(2)(d) because the rider does not in any way limit "customer shopping for retail electric generation service." By specifically tying "customer shopping" to "retail electric generation service," Ohio law makes clear that such restrictions on customer shopping must be with regards to the "supply of electricity" to FirstEnergy's customers.[35] Yet neither the approval of Rider RRS, nor consummation of the proposed transaction, would have any impact on customers' ability to shop for the electric supply they receive.[36] FirstEnergy has acknowledged this point repeatedly throughout the proceeding. For example:

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[33] For similar reasons, Rider RRS cannot be authorized pursuant to R.C. 4928.143(B)(1). That provision states that an "electric security plan shall include provisions relating to the supply and pricing of electric generation service." As the Companies have acknowledged, the energy that the Companies plan to purchase from FES under the proposed transaction would not be used to serve the Companies' customers, but would instead be sold into the wholesale PJM markets. *See* Tr. I at 37-38 (confirming that the energy, capacity, and ancillary services obtained through the proposed transaction would not be used to supply SSO customers).

Nor can Rider RRS be justified under 4928.143(B)(2)(a), which permits an EDU to recover "the cost of fuel used to generate the electricity supplied under the offer; the cost of purchased power supplied under the offer, including the cost of energy and capacity, and including purchased power acquired from an affiliate; the cost of emission allowances; and the cost of federally mandated carbon or energy taxes." This provision has no bearing on Rider RRS because the energy and capacity purchased from FES under the proposed transaction would not be "supplied" to the Companies' customers, but would instead be sold into the PJM markets. Tr. I at 36-38; *see also* Ruberto Direct at 3.

[34] Tr. I at 38-39, 107-08.

[35] R.C. 4928.01(27).

[36] Tr. I at 39, 108.

- FirstEnergy's initial ESP Application states that "[t]he Economic Stability Program, as designed, will have no adverse impact on . . . . customers' ability to shop for generation service . . . ."[37]

- FirstEnergy witness Steven Strah's written testimony notes that "the Economic Stability Program will have no adverse impact on shopping."[38]

- FirstEnergy witness Eileen Mikkelsen testified that Rider RRS "does not in any way limit a customer's ability to shop."[39]

Especially given that FirstEnergy bears the burden of supporting its own application, these concessions should be the end of the story. The record demonstrates that customers' ability to shop for their retail electric service would be unaffected by Rider RRS. As such, the rider does not qualify as a limitation on customer shopping and is not authorized under R.C. 4928.143(B)(2)(d).[40]

Finally, Rider RRS also fails to satisfy R.C. 4928.143(B)(2)(d) because it would not "have the effect of stabilizing or providing certainty regarding retail electric service." FirstEnergy repeatedly claims that Rider RRS would serve as a hedge against possible future

[37] Co. Ex. 1, ESP Application at 9.

[38] Co. Ex. 13, Strah Direct at 7.

[39] Mikkelsen Fifth Suppl. at 9; *see also* Tr. I at 108 (acknowledging that "the companies' customers' ability to shop for their own energy service would remain unchanged, whether or not rider RRS were approved").

[40] Nor can Rider RRS be justified on grounds that, under the RRS mechanism, the bills of customers who shop for their retail electric service would no longer be based 100% on shopping costs. If approved, a portion of each bill would be based on the cost of Sammis, Davis-Besse, and the OVEC entitlement, which FirstEnergy may characterize as a financial restraint on the consequences of customer shopping. But the customer shopping provision of R.C. 4928.143(B)(2)(d) speaks not of the pricing of retail electric generation service, but of shopping for such service itself. And there is no basis in the record to conclude that customers' ability to shop for retail service would be restrained or limited merely because they are required to pay a separate charge on their bills related to the generation of energy for sale into the wholesale market. The exact same amount of shopping for retail service could occur with or without Rider RRS. As such, and as FirstEnergy has repeatedly conceded, the RRS mechanism would not limit customer shopping for retail electric generation service.

increases in energy prices.[41] But FirstEnergy's effort to portray its proposal as a hedge for customers does not demonstrate that Rider RRS would have the effect of stabilizing or providing certainty regarding retail electric service for at least two reasons. First, even assuming, arguendo, that Rider RRS would have a hedging impact – it would not, as explained below – that hedging impact would not impact retail electric rates. For an item to be approved under R.C. 4928.143(B)(2)(d), the stabilization or certainty provided must be with regards to "retail electric service," which, as discussed above at 8-9, means electricity purchased by the Companies to supply their customers' needs.[42] Even if there were a hedging impact from Rider RRS, all it would do would be to offset the cost (or benefit) of a retail rate increase (or decrease) by essentially turning FirstEnergy's customers into merchant generators subject to the vagaries of the wholesale energy market. Such hedging would not stabilize or provide certainty regarding the rates that FirstEnergy's customers pay for the actual retail energy supply that they use. Without such an impact, Rider RRS is simply not authorized by the plain language of R.C. 4928.143(B)(2)(d),

Second, even if the statute did not mandate that any hedging effects be tied to retail electric service – which it does – RRS would still not be permissible because it would not, in fact, have the effect of stabilizing or providing certainty to customers' bills. Although FirstEnergy has touted Rider RRS as a retail rate stabilization mechanism,[43] as explained *infra* in Section V, the Companies have failed to demonstrate that retail electric rates are volatile, much

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[41] FirstEnergy witness Strah also asserts that Rider RRS promotes stability and certainty by preserving baseload generation and, therefore, helps ensure adequate and reliable energy service. Strah Direct at 8-10. As discussed in Sections VI.C.1 and VI.C.3 below, however, PJM is responsible for ensuring system adequacy and reliability and, through reforms such as the approval of the Capacity Performance product, is in fact doing so.

[42] R.C. 4928.01(27).

[43] Tr. III at 513.

less that Rider RRS would provide stability to customers' bills. Because the record is devoid of any such evidence, Rider RRS cannot be authorized under R.C. 4928.143(B)(2)(d).[44]

II. FirstEnergy Has Failed to Show That Customers Would Receive a Net Credit Over the Eight-Year Term of Rider RRS and, Instead, the Record Evidence Demonstrates that Customers Will Almost Certainly Lose Hundreds of Millions of Dollars or More Under Rider RRS.

At its core, Rider RRS amounts to a proposal that if customers relieve FES of hundreds of millions of dollars of projected losses in the short term, and cover FES's costs and return for Sammis, Davis-Besse, and the OVEC entitlement, they will purportedly receive a benefit projected at $260 million net present value over the eight-year term of the rider.[45] As explained in Section I above, such a rider is not legally permissible under Ohio law because it is not authorized under R.C. 4928.143(B)(1) or (B)(2). But even if Rider RRS were legally permissible, the Commission cannot approve it because FirstEnergy has not satisfied its burden of demonstrating that customers would benefit under the rider.

Instead, the evidence in the record shows that FirstEnergy (i) has almost certainly underestimated the initial losses that customers would incur under Rider RRS and (ii) has provided no reasonable basis to conclude that customers would receive a net benefit over the full eight-year term. In fact, forecasts provided by FES – the entity that owns the plants and would

[44] Rider RRS is also inconsistent with the statutory intent of R.C. 4928.143(B)(2)(d). The provision related to "limitations on customer shopping" addresses a situation where customer shopping or other factors could interfere with an electric distribution utility's ability to provide stable and certain retail electric service to its customers. For example, if a large portion of a utility's customers decided to shop for other service in one year, and then switch back to the utility's service in the next year, that rapid change could significantly impact the ability of the utility to provide stable service. R.C. 4928.143(B)(2)(d) addresses that potential situation by allowing a utility to propose limits on such shopping in order to preserve the utility's ability to provide reliable service to all of its customers. There is no basis for concluding that the General Assembly intended that such a straightforward statutory provision could instead be used to force all of a utility's customers to stand in the shoes of a merchant generator.

[45] SC Ex. 89, line 13.

receive all of the certainty under Rider RRS – shows that Rider RRS would [redacted] and, instead, customers would [redacted] over the eight-year term.[46] And other analyses using more up-to-date forecasts and assumptions than those used by the Companies project net present losses to customers ranging between $793 million and $2.7 billion over the eight-year term of Rider RRS.[47] As such, Rider RRS is not just and reasonable, and therefore should be rejected. For this same reason, the stipulated ESP with Rider RRS, under which customers would be required to take ultimate responsibility for the costs and financial risks of Sammis, Davis-Besse, and the OVEC entitlement, has not been shown to be more favorable in the aggregate than a market rate offer.

The Companies' projection of charges and credits is the result of a single dispatch modeling run.[48] FirstEnergy used an Excel spreadsheet-based modeling program that estimated how often Sammis, Davis-Besse, and the OVEC plants would operate, and the revenues that would result, by comparing the variable operating cost of the plants to forecasted market energy prices. After adding in capacity revenues and revenues for ancillary services, the Companies then compared those revenues to the plants' projected costs, including depreciation, a return on equity, interest expenses, and taxes. The resulting difference between such revenues and costs represents the Companies' projection of the amount of charge or credit that would be passed through to customers through Rider RRS.

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[46] SC Ex. 96c, Comings Third Suppl. at 4 (describing FES figures generated using SC Ex. 36c). The public version of Comings' Third Supplemental Testimony is admitted as SC Ex. 95.

[47] P3/EPSA Ex. 12, Kalt Second Suppl. at 17 (the confidential version of Kalt's Second Supplemental Testimony is admitted as P3/EPSA Ex. 13c); OCC/NOPEC Ex. 9, Wilson Second Suppl. at 12 (the confidential version of Wilson's Second Supplemental Direct Testimony is admitted as OCC/NOPEC Ex. 10c).

[48] Tr. VIII at 1580.

The reasonableness of FirstEnergy's projection turns on three critical elements: (1) the market energy, natural gas, and capacity price forecasts upon which the revenue projections are primarily based; (2) the costs assumed for the plants; and (3) the robustness of the model used to project the dispatching of the plants. Unfortunately, FirstEnergy's projection fails to pass muster with respect to each of these elements. The market forecasts, which date from mid-2014, are outdated, unreasonable, and already proving to be wrong. The cost assumptions are unsupported, do not reflect the recent promulgation of rules addressing coal ash discharges and disposal from coal plants, and likely underestimate future environmental compliance costs at the Sammis plant. The model used by the Companies is unsophisticated, has never been evaluated for accuracy, and fails to account for the fact that FES's plants must compete against other power plants. As such, the Companies' projection of a net credit to customers under Rider RRS is unreliable and unsupported in the record, and the Companies have failed to demonstrate that Rider RRS would be just and reasonable or benefit customers.

A. Customers would likely lose money throughout the term of Rider RRS.

At the outset, it is important to note two things about FirstEnergy's projection of credits and charges under Rider RRS. First, there is no dispute that the Companies' customers would incur hundreds of millions of dollars of losses through 2018 if Rider RRS is approved. Second, while there are a number of projections of credits and charges in the record, FirstEnergy's projection is the [redacted] to conclude that customers would receive a [redacted] over the life of Rider RRS.

On the first point, the Companies' own filing projects a net present value loss to customers of $363 million over the first 31 months of Rider RRS.[49] Using FES's own internal

[49] SC Ex. 89.

market projections, rather than the forecasts from Judah Rose that the Companies used, shows that [redacted].[50] While recent drops in energy and natural gas prices suggest that such early losses under Rider RRS could be even larger, there is no evidence in the record disputing that [redacted].

On the second point, FirstEnergy attempts to sell Rider RRS on the claim that the $363 million customer loss that it projects through 2018 will be more than offset by gains after 2018. While the Companies' projection shows Rider RRS not breaking even until 2021, customers would purportedly receive a net credit of $260 million over the eight-year term of Rider RRS.[51] Such projection is [redacted], however, which show Rider RRS [redacted] and, instead, leading to a [redacted] over the proposed term of the rider.[52] Other projections show even bigger losses to customers. For example, P3-EPSA witness Dr. Joseph Kalt, using more up-to-date natural gas price forecasts, estimated that customer losses could have net present value losses as high as $793 million to $858 million.[53] Similarly, Ohio Consumers' Counsel (OCC) and Northeast Ohio Public Energy Council (NOPEC) witness James F. Wilson estimated that the total net present value cost to customers under Rider RRS could run as high as $1.9 billion to $2.7 billion when updated natural gas and energy prices are used.[54]

[50] Comings Third Suppl. at 4.

[51] SC Ex. 89, line 13.

[52] Comings Third Suppl. at 4 (describing FES figures generated with SC Ex. 36c).

[53] Kalt Second Suppl. at 17.

[54] Wilson Second Suppl. at 12. Mr. Wilson also projected that Rider RRS would essentially break even under a scenario using the U.S. Energy Information Administration's 2015 Annual Energy Outlook reference case natural gas price forecast. As Mr. Wilson explains, however, that scenario is no longer consistent with market conditions and, therefore, not a likely outcome. *Id*. at 12.

Given that all forecasts of the future are inherently uncertain, the Commission need not determine the exact level of losses that customers would experience under Rider RRS. But what is clear, given the extensive record in this proceeding, is that customers would almost certainly lose significant sums of money if Rider RRS were approved. At a minimum, and as discussed below, FirstEnergy has plainly not satisfied its burden of demonstrating that Rider RRS would somehow provide a net benefit to customers over its proposed eight-year term.

B. Significant changes in market and regulatory conditions that have occurred since the Companies filed their application have rendered FirstEnergy's projection of charges and credits under Rider RRS outdated and unreliable.

As described previously, the Companies are proposing for each of the eight years of Rider RRS to pass through to their customers a charge or credit reflecting the difference between the revenues obtained through the sale into the PJM market of energy, capacity, and ancillary services from Sammis, Davis-Besse, and the OVEC entitlement, and the full costs (including depreciation, interest, a return on equity, and taxes) of those plants. The Companies provided with their August 2014 application a single projection of such revenues, costs, and the net credit or charge that would be passed through Rider RRS to claim that customers would receive a net credit over the term of the rider. For the most part, that projection relied on forecasts of market conditions and costs that were developed in mid-2014. Since then, the Companies have steadfastly refused to update their projections, or the assumptions and market forecasts underlying those projections, even though significant market and regulatory changes have rendered the Companies' projection outdated and unreliable.

Particular factors that have significantly changed since the forecasts and assumptions upon which the Companies based their projection of charges and credits under Rider RRS include:

- Market energy prices are 10 to 15% [redacted] lower than what FirstEnergy witness Judah Rose projected for 2015,[55] and market energy forwards through 2019 are approximately $5/MWh to $6/MWh lower than the forwards for that time frame included in Mr. Rose's direct testimony.[56]

- Natural gas prices in 2015 were 61% lower than what Mr. Rose projected. Whereas the Companies' application has Henry Hub natural gas prices at $4.34/MMBtu in 2015 and $4.26/MMBtu in 2016, an August 2015 projection from Mr. Rose's consulting firm, ICF International, showed Henry Hub natural gas prices not even clearing $4/MMBtu until after 2018.

- In comparison to the 2014 PJM Load Forecast that Mr. Rose relied on, PJM has twice lowered its energy demand and peak load forecasts for every year of proposed Rider RRS, which will put downward pressure on future energy and capacity prices.

- PJM finalized its Capacity Performance product, which is already having significant impacts on capacity prices and generator reliability.

- At least five new natural gas combined cycle plants in Ohio, with a combined capacity of 3,940MW, have commenced construction or otherwise advanced,[57] weakening claims about a purported lack of new Ohio generation and transmission reliability impacts if Sammis and/or Davis-Besse were to retire.

- The U.S. Supreme Court recently overturned a decision of the U.S. Court of Appeals for the District of Columbia, which had held that the Federal Energy Regulatory Commission ("FERC") could not include demand response in the PJM energy market.[58] Mr. Rose had identified the D.C. Circuit decision, and a follow-up petition by FirstEnergy to try to extend that ruling to the PJM capacity market, as potentially creating a large drop in demand response, which could have put upward pressure on capacity prices.[59]

- The U.S. EPA has finalized both the Effluent Limitations Guidelines and the Coal Combustion Residuals rules, which could require significant spending at the Sammis and OVEC plants, but for which FirstEnergy has provided no written evaluation of compliance costs or strategies.

[55] Tr. XXXV at 7228.

[56] Co. Ex. 17, Rose Direct at 34, Tbl. 7. The confidential version of Rose's Direct Testimony is admitted as Co. Ex. 18c.

[57] Comings Third Suppl. at 11.

[58] *Fed. Energy Regulatory Comm'n v. Elec. Power Supply Ass'n*, 136 S. Ct. 760 (2016) ("*EPSA*"), *reversing Elec. Power Supply Ass'n v. Fed. Energy Regulatory Comm'n*, 753 F.3d 216 (D.C. Cir. 2014).

[59] Rose Direct at 51-52.

- While FirstEnergy relies heavily on the polar vortex in 2014 to raise fears about system adequacy and reliability, PJM found that the application of lessons learned from the polar vortex enabled the system to avoid adequacy and reliability concerns during a similar cold snap in 2015 even while the system experienced the highest winter peak load on record.[60]

In short, conditions regarding almost all of the key factors at issue in this proceeding – energy, natural gas, and capacity prices, energy and peak load forecasts, demand response, energy system reliability, and environmental compliance costs – have fundamentally changed since FirstEnergy filed its application. As explained in detail below, almost all of these changes either make the economics of Rider RRS less favorable to customers than what the Companies projected, or alleviate the reliability, volatility, and other concerns that supposedly justify the rider. Even if those forecasts and assumptions had been reasonable at the time FirstEnergy filed its application, which they were not, the changed conditions listed above show that they are now outdated and cannot reasonably be found to reflect present or likely future circumstances. As such, the Commission should reject Rider RRS. In the alternative, the Commission should, at a minimum, require FirstEnergy to provide up-to-date projections, based on current assumptions and forecasts of energy, natural gas, and capacity prices, before proceeding to evaluate Rider RRS.

C. FirstEnergy's projection of credits and charges under Rider RRS is based on market energy, natural gas, and capacity price forecasts that are outdated, unreasonably high, and already proving to be wrong.

FirstEnergy's projection of revenue from Sammis, Davis-Besse, and the OVEC entitlement is based almost entirely on three market forecasts, each of which were sponsored by witness Judah Rose. First, Mr. Rose developed a forecast of natural gas prices at the Henry Hub, which served as a key input into his second forecast, concerning wholesale PJM market energy

[60] SC Ex. 73, Comings Suppl. at 29. The confidential version of Comings' Supplemental Testimony is admitted as SC Ex. 74c.

prices. Third, Mr. Rose developed a forecast of capacity prices, which represent the level of capacity revenue a plant that clears PJM's capacity auction would receive simply for being available to operate. Combined, these three market forecasts were used to estimate how often Sammis, Davis-Besse, and the OVEC plants would operate and how much revenue they would receive. Because Mr. Rose's forecasts of energy, natural gas, and capacity prices are unreasonably high, FirstEnergy's projection of revenues from the plants is likewise unreasonably high. As such, the Companies have failed to provide credible evidence to support their claim that customers would receive a net credit under Rider RRS.

1. FirstEnergy's energy price forecast is outdated and unreasonably high.

A core element of FirstEnergy's projection that Rider RRS will provide a net credit to customers over the eight-year term is Mr. Rose's forecast of increasing wholesale energy prices. In particular, while market energy prices in the ATSI zone averaged $36/MWh from 2011 through 2013,[61] Mr. Rose forecasted that they would [redacted], and [redacted], after which prices would [redacted].[62] In other words, Mr. Rose forecasted a [redacted] in energy prices by 2015 compared to the 2011-2013 average, and a [redacted] in energy prices from the 2011-2013 average to 2020.

Such forecasted increases in energy prices inflates the amount of revenue that FirstEnergy projected would be created by Sammis, Davis-Besse, and the OVEC entitlement in two ways. First, the energy price plays a key role in projecting how often those plants would dispatch, because FirstEnergy's model decides whether to dispatch a plant by comparing the

[61] Rose Direct at 13, Tbl. 1. Unless otherwise noted, all market prices referenced in this brief are expressed in nominal dollars.

[62] Rose Direct, Att. II.

plant's variable O&M cost to the wholesale market energy price; the model dispatches the plant whenever the former is less than the latter.[63] Second, the energy price provides the basis for calculating how much revenue would be generated whenever a plant dispatches. In short, all else being equal, forecasted increases in energy prices lead to projected increases in revenues from Sammis, Davis-Besse, and the OVEC entitlement.

The record plainly demonstrates that Mr. Rose's energy price forecast is unreasonably high. As Mr. Rose admitted in the rebuttal hearing in late October 2015, actual year-to-date energy prices had been approximately 10 to 15% lower than he forecast.[64] Actual energy prices in the ATSI zone in 2015 (through December 18, 2015) were $32.93/MWh,[65] which is an 8.5% decline from the 2011-2013 average, and [redacted] than what Mr. Rose forecasted.[66]

Further evidence that Mr. Rose's energy price forecast is outdated and unreasonably high abounds. For example, Mr. Rose's forecast is based on an outdated overestimate of future energy demand. In his energy price forecast, Mr. Rose used PJM's 2014 load forecast as the source for his model's assumption regarding energy demand in both the PJM RTO and the ATSI zone.[67] Since that forecast was created, however, PJM has reduced its energy demand forecast for each of the years 2016 through 2024 in both its 2015 and 2016 load forecasts, as shown in Tables 1 and 2 below.

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[63] Tr. VIII at 1575-77.

[64] Tr. XXXV at 7228.

[65] Comings Third Suppl. at 12.

[66] Mr. Rose [redacted] on his 2015 projection of energy prices in the AEP Dayton Hub. The actual 2015 price through December 18, 2015, was $31.80/MWh, Comings Third Suppl. at 12, which is [redacted] than Mr. Rose's forecast of [redacted]. Rose Direct, Att. II.

[67] *Id.* at 50-51.

Table 1: PJM RTO Forecast Energy Demand (GWh)

	PJM 2014 / Rose[68]	PJM 2016[69]	% Change
2016	863,762	811,335	- 6.07%
2017	870,847	821,812	- 5.63%
2018	878,209	833,095	- 5.14%
2019	884,188	839,492	- 5.06%
2020	894,896	841,989	- 5.91%
2021	901,010	843,262	- 6.41%
2022	908,770	848,709	- 6.61%
2023	915,559	854,214	- 6.70%
2024	923,919	862,838	- 6.61%

Table 2: PJM ATSI Forecast Energy Demand (GWh)

	PJM 2014 / Rose[70]	PJM 2016[71]	% Change
2016	72,265	69,542	- 3.77%
2017	72,369	69,950	- 3.34%
2018	72,598	70,515	- 2.87%
2019	72,681	70,781	- 2.61%
2020	73,281	71,065	- 3.02%
2021	73,466	71,088	- 3.24%
2022	73,751	71,430	- 3.15%
2023	73,918	71,701	- 3.00%
2024	74,253	72,189	- 2.78%

In fact, as shown in the tables above, PJM has lowered its energy demand forecast so much that in its 2016 load forecast, PJM projects energy demand within the PJM RTO and the ATSI zone to be lower in 2024 than what was projected for the year 2016 in its 2014 load forecast – the forecast that Mr. Rose used. There is no reasonable dispute that reduced energy demand would have downward pressure on energy prices, as Mr. Rose himself identified reduced energy demand triggered by the Great Recession of 2007-2009 as "result[ing] in lower electrical energy

[68] Rose Public Workpapers at 1. Note: Although Mr. Rose's workpapers were designated confidential (Co. Ex. 20c), the load forecast assumptions are public and were included in the public version of his workpapers filed on the docket on August 4, 2014. Mr. Rose also acknowledges that these numbers came straight from PJM's 2014 load forecast. Rose Direct at 51, Tbl. 9.

[69] Co. Ex. 171, PJM 2016 Load Forecast, at 88, Tbl. E-1.

[70] Rose Public Workpapers at 1.

[71] Co. Ex. 171 at 88, Tbl. E-1.

prices,"[72] and further testified that "[e]xpected demand growth will raise electrical energy prices."[73] As such, the drop in forecasted demand provides further evidence that Mr. Rose's energy price forecast is outdated and unreasonably high.

Declining forward market energy prices also show that Mr. Rose's energy price forecast is outdated and unreasonably high. In his direct testimony, Mr. Rose identified "the observable forward prices for the delivery of wholesale power to FirstEnergy" as "[o]ne basis for concluding" that energy prices will increase.[74] In support, Mr. Rose provided five years of market forward energy prices showing an ATSI zone price of $39.80/MWh in 2015 increasing to $41.60/MWh by 2019.[75] As noted above, actual ATSI zone energy prices in 2015 were significantly lower than the market forward price for 2015 that Mr. Rose cited in his testimony. And at hearing, Mr. Rose testified that market forward energy prices for 2016 through 2019 were "pretty much steady at 35 or so dollars per megawatt-hour."[76] [redacted], Mr. Rose forecasted ATSI zone energy prices of [redacted].[77]

In his rebuttal testimony, Mr. Rose does not attempt to explain why actual energy prices are significantly lower than he projected or offer any substantive argument that his forecast is still valid. Instead, Mr. Rose contends that he is the only witness in this proceeding who used an "appropriate approach to forecasting wholesale power prices" because his forecast came out of a

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[72] Rose Direct at 14-15.

[73] *Id.* at 19.

[74] *Id.* at 33.

[75] *Id.* at 34, Tbl. 7.

[76] Tr. VI at 1228. Documents obtained by Sierra Club through a subpoena show that [redacted]. SC Ex. 45c at 7.

[77] Rose Direct, Att. II.

"widely recognized and used" computer modeling program.[78] The problem for Mr. Rose, however, is that the proof is in the pudding – regardless of how sophisticated and widely used the model might be, the inescapable reality is that actual 2015 energy prices are considerably lower than Mr. Rose forecasted, and declining demand forecasts along with market forwards provide strong evidence that such prices will continue to be well below Mr. Rose's forecast. Nothing in the record suggests otherwise.

2. FirstEnergy's natural gas price forecast is outdated and unreasonably high.

Mr. Rose identifies "natural gas prices increasing" as a "key assumption[]" in his forecast of escalating market energy prices.[79] According to Mr. Rose, natural gas prices are "an important determinant" in on-peak wholesale power pricing in ATSI and AEP Dayton Hub and "will be increasingly important over time."[80] Mr. Rose's natural gas price forecast is based on NYMEX market forwards for 2015 and 2016, an average of NYMEX forwards and ICF's forecast for 2017, and then entirely ICF's forecast for 2018 and beyond.[81] The forecast shows natural gas prices at $4.34/MMBtu in 2015, steadily increasing to [redacted] in 2019 ([redacted] increase over four years), jumping to [redacted] in 2020 ([redacted] increase in one year), and then gradually increasing to [redacted] in 2024 ([redacted] increase).[82] In total, Mr. Rose is projecting a [redacted] total increase in natural gas prices (in nominal dollars) from 2015 to 2024.

Such a projected increase in natural gas prices would increase revenue from Sammis,

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[78] Co. Ex. 151, Rose Rebuttal at 5. The confidential version of Rose's Rebuttal Testimony is admitted as Co. Ex. 152c.

[79] Rose Direct at 46-50.

[80] *Id.* at 46.

[81] *Id.* at 47, Tbl. 8.

[82] Rose Confidential Workpapers at 4.

Davis-Besse, and the OVEC plants in at least two ways. First, higher natural gas prices would put upward pressure on energy prices which, in turn, helps ensure that coal and nuclear plants will dispatch more often and receive significant revenue for doing so. Second, higher natural gas prices increase the variable O&M costs and thereby reduce the dispatching of natural gas combined cycle units that would be in primary competition with Sammis, Davis-Besse, and the OVEC units.[83] In short, all else being equal, forecasted increases in natural gas prices lead to projected increases in revenues from Sammis, Davis-Besse, and the OVEC entitlement.

The record, however, reveals that Mr. Rose's natural gas price forecast is unreasonably high and lacking in credibility. In contrast to Mr. Rose's forecast of increasing natural gas prices, actual prices in 2015 averaged $2.61/MMBtu, which was the lowest annual average price since 1999.[84] The $4.34/MMBtu forward price assumed by Mr. Rose is 66% higher than the actual 2015 price. Similarly, the natural gas prices for 2016 and 2017 forecasted by Mr. Rose – $4.28/MMBtu and [redacted]/MMBtu, respectively – are 70% higher and [redacted], respectively, than the market forwards for those two years as of December 29, 2015.[85]

That Mr. Rose's natural gas price forecast is substantially too high for the entire eight years of Rider RRS, rather than just the first few years, is also demonstrated by ICF's own more recent natural gas price forecast from August 2015.[86] As shown in Figure 1 below, ICF's August 2015 forecast projects that natural gas prices will not exceed $4/MMBtu until after 2018,

[83] Comings Third Suppl. at 12.

[84] Co. Ex. 174 at 2.

[85] Comings Third Suppl. at 9.

[86] The August 2015 forecast was generated through the same Gas Market Model ("GMM") that Mr. Rose used to create the forecast he relies on. *Compare* Rose Direct at 46-47 *with* Comings Third Suppl., Ex. TFC-44, A-25 at 9-10, 68.

$5/MMBtu until after 2020, and does not clear $6/MMBtu through 2024.[87] By contrast, Mr. Rose's forecast has natural gas prices over $4/MMBtu in 2015, clearing [redacted] in 2018, exceeding [redacted] in 2020, and nearly reaching [redacted] by 2024.[88] Despite this lower natural gas price forecast from ICF, and the fact that actual 2015 gas prices and 2016 and 2017 natural gas price forwards are even lower, the Companies have failed to update their gas price forecast or evaluate how such lower-than-forecasted gas prices would impact the level of charges or credits (through lower energy prices) that would pass through Rider RRS to the Companies' customers.

[87] Comings Third Suppl., Ex. TFC-44, A-25 at 17. Unlike the Companies' decision to designate Mr. Rose's natural gas price forecast as confidential in this proceeding, ICF's August 2015 natural gas price forecast was filed in a Michigan PSC proceeding on the public docket without any accompanying claim of confidentiality.

[88] Rose Confidential Workpapers at 4.

[redacted]

Figure 1: Comparison of Rose and ICF Aug. 2015 Natural Gas Price Forecasts ($/MMBtu)[89]

The fact that the natural gas price forecast Mr. Rose provided for FirstEnergy's application is already outdated and unreasonably high is not an isolated incident. In recent years, Mr. Rose and ICF have repeatedly [redacted]. As shown in Figure 2 below, with a few small exceptions, ICF's quarterly natural gas price forecasts dating back to March 2010 share two characteristics: [redacted].

[89] Comings Third Suppl. at 10, Fig. 2.

[redacted]

Figure 2: Comparison of ICF Natural Gas Price Forecasts to Actual Prices (Henry Hub/$/MMBtu)[90]

Mr. Rose's February 2012 testimony submitted in the Arkansas Public Service Commission, which concerns a proposed retrofit of the Flint Creek power plant, is a good example of just how far off his natural gas price forecasts have been, as shown in Table 3 below.

Table 3: Comparison of Select Natural Gas Price Projections From Judah Rose/ICF

Year	Flint Creek Forecast[91]	FirstEnergy's Application[92]	August 2015 Forecast (Approx.)[93]	NYMEX Futures[94]
2016	5.97	4.28	3.50	2.51
2017	6.19	[redacted]	3.50	2.82

[90] Comings Suppl. at 8 and Ex. TFC-34.

[91] SC Ex. 9 at 19. Unlike the Companies' decision to designate Mr. Rose's natural gas price forecast as confidential in this proceeding, Mr. Rose's natural gas price forecast in his Flint Creek testimony was publicly disclosed.

[92] Rose Confidential Workpapers at 4.

[93] Comings Third Suppl., Ex. TFC-44, A-25 at 17.

[94] Comings Third Suppl. at 9.

2018	6.42	[redacted]	3.75	
2019	6.66	[redacted]	4.50	
2020	6.90	[redacted]	4.95	
2021	7.18	[redacted]	5.10	
2022	7.47	[redacted]	5.25	
2023	7.77	[redacted]	5.45	
2024	8.15	[redacted]	5.50	

At the hearing in this case, Mr. Rose offered a series of excuses as to why ICF lowered its natural gas price forecasts since 2011, including that [redacted].[95] But offering particular explanations for each time ICF lowers its gas price forecast misses the point. The fact remains that time and time again Mr. Rose/ICF have projected [redacted]. Then, in a subsequent forecast, they have had to [redacted] during [redacted], their [redacted] have been more pronounced in the past two years. Indeed, ICF's August 2015 natural gas price forecast [redacted].

In short, actual natural gas prices and forwards, a new natural gas price forecast issued by ICF, and [redacted] all demonstrate that the natural gas price forecast used by the Companies in this proceeding is outdated, unreasonably high, and unsupported on the record.

[95] Conf. Tr. VII at 1438-40.

3. The significantly lower-than-forecasted energy and natural gas prices and forwards would have a significant impact on the economics of Rider RRS.

At the hearing, Mr. Rose attempted to downplay the effect of the lower-than-forecasted energy and natural gas prices by claiming that the average energy price over the 15-to-20 year forecast is reduced by only 1% to 2%, and his 15-to-20 year natural gas price forecast is only reduced by 4%.[96] But this claim is misleading at best for at least two reasons. First, Mr. Rose is suggesting that energy and natural gas prices would return to the levels he forecasted starting in 2018. Given how far off Mr. Rose's forecast was from actual 2015 prices and 2016 forwards, it is unrealistic to assume that prices will jump back up to the levels projected by Mr. Rose for 2018 and thereafter, especially when energy market forwards through 2019 are considerably lower than the forwards Mr. Rose cited in his testimony.[97] Instead, given these lower-than-forecasted prices, it is far more reasonable to conclude that Mr. Rose's forecasts are fundamentally off-base and that new, up-to-date forecasts are necessary so that a credible and supported projection of charges and credits under Rider RRS can be completed.

Second, Mr. Rose's attempt to minimize the effect of the lower-than-forecasted energy and natural gas prices ignores the significant reduction in the dispatching of, and revenue brought in by, Sammis, Davis-Besse, and the OVEC plants that would result from such lower prices. As Mr. Rose acknowledged in his Flint Creek testimony:

> The natural gas price directly affects the costs and competitiveness of natural gas power plants. Every $l/mmBtu increase or decrease in the natural gas price forecast results in an approximately $7/ to $8/MWh (in real dollars) advantage or disadvantage to Flint Creek coal generation over natural gas generation (combine cycle generation), all else equal.[98]

[96] Tr. XXXV at 7464-66.

[97] Tr. VI at 1228.

[98] SC Ex. 9 at 18.

The impact of significantly lower-than-forecasted energy and natural gas prices can be seen in the actual versus projected dispatching of the Sammis plant in 2015. In particular, FirstEnergy's dispatch model, using Mr. Rose's market forecasts, projected that the Sammis plant would run at an [redacted] capacity factor in 2015.[99] In actuality, from January through October 2015, the plant ran at a 47% capacity factor.[100] The combined impact of lower-than-forecasted energy prices and [redacted] also seriously reduced projected revenues from the plant in 2015. In un-rebutted testimony, Sierra Club witness Tyler Comings estimated that energy revenue from Sammis in 2015 would be [redacted] than FirstEnergy projected.[101] And given that FirstEnergy's dispatch modeling projected that Sammis would have an average capacity factor of [redacted] from 2016 through 2024, the fact that Sammis ran at only 47% capacity in 2015 raises serious concerns that it will also dispatch less and bring in less energy revenue than assumed in at least some of the years of Rider RRS, thereby virtually assuring that customers would incur a net loss under Rider RRS. In fact, P3-EPSA witness Dr. Kalt calculated that if you hold everything else constant and simply assume that Sammis, Davis-Besse, and the OVEC units operate during Rider RRS at the same level that they did during the past decade, the Companies' customers would incur a $201 million loss under Rider RRS.[102]

4. FirstEnergy's capacity revenue projections are outdated and unreasonably high

After market energy revenues, the second major source of revenues for power plants like Sammis, Davis-Besse, and the OVEC units is capacity payments. FirstEnergy forecasts that

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[99] Comings Third Suppl. at 12; *see also* SC Ex. 49c, Att. 1 (projecting capacity factors at Sammis); Conf. Tr. XII at 2649 (discussing source of the projected capacity factors).

[100] Comings Third Suppl. at 12.

[101] *Id.* at 13-14.

[102] Kalt Second Suppl. at 22.

capacity prices are going to escalate significantly, which would increase the level of revenues available to offset costs in projecting the level of charges or credits that would pass through to the Companies' customers over Rider RRS. The record, however, shows that FirstEnergy's capacity price forecast and resulting projection of capacity revenue is unreasonably high and unsupported.

In PJM, 80 to 85% of the revenue for power plants like Sammis, Davis-Besse, or the OVEC units typically comes from energy sales, while almost all of the remaining 15 to 20% comes from capacity payments.[103] Such capacity payments are primarily obtained through an auction process, known as the RPM Base Residual Auction ("BRA"), through which plant owners bid in their capacity for a delivery year three years after the auction (so, for example, the 2015 auction was for the 2018/2019 delivery year). PJM is in the process of incorporating a new Capacity Performance product, which was approved by FERC in June 2015, into its annual BRA, with 80% of capacity in the 2018/2019 auction having to qualify as a Capacity Performance resource and 100% of the capacity so qualifying by the 2020/2021 auction.

While the Capacity Performance product makes significant modifications to the PJM capacity market, FirstEnergy continues to rely on a capacity price forecast that predates PJM's issuance of the Capacity Performance proposal even in draft form. FirstEnergy's forecast, which is sponsored by Mr. Rose, [redacted] the results of PJM's 2018/2019 BRA, and unreasonably projects that capacity prices [redacted] in future delivery years. And FirstEnergy has not provided any analysis of potential penalties or bonuses under the Capacity Performance product, which is especially problematic because the Stipulation makes it easier for capacity performance penalties than bonuses to be passed through to the Companies'

[103] Tr. VI at 1140.

customers under Rider RRS.

Through its capacity price forecast and assumptions regarding how much of its capacity would clear in the auction, FirstEnergy has projected that it will receive [redacted] in capacity revenues. FirstEnergy projected that capacity prices would [redacted] between the 2017/2018 and the 2023/2024 delivery years.[104] The [redacted] of that increase was projected to happen between 2017/2018 and 2018/2019, when FirstEnergy projected an increase from the known value of $120/MW-day in 2017/2018 to [redacted] in 2018/2019, which is an increase of [redacted].[105] FirstEnergy then projects that capacity prices [redacted] between the 2018/2019 and 2019/2020 delivery years, and [redacted] between the 2019/2020 and 2020/2021 delivery years.[106] Largely as a result of these increases in capacity price, FirstEnergy's projection of charges and credits under Rider RRS assumed that annual capacity revenues from Sammis, Davis-Besse, and the OVEC entitlement would [redacted] in 2017/2018, [redacted] in 2019/2020, [redacted] in 2023/2024.[107]

Since Mr. Rose created his capacity price forecast, the auction for the 2018/2019 delivery year has occurred. The results of that auction show that, just as with energy and natural gas prices, Mr. Rose's capacity price forecast is unreasonably high. In particular, in contrast to Mr. Rose's forecast of [redacted], the actual result for the 2018/2019 Capacity Performance product was $164.77/MW-day. Mr. Rose attempts to spin this result by contending that his claim "that there's going to be a massive increase in the capacity price has been sustained."[108] This testimony merely underscores the unreasonableness of Mr. Rose's own forecast because,

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[104] Co. Ex. 25c, Lisowski Workpapers at page 5 line 2.

[105] *Id.*

[106] *Id.*

[107] *Id.* at page 1, line 3, page 3, line 3, and 5 line 3.

[108] Tr. VII at 1487.

dollar-wise, Mr. Rose [redacted] that Mr. Rose refers to as "massive."[109] Regardless, using FirstEnergy's assumption in its modeling that [redacted] the 2018/2019 auction, FirstEnergy's [redacted] of the 2018/2019 capacity price led FirstEnergy to project [redacted] capacity revenues for the 2018/2019 delivery year than would be received under the actual results of the auction. If FirstEnergy's projection of capacity prices and revenues [redacted] for delivery years 2019/2020 through 2023/2024, [redacted] of purported credits that the Companies projected would be provided to their customers under Rider RRS.[111]

FirstEnergy's projection of capacity revenues is also unreasonably inflated because it is based on the assumption that [redacted] Sammis, Davis-Besse, and the OVEC

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[109] FirstEnergy is likely to point to a scenario analysis recently carried out by PJM that purported to estimate the capacity price if the 2018/2019 auction had been 100% capacity performance rather than 80% to claim that Mr. Rose's capacity price projection for future years is credible. *See* Co. Ex. 169. As OCC witness Wilson explained, however, PJM has provided no explanation for how the capacity price was projected for a hypothetical scenario in which 100% of the 2018/2019 auction was capacity performance products. Tr. XXXVIII at 8140-41. In addition, both FERC in approving the Capacity Performance product, and PJM in proposing it, explained that the reason for transitioning in the product over five years, rather than requiring 100% Capacity Performance product in the 2018/2019 auction, was to "allow resources to make gradual improvements" so as to "reduce the burdens such improvements may impose" and to minimize exactly the kind of price spikes that Mr. Rose projected. *See In re PJM Interconnection LLC, Order on Proposed Tariff Revisions,* Docket Nos. ER15-623-000, EL15-29-000, ER15-623-001, and EL15-41-000, 151 FERC 61,208 at ¶¶ 214, 253 (June 9, 2015); *see also* Tr. XXXVIII at 8140.

[110] *See* SC Ex. 89, line 5.

[111] Given that FirstEnergy's forecast has capacity prices [redacted] capacity prices, it is not implausible that FirstEnergy's projected capacity revenue may be [redacted] for each of the six delivery years from 2018/2019 to 2023/2024. If so, the total capacity revenue over-projection would be [redacted], which is [redacted] the $561 million that FirstEnergy is claiming customers would receive over the eight-year term of Rider RRS.

entitlement cleared the auction. According to FirstEnergy witness Jason Lisowski, [redacted] Capacity Performance products in the 2018/2019 auction,[112] which means that, assuming [redacted].[113] Using the actual Capacity Performance product clearing price of $164.77/MW-day, FirstEnergy would receive [redacted] in capacity revenues for Sammis, Davis-Besse, and the OVEC entitlement in the 2018/2019 delivery year, which is [redacted] than FirstEnergy assumed in its projection of charges and credits under Rider RRS. If FirstEnergy [redacted] during the term of Rider RRS, the purported $561 million credit to customers projected by the Companies [redacted].[115] FirstEnergy, however, has not provided any analysis or explanation of how much capacity it expects to clear each year now that the Capacity Performance requirements are in place.

That FirstEnergy's capacity price forecast is unreasonably high is also shown by the fact that ICF issued two reports in 2015 providing [redacted] for the 2018/2019 delivery year. The first, which Mr. Rose was fairly certain was released after PJM issued the draft Capacity Performance proposal but before that proposal was finalized, estimated that the capacity price for 2018/2019 would be between $170/MW-day and $200/MW-day.[116] The second, which was issued after the Capacity Performance product was finalized in June 2015, estimated a 2018/2019 Capacity Performance product price between $150/MW-day and

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[112] Conf. Tr. IX at 1986-87.

[113] [redacted]

[114] [redacted].

[115] [redacted] x 4 years = [redacted].

[116] SC Ex. 88; Tr. XXXV at 7258-61, 7263-64.

$160/MW-day.[117] Despite the fact that these capacity price estimates were created after the draft and then final versions of the Capacity Performance product were issued, Mr. Rose's capacity price projection was never updated to reflect the [redacted] estimated for the 2018/2019 delivery year.

One reason why FirstEnergy's capacity price forecast was [redacted] is that Mr. Rose did not revise it to reflect PJM's January 2015 lowering of its peak load forecast.[118] Mr. Rose acknowledges that a lowering of peak load would put downward pressure on capacity prices,[119] and an ICF report regarding the 2018/2019 capacity auction results found that the downward impact on capacity prices of PJM's January 2015 reduction of its peak load forecast is almost as large as the upward impact on capacity prices of the Capacity Performance product.[120] FirstEnergy's failure to revise its capacity price forecast in 2015 to reflect PJM's lowering of its load forecast (and the release of the Capacity Performance product) further demonstrates that its capacity price forecast is outdated and unreliable.

FirstEnergy's projection that capacity prices [redacted] is questionable for at least three more reasons. First, PJM lowered its load forecast yet again in January 2016, which should place further downward pressure on capacity prices that is not accounted for in FirstEnergy's capacity price forecast, which was created in mid-2014. Table 5 shows the magnitude of the change between PJM's 2016 load forecast and the 2014 PJM forecast that Mr. Rose used.

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[117] SC Ex. 87; Tr. XXXV at 7264-65.

[118] Tr. XXXV at 7229-30.

[119] *Id.*

[120] SC Ex. 87 at 2.

Table 5: PJM RTO Gross Load Forecast

	Rose / PJM 2014[121]	PJM 2016[122]	% Change
2016	162,468	152,130	- 6.36%
2017	164,195	154,148	- 6.12%
2018	165,480	155,910	- 5.78%
2019	166,899	156,956	- 5.96%
2020	168,592	156,887	- 6.94%
2021	170,026	157,357	- 7.45%
2022	171,216	157,987	- 7.73%
2023	172,541	158,972	- 7.86%
2024	173,728	159,991	- 7.91%

In an attempt to downplay this problem, FirstEnergy may argue that in its 2016 load forecast PJM significantly reduced its forecast of load reduction from demand response which would put upward pressure on capacity prices. But this argument fails, because even with the reduction in demand response, PJM's 2016 restricted load forecast is still lower for each of the years 2016 through 2024 than in the outdated forecast that Mr. Rose relied on, as shown in Table 6.[123]

Table 6: PJM Restricted Load Forecast

	Rose / PJM 2014[124]	PJM 2016[125]	% Change
2016	148,943	143,353	- 3.75%
2017	151,881	145,265	- 4.36%
2018	153,068	146,933	- 4.01%
2019	154,382	147,921	- 4.19%
2020	155,946	153,471	- 1.59%
2021	157,274	153,933	- 2.12%
2022	158,375	154,551	- 2.41%

[121] Rose Public Workpapers at 1 (citing Table B-10 in PJM's 2014 Load Forecast).

[122] Co. Ex. 171 at 73, Tbl. B-10.

[123] The suggestion that there will be less demand response in the future was likely based at least in part on the ruling of the U.S. Court of Appeals for the D.C. Circuit that FERC could not compensate demand response in the PJM energy markets. Now that the Supreme Court has reversed that ruling, however, demand response will presumably at least partially recover.

[124] Rose Public Workpapers at 1-2 (Restricted load = Gross Peak Demand – Demand Response – Energy Efficiency).

[125] Co. Ex. 171 at 70, 73 (Restricted Load = Gross Load from Table B-10 on p. 73 minus Total Load Management from Table B-7 on p. 70).

2023	159,602	155,522	- 2.56%
2024	160,695	156,513	- 2.60%

Second, a recent ICF whitepaper explains that there is a "plausible scenario" in which the 2019/2020 capacity price is slightly lower than the 2018/2019 price.[126] Two of the elements of that "plausible scenario" is PJM's further lowering of its load forecast, which as noted above occurred in January 2016, and the recovery of demand response, which is possible now that the U.S. Supreme Court has reversed the D.C. Circuit's ruling that FERC could not compensate demand response in the PJM energy markets. In this "plausible scenario," ICF forecasted a capacity price between \$143/MW-day and \$159/MW-day in the 2019/2020 delivery year, which is a bit lower than the actual 2018/2019 results, and between [redacted] the price that Mr. Rose forecast for that delivery year. Assuming that [redacted] of the Sammis, Davis-Besse, and OVEC entitlement capacity clears the 2019/2020 auction, under ICF's plausible scenario capacity price forecast, FirstEnergy would receive between [redacted] in capacity revenues. By contrast, FirstEnergy's projection of charges and credits under Rider RRS includes [redacted] in capacity revenues for the 2019/2020 auction.[127]

Third, FirstEnergy's projection that capacity prices will continue to increase significantly even after [redacted] runs counter to the history of capacity prices over the past decade. In particular, consistent with the law of supply and demand, capacity prices in PJM have typically cycled between going up for one or two years in a row and then declining for a year or two in a row.[128]

[126] SC Ex. 87 at 11.

[127] Co. Ex. 25c, Lisowski Workpapers at page 1 line 3, page 3 line 3, and page 5 line 3.

[128] IGS Ex. 5, 2018/2019 RPM Base Residual Auction Results at 17.

In the twelve-year history of PJM capacity auctions, there has never been a situation where the capacity price went up or down more than three years in a row. Yet, FirstEnergy is projecting [redacted].[129] Such a projection is simply not reasonable.

Finally, PJM's recent creation of the Capacity Performance product highlights another risk to the Companies' customers under Rider RRS. In particular, under the Capacity Performance requirements, generating units can be subject to penalties if they do not perform when called upon during certain high-demand periods.[130] These penalties are higher than they were under PJM's prior capacity rules. And if FES receives a penalty associated with the capacity performance requirements, such penalty would flow through to the Companies under the proposed transaction[131] – and be passed along to customers under Rider RRS.[132] Yet the Companies have not presented any analysis or projection in this proceeding of the level of penalties or bonuses any of the Sammis units, Davis-Besse, or OVEC units might face. As such, even though the Companies' customers are taking on the risk of having significant penalties under the Capacity Performance requirements passed on to them through Rider RRS, the record

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[129] Co. Ex. 25c, Lisowski Workpapers at 1 line 2.

[130] *PJM Interconnection LLC*, Docket Nos. ER15-623-000 et al., 151 FERC ¶ 61,208, Order on Proposed Tariff Revisions, ¶ 46 (June 9, 2015).

[131] Tr. X at 2197-98; *see also* Tr. XIII at 2809-10.

[132] The only circumstance in which a capacity performance penalty would not flow through the Companies' customers is if the Commission found that the penalty was the result of unreasonable actions, and therefore disallowed the penalty. Tr. XXXVI at 7711.

But under the terms of the Stipulation, in some circumstances customers could even be forced to bear the financial consequences of a capacity performance penalty that was the result of unreasonable action. If, in a given year, FES received both a capacity performance penalty and bonus, and the Commission disallowed the penalty, the unreasonably-incurred penalty would be netted against the bonus. Stipulation at 8; *see also* Tr. XXXVI at 7711-14. Thus, in that situation, customers would not receive the bonus they would otherwise be entitled to. *Id.* at 7715. In effect, this stipulation provision treats capacity performance bonuses differently than capacity performance penalties, with the latter more likely to flow to customers than the former.

is entirely bereft of any data regarding how such penalties (or bonuses) might impact the amount of charges or credits that would be passed through to them under Rider RRS.

D. The Dispatch Modeling Performed For the Companies Was Unsophisticated, Not Independently Verifiable, and not Subject to any Sensitivities.

In this proceeding, the Companies' customers are being asked to ensure the Companies' payment to FES of an estimated $11.616 billion in costs (including a [redacted] return on equity for FES)[133] for operating the Sammis, Davis-Besse, and the OVEC entitlement for eight years, and to take on the significant risk that the revenues from those plants may be inadequate to cover such costs. Given the substantial amounts of customer money at issue, one would expect that the Companies would have insisted on a robust and rigorous evaluation of the potential costs and risks that customers would be exposed to. Unfortunately, such evaluation never occurred. Instead, these billions of dollars of potential costs and risks were evaluated through a single modeling run using a Microsoft Excel-based spreadsheet program that has not been subject to independent review and verification. Quite simply, this is not due diligence. The Companies' failure to thoroughly assess the costs and risks at stake provides yet further evidence that FirstEnergy has not satisfied its burden of demonstrating the Rider RRS is just and reasonable or that it would provide a significant benefit to customers.

1. The Microsoft Excel-based spreadsheet model is unsophisticated.

Leaving aside the serious problems with the inputs and assumptions that went into the modeling that was done for the Companies to support Rider RRS, another major shortcoming in the Companies' proposal is that they relied on an unsophisticated model to assess the costs and revenues that would be passed through to customers under Rider RRS. While there are a

[133] SC Ex. 89; SC Ex. 90c.

plethora of complex and robust models that are commercially available, the Companies here instead relied on a dispatch model that FirstEnergy Service Company developed in Microsoft Excel,[134] a program anyone can buy at their local office supply store. The model is [redacted], models nine different time periods on a monthly basis and then reports the results on an annual basis.[136] [redacted].[137] In addition, in dispatching, the model only compares an individual plant or unit against the market energy price; it does not directly assess how well that plant or unit competes against other generators.[138] And when modeling the OVEC plants – Kyger Creek and Clifty Creek – the model has to treat the two plants as a single unit, rather than assessing their dispatching separately.[139] In short, the model run for the Companies in this proceeding does not have a level of sophistication and robustness that is commensurate with the scope and gravity of the costs and risks that the Companies' customers are being asked to take on.

2. The accuracy and reasonableness of the model is not independently verifiable.

A second major concern with the modeling in this proceeding is that the model itself has not been subject to any sort of independent evaluation or verification. The single modeling run was not carried out by an independent third party or even the Companies. Instead, the modeling

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[134] Tr. VIII at 1562.

[135] Conf. Tr. VIII at 1743.

[136] Tr. VIII at 1580.

[137] Conf. Tr. VIII at 1743-45.

[138] Tr. VIII at 1577-78.

[139] *Id.* at 1579-80.

was done primarily by Jason Lisowski, a FirstEnergy Service Company employee who was also a member of the team that negotiated the proposed transaction on behalf of FES.[140] The model is considered proprietary to FirstEnergy Service Company and, therefore, was never produced to any party in this proceeding.[141] As such, there was no way for the Commission, Staff, or any intervenor to assess the model, its settings, or the algorithms that FirstEnergy Service Company has input into the Excel spreadsheet. In fact, there is not even a manual or technical documentation for the model that could allow for some level of review and evaluation of the model.[142] And there has never been a formal study evaluating the accuracy of the modeling results and how actual plant dispatching compares to what the model projected.[143]

In short, the model used to project the financial costs and risks that customers are being asked to take on is essentially a black box into which inputs go in and outputs come out, with no assessment of what actually happens in the black box. This lack of transparency raises further concerns about the justness and reasonableness of Rider RRS.

3. No alternative scenarios or sensitivities were modeled.

A third serious shortcoming in the modeling done to evaluate Rider RRS is that no sensitivities or alternative scenarios were modeled. The purpose of carrying out a sensitivity analysis is to evaluate how the net present value revenue requirements or other measure of the economics of a proposal would change if certain economic drivers ended up being different than assumed in one's analysis.[144] By evaluating a reasonable range of potential values for an uncertain factor such as, for example, natural gas prices, sensitivity analyses help provide a

[140] *Id.* at 1559-61, 1591.

[141] *Id.* at 1567.

[142] *Id.* at 1566.

[143] *Id.* at 1583.

[144] Tr. VI at 1150.

better idea of the economic risks and range of possible economic outcomes for a particular proposal. Sensitivity analyses are important to ensuring that one's analysis of a proposal is robust, which is perhaps part of why it is the practice of Mr. Rose's employer, ICF International, to always ask clients if they want sensitivities analyzed.[145] Here, however, FirstEnergy failed to obtain any sensitivities or alternative forecasts from Mr. Rose, and it carried out only one modeling run which only considered a single view of the future. In other words, the economic modeling of Rider RRS carried out for the Companies failed to provide any useful information about what would happen to the economics of Rider RRS if, for example, natural gas, energy, and/or capacity prices turn out different than Mr. Rose projected.

The failure of FirstEnergy to carry out any sensitivity analyses regarding Rider RRS is egregious for a few reasons. First, FirstEnergy's own witnesses acknowledge that there is significant uncertainty regarding key inputs, such as forecasted energy prices and capacity prices, that would greatly impact the future economics of Rider RRS.[146] As witness Lisowski stated, [redacted] Yet without sensitivity analyses, the impact of such uncertainty cannot be adequately explored. Second, FirstEnergy's consultant, Mr. Rose and his firm, ICF International, are fully capable of carrying out sensitivity analyses and have alternative forecasts readily available. In particular, ICF's quarterly energy outlook now includes a reference natural gas price forecast, as well as low and high cases that represent a reasonable range around that reference case.[148] Those natural

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[145] *Id.* at 1149-50.

[146] *See, e.g., id.* at 1144-45, 1147.

[147] Conf. Tr. IX at 1907.

[148] Tr. VI at 1154-55; SC Ex. 10.

gas price forecasts are then used to create a reference, low, and high energy price forecast.[149] And in the Flint Creek case that Mr. Rose testified in back in 2012, he evaluated the potential economics of a proposed retrofitting of a coal plant in Arkansas under a base case and six alternative scenarios.[150] There is no reason why a similar approach of evaluating a base case and a range of alternative scenarios involving different energy prices, different natural gas prices, etc. could not have been performed in this proceeding. Finally, [redacted], [redacted].[151] Regardless, the likely cost of doing some sensitivity analyses almost certainly pales in comparison to the magnitude of costs and risks that customers would be saddled with under Rider RRS. Failing to evaluate more than a single view on how such costs and risks are likely to turn out for customers is a textbook example of an approach that was neither just nor reasonable.

E. FirstEnergy has not Demonstrated that its Projection of Charges and Credits Under Rider RRS Adequately Account for Environmental Costs Facing the Sammis Plant.

Under Rider RRS, the Companies' customers would also be taking on the risk that the costs for the Sammis, Davis-Besse, and OVEC units would be higher than projected. Throughout the term of Rider RRS, the O&M costs for the plants would be paid by the Companies, and then passed through to customers under Rider RRS. And while capital investments would be financed by FES, the Companies would pay the depreciation, interest expense, and return on equity on capital expenditures for each year of Rider RRS, and those costs would be passed through to customers under the rider. The risk that such costs will be

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[149] *Id.*

[150] SC Ex. 9 at 7; Tr. VI at 1148-50.

[151] Conf. Tr. VII at 1466-67.

higher than the Companies assumed in their projection of charges and credits under Rider RRS is heightened by the fact that FirstEnergy has provided little to no documentation for at least two set of costs that would be passed through to customers under Rider RRS. First, the evidentiary shortcoming regarding costs is most clearly demonstrated with regards to legacy costs which, as explained in Section III.B, FirstEnergy has failed to quantify or even fully identify.

Second, FirstEnergy has failed to demonstrate that it has fully accounted for environmental compliance costs that the Sammis plant is likely to face during the term of Rider RRS. In his supplemental testimony, FirstEnergy witness Raymond Evans contends that costs for all existing and pending environmental regulations "are included in the Companies' cost forecast provided by Company witness Lisowski."[152] The record, however, demonstrates that FirstEnergy has not shown that its cost forecast fully reflects all environmental compliance costs. Instead, FirstEnergy steadfastly failed, [redacted]. Similarly, one of FirstEnergy's environmental compliance witnesses, Paul Harden, who also represented FES in negotiations over the proposed transaction,[154] testified that he never received any written documentation of compliance with potential future environmental regulations from the environmental department charged with evaluating such issues.[155] It strains credulity for FirstEnergy to contend that it has fully accounted for environmental compliance costs when it cannot identify the costs assumed

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[152] Co. Ex. 46, Evans Suppl. at 3. The confidential version of Evans' Supplemental Testimony is admitted as Co. Ex. 47c.

[153] *See* SC Ex. 41c, 42c.

[154] Tr. XII at 2533-34.

[155] *Id.* at 2536.

for compliance with each regulation or provide any documentation regarding how such compliance would be achieved.

Two recently finalized regulations that FirstEnergy acknowledges could require some additional spending at the Sammis plant are the Effluent Limitations Guidelines ("ELG")[156] and the Coal Combustion Residuals ("CCR") rule. At the rebuttal hearing, Mr. Evans attempted to downplay those costs by contending that biological treatment for selenium required by the ELGs would cost $8 to $18 million spread over three to four years,[157] and that it would cost $3 to $5 million to address the bottom ash waste stream, including lining of a bottom ash pond, under the ELG and CCR rules.[158] FirstEnergy, however, has provided no basis or support for such cost estimates or for the implication that those cost figures represent the total that the Sammis plant would face to achieve compliance with the ELG and CCR rules. And, in fact, FirstEnergy acknowledges that it has never produced any study of ELG compliance methods or costs,[159] and that its analysis of compliance with the CCR rules will not be completed until 2017.[160] In short, FirstEnergy has failed to demonstrate that potential environmental compliance costs facing the Sammis plant have been fully accounted for in this proceeding.

[156] While Mr. Evans's testimony contends that the Sammis plant is already in compliance with the ELGs, Evans Suppl. at 5, Mr. Evans acknowledged at hearing that such reference was only regarding the ELGs that were then in effect which dated from 1982, as opposed to the update to those standards which was finalized in 2015. Tr. XIX at 3803.

[157] Tr. XXXIII at 6788.

[158] *Id.* at 6794.

[159] *Id.* at 6787.

[160] Tr. XIX at 3800-02.

III. The structure of FirstEnergy's proposal exacerbates the financial risks of Rider RRS.

Rider RRS poses significant risks for the Companies' customers. By its very nature, the Rider would shift the financial risks of Sammis, Davis-Besse, and the OVEC plants onto the Companies' customers. And these risks are substantial: even under the Companies' own projections – which, as explained above in Section II, are overly optimistic – customers would pay $363 million in charges, on a net present value basis, during the first 31 months of the Rider. Customers are likely to incur even greater costs throughout the term of Rider RRS, both because revenues from the plants are likely to be lower than FirstEnergy has projected, and because customers could incur additional, unanticipated costs due to the strong likelihood that FirstEnergy underestimated future environmental compliance costs at the Sammis plant.

These risks are compounded by the structure of FirstEnergy's proposal. The specific terms of the Companies' proposal – including the proposed transaction between FES and the Companies – magnify the financial, operational, and regulatory risks that ratepayers would face if Rider RRS is approved. Moreover, although FirstEnergy has touted the supposed benefits of its proposed "risk-sharing" credits and the audit process, these Stipulation terms provide inadequate protections against the financial and operational risks associated with FES's generating plants. The structure of FirstEnergy's proposal, and lack of adequate customer safeguards, provide an additional basis for rejecting Rider RRS.

A. The Proposed Transaction exacerbates the financial risks customers would face under Rider RRS.

Although the Commission is not being asked to approve it,[161] the proposed transaction between FES and the Companies directly relates to Rider RRS. Simply put, one would not exist

[161] Tr. I at 40.

without the other.[162] This is clear from the structure of the Companies' proposal: under Rider RRS, customers would receive a charge or credit depending on whether the Companies' revenues from Sammis, Davis-Besse, and the OVEC entitlement exceed the payments made to FES under the proposed transaction. In effect, the proposed transaction would allow FES to shift the financial risks of its generating facilities to the Companies, and Rider RRS would further shift those risks to customers.

Because the proposed transaction and Rider RRS are inextricably intertwined, the terms of the former directly affect the reasonableness of the latter. And here, the structure of the proposed transaction is both highly favorable to FES, and deeply prejudicial to the Companies' customers – who will bear ultimate responsibility for the costs of FES's plants. The proposed transaction exacerbates the risks that are inherent in the Companies' scheme.

As a threshold matter, the proposed transaction is a risky proposition for the Companies' customers because the agreement itself does not yet exist. Even though FirstEnergy initially proposed Rider RRS a year and a half ago, it has still not drafted the PPA that would actually govern the proposed transaction between FES and the Companies.[163] Instead, FES and the Companies prepared a term sheet, which lays out certain provisions that would purportedly be included in a final PPA.[164]

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[162] FirstEnergy witness Moul acknowledged this in his testimony, noting "the structure of rider RRS relies on generating assets as part of the proposed transaction. So I don't see that they would exist separately." Tr. XI at 2333; *see also* Co. Ex. 33, Ruberto Direct at 2-3 (describing the Economic Stability Program, including the relationship between the proposed transaction and Rider RRS); Tr. IV at 703 (when asked if he would advise the Companies to enter into the proposed transaction if Rider RRS were rejected, Companies' witness Strah stated that "we need approval of Rider RRS to trigger any future actions that the companies would take").

[163] Tr. I at 56-57; Tr. XIII at 2750. Of course, the Companies and FES have also not entered into a final PPA. Tr. XIII at 2750-51; Tr. XXXVI at 7527.

[164] *See generally* Term Sheet.

This term sheet, however, does not provide any guarantees regarding the specific provisions of the proposed transaction. Because the PPA has not been written, and has therefore not been subject to Commission review, FES and the Companies could modify any of the terms of the proposed transaction when they draft the actual PPA. Although FirstEnergy claims that the term sheet represents an agreement in principle,[165] there is no guarantee that all of the term sheet's conditions will end up in the final PPA. FES and the Companies could jointly agree to modify the term sheet's provisions, and they could also include additional provisions in the PPA that are detrimental to customers.[166]

Even if the term sheet's conditions were fully incorporated into the final PPA, that would still provide little assurance for the Companies' customers, because the term sheet provisions are tilted in favor of FES, and would largely insulate the generating plants' costs from scrutiny. The term sheet disfavors the Companies – and thus the customers who will bear those financial risks under Rider RRS – in at least three major respects.

1. The Term Sheet Excuses FES's Performance During Many Unit Outages.

First, the term sheet includes a broad exemption that excuses FES from providing energy, capacity, and ancillary services during unit outages. Under this "unit contingent" provision, FES is excused from providing energy, capacity, and ancillary services to the Companies during unit outages of up to 180 days.[167] These excuses are provided on a unit-by-

[165] Tr. I at 53; Tr. XIII at 2786.

[166] As Companies' witness Strah acknowledged, he does not know "what the exact contract is going to look like or the exact words putting forth those provisions in the term sheet." Tr. IV at 869-70. Likewise, although witness Moul insisted that the term sheet provisions would be included in the final PPA, he acknowledged that additional provisions could potentially be added to the contract. Tr. XI at 2332.

[167] Term Sheet § 8.

unit basis, and the 180-day clock starts over with each new outage.[168] And during such outages, even though the unit is unavailable, the Companies would continue to pay many of the costs associated with that unit, including fixed operation and maintenance ("O&M") costs, taxes, and a return on equity.[169] (And the Companies, in turn, would pass those costs onto their customers through Rider RRS.) This unit contingent provision is a potentially sweeping exemption from FES's performance under the PPA, because – notwithstanding the fact that [redacted][170] – outages are almost always for periods less than 180 days.[171]

The only exception to the Companies' obligation to pay FES's costs during outages of less than 180 days is if the outage could have been avoided "by exercise of Good Utility Practice."[172] This provision, however, provides little financial protection to the Companies – or their customers. First, under the term sheet, the good utility practice requirement only has teeth where there is unit outage or FES otherwise fails to perform its obligations. Although the term

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[168] Term Sheet § 13; *see also* Tr. XI at 2296, 2298.

[169] Term Sheet §§ 8, 13; *see also* Conf. Tr. IX at 1998 [redacted]

[170] SC Ex. 37c, Att. 1 at 35.

[171] FirstEnergy witness Ruberto, who evaluated and negotiated the proposed transaction on behalf of the Companies, was unaware of any outages at Sammis or Davis-Besse that extended to 180 days within the past five years. Tr. XIII at 2894. FirstEnergy witness Harden testified that he was aware of only one outage at Sammis within the past five years that extended more than 180 days, and no such outages at Davis-Besse. Tr. XII at 2593-94. [redacted]

Although the Companies claim that they could receive capacity payments even during a unit outage, Tr. XI at 2472, [redacted]. *See, e.g.*, SC Ex. 90c, Att. JJL-1 [redacted]

[172] Term Sheet § 8. "Good utility practice" is defined on page 14 of the term sheet. The term sheet makes clear that good utility practice does not require "the optimum practice, method, or act." *Id.* at 14. Nor does this definition necessarily require FES to minimize costs. *See* Tr. III at 535-36.

sheet directs FES to operate the plants "in accordance with Good Utility Practice," the term sheet does not establish any consequence for failing to meet this requirement, except in the context of a unit outage.[173] Moreover, even if an outage were arguably caused by FES's failure to follow good utility practice, nothing in the term sheet provides that the Companies, as opposed to FES, would have the final say regarding whether good utility practices were followed.[174] And despite questioning of several FirstEnergy witnesses about this issue, none could identify how a dispute about whether good utility practices were followed would be resolved.[175] Instead, that crucial question has been deferred to the final PPA[176] – which has not been drafted and would not be subject to Commission review. The uncertainty over the good utility practice requirement underscores yet another risk facing the Companies' customers: FirstEnergy has admitted that if there were a dispute between the Companies and FES about whether certain costs were consistent with good utility practice, and FES prevailed in that dispute, the Companies would pass along those costs to customers through Rider RRS.[177]

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[173] Term Sheet §§ 8, 11. In addition to the outage provisions of Section 8, "Good Utility Practice" is also mentioned in Section 16. That section specifies that "Force Majeure" does not "include any event, circumstance or occurrence which could have been avoided through the exercise of Good Utility Practice." Term Sheet § 16. If FES was unable to perform its obligations under the PPA, but its non-performance was attributable to a failure to exercise good utility practice, then its non-performance would not be excused. Thus, the force majeure provision of Section 16, similar to the outage provisions of Section 8, applies in situations where FES fails to provide energy, capacity, or ancillary services from one of the Rider RRS units.

[174] *See generally* Term Sheet; *see also* Tr. I at 53-54 (failing to identify anywhere in term sheet stating that the Companies get to decide whether good utility practices were followed).

[175] *See* Tr. XI at 2295 (admitting that the term sheet does not delineate which party decides whether the plants were operated consistent with good utility practice); Tr. XII at 2530.

[176] Tr. XII at 2530.

[177] Tr. III at 530.

2. Under the Term Sheet, FES – not the Companies – controls capital expenditures.

Second, the term sheet provides the Companies (and their customers) no control over FES's capital expenditures at Sammis and Davis-Besse. Because such expenditures directly impact the Companies' payments to FES, and because FES has an economic incentive to bolster capital investments in these plants, this provision of the term sheet creates additional financial risk for ratepayers.

Under the term sheet, FES – rather than the Companies – has the final word over capital expenditure decisions at the plants.[178] Once those capital expenditures are made, the Companies would be responsible for paying depreciation on those expenditures for the remaining term of the proposed transaction.[179] And those depreciation costs would then be passed on to the Companies' customers through Rider RRS.[180]

These financial risks associated with capital expenditures are compounded by the fact that, under the term sheet, "capital costs are not bound by good utility practices."[181] This means, for example, that if FES incurred a capital expenditure that was made necessary by its failure to employ good utility practice, the Companies would still pay depreciation on those capital

[178] Term Sheet § 12; *see also* Tr. I at 80; Tr. XIII at 2781. Under the term sheet, the Companies are allowed to comment upon FES's capital expenditure plans, but FES has no obligation to follow to Companies' recommendations. Term Sheet § 12.

[179] Tr. XIII at 2783-84; *see also id.* at 2856-57. The Companies would also be required to pay a return on equity on the newly-enlarged rate base for the plant. *See* Term Sheet at 13 (capacity payment calculated using seller's invested capital); *id.* § 13(1)(iv) (requiring Companies to pay FES this capacity payment).

[180] *See* Tr. I at 81 (cost of capital expenditures would be passed along to ratepayers, subject to any Commission review process).

[181] Tr. XIII at 2856. *Compare* Term Sheet § 11 (stating that "Seller has an obligation to perform the Operating Work in accordance with Good Utility Practice") *with id.* at 15 (definition of "Operating Work," which "exclud[es] any Capital Expenditures Work"); *see also* Tr. XIII at 2856-57.

expenditures even if the Companies had concluded that FES had failed to follow such good utility practices.[182]

Although FirstEnergy witness Jay Ruberto – who had previously admitted that good utility practices are not required for capital expenditures – sought to backtrack on his concession, his testimony is unpersuasive. During his redirect examination, Mr. Ruberto claimed that the Companies' depreciation payments, and the capacity payment (which includes a return on equity for Sammis and Davis-Besse), were subject to the good utility practice requirement.[183] But Mr. Ruberto was mistaken, because the term sheet says exactly opposite: namely, that "Capital Expenditures Work" is excluded from the definition of "Operating Work," with only the latter being subject to the good utility practices requirement.[184] Moreover, Mr. Ruberto's suggestion that the depreciation of a capital asset is a type of "operating work" that could be subject to good utility practices makes no sense: As Mr. Ruberto ultimately conceded, depreciation is a straight-line accounting exercise,[185] which cannot be shoehorned into the term sheet's definition of "Good Utility Practice." The same holds true for the return on equity that FES receives under Section 13(1)(iv) – that payment is calculated based on a straightforward mathematical formula,[186] and cannot be characterized as a type of "operating work." In sum, FES has control over capital expenditures at Sammis and Davis-Besse, and those decisions are exempt from the "good utility practice" requirement.

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[182] Tr. XIII at 2852-53.

[183] Tr. XIV at 3000-01.

[184] Term Sheet at 15; *id.* § 11.

[185] Tr. XIV at 3027-28.

[186] Term Sheet § 13(1)(iv); *id.* at 13 (defining "Capacity Payment," Seller's Invested Capital," and "Seller's Return on Equity").

The term sheet's capital expenditure provisions pose a financial risk to customers, not only because the Companies have no veto over capital spending decisions, but because FES has an economic incentive to bolster investments in its plants. To the extent FES makes capital expenditures, under the proposed transaction the Companies would pay depreciation on those expenditures for the remainder of the transaction, as well as a weighted average cost of capital return.[187] Consequently, as FirstEnergy witness Donald Moul acknowledged in response to questioning from Attorney Examiner Price, [redacted]."[188] Moreover, because FES would regain control of its plants' output starting on May 31, 2024, it has an additional economic incentive to enhance those plants' infrastructure prior to that date.[189] These incentives heighten the risk that FES will over-invest in its plants during the term of the proposed transaction, with the depreciation expenses from such investments being paid for by the Companies and then passed on to customers through Rider RRS.[190]

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[187] Term Sheet § 13(1)(iii), (iv); *see also* Conf. Tr. XI at 2462. Moreover, if Rider RRS were extended beyond its current proposed end date – a definite possibility under the Stipulation, Tr. XXXVI at 7526-27 – customers could continue to pay depreciation and a return on equity beyond May 31, 2024.

[188] Conf. Tr. XI at 2462-63.

[189] [redacted]

[190] Although the term sheet discusses situations where a capital investment would render a facility "uneconomic," Term Sheet § 8, that provision does not protect the Companies (or their customers) from the risk of FES over-investing in the plants. For one thing, the provision does not apply to situations where FES's capital spending is excessive, but not so large that the capital spending alone would make the plant uneconomic.

Furthermore, this provision only applies where both parties agree that the facility is uneconomic. Term Sheet § 8; Tr. XI at 2299; Tr. XIII at 2784. So even if the Companies believed that a given capital expenditure would render a unit uneconomic, if FES disagreed with the Companies, the unit would remain in the PPA. The lack of teeth in this provision is compounded by the term sheet's failure to define

3. The Term Sheet Does Not Protect Against Modification or Early Termination of the Proposed Transaction.

Third, the term sheet provides the Companies' customers little protection against the risk that FES could terminate the agreement early, or modify its terms to financially benefit FES. As noted above, the Companies have projected that Rider RRS would result in a $363 million charge to customers through 2018 (because payments to FES under the proposed transaction would exceed the generating plants' revenues), but would provide credits to customers during the later years of the proposed transaction.[191] Those future projected credits are unreasonably optimistic for the reasons explained in Section II above. But in the unlikely event that Sammis, Davis-Besse, and the OVEC entitlement become highly profitable during the term of the proposed transaction, FES would have an incentive to renegotiate the agreement, or terminate it prematurely, so it could reap those profits for itself. In that scenario, the Companies' customers would be left holding the bag: they would have subsidized the plants in the near term, when FirstEnergy's own projections show the plants would be losing hundreds of millions of dollars, without reaping any financial benefit in the later years of Rider RRS.

The risk of FES terminating the agreement early, or modifying its terms to FES's advantage, could manifest itself in several different ways. First, FES and the Companies could mutually agree to renegotiate the PPA. Under the Companies' proposal, the Commission would have no direct oversight of the proposed transaction.[192] Consequently, the parties to the transaction could renegotiate its terms without Commission approval. As FirstEnergy witness

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"uneconomic." In short, this provision offers no protection against the risk of over-investments in the plants.

[191] *See* SC Ex. 89.

[192] As FirstEnergy witnesses have repeatedly stated, the Commission has not been asked to approve the proposed transaction. *See, e.g.*, Tr. XI at 2284 (confirming that "the proposed transaction is not before the Commission for review").

Lisowski has acknowledged, FES would have an incentive to renegotiate the PPA once it gets through the early years of the agreement, when its plants are projected to be less profitable.[193] Notably, this possibility – that FES and the Companies renegotiate the agreement at a future date, after customers have already subsidized the plants for several years – is a contingency that the term sheet does not address.[194] FirstEnergy admitted as much under questioning from the Attorney Examiner:

> EXAMINER PRICE: What is to stop FirstEnergy Solutions from seeking to renegotiate the proposed transaction when market prices increase and it will be economically beneficial for FirstEnergy Solutions to terminate the proposed transaction and return to market prices?
>
> THE WITNESS: There's a section in the term sheet that specifically calls out the duration of this contract, that's a 15-year contract between FES and the companies. We're not going to breach the contract.
>
> EXAMINER PRICE: I didn't ask if you were going to breach the contract. I said what is to stop FirstEnergy Solutions from seeking to renegotiate the contract when [it's] in their economic interest to do so?
>
> THE WITNESS: I don't think that's specifically addressed in the term sheet. I would expect though when a final purchase power agreement were this approved would be developed, there would be some controls along those lines.[195]

This testimony underscores the risk that FES and the Companies could later modify the agreement.

Second, even if the Companies were unwilling to renegotiate the agreement, FES could still terminate it early without the Companies' consent. And if FES did so, the Companies'

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[193] Tr. VIII at 1723-24.

[194] Tr. XI at 2284-85.

[195] *Id.* at 2284-86.

customers would have no effective recourse. If FES did terminate the PPA prior to May 31, 2024, it would arguably be in breach of the proposed transaction.[196] But even assuming that were true, and further assuming that the Companies were willing to litigate against their corporate affiliate,[197] the term sheet would likely preclude the Companies from recovering their expected future profits (i.e., the difference between the expected future revenues from selling the plants' output into the PJM markets, and the plants' future estimated costs). The term sheet includes a "Limitations of Liability" provision that strictly limits the remedies for breach. This provision, which is in Section 19 of the term sheet, limits a breaching party's liability to direct damages, with the non-breaching party waiving "all other remedies or damages."[198] The provision further states that "[n]o Party shall be liable for consequential, incidental, punitive, exemplary, or indirect damages, lost profits or other business interruption damages."[199]

By its plain terms, this provision appears to bar the Companies from recovering their anticipated future net revenue stream from selling the plants' output into PJM. In the event of a breach, FES would not be liable for consequential damages, which encompass losses that are contingent on third-party agreements, such as returns from re-sale transactions – like those that the Companies would be engaging in by selling output into PJM.[200] Because the Companies' lost

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[196] This may not be the case, however, because the final purchase power agreement has not been drafted. Tr. I at 56-57; Tr. XIII at 2750. Although the term sheet does not explicitly empower FES to terminate the agreement early, it also does not specifically prohibit early termination. Consequently, such a provision could be included in the final contract. *See* Tr. XI at 2332 (Mr. Moul acknowledging that additional provisions could potentially be added to the contract). The Commission, and the Companies' customers, simply would not know until the PPA is actually drafted.

[197] It is highly unlikely that the Companies would vigorously pursue litigation against FES, given that they have the same parent corporation. Tr. X at 2081, 2203; Tr. XXXIII at 6808-09.

[198] Term Sheet § 19.

[199] *Id*.

[200] *Id.*; *Airlink Commc'ns, Inc. v. Owl Wireless, L.L.C.*, 2011 WL 4376123, at *3 (N.D. Ohio 2011). In *Airlink*, a limitations of liability clause resembling Section 19 barred a cellphone industry middleman from recovering losses after a change in the supplier's prices decreased the middleman's re-sale returns.

returns from wholesale sales would be consequential damages, Section 19 of the term sheet bars their recovery.

In his rebuttal testimony, FirstEnergy witness Moul offered a different interpretation of this provision, with the cursory claim that "[u]nder Section 19, FES would be responsible to pay the Companies the difference between contract payments and the amount of revenue that the Companies would have received for the output of the Plants."[201] This claim is unpersuasive as Mr. Moul, who is not an attorney,[202] offered no support for this legal conclusion. In addition, Mr. Moul's testimony is contradicted by the plain language of the term sheet, as well as applicable case law, which establishes that the loss of a revenue stream that was contingent on third-party sales is a consequential damage. Here, the Companies' lost revenue is a consequential damage, as it is contingent upon sales into the PJM markets. Therefore, under Section 19, FES would have no responsibility to make up for such losses to customers.[203] And even if remedies under the term sheet were not so limited, there is no guarantee that the

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See id. (damages were consequential because "Plaintiff's lost profits, if any, were contingent upon third-party agreements"). In another case involving a provision similar to Section 19, a scrap metal middleman was barred from recovering losses after supply problems kept the business from taking advantage of the re-sale market at a time when prices were rising. *See Allied Indus. Scrap, Inc. v. Omnisource Corp.*, 2012 WL 4483283, at *3 (N.D. Ohio 2012), *rev'd on other grounds*, 776 F.3d 452 (6th Cir. 2015). This case, too, is analogous to the situation the Companies would face if FES unilaterally terminated the PPA.

[201] Co. Ex. 141, Moul Rebuttal at 6. The confidential version of Moul's Rebuttal Testimony is admitted as Co. Ex. 142c.

[202] Tr. XXXII at 6628.

[203] FirstEnergy's reliance on Mr. Moul for an interpretation of Section 19 is ironic, given that he previously testified that he had no knowledge about this provision. When first asked whether he was aware of any term sheet provision that deals with a breach, Mr. Moul could not recall such a provision. Tr. XI at 2301. He further testified that he had no input or consideration of that part of the term sheet. *Id.* at 2302. And when asked whether he had "any testimony as to what damages are or are not allowed in the event FES were to breach the contract," Mr. Moul simply stated "none other than what's written in the words." *Id.* Indeed, during the main hearing, FirstEnergy's counsel took pains to emphasize that Mr. Moul was not "the witness for the companies on the term sheet." Tr. XI at 2296.

Companies would vigorously pursue litigation against their corporate affiliate in the event that FES terminated the transaction early.

B. The Companies are seeking approval of a large category of legacy costs that are unquantified and ill-defined.

The financial risks posed by Rider RRS are further compounded by the fact that, under the Companies' proposal, a significant proportion of the Rider RRS costs – the so-called "legacy cost components" – would be deemed reasonable and not subject to future challenge in a future Commission proceeding.[204] FirstEnergy's definition of legacy cost components is capacious: They include "all costs that arise from decisions or commitments made and contracts entered into prior to December 31, 2014, including any costs arising from provisions under such historic contracts that may be employed in the future."[205] There is no start date for which historic contracts (or other "decisions or commitments") qualify as legacy cost components, and there is no limit on the amount of legacy costs that can be included in Rider RRS.[206] And the potential amounts are enormous. For example, FirstEnergy has confirmed that the $1.8 billion investment in scrubbers at the Sammis plant in 2010 constitutes a legacy cost component.[207] Under FirstEnergy's proposal, all legacy cost components would be deemed reasonable if the Commission approves Rider RRS.[208] This broad category of costs would therefore not be subject to a future audit or prudency review.[209]

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[204] Tr. I at 79.

[205] Co. Ex. 7, Mikkelsen Direct at 14.

[206] Tr. I at 88.

[207] Tr. XII at 2597.

[208] Tr. I at 92; *id.* at 93.

[209] *See* Mikkelsen Direct at 14 ("Approval of this ESP IV shall be deemed as approval to recover all Legacy Cost Components through Rider RRS as not unreasonable costs"); *id.* at 15 (legacy cost components "shall not be included in this second review or challenged in any subsequent audit or review").

FirstEnergy justifies this massive carve-out by claiming that legacy cost components "were reviewed by the EDU Team that Company witness R[u]berto led and found to be reasonable."[210] There are several problems with this claim. First, the EDU Team's review of legacy cost components was extremely limited. As the evidence in this proceeding demonstrates, the EDU Team did not [redacted].[211] The EDU Team's failure to take a hard look at the legacy cost components underscores the unreasonableness of FirstEnergy's attempt to shield these costs from future Commission scrutiny.

Moreover, in this proceeding FirstEnergy has failed to provide adequate information about these legacy cost components and their ultimate future impact. FirstEnergy never identified the specific monetary amounts that it is asking the Commission to deem reasonable and never provided any basis on which the Commission, Staff, or intervenors could calculate such amounts.[212] And although multiple parties requested information about the legacy cost components in discovery, FirstEnergy's responses [redacted]. In discovery, FirstEnergy was asked [redacted][213] FirstEnergy's initial response [redacted]

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[210] Mikkelsen Direct at 14.

[211] *See* SC Ex. 53c. The response to subpart (a) of this request, [redacted] references SC Ex. 38c, Att. 1, SC Ex. 37c, Att. 1, and SC Ex. 55c, Att. 1. [redacted]. *See* Conf. Tr. IX at 1837-38 (discussing SC Ex. 38c), 1838-40 (discussing SC Ex. 37c, Att. 1 at 37); Conf. Tr. XIV at 2947 (discussing SC Ex. 55c).

[212] Tr. I at 92.

[213] *See* SC Ex. 40c; *see also* SC Ex. 39c (P3/EPSA requests, the responses to which simply cross-reference SC Ex. 40c).

[redacted].[215] After undersigned counsel notified FirstEnergy that its response was deficient, FirstEnergy supplemented its response, as shown in SC Ex. 40c. This supplemental response, however, [redacted].[216]

Because all legacy costs would be shielded from Commission review, this aspect of the Companies' proposal further underscores the significant financial risk that customers would bear under Rider RRS.

C. The Rider RRS Proposal Lacks Safeguards to Mitigate the Financial Risks Facing the Companies' Customers.

Although the proposed transaction and Rider RRS would shift significant financial and operational risks onto the Companies' customers, FirstEnergy's proposal lacks any safeguards that would truly mitigate those risks. FirstEnergy may argue that two aspects of its proposal – the Commission's ability to review some of the costs incurred under the proposed transaction, and the potential for "risk sharing" credits in certain circumstances – serve to mitigate such

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[214] Conf. Tr. IX at 1830.

[215] *Id.* at 1833-37 (discussing pp. 7-8 of Mr. Lisowski's workpapers), 1837-38 (discussing SC Ex. 38c), 1838-40 (discussing SC Ex. 37c, Att. 1 at 37), 1840-41 (discussing Co. Ex. 22c, Lisowski Direct, Atts. JJL-1, -2, -3).

[216] *See* SC Ex. 40c (SC Set 1-INT-74 Supplemental Response + Attachment 1). [redacted] Conf. Tr. IX at 1848-49.

risks.[217] But to the extent FirstEnergy advances such an argument, it would be misplaced. These provisions offer minimal protections to customers, and they certainly do not mitigate the serious financial risks posed by Rider RRS. The inadequacies of these purported safeguards are detailed below.

Before addressing those provisions, however, it is important to recognize what FirstEnergy's proposal would *not* do: First, it would not establish a cap on the amount of charges that customers could be responsible for under Rider RRS.[218] (Likewise, there is no guarantee that customers would receive the amount of credits highlighted by FirstEnergy witness Mikkelsen.)[219] Because there is no ceiling on the total charges permitted under Rider RRS, customer are required to pay those charges – no matter how costly Rider RRS becomes. Given that the Companies' projections are based on outdated and inaccurate price forecasts, *supra* at Section II.C, the absence of a cap exacerbates the financial risk that customers would face under Rider RRS.[220]

Second, under FirstEnergy's proposal, none of these financial risks are allocated to FES. The problem with FES, as the owner of the plants, not sharing in the financial risk has been

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[217] The review process is described in the testimony of FirstEnergy Witness Mikkelsen. *See* Mikkelsen Direct at 14-15 (describing proposed review process); Co. Ex. 9, Mikkelsen Second Suppl. at 12 (arguing that the Commission's review process allocates risk between the Companies and their customers); Mikkelsen Fifth Suppl. at 4. The "risk sharing" credits are discussed both in testimony and in the Stipulation. *See id.* at 3-4 (stating that the "risk sharing element in the Companies' original filing is expanded," and citing to the Stipulation's risk-sharing provision); Stipulation at 7-8 ("Risk Sharing," section V.B.2).

[218] Tr. XXXVI at 7523-24, 7675.

[219] *Compare* Mikkelsen Fifth Suppl. at 11 *with* Tr. XXXVI at 7675.

[220] FirstEnergy also refused to consider any risk-sharing provision that would directly link the Companies' finances to the costs that customers will face under Rider RRS. During the evidentiary hearing, FirstEnergy witness Strah was asked if the Companies would consider a scenario in which they would bear a percentage of the risk associated with RRS. Tr. IV at 717, 720. Mr. Strah declined the invitation to endorse that proposal. *Id.* at 717-20. Likewise, the leader of the team representing the Companies in negotiating and evaluating the proposed transaction did *not* consider the possibility of the Companies retaining a portion of the projected benefits – "and the consequent risks." Tr. XIII at 2830.

highlighted by multiple witnesses.[221] Indeed, FES itself has recognized the benefits that accrue when a generation owner bears responsibility for its own decisions. In the Dayton Power & Light ESP proceeding, Case No. 12-426-EL-SSO, FES witness Sharon Noewer stated that:

> Competition also shifts the inherent risks of capital investments in generation away from customers. In a competitive market, owners of generation and their shareholders [bear] the risk that generation investments will not be economic. Under a market system with effective competition, generation owners have a strong incentive to minimize their costs and make their generation resources more efficient because they [bear] the risk of their business decisions. Thus, competition provides incentives for generation owners to reduce their costs while maintaining or increasing production leading to improved operating performance from existing generating plants. As a result, competition promotes more innovative least cost solutions to provide electric service in the most efficient and cost effective manner.[222]

In this case, Staff Witness Choueiki testified that, if the Commission were inclined to approve Rider RRS, it should require "a sharing mechanism whereby FES commits to be responsible for a portion of the costs associated with Rider RRS in exchange for a portion of the revenues associated with Rider RRS."[223] Dr. Choueiki further recommended that FirstEnergy's proposal should be structured so that if the Commission disallowed certain costs to flow through Rider RRS, the risk of disallowance should fall on FES, rather than the Companies.[224] Yet, neither of these recommendations were adopted in the Stipulation. FES would have no responsibility for any of the "risk sharing" credits described in Section V.B.2 of the

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[221] *See, e.g.*, P3/EPSA Ex. 1, Kalt Direct at 8-9, 25 (the confidential version of Kalt's Direct Testimony is admitted as P3/EPSA Ex. 2c); OCC/NOPEC Ex. 4, Wilson Direct at 58 (the confidential version of Wilson's Direct Testimony is admitted as OCC/NOPEC Ex. 6c); Staff Ex. 12, Choueiki Pre-filed at 13, 16-17.

[222] Tr. XI at 2396-97.

[223] Choueiki Pre-filed at 16-17.

[224] Tr. XXX at 6243-44.

Stipulation.[225] And if the Commission were to disallow any costs incurred at FES's generating units to flow through Rider RRS, those costs would not be borne by FES.[226] As Dr. Choueiki confirmed, "under the companies' proposal, the Commission would not have the right to do anything that would affect what FES -- FES would be paid."[227] Put simply, there is nothing in FirstEnergy's proposal, even as modified in the Stipulation, that allocates any of the financial risks of Rider RRS to FES.[228]

1. FirstEnergy's proposed audit process provides inadequate protection against the financial risks of Rider RRS.

Throughout this case, FirstEnergy has repeatedly argued that customers' financial risks would be mitigated by its proposed audit process. Under FirstEnergy's proposal, the Commission Staff would be able to review a portion of the Rider RRS costs for reasonableness.[229] The Companies claim that this review process "serves as a mechanism to allocate the financial risk associated with Rider RRS between the Companies and the customers."[230] But this claim is mistaken.

As an initial matter, the proposed audit process does not "allocate . . . financial risk" to the Companies. The notion that there might be some Commission scrutiny of the costs that

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[225] Tr. XXXVI at 7525.

[226] *See* Tr. XXXVI at 7593-94; *see also* Tr. I at 68.

[227] Tr. XXX at 6302. In his pre-filed testimony, Dr. Choueiki also recommended, as an alternative to risk-sharing with FES, that the Commission consider "appropriate charge and credit caps on Rider RRS." Choueiki Pre-filed at 17. But, as noted above, FirstEnergy's proposal lacks this safeguard as well: There is no cap on the magnitude of the charges that customers could be responsible for under Rider RRS.

[228] Tr. I at 61, 65.

[229] Stipulation at 8 (adopting the "[t]he rigorous review process set forth in the Companies' ESP IV filing in the testimony of Company Witness Mikkelsen"); Mikkelsen Direct at 14-15 (describing proposed review process). In both her written and live testimony, Ms. Mikkelsen sometimes referred to this as a "review process," and sometimes as an "audit." *Compare* Mikkelsen Second Suppl. at 12:6-16; Mikkelsen Fifth Suppl. at 4:4 *with* Mikkelsen Direct at 15:3-8, 15:21-22; Tr. II at 453.

[230] Mikkelsen Second Suppl. at 12.

FirstEnergy is passing off to ratepayers is not, in a real sense of the term, a "risk-sharing mechanism." Rather, this audit process represents a minimal safeguard against wholly unreasonable actions taken by FES or the Companies, but not a protection against market revenues being lower than projected. The fact remains that, under Rider RRS, customers would be responsible for the difference between the costs and the revenues of Sammis, Davis-Besse, and the OVEC entitlement no matter how large of a loss to customers would result. As Dr. Choueiki emphasized in his testimony, the Companies' proposed review process does not represent a commitment to share "the financial risk associated with Rider RRS with its distribution customers."[231] Thus, although FirstEnergy characterizes this audit process as a "risk sharing element,"[232] it is not.[233]

At best, FirstEnergy's proposed audit process would provide the Commission limited oversight over *some* of the costs that would be passed along to customers under Rider RRS.[234] The focus of this review process would be whether, based on "the facts and circumstances known at the time," the Companies' actions were reasonable.[235] However, the Commission

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[231] Choueiki Pre-filed at 13.

[232] *See, e.g.*, Mikkelsen Second Suppl. at 12; Mikkelsen Fifth Suppl. at 3 (referring to the "the risk sharing element contained in the Companies' original filing"); Tr. XXXVI at 7592.

[233] As discussed below in Section VII, this also means that the audit process does not satisfy the Commission's admonition in the AEP ESP III Order that the utility "include an alternative plan to allocate the rider's financial risk between both the Company and its ratepayers." Case No. 13-2385-EL-SSO et al., Opinion and Order (Feb. 25, 2015), at 25.

[234] In addition to the reasonableness audit/review discussed in the text, the Companies have proposed another, mathematical review process. Under this separate process, the "first" review described in Ms. Mikkelsen's direct testimony, there would be an annual review by Commission Staff for mathematical errors. Mikkelsen Direct at 14-15. This would be a mathematical review, with no review of the reasonableness of those costs. The review process would be limited to Staff, with customers being precluded from any participation. *See* Tr. I at 66-67; Tr. II at 449-50. And the review would "not involve any assessment of the reasonableness or prudence of any costs incurred by the companies under the proposed transaction." Tr. I at 67.

[235] Stipulation at 8 ("Specifically, the Companies agree to participate in annual compliance reviews before the Commission to ensure that actions taken by the Companies when selling the output from generation

would not be entitled to consider the reasonableness of the revenue projection that has been presented in this case[236] – a projection that almost certainly overestimates the future revenues from FES's generating plants. Instead the audit process would focus on narrower issues, such as whether the Companies acted reasonably in bidding the plants' output into the PJM markets.[237] If market revenues turn out to be lower than FirstEnergy projected, the Commission would not be able to make an unreasonableness finding, so long as the Companies' bidding practices were reasonable.[238] This limitation in the audit proposal would significantly limit the scope of the Commission's review of costs being passed through Rider RRS.[239]

Equally troubling, a significant proportion of the Rider RRS costs – the so-called "legacy cost components" – would be unreviewable under the proposed audit process.[240] As explained

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units included in Rider RRS into the PJM market were not unreasonable. . . . Any determination that the costs and revenues included in Rider RRS are unreasonable shall be made in light of the facts and circumstances known at the time such costs were committed and market revenues were received."); *see also* Mikkelsen Direct at 15.

[236] Tr. I at 73-76.

[237] *See* Stipulation at 8 ("the Companies agree to participate in annual compliance reviews before the Commission to ensure that actions taken by the Companies when selling the output from generation units included in Rider RRS into the PJM market were not unreasonable").

[238] Tr. I at 73-76.

[239] The risk that FirstEnergy's actions could be reasonable, and yet customers could still lose money, is underscored by FirstEnergy witness Mikkelsen's testimony that previously-incurred cost obligations "were assumed by a competitive company that prudently and conservatively incurred costs to effectively participate in the competitive market and deliver shareholder value." Mikkelsen Direct at 14. This "competitive company," of course, is FES. At the hearing, Ms. Mikkelsen suggested that FES was participating effectively in the market, but nevertheless found itself "in a situation where the markets have not and are not providing sufficient revenue to ensure the continued operation of the plants." Tr. I at 95; *see also* Tr. III at 520 ("I think what I am offering here in my testimony is my view that a competitive company that is trying to participate in markets would make reasonable business decisions with respect to their assets"). Assuming Ms. Mikkelsen were correct, and FES's prior actions were reasonable, that means that even reasonable actions offer no guarantee that the plants would generate sufficient revenue. Put simply, the audit process will not protect customers from paying higher-than-expected charges under Rider RRS.

[240] Tr. I at 79; Tr. III at 519. These costs would only be subject to a mathematical/accounting review, as discussed above in note 234. Tr. I at 79.

above in Section III.B, such costs would be excluded entirely from the audit process.[241] This limitation sharply restricts the scope of the audit process proposed by the Companies.

These substantive limits on the Commission's audit are compounded by procedural deficiencies. Under FirstEnergy's proposal, any refund to customers for unreasonable charges would be long delayed. The audit would not begin until after actual costs were incurred and actual revenues received,[242] and if the reasonableness of any costs were challenged, FirstEnergy would continue to collect those disputed costs while the issue was being litigated.[243] Customers would receive no refund at all until there was a final, non-appealable order,[244] which, given the possibility of an appeal to the Supreme Court of Ohio, could drag out the issue for a lengthy period of time.

Worse, if costs were found to be unreasonable, such that customers were entitled to a refund, the customers would be forced to foot FirstEnergy's bill for defending its unreasonable actions. Under FirstEnergy's proposal, the Companies would be entitled to recover the costs incurred through the audit – even if the charges are ultimately found to be unreasonable.[245] This absurd provision underscores the inadequacies with the Companies' proposed audit process.

The audit proposal includes other serious shortcomings as well. As noted above, *supra* at note 132, Capacity Performance penalties can flow through to customers more easily than

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[241] *See* Mikkelsen Direct at 14 ("Approval of this ESP IV shall be deemed as approval to recover all Legacy Cost Components through Rider RRS as not unreasonable costs"); *id.* at 15 (legacy cost components "shall not be included in this second review or challenged in any subsequent audit or review").

[242] Mikkelsen Direct at 15 (audit based on actual costs and revenues). For example, if in May 2016 the Companies bid the capacity from the plants into the 2019/20 base residual auction, any capacity revenues collected from its 2016 bids would not be received for three more years. Consequently, the audits for those capacity revenues would not begin until 2019 and 2020. Tr. XXXVI at 7615-18.

[243] Tr. I at 71.

[244] *Id.* at 70.

[245] *Id.* at 69-70; Tr. II at 453.

Capacity Performance bonuses. And, more significantly, although FES is the owner of the generating plants, and thus would possess important cost information that would be the subject of an audit, the Commission Staff would be unable to submit data requests to FES.[246] Instead Staff would have to submit their requests to the Companies, and then rely on the Companies to collect the underlying information from FES.[247] The Companies claim that FES has agreed to provide such information, due to a provision in the term sheet discussing information requested by a governmental authority.[248] But this means that Staff's ability to get FES cost data hinges on a term sheet provision it has no direct control over, and which has not been memorialized in a final contract.[249] And although FirstEnergy suggests otherwise, shielding FES from direct involvement in the audit process could significantly restrict the information available for Commission review. Given the many flaws in this proposed audit process, it is not surprising that Dr. Choueiki found that FirstEnergy's audit proposal was "vague and does not satisfy the definition of a rigorous Commission oversight."[250]

Notably, nothing in the Stipulation addresses any of the deficiencies discussed above. Apart from providing a clarification regarding PJM's Capacity Performance product, the only difference between FirstEnergy's original audit proposal and the Stipulation is the inclusion of a provision permitting the Staff, but not intervenors, limited review of FES fleet information.[251] The scope of this review is narrow: As with information related to the plants included in the

[246] Tr. I at 81-82.

[247] *Id.* at 83.

[248] *Id.* (referring to Term Sheet § 18).

[249] Under FirstEnergy's proposal, non-governmental intervenors would have no ability at all to compel the disclosure of information from FES. Tr. I at 85-86.

[250] Choueiki Pre-filed at 13.

[251] *See* Stipulation at 8; Tr. XXXVI at 7516-17.

proposed transaction, Staff would be unable to request data directly from FES, and instead would need to rely on the Companies to pass along such requests.[252] And FES's commitment to share such information is exceptionally vague: FES has provided no written commitment to the Commission; its agreement to provide this information was communicated verbally between FES and the Companies.[253] Moreover, this commitment does not extend to information solely within the possession of OVEC.[254] And access to all such information would be tightly restricted, with intervenors being unable to review any of it, and with all of it being treated as critical energy infrastructure information (regardless of its content). In any event, this fleet-sharing does nothing to cure the numerous, serious shortcomings of the audit process proposed by FirstEnergy. Given the significant financial risks associated with FirstEnergy's proposal, the audit provision does little to protect the Companies' customers.

2. The Stipulation's "risk sharing" credits fail to protect customers from financial risks.

In an apparent effort to assuage concerns about the financial risk that Rider RRS poses for ratepayers, FirstEnergy included a "new risk sharing mechanism"[255] in the Stipulation. Like the deficient audit proposal discussed above, this provision, however, does little to mitigate the risks facing customers under Rider RRS. Under this Stipulation provision, the Companies could pay out limited credits to customers, under certain conditions, based on the financial performance of Rider RRS in the last four years of the eight-year ESP.[256]

The shortcomings of this provision are numerous. First, this provision offers no

[252] Tr. XXXVI at 7519.

[253] *Id.* at 7520.

[254] *Id.* at 7521.

[255] Stipulation at 3.

[256] *Id.* at 7-8.

protections to customers during the first four years of Rider RRS. Under the Companies' own projections, customers would be forced to pay a net present value of $363 million through Rider RRS in 2016-18.[257] And, as explained above, those projections are overly optimistic: in all likelihood customers will face greater charges if the rider is approved. In fact, [redacted].[258] But regardless of how large the charges are during the first four years, nothing in this provision would offset those costs to customers.[259] Second, although this provision could trigger the payment of company-funded credits during the later years of the ESP, it does not ensure that customers will receive a *net* credit in any of the eight years.[260] So even if the Companies paid out all of the credits authorized by this provision, customers could still be required to pay a charge for each year that Rider RRS remains in effect. Third, because these credits would be funded by the Companies, without any subsequent reimbursement from either FES or FirstEnergy Corp.,[261] customers may ultimately be responsible for the cost of these credits. If this provision is triggered, and the Companies' balance sheet weakens as a result of paying the credits, there is a possibility that the Companies could seek to recoup losses at a future date (through either a rate increase or a rider). And as FirstEnergy witness Mikkelsen conceded, "there is no language in the Third Supplemental Stipulation and Recommendation that precludes

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[257] SC Ex. 89.

[258] Comings Third Suppl. at 5.

[259] Indeed, by limiting the company-funded credits to the last four years of the Rider RRS, when the Companies project that the Rider will produce far more credits than during the first four years, SC Ex. 89, this provision has been designed to minimize the likelihood of it being triggered. *See also* Comings Third Suppl. at 6 (explaining that this provision would not be triggered under the Companies' [redacted] valuation estimates). For this reason, the Companies did not prepare any analysis of this provision's effect on their finances. Tr. XXXVI at 7600.

[260] Tr. XXXVI at 7741; Tr. XXXVII at 7771.

[261] Tr. XXXVI at 7525.

the companies from recovering those costs in a future Commission proceeding . . . ."[262] Consequently, this provision creates a risk of future cost recoveries from the Companies' customers – the very population for whose benefit this provision was purportedly created.[263]

IV. The Companies failed to adequately scrutinize the proposed transaction.

As explained above in Sections II and III, the proposed transaction and Rider RRS present serious financial and other risks for the Companies' customers. Given these risks, not to mention the magnitude of this proposal (whose projected costs and revenue both exceed $11.5 billion over the eight-year term),[264] the Companies should have carefully scrutinized this proposal before agreeing to it. But that did not happen. After FES approached the Companies about a proposed PPA for Sammis, Davis-Besse, and the OVEC entitlement, the Companies engaged in a rushed evaluation and negotiation process. The Companies' inadequate evaluation and negotiation of the proposed transaction further underscores the unreasonableness of Rider RRS.

Although the Companies have been the main advocates for Rider RRS before the Commission, they did not come up with this idea; FES did. After reviewing profit-and-loss

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[262] *Id.* at 7525. It is also worth reiterating what this provision does not do: these credits do not shift any risk to FES. *See, e.g.*, *id.* at 7733 (confirming that the credits "are not intended to provide an incentive to FES").

[263] The "risk sharing" provision is problematic in other respects as well. For one thing, the payment of these credits would be subject to a significant time lag: If the provision were triggered in a given year, the credits themselves would not actually be paid out until the following year – at best, the credits would begin to be paid in the last 60 days of the year. *Id.* at 7731-32. And this holds true even if there is an earlier forecast showing that unexpected losses will occur. *Id.* This also means that the earliest any company-funded credits would be paid out is 2021 – near the end of Year 5, or the start of Year 6. Tr. XXXVII at 7772. These time lags further reduce the value of this provision, because the risk-sharing credits would be paid in nominal dollars. Tr. XXXVI at 7733.

[264] SC Ex. 89. At the time the Companies considered the proposed transaction, the proposal was even greater, with projected costs and revenues each exceeding $24.5 billion over the 15-year term of the Rider. *See* Co. Ex. 34, Att. JAR-1 revised.

statements for its generating plants, and with knowledge that the Companies were getting ready to file an ESP application, FES first approached the Companies about a possible PPA in May 2014.[265] After the Companies notified FES that it could not do a PPA for all of FES's units, on June 11, 2014, FES made a follow-up offer involving Sammis, Davis-Besse, and the OVEC entitlement.[266]

Following FES's initial overture in May, the Companies assembled a team, dubbed the "EDU Team," to evaluate and negotiate the proposed transaction. This team, which was led by FirstEnergy Witness Jay Ruberto, was formed on May 20, 2014, and its first meeting occurred at some point after that.[267] The term sheet was finalized in late July – barely two months later.[268]

[redacted]

The shortcomings of the evaluation process the EDU Team undertook are numerous. As an initial matter, the EDU Team performed its work without the benefit of any written instructions.[270] And the evaluation was done on a highly compressed timeframe, with little information from FES, and the Team making decisions before receiving all of the information it had requested. For example:

- [redacted]
- [redacted]

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[265] Tr. XI at 2290, 2291.

[266] SC Ex. 37c, Att. 1 at 1, 4.

[267] Tr. XIII at 2758, 2760; *see also* SC Ex. 52 at 2.

[268] Tr. XIII at 2751.

[269] Conf. Tr. XIV at 2936.

[270] Tr. XIII at 2758-59.

[271] Conf. Tr. XIII at 2911-12, 2916; SC Ex. 37c, Att. 1 at 12-15 (initial forecast); *see also id.*, Att. 1 at 20-22, 30-32 (subsequent forecasts); SC Ex. 37c, Att. 2, at 7-9, 20-22 (same).

- [redacted]
- [redacted]

More troubling still are the myriad things the EDU Team did *not* do at all. The EDU Team did not [redacted].[275] Nor did the Team consider alternatives to FES's proposed PPA. The only generation mix it fully evaluated was the one offered by FES:[276] [redacted],[277] nor did it issue a request for proposalRFP for other resource options.[278] And despite FirstEnergy's claim that the EDU Team reviewed legacy cost components and found them "to be reasonable,"[279] the Team failed [redacted].[280]

[272] Conf. Tr. XIII at 2917-18; SC Ex. 37c, Att. 1 at 36-39.

[273] SC Ex. 37c, Att. 1 at 34-35; Conf. Tr. XIII at 2919-20.

[274] Conf. Tr. XIV at 2934.

[275] *Id.* at 2934-35.

[276] Tr. XIII at 2747-48, 2846.

[277] Conf. Tr. XIV at 2994.

[278] Tr. XIII at 2748. The EDU Team also did not consider [redacted]. Conf. Tr. XIV at 2952.

[279] Mikkelsen Direct at 14.

[280] *See supra* at 59 & note 211.

Although the Team compared the costs of Sammis and Davis-Besse [redacted],[281] its cost comparison analysis was limited. The EDU Team:

- Did not compare the costs of Sammis and Davis-Besse to the costs of [redacted].[282]
- Only compared Sammis's costs [redacted].[283]
- Did not know whether [redacted],[284] thereby preventing an assessment of whether Sammis's cost profile was competitive.
- Did not ask FES to provide [redacted].

The EDU Team also failed to adequately analyze the little financial information that was provided by FES. FirstEnergy witness Lisowski provided the Team with a 15-year projection of costs and revenues for Sammis, Davis-Besse, and the OVEC entitlement.[286] This projection was created using Mr. Rose's price forecasts and FirstEnergy's Microsoft Excel-based dispatch model,[287] the deficiencies of which are outlined in Section II.D above. Despite the importance of cost and revenue projections to understanding Rider RRS's potential impact on customers, the EDU Team did not request any sensitivities on Mr. Rose's price forecasts,[288] instead simply

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[281] SC Ex. 37c at 2-3 (excerpt from the "Competitively Sensitive Confidential report of the EDU Team" reference in the original 9/30/14 response).

[282] Conf. Tr. XIV at 2937.

[283] *Id.* at 2938. Mr. Ruberto also separately looked at the costs of the Fort Martin plant (owned by a FirstEnergy Corp. subsidiary), but that was not part of the formal cost comparison. *See id.* at 2988; *see also* SC Ex. 37c at 2-3 (table 2 displays the five plants whose costs were compared to Sammis's).

[284] Conf. Tr. XIV at 2941.

[285] Tr. XIII at 2861-62.

[286] *Id.* at 2766-67.

[287] *Id.* at 2776-77, 2772-73.

[288] *Id.* at 2776.

relying on what Mr. Rose initially provided.[289] Indeed, the EDU Team failed to perform *any* alternative modeling runs.[290] And, apparently, the EDU Team did not even review the inputs used for Mr. Lisowski's modeling run.[291] Given the perfunctory review performed by the EDU Team, it is hardly surprising that the team failed to catch a computational error in Lisowski's revenue projection.[292]

The EDU Team also failed to critically assess the potential impact of this proposal on the Companies' customers. The Team did not consider whether the inclusion of a different collection of units (such as excluding the less profitable Sammis units) would result in a more favorable outcome for the Companies' customers.[293] And the Team [redacted].[294] The Team did not engage any third-party consultants to evaluate the proposed transaction,[295] and it did not study large-scale governmental aggregations at all.[296] And although the EDU Team was quick to identify customer benefits that would purportedly result by preventing Sammis and Davis-Besse's

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[289] *Id.* at 2830. Mr. Ruberto did not bother discussing with Mr. Rose whether his price forecast could produce alternative results. Nor did he discuss with Mr. Rose the assumptions underlying Mr. Rose's forecasts. *Id.* at 2847-48.

[290] *See id.* at 2775. After receiving Mr. Lisowski's projection, the only dispatch modeling that the EDU Team commissioned was to run the exact same modeling inputs files through the same Microsoft Excel-based model. *See id.* at 2774-75. Not surprisingly, this exercise produced identical results. *Id.* at 2775.

[291] Mr. Ruberto did not receive those modeling inputs, and he is not aware if any other team member received those inputs. *Id.* at 2862-63.

[292] *Id.* at 2778.

[293] *See id.* at 2843 ("Q. So would it have been part of your evaluation to consider proposing, say, a PPA for only certain units of Sammis? A. We never considered only taking a portion of Sammis.").

[294] Conf. Tr. XIV at 2993. The EDU Team also did not evaluate whether the assumed debt rate used for Mr. Lisowski's projection was reasonable. Tr. XIII at 2779.

[295] Tr. XIII at 2765.

[296] *Id.* at 2872. Mr. Ruberto was personally not familiar with the NOPEC, the largest governmental aggregator within the Companies' service territory. *Id.*

retirement,[297] the Team did not specifically analyze the risk that these plants would retire in the absence of the proposed transaction.[298] In sum, given the serious financial risks that the proposed transaction and Rider RRS pose for the Companies' customers, the EDU Team's evaluation of the proposal was inadequate.

The negotiation of the proposed transaction was equally flawed. This negotiation – between corporate affiliates, with the same parent corporation – was conducted almost entirely by employees of the same entity: FirstEnergy Service Company. Though it was negotiating a term sheet that would affect the Companies' customers, the EDU Team included no employees of the Companies.[299] Instead, all nine members of the EDU Team were Service Company employees, and all but three members of the team representing FES were also employed by the Service Company.[300] There was no independent consultant involved in the negotiation of the proposed transaction, nor did the Companies hire an independent financial advisor to review the transaction.[301] And although it was purportedly protecting the interests of the Companies' customers, the EDU Team conducted the negotiations on the assumption that all of the risks of FES's generating plants would be passed off to ratepayers.[302] The Team did not consider the possibility of the Companies retaining a small proportion of the projected benefits (and

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[297] *See, e.g.*, Ruberto Direct at 8; SC Ex. 37, p. 3 (discussing purported reliability and economic development benefits).

[298] Tr. XIII at 2871. Moreover, although the EDU Team claimed to have reviewed the proposal's impact on reliability, Ruberto Direct at 8, the Team simply relied on the advice of FirstEnergy witness Gavin Cunningham. Tr. XIII at 2791-92.

[299] SC Ex. 52 at 2; Tr. XIII at 2754.

[300] *See* SC Ex. 52, subp. (a), (e).

[301] Tr. XIII at 2765-66, 2832.

[302] *Id.* at 2831.

consequent risks).[303] Finally, as noted above, the EDU Team [redacted].[304]

Fundamentally, the proposed transaction was not the product of an arm's-length negotiation. Rather than carefully evaluating FES's proposal, the EDU Team simply accepted FES's information at face value, without seriously considering alternatives that could better serve the Companies' customers. And the negotiations themselves – between two lateral affiliates with the same parent corporation – resulted in a term sheet that favors FES to the ultimate detriment of the Companies' customers. FirstEnergy's failure to seriously evaluate and negotiate the proposed transaction further underscores the unreasonableness of the Rider RRS scheme.

V. FirstEnergy Has Failed to Demonstrate that Customers Face Significant Retail Rate Volatility, or that Shifting Merchant Generation Risks to Customers Would Provide Rate Stability and Certainty to Customers.

In an effort to shoehorn Rider RRS into R.C. 4928.143(B)(2)(d), FirstEnergy repeatedly portrays the proposed rider as addressing purported retail electric price volatility by providing certainty and stability regarding electric pricing.[305] As described in Section I above, Rider RRS is not legally authorized under R.C. 4928.143(B)(2)(d) because it would neither limit customer shopping, nor is it in any way related to retail electric service. However, even if Rider RRS did satisfy those two requirements, it would not pass muster under section 4928.143(B)(2)(d) because FirstEnergy has failed to demonstrate that retail electric rates are volatile, much less that Rider RRS would address any such volatility. There is simply no basis in the law or on this

[303] *Id.* at 2830.

[304] Conf. Tr. XIII at 2917-18; SC Ex. 37c, Att. 1 at 34-39; Conf. Tr. XIII at 2919-20.

[305] *See, e.g.*, Strah Direct at 7, 10-12.

record to approve Rider RRS under R.C. 4928.143(B)(2)(d), and the purported stability benefit of Rider RRS is illusory at best.

FirstEnergy's attempt to portray Rider RRS as providing stability against retail price volatility is misguided because the entire premise is flawed. The primary impact of Rider RRS and the accompanying proposed transaction is to shift the market risks facing Sammis, Davis-Besse, and the OVEC entitlement away from FES and on to customers. Doing so is, of course, the exact opposite of providing increased stability and certainty to customers. As shown in Section II above, whether Rider RRS would produce charges or credits in each year depends on numerous uncertain factors, such as the price of energy, natural gas, coal, and capacity, the level of environmental costs that Sammis faces, and how quickly newer, more efficient, and lower cost generation comes online. How those factors turn out will determine whether Rider RRS would lead to a net credit or, far more likely, hundreds of millions of dollars in charges for customers. FES apparently does not want to bear these risks for at least the next eight years and, instead, is seeking to provide itself with stability by shifting such risks to customers through the proposed transaction and Rider RRS. To suggest that forcing customers to effectively become merchant generators with all of the market risks that doing so entails somehow provides stability and certainty to those customers is patently absurd and cannot be used to justify Rider RRS.

FirstEnergy creatively contends, however, that Rider RRS would provide stability because the risks under Rider RRS would be counter-cyclical to whatever risks customers might face with regards to retail electric rates.[306] Therefore, according to FirstEnergy, if retail electric rates go up, market conditions would presumably be such that Rider RRS would be providing an offsetting credit to customers. And, conversely, although not emphasized by FirstEnergy, if

[306] *See, e.g.*, Strah Direct at 12, 13-14.

retail electric rates stay low, the benefit of such low costs to customers would be offset by a charge under Rider RRS.

As OCC witness Wilson explained, however, such offsetting is not guaranteed to occur because of the mismatch between the way retail rates are priced, and charges or credits under Rider RRS are determined.[307] In particular, for SSO customers, retail rates reflect the blended results of a series of auctions generally held months to years in advance of delivery for contracts typically of one- to three-years in length. Shopping customers, meanwhile, are served through contracts that may be even longer-term than the SSO contracts, and that have either relatively fixed rates or fluctuate more with the market. Under Rider RRS, however, the charge or credit is to be determined by a projection for the coming year and then trued up at the end of the year. Given the differing time frames covered by SSO auction contracts, shopping customer contracts, and Rider RRS, it is not clear over what time frame a jump in prices from an event such as the polar vortex, or a decline in prices from an event such as low natural gas prices, would filter through to the retail rates being paid by customers, or that it would filter through Rider RRS in the same time frame. In short, there is no guarantee that Rider RRS would actually be counter-cyclical to the retail rates paid by customers,[308] and FirstEnergy has produced no evidence showing that such price impacts would be counter-cyclical. As such, FirstEnergy has not met its burden to show that Rider RRS would provide rate stability to customers.

A final fundamental flaw in the effort to sell Rider RRS as providing stability and certainty is that FirstEnergy has failed to demonstrate that customers are facing any sort of significant retail rate volatility in the future. The weakness of FirstEnergy's case regarding volatility is readily apparent upon review of the Companies' initial application and testimony,

[307] Wilson Direct at 49-51.

[308] *Id.*

which are riddled with references to volatility and stability, but lacking any analytical support. For example, FirstEnergy witness Strah identifies the promotion of "certainty and stability regarding the long term pricing of retail electric service" as a benefit of Rider RRS,[309] but he fails to provide any analysis showing that long term pricing for retail electric service is volatile or unstable. At the hearing, Mr. Strah acknowledged that he was primarily relying on the testimony of Mr. Rose to support his belief that power prices are expected to be significantly volatile.[310] But Mr. Rose acknowledged at hearing that he had only projected wholesale power prices, and had not "done a detailed forecast of retail prices in this proceeding," and had not performed any quantitative analysis of retail price volatility in the Companies' service territories.[311]

At the rebuttal stage, FirstEnergy attempted to fill this significant gap in their evidentiary showing by submitting testimony from Ms. Mikkelsen that purports to provide some examples of retail rate volatility over the past few years.[312] What Ms. Mikkelsen's testimony does not do, however, is provide any analysis projecting or quantifying future retail rate volatility. Instead, her analysis only showed, at most, that there may have been some increase in retail rates in the months after the polar vortex in comparison to the months before the polar vortex. For example, Ms. Mikkelsen analyzed competitive retail electric service ("CRES") offers available for select months on the Commission's Apples-to-Apples website to contend that the average offer in May

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[309] Strah Direct at 3.

[310] Tr. IV at 706. Mr. Strah also cited his "experience," but the examples he cited involved past events (one dating from a decade ago), neither of which speak to whether power prices are expected to be volatile in the future. *Id.* at 704, 706-07.

[311] Tr. VI at 1198-99.

[312] Co. Ex. 146, Mikkelsen Rebuttal at 2-4.

2014 was 35% higher than in December 2013.[313] But Ms. Mikkelsen did not present any analysis of actual rates paid by shopping customers, and more recent Apples-to-Apples data shows that the prices of CRES offers have declined since the months that Ms. Mikkelsen focused on.[314] As such, FirstEnergy has simply failed to demonstrate that there will even be significant retail rate volatility during the term of Rider RRS, much less that Rider RRS would address such volatility.

VI. The Purported Reliability, Fuel Diversity, and Job and Economic Growth Benefits of Rider RRS are Illusory because there is no Credible Evidence in the Record That Sammis and Davis-Besse Would Retire Without Rider RRS

FirstEnergy attempts to scare the Commission into approving Rider RRS by raising the specter that FES would suddenly retire the Sammis and Davis-Besse plants without Rider RRS. Numerous FirstEnergy witnesses recite a parade of horribles that would purportedly result from such sudden retirements, including claims that electric reliability would be degraded, more than $1 billion in transmission upgrades would be needed, fuel diversity would be lacking in Ohio, and the state would lose jobs and economic growth. According to FirstEnergy's witnesses, Rider RRS would prevent all these problems by ensuring the continued operation of Sammis and Davis-Besse. Thus, FirstEnergy characterizes the avoidance of these illusory harms as "benefits" of Rider RRS.

The Commission should ignore such scare tactics for at least three reasons. First, none of the Companies' witnesses were willing to testify that Sammis or Davis-Besse would actually retire without Rider RRS and no analysis showing that such retirement would occur has been presented. Second, if the Companies put credence into their own revenue and cost projections it

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313 *Id*. at 4.

314 SC Ex. 84; Tr. XXXIII at 6977-83.

is clear that the plants would not retire. Third, FirstEnergy's claims of adverse impacts to reliability, jobs and economic growth, and fuel diversity are otherwise flawed and overstated.

A. There is no Evidence in the Record That FES Would Retire Sammis or Davis-Besse if Rider RRS is Rejected.

While FirstEnergy bases much of its case for Rider RRS on the implicit threat that the Sammis and Davis-Besse plants will retire if Rider RRS is not approved, there is no evidence in the record to support that claim. While some FirstEnergy witnesses made vague claims that the future of the Sammis and Davis-Besse plants is "uncertain" or "in doubt,"[315] none of the witnesses were willing to state on the record that the plants would close absent Rider RRS. In addition, none of the Companies' witnesses were able to identify any analysis or even discussions by FES or the Companies of whether the plants would be retired. In short, the Companies have not demonstrated that approval of Rider RRS is necessary to avoid retirement of the Sammis or Davis-Besse plants.

On this point, the testimony of FirstEnergy witness Donald Moul, former Vice President of Commodity Operations at FES, is telling. While Mr. Moul's job responsibilities would include advising senior FES management on whether a generating unit should retire, he testified at hearing that no one at FES had asked him his opinion as to whether the Sammis plant would retire, and that he had not been part of any conversation regarding retirement of Sammis or Davis-Besse.[316] Mr. Moul also sponsored a discovery response in which he acknowledged that

[315] Co. Ex. 29, Moul Suppl. at 1, 3, 4 (the confidential version of Moul's Supplemental Testimony is admitted as Co. Ex. 30c); *see also* Tr. II at 418 ("Q. If the Commission does not grant the rider RRS as cried [sic] in the application, is it your testimony that the plants will close? . . . . A. No, sir. My testimony is that the future of the plants is uncertain if the Commission doesn't approve rider RRS.").

[316] Tr. XI at 2305.

FES had not undertaken any economic analysis of the retirement of Sammis or Davis-Besse,[317] a fact which he later confirmed at the hearing.[318]

Similar testimony was provided by Paul Harden, with whom the following colloquy occurred at the hearing:

> Q. Am I correct that no one has told you that Sammis or Davis-Besse would be retired if the proposed transaction were not entered into?
>
> A. That's correct.
>
> Q. And you do not recall any discussions as to whether Sammis or Davis-Besse would be retired if the proposed transaction were not entered into; is that correct?
>
> A. That's correct.
>
> Q. But you would likely be asked to provide an opinion regarding whether to retire one of those plants; is that correct?
>
> A. Yes, I expect that I would be asked for an opinion on such matters.
>
> Q. And you've never been asked to provide such an opinion to date; is that right?
>
> A. Not that I remember.[319]

Similarly, FirstEnergy witness Sarah Murley, who presented testimony regarding possible job and economic impacts of retiring the Sammis and Davis-Besse plants, acknowledged that she had never evaluated whether those plants would actually retire in the absence of Rider RRS.[320] In addition, no one at FirstEnergy told Ms. Murley that the plants would actually retire if the Commission were to deny the Companies' application.[321]

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[317] SC Ex. 46.

[318] Tr. XI at 2307.

[319] Tr. XII at 2540.

[320] Tr. XV at 3076.

[321] *Id.* at 3076-77.

Finally, FirstEnergy witness Lawrence Makovich, who provided testimony about his "missing money" theory, testified that "[t]he probability exists" that the Sammis and Davis-Besse plants "will retire prematurely" without Rider RRS.[322] Dr. Makovich's testimony specific to those two plants, however, should be given no weight because it was not based on any independent research or knowledge but, instead, was entirely derivative of the direct testimony of Mr. Moul. For example, at hearing Dr. Makovich testified as follows:

> Q. And, Dr. Makovich, in preparing your testimony you did not review any cost estimates for Sammis, correct?
>
> A. That's correct.
>
> Q. Nor did you review any revenue estimates for Sammis, correct?
>
> A. That's correct.
>
> Q. And your opinion regarding the Sammis plant's economics is dependent entirely upon Mr. Moul's direct testimony, correct?
>
> A. That's correct.[323]

Moreover, Mr. Moul stated at hearing that he had never discussed FES's power plants or their financial viability with Dr. Makovich, and never provided Dr. Makovich any information about the financial viability of Sammis or Davis-Besse.[324] In effect, Dr. Makovich's testimony regarding the viability of Sammis and Davis-Besse was simply parroting Mr. Moul's testimony. As such, Dr. Makovich's testimony provides no evidentiary support for the claim that these plants would retire in the absence of Rider RRS.

In short, there is no evidence in the record that the Companies or FES have evaluated or even discussed retiring Sammis and/or Davis-Besse in the event that Rider RRS were not

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[322] Co. Ex. 42, Makovich Suppl. at 3.

[323] Tr. XVII at 3477-78.

[324] Tr. XI at 2309-11.

approved. And it strains credulity to suggest that FES would suddenly retire such significant generating units without being able to provide any internal analysis or identifying any discussions showing that such retirements should occur. For this reason alone, the Commission should reject the insinuation that Rider RRS is necessary to prevent the retirement of Sammis and Davis-Besse, or to avoid the harms that would purportedly occur in the event of such retirements.

B. Under the Companies' Revenue and Cost Projections, Neither Sammis nor Davis-Besse Would Retire.

The fact that no FirstEnergy witness was willing to testify that the Sammis and Davis-Besse plants would retire in the absence of Rider RRS is not surprising given that, using the Companies' projections of revenues and costs, the plants would not retire. Mr. Moul's testimony on this point was unequivocal – [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

325 Conf. Tr. XI at 2432-33; *see also id.* at 2445.

And that is exactly what the Companies' projections show. In each year of proposed Rider RRS, the Companies project that the [redacted], as shown in Tables 7 and 8 below.

Table 7: Companies' Projected Sammis Revenues vs. Costs (in $millions)[326]

[redacted]

Table 8: Companies' Projected Davis-Besse Revenues vs. Costs (in $millions)[327]

[redacted]

FES's projections provided in response to a Sierra Club subpoena show [redacted]. While for the last seven months of 2016 FES projects that [redacted]

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[326] SC Ex. 90c, Att. JJL-1.

[327] SC Ex. 90c, Att. JJL-2.

[redacted]

Sammis and Davis-Besse.[328]

In short, under [redacted] the Companies' [redacted] projections, both Sammis and Davis-Besse would [redacted] in every year of the projection [redacted]. In such situation, the testimony of Mr. Moul is clear – [redacted]. If the Companies believe their own projections,[329] then their insinuation that Sammis or Davis-Besse would retire without Rider RRS is nothing more than a bluff to get customers to provide the full level of profits that FES desires. Conversely, if the Companies do not believe their own projections, then losses to customers under Rider RRS would be far higher than what the Companies are forecasting. Either way, there is no justification for Rider RRS to be approved.

In his supplemental testimony, Mr. Moul points to [redacted] by the Sammis and Davis-Besse plants before interest and return on investment from 2009 through 2014 as providing a basis for concluding that those plants are at risk of closure.[330] At hearing, however, Mr. Moul acknowledged that [redacted].[331] And, regardless, under the Companies' projections, those [redacted]. It is true that the Companies project that total costs under Rider RRS would exceed revenues through 2018, but those costs [redacted]. As such, the revenue deficiency that the Companies are projecting [redacted]

[328] SC Ex. 36c at 1, 2.

[329] At the January 2016 hearing, Ms. Mikkelsen confirmed that the Companies stand by their projections for the eight-year term of Rider RRS. Tr. XXXVI at 7675, 7677.

[330] Moul Suppl. at 1-3.

[331] Conf. Tr. XI at 2444-46.

[redacted]. And, as Mr. Moul made clear, [redacted]. So long as the plants are [redacted], they are able to [redacted]. While the [redacted] might not be as much as FirstEnergy Corporation and its shareholders desire, retirement in those circumstances would mean [redacted] which, in the absence of some other factor (such as the need for a significant capital investment or compliance with an environmental regulation) that the Companies have not shown here, would not make economic sense. Put simply, there is no factual basis for FirstEnergy's insinuation that Sammis and Davis-Besse would retire without Rider RRS.

The rebuttal testimony of FirstEnergy witness Lisowski, which sought to counter the conclusion of P3-EPSA witness Joseph Kalt that Sammis and Davis-Besse "are in no credible danger of being retired by FES,"[332] does not lead to a different conclusion. Mr. Lisowski criticized Dr. Kalt's analysis, arguing that Dr. Kalt improperly relied on the fact that revenues from Sammis and Davis-Besse are projected to exceed avoidable costs to conclude that those plants would not retire.[333] According to Mr. Lisowski, such analysis improperly fails to account for expenses such as depreciation and interest that are related to necessary capital investments in the plants. If the Companies cannot afford to make such capital investments, Mr. Lisowski opines, the reliability of the plants will begin to erode, thereby reducing revenues and leading to

[332] P3/EPSA Ex. 5, Kalt Suppl. at 11. The confidential version of Kalt's Supplemental Testimony is admitted as P3/EPSA 6c.

[333] Co. Ex. 143, Lisowski Rebuttal at 2-3. The confidential version of Lisowski's Rebuttal Testimony is admitted as Co. Ex. 144c.

a downward spiral where the plant is no longer able to cover even its avoidable costs and eventually has to retire.[334]

Mr. Lisowski's rebuttal testimony does not demonstrate that Sammis and Davis-Besse, using the Companies' own projections, are likely to retire. First, as Mr. Lisowski acknowledged at hearing, the Companies' projections of costs and revenues from Sammis and Davis-Besse accounted for the capital expenditures needed to keep the plants operating.[335] Second, unlike Dr. Kalt's focus solely on avoidable costs, the projected revenues from Sammis and Davis-Besse discussed above are [redacted].[336] Finally, Mr. Lisowski was unable to identify any capital expenditures at Sammis that were deferred in 2012, 2013, 2014, or 2015, despite the fact that Sammis was [redacted].[337] In short, regardless of the merits of Dr. Kalt's analysis comparing revenues to only avoidable costs, Mr. Lisowski's concern about whether necessary capital investments can be funded does not apply to Sammis and Davis-Besse under the Companies' own projections.

Even if the Companies' projections of [redacted] in the short term created a risk of retirement in the next few years (which, as just explained, they do not), other factors compel the conclusion that a sudden retirement of those plants would not occur even in the absence of Rider RRS. First, [redacted]

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[334] Tr. XXXII at 6542.

[335] *Id.* at 6693.

[336] Co. Ex. 22c, Atts. JJL-1, -2; Co. Ex. 24c, Att. JJL-3 revised; SC Ex. 90c, Atts. JJL-1, -2. The projected revenues are [redacted]. These projections of [redacted] did not change when the Companies modified the Rider RRS proposal in the Stipulation. *See* SC Ex. 90c.

[337] Tr. XXXIII at 6827-29; Lisowski Rebuttal, Att. JJL-4.

[redacted].[338] This means that FES has committed to [redacted], and will receive revenue for doing so.[339]

Second, in the unlikely event that Davis-Besse or any of the Sammis units did retire, that retirement would be reviewed by PJM to determine whether transmission grid upgrades would be needed to prevent any reliability problems that such retirements might cause. While FES would be required to provide PJM with only 90-days' notice of any planned retirement, in the event that PJM determined any transmission grid upgrades would be needed, FES would be able to enter into a Reliability Must Run ("RMR") contract to subsidize the continued operation of the plant while such upgrades are completed.[340] Not only would such process ensure that reliability problems would not result from any unit retirement, it would also ensure that the Sammis units or Davis-Besse would remain open for a period of time after any retirement announcement and likely well after the June 1, 2017 retirement date assumed in the transmission impact study discussed by FirstEnergy witness Rodney Phillips. *See* Section VI.C.1 *infra*.

Mr. Moul notes that RMR contracts are voluntary in that a plant owner can choose whether to enter into them.[341] But it is highly doubtful that FES, as a major generator within PJM, would rebuff a PJM request to delay a plant retirement (and to receive compensation for doing so) and, instead, potentially cause reliability problems by shutting down Sammis or Davis-

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[338] Conf. Tr. X at 2140-44.

[339] While FES could withdraw its commitment of Sammis and Davis-Besse capacity into those auctions, the company would incur significant penalties for doing so. Such penalties are calculated pursuant to Section 8 (Resource Performance Assessment) of PJM Manual 18: PJM Capacity Market, Revision 30, December 17, 2015, available online at: http://www.pjm.com/~/media/documents/manuals/m18.ashx.

[340] SC Ex. 67, Lanzalotta Suppl. at 9-10. The confidential version of Lanzalotta's Supplemental Testimony is admitted as SC Ex. 68c.

[341] Moul Suppl. at 7; Tr. XI at 2258.

Besse before any necessary reliability upgrades are in place. Mr. Moul also raised concerns that an RMR contract does not provide sufficient revenue to be "financially advantageous for FirstEnergy Solutions," and allows for only $2 million per year in capital investments.[342] But, as Mr. Moul acknowledged at hearing, this testimony ignored the option for a plant owner to apply for a "cost of service recovery rate" under the PJM Open Access Transmission Tariff, through which the owner can seek recovery of all of its cost of service.[343] As such, in the event that, contrary to the evidence in the record, FES sought to retire Sammis or Davis-Besse if Rider RRS were rejected, such retirement would almost certainly be delayed until such time as any reliability upgrades that may be needed are put into place.

C. Even if Sammis and Davis-Besse Were to Retire, FirstEnergy's Claims About the Harms that Would Result Are Flawed and Overstated.

1. FirstEnergy's reliability concerns do not justify approval of Rider RRS.

The Companies have also attempted to justify Rider RRS on grounds that rejecting it could saddle their customers with substantial transmission costs necessitated by the retirement of Sammis and Davis-Besse. Indeed, the Companies' witnesses have repeatedly pointed to these purportedly avoided transmission costs as a key benefit of Rider RRS.[344] And they have used the specter of these plant retirements to manufacture enormous cost figures with the apparent goal of

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[342] Tr. XI at 2258, 2260.

[343] *Id.* at 2263, 2265.

[344] *See, e.g.*, Mikkelsen Direct at 3; Co. Ex. 37, Cunningham Direct at 2, 4-6 (the confidential version of Cunningham's Direct Testimony is admitted as Co. Ex. 38c); Co. Ex. 39, Phillips Suppl. at 4-5, 7-10 (providing additional estimates of the cost of transmission upgrades that would purportedly be required if Sammis and Davis-Besse both retired).

spooking the Commission.[345] But these purported reliability benefits of Rider RRS are fictitious, and the Commission should disregard these claims in evaluating the proposed Rider.

As a threshold matter, the purported reliability benefits of Rider RRS hinge on a highly implausible scenario: retirement of both Davis-Besse *and* all seven units at the Sammis plant by June 1, 2017.[346] As explained in Sections VI.A and VI.B above, there is no evidence in the record that these generating units would, in the absence of Rider RRS, retire in the near future.[347] And as the Companies have conceded, the transmission upgrades identified by Companies' witness Rodney Phillips (and the costs associated with such upgrades), would only be incurred if Davis-Besse and all of the Sammis units closed.[348] In the absence of any evidence that these units would actually retire, the purported transmission benefits of Rider RRS are fictitious. For this reason alone, the Commission should disregard the lengthy testimony submitted by the Companies on this issue.

Even assuming, for the sake of argument, that Davis-Besse or some of the Sammis units might retire in the absence of approval of Rider RRS, the Companies' cost figures, and their testimony regarding the purported reliability benefits of these units, should not be credited. In pre-filed testimony, the Companies use a FirstEnergy-directed transmission impact study to come up with two cost estimates for the transmission upgrades that would be needed in the unlikely event that Sammis and Davis-Besse both retired in June 2017. The Companies claim that a "conservative" estimate would be $436.5 million, while a "higher end" estimate would be $1.1 billion, and they further claim that 82% of these costs could be allocated to the Companies'

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[345] *See, e,g.*, Mikkelsen Second Suppl. at 7-8; *id.* at Atts. EMM-1, -2.

[346] Tr. XV at 3224, 3226, 3264.

[347] *See also* Conf. Tr. X at 2144-45 [redacted]

[348] Tr. I at 99-100; Tr. XV at 3224.

customers.[349] These figures, which were derived from a flawed transmission impact study that relied on outdated information and unrealistic assumptions, are highly misleading. Because these cost estimates are not credible, the Commission should disregard them.

First, the transmission impact study presented by the Companies – and the accompanying cost figures provided by Ms. Mikkelsen – fail to address any scenarios other than the simultaneous retirement of both plants. The Companies presented no evidence regarding the potential transmission upgrades that would be needed if only one of the plants, or a subset of the Sammis units, were to retire. Instead, they only addressed a scenario in which both plants – with a total of eight generating units – closed in their entirety by June 2017.[350] This represents a major oversight on the Companies' part, because by limiting their analysis to this implausible two-plant retirement scenario, the Companies have presented a misleadingly large estimate of transmission upgrade costs. As Sierra Club witness Peter Lanzalotta explained:

> The cost estimates for transmission reinforcements developed by Messers. Cunnningham and Phillips look at retiring all the generating units at Sammis, or none of them. There are seven generating units at Sammis, with Units 1 through 5 having a combined 1,020 MW of load following capacity and Units 6 and 7 having a combined 1,200 MW of base-load capacity. Some of these generating units feed into local 138 kV transmission facilities, while others feed into local 345 kV transmission facilities. The evaluation presented in FirstEnergy's filings only considers scenarios in which all of the units at Sammis or Davis-

[349] Phillips Suppl. at 4, 8; Mikkelsen Second Suppl. at 7.

[350] Tr. XV at 3224, 3226, 3264; Tr. XVI at 3360 (transmission study assumed full closure of Davis-Besse and Sammis on June 1, 2017). *See* Tr. XVI at 3318 (Witness Phillips stating that "I did not do any reviews or studies of only Sammis or Davis-Besse retiring. I only did the review of Sammis -- Sammis and Davis-Besse both retiring"). *See also id.* at 3318-19 (Mr. Phillips not aware of whether the Companies evaluated the retirement of only a subset of the Sammis units).

In discovery, FirstEnergy produced a document summarizing results of a study that apparently considered the retirement of Sammis and Davis-Besse separately. *See* SC Ex. 63c. As noted above, however, FirstEnergy's transmission witness, Mr. Phillips, did not review any such studies. Tr. XVI at 3318. And there is no evidence that anyone at FirstEnergy considered the retirement of only a subset of the Sammis units.

> Besse, or both, would retire. These evaluations discount the possibility that, if retirements were to occur, only a limited number of generating units at Sammis might be retired, and the rest would remain in service. These alternatives were not evaluated by Mr. Cunningham or Mr. Phillips. Evaluation of such alternatives would provide the Commission with some additional perspective to the Company's all or nothing evaluation of transmission cost impacts.
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> Additionally, scenarios in which only a portion of the Sammis units retired are likely to have smaller resultant transmission system overloads than would be the case if all of the Sammis were retired at once, and might avoid the need for some of the transmission reinforcements needed if all the units are retired at once. . . . . Reducing the amount of generating capacity being retired would be expected to reduce the magnitude of some or all of the overloadings that would be caused if all the generating capacity at Davis-Besse and Sammis were retired.[351]

The Companies' oversight is especially problematic given that the available evidence indicates that the transmission impacts would be much smaller if only Sammis or Davis-Besse retired.[352]

Second, the Companies' transmission impact study is further flawed because it relies on outdated information. As Companies' witness Phillips acknowledged, the Companies generated these figures using PJM base case models that were developed by mid-2014.[353] Consequently, their analysis was based on data that would not reflect updates that have been made since mid-2014.[354] This is a crucial oversight because there are several new natural gas plants slated to go

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[351] Lanzalotta Suppl. at 4-6. Mr. Lanzalotta further explained that, [redacted]. *Id.* at 5, 6. The Companies' all-or-nothing approach also contrasts with the methodology that PJM employs when it considers the transmission impacts of generating unit retirements. As a recent study made clear, PJM identifies and considers each individual generating unit, even when identifying transmission upgrades resulting from multiple generator deactivations. *See* SC Ex. 60 at 2-3 (identifying generator deactivation requests).

[352] *See* SC Ex. 63c (Companies' discovery response) ([redacted]).

[353] Tr. XV at 3223-24.

[354] *Id.* at 3259.

in-service over the next several years that were not included in the models used by the Companies. These include the 800 MW Lordstown plant, which is scheduled to go into service in 2018, and 700 MW Carroll County plant, which is currently under construction and has an in-service date of 2017.[355] Although both plants are scheduled to come online by 2019, the year in which FirstEnergy's study indicated reliability problems,[356] neither was accounted for in FirstEnergy's transmission impact study.[357] And although the Carroll County plant developer signed an interconnection service agreement with PJM in March 2015, such that it would be included in an updated PJM base case model, this plant was omitted from the earlier model used for the Companies' analysis.[358]

FirstEnergy's failure to consider these generating facilities is significant because they could reduce the need for transmission upgrades if Sammis and Davis-Besse, despite evidence to the contrary, both retired. As Mr. Lanzalotta explained:

> As I noted above, the transmission upgrade costs described by Messrs. Cunningham and Phillips assume that both Davis-Besse and the entire Sammis plant retired. If those plants retired, but a new generating unit came online that was connected to the grid at an appropriate location, that could reduce the need for some of the

[355] *See* Comings Third Suppl. at 11, Tbl. 2 (discussing new generating plants being developed in Ohio); Tr. XI at 2314 (Companies' witness Moul acknowledging that Carroll County plant is under construction).

[356] *See* Tr. XVI at 3349.

[357] Tr. XV at 3229 (Carroll County); *id.* at 3260 (Lordstown).

[358] Tr. XVI at 3334 (confirming that if PJM were putting together its model in May 2015, "it would have included a plant that had an interconnection service agreement and that had an in-service date in the fall of 2017); *id.* at 3335 (Carroll County plant not included in Companies' study); *see also* SC Ex. 59 (interconnection service agreement for the Carroll County plant).

In addition, since Mr. Phillips's testimony was filed, two other gas plants with in-service dates prior to 2019 – the 800 MW Lordstown plant and the 513 MW Middletown plant – have signed interconnection service agreements with PJM. *See* Middletown ISA (Oct. 2, 2015), available at http://www.pjm.com/pub/planning/project-queues/isa/z1_079_isa.pdf; Lordstown ISA (Feb. 3, 2016), available at http://www.pjm.com/pub/planning/project-queues/isa/z2_028_isa.pdf (FERC approval pending). Just as the Commission took administrative notice of the Carroll County agreement (SC Ex. 59), *see* Tr. XVI at 3411, the Commission can take administrative notice of these agreements as well.

> transmission upgrades cited in the testimony of Messrs. Cunningham and Phillips.[359]

Although Mr. Lanzalotta did not analyze the potential impacts of any specific plants, he noted that "it remains the case that a new, appropriately-located plant could reduce the need for some of the cited transmission upgrades, thereby reducing the transmission-related costs that might result from retirement of Sammis and Davis-Besse."[360]

Third, the Companies' transmission upgrade cost estimates – particularly the cost figures cited in Ms. Mikkelsen's testimony[361] – significantly overstate the likely costs that the Companies' customers would incur if Sammis and Davis-Besse both retired in June 2017. For one thing, FirstEnergy's upper-end scenario, which Ms. Mikkelsen used in suggesting that transmission upgrades could cost the Companies' customers up to $1.3 billion,[362] is premised on the unlikely assumption that every overloaded transmission facility needs to be rebuilt instead of reconductored.[363] As Mr. Lanzalotta explained, this assumption is questionable, for multiple reasons:

> While it may be the case that some of the overloaded transmission lines would need to be rebuilt because of the age or condition of the transmission line structures, it is highly unlikely that all of these overloaded lines would need to be rebuilt.

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[359] Lanzalotta Suppl. at 6.

[360] *Id.* at 6. Mr. Phillips tries to cast doubt on the likelihood of new generation plants coming online by noting that a small proportion of projects that enter PJM's Feasibility Study phase go into service. Phillips Suppl. at 7. But Mr. Phillips ignores the fact that the proportion is much higher for those projects – such as the Carroll County facility – that have executed an interconnection service agreement with PJM. According to the same document that Mr. Phillips relied on his testimony, more than half of such projects go into service. *See* SC Ex. 58 at 3; *see also* Tr. XVI at 3326. The strong likelihood that the Carroll County and Middletown plants will be in-service by 2018 is further supported by Mr. Rose's employer, ICF, which believes that these plants cleared the 2018/19 base residual auction. SC Ex. 87 at 8.

[361] Mikkelsen Second Suppl. at 7-8.

[362] *Id.* at 8 (positing that nominal costs could be as high as $4.1 billion, with a net present value of $1.3 billion). *See also id.* at Att. EMM-2.

[363] Phillips Suppl. at 8.

> Additionally, while the advanced age of the existing transmission line towers may increase the need to rebuild these towers in the process of reconductoring the line to increase its capacity, this advanced age also hastens the day when such transmission towers would have to be rebuilt regardless of whether or not Davis-Besse and Sammis were retired simply because the advanced age of such transmission lines makes them increasingly unreliable. In other words, some older transmission towers may need to be rebuilt regardless of whether these generating units retire. . . . Depending on the age of the transmission lines which FirstEnergy has identified as needing reinforcement in the even of plant retirements, some of those lines would likely need to be replaced anyways and, therefore, not all the costs of rebuilding such lines should or would be attributable to the retirement of the Davis-Besse and Sammis generating units. Mr. Cunningham and Mr. Phillips's analyses do not appear to address this issue.[364]

The Companies' cost estimate is also unrealistic because there is no basis for their assumption that 82% of the transmission upgrade costs would be borne by the Companies' customers. The manner in which FirstEnergy came up with this 82% figure underscores its unreasonableness. According to FirstEnergy, its customers paid 82% of the approximately $1 billion of transmission upgrade costs that resulted from the retirement of several coal units along Lake Erie (and deep within the ATSI zone).[365] FirstEnergy witness Mikkelsen took this 82% figure – which stems from the deactivation of different generating units, at different locations, and which involved different transmission upgrade – and presents a series of cost estimates premised on the assumption that the dual retirement of Sammis and Davis-Besse would impose an identical percentage of costs on the Companies' customers. Ms. Mikkelsen does not provide

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[364] Lanzalotta Suppl. at 7.

[365] Phillips Suppl. at 10. Setting aside its irrelevance to the Companies' Sammis/Davis-Besse retirement scenario, this estimate overstates the transmission costs borne by the Companies' customers, because some of these transmission projects were attributable to generator deactivations other than those referenced by Mr. Phillips. *See* SC Ex. 60 at 6, 7-8.

any rationale for that assumption,[366] and the record demonstrates that the assumption is both unsupported and unreasonable.

This 82% cost allocation assumption is unsupported because, simply put, FirstEnergy does not know what the cost allocation would be for any transmission upgrade necessitated by FirstEnergy's Sammis/Davis-Besse retirement scenario. FirstEnergy did not consult with PJM about the potential upgrades that may be needed if these generating units retired,[367] and FirstEnergy itself does not have the capability to determine how any transmission costs would be allocated. Because FirstEnergy did not ask PJM to perform a cost allocation analysis, and because FirstEnergy itself does not have the capability to perform such a study,[368] the 82% assumption is nothing more than a guess.

In addition, a review of PJM's methods for allocating transmission project costs suggests that far less than 82% of the costs of the projects identified by FirstEnergy for retiring both Sammis and Davis-Besse would be allocated to the Companies' customers. PJM uses two methods to allocate the cost of transmission projects that cost more than $5 million. For projects that involve double circuit 345 kV lines or greater, half of the costs are allocated through a method referred to as DFAX, and the other half are allocated across all PJM zones on a load-

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[366] None of FirstEnergy's pre-filed testimony explains the basis for this 82% assumption. Mr. Phillips's supplemental testimony does not address the issue; he merely states that the Companies' customers would bear "some of the costs." Phillips Suppl. at 10. And he only cites the 82% figure in discussing the earlier retirements of those units alongside Lake Erie. *Id.* at 10. Ms. Mikkelsen then presents a series of cost estimates based on the assumption that "costs associated with the transmission projects needed to maintain reliability if the [Sammis and Davis-Besse] Plants were to retire were allocated in a similar fashion." Mikkelsen Second Suppl. at 7-8. She does not explain the basis for that assumption. Ms. Mikkelsen later testified that Mr. Phillips made the decision to use the 82% assumption, Tr. I at 101-02, but, again, Mr. Phillips himself did not submit testimony on that point. *See also* Lanzalotta Suppl. at 9 (discussing Mr. Phillips's and Ms. Mikkelsen's testimony, and noting that "no basis is provided for whether or why FirstEnergy ratepayers would be responsible for [an 82%] proportion of future upgrade-related costs").

[367] Tr. XV at 3247-48.

[368] Tr. XVI at 3321-22.

ratio-share basis.[369] For projects that involve single circuit 345 kV lines or smaller, the entire cost is allocated using DFAX.[370] Under the DFAX method, costs are allocated based on a determination of which load zone or zones will benefit from a particular upgrade.[371]

Using PJM's two methods for allocating transmission costs for projects that cost more than $5 million indicates that FirstEnergy's 82% assumption is unreasonably high. Many of the transmission facilities that were predicted to overload under the Companies' study [redacted].[372] Of the [redacted] reliability violations identified in the study, only [redacted] The [redacted] most expensive transmission upgrades identified in the study, whose costs represent more than [redacted], were all [redacted], with [redacted] of those [redacted] To take but one example, [redacted].[375]

Although a transmission facility's location is not determinative of which transmission zone benefits under the DFAX methodology, the fact that [redacted]

[369] Tr. XVI at 3321; *see also* Conf. Tr. XVI at 3389.

[370] Tr. XVI at 3321.

[371] The DFAX methodology was described in a colloquy between Mr. Phillips and counsel: "Okay. And the DFAX method is a study that PJM does to determine which load zones will benefit from an upgrade; is that right A. Yes. they do a study to determine who will benefit, essentially what load -- because you are putting an upgrade in, what load is benefiting from that upgrade going in. Q. Okay. And then the load zone that benefits from the upgrade will pay at least a portion of the costs of those upgrades; is that right? A. Yes. For the DFAX piece, whatever that's representing, is the overall percentage that they are doing. Then that will be spread across however they determine for what zones would be applicable for that." Tr. XVI at 3320-21.

[372] SC Ex. 61c; Conf. Tr. XVI at 3388.

[373] SC 61c.

[374] *See* Co. Ex. 41c at 1-2 (Mr. Phillips's workpapers); SC Ex. 61c.

[375] *Id.*

[redacted] casts serious doubt on the 82% allocation assumed in Ms. Mikkelsen's cost estimate. Further doubt is cast by the fact that at least two of the highest-cost transmission upgrades would have half of their costs allocated across all PJM zones, further diluting the amount of costs that would be allocated to FirstEnergy's customers:

- For [redacted];
- For [redacted].[376]

Thus, at a minimum, [redacted].[377] The fact that several of the largest transmission upgrades identified in the Companies' study would have their costs allocated across PJM zones further undermines the 82% assumption. Put simply, there is no reliable evidence supporting the 82% cost allocation that the Companies relied on in estimating the transmission costs that result in the highly unlikely event that Sammis and Davis-Besse both retired next year.

Finally, the Companies' transmission impact study is also questionable because it was not conducted by an independent third party selected by the Commission or its Staff. This was one of the many flaws of FirstEnergy's Rider RRS proposal identified by the Commission Staff. As Dr. Hisham Choueiki explained, "[t]he Companies and FES did not provide an independent

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[376] *See* Co. Ex. 41c; SC Ex. 61c; Conf. Tr. XVI at 3389-91.

[377] At the hearing, Mr. Phillips [redacted]. Conf. Tr. XVI at 3393-94. If they were, these two projects, whose collective cost represents [redacted] of the total estimated costs, would also [redacted]. Co. Ex. 41c. It's worth noting as well that neither of these transmission lines [redacted]. SC Ex. 60c.

assessment of the impact of the closures of Davis-Besse and Sammis on grid reliability."[378] Dr. Choueiki recommended that, if the Commission agreed with FirstEnergy's request to approve Rider RRS, the Companies should be required to "commit to use investor dollars for an independent reliability and economic analysis conducted by a third party of the Commission's choosing."[379] This has not happened. Instead, FirstEnergy continues to rely on a study, using outdated data from mid-2014, that was performed under the direction of its own staff. Although it contracted with an outside firm to run the load flow studies, FirstEnergy dictated the assumptions for the analysis.[380] This does not satisfy Staff's recommendation, which specifically called for the *Commission*, not FirstEnergy, to choose the reliability expert.[381] The failure to conduct an independent reliability analysis further underscores the dubiousness of FirstEnergy's transmission cost estimates.

In addition to presenting a flawed estimate of the transmission upgrade costs that the Companies' customers would face if Sammis and Davis-Besse both retired next year – a scenario that, as explained above, strains credulity – FirstEnergy's reliability claims are otherwise without merit. In his supplemental testimony, Mr. Phillips asserts that Sammis and Davis-Besse are

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[378] Choueiki Pre-filed at 12.

[379] *Id.* at 17.

[380] If FirstEnergy argues that the use of an outside firm somehow qualifies its study as "independent," the Commission should reject this argument. The pre-filed testimony of Mr. Cunningham makes clear that FirstEnergy directed the transmission study. *See, e.g.*, Cunningham Direct at 5 (" Using this data, I was able to complete generation deliverability and load deliverability analyses in which I estimated the cost of potential transmission projects that would be necessary if these Plants are retired."). And when queried about this issue at the hearing, Mr. Phillips made clear that FirstEnergy supervised the study. *See, e.g.*, Tr. XV at 3245 ("[Mr. Cunningham] and his team decided what type of studies needed to be done"). Indeed, Mr. Phillips referred to this transmission study as "the study that *we* did." *Id.* at 3237 (emphasis added).

[381] Choueiki Pre-filed at 17; *see also* Tr. XXX at 6311. Although counsel for FirstEnergy suggested that this recommendation could not have been satisfied, Dr. Choueiki rejected that suggestion, noting that the Companies could have hired an independent reliability expert, but chose not to do so. *Id.* at 6312-13. Dr. Choueiki also indicated that FirstEnergy's use of an outside contractor, PowerGEM, to run the load flow studies does not qualify the transmission impact study as an "independent assessment." *Id.* at 6318.

"necessary to maintain future reliability," and contrasts them with the new gas-fired generating facilities being developed, suggesting that the latter are somehow less reliable.[382] This claim does not withstand scrutiny. Mr. Phillips made this assertion without knowledge of PJM's recently-approved Capacity Performance product, and his testimony is particularly unpersuasive given his lack of knowledge about generation.[383]

Equally important, Mr. Phillips's claims about the necessity of Sammis and Davis-Besse "to maintain future reliability" ignore the fact that PJM is charged with maintaining reliability in Ohio and elsewhere, and there is no evidence that PJM will cease doing so in the future. Moreover, as explained above in Section VI.B, PJM's reliability must run contracts can address situations where a generator deactivation could affect reliability. As Mr. Lanzalotta explained:

> PJM has a well-established generation deactivation process that is designed to ensure that transmission reliability issues that could arise if a generating unit is proposed for retirement are addressed before any such retirement occurs. . . . If a generation owner agrees to keep the unit operating, the owner will typically enter into a Reliability Must Run ("RMR") contract with PJM that subsidizes the continued operation of the unit until the necessary transmission projects are finished. Generating units within PJM, including some FirstEnergy units, have availed themselves of this process and, presumably, FirstEnergy Solutions would do so here if the company decided at some future time to retire any of the Sammis or Davis-Besse units.[384]

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[382] Phillips Suppl. at 5, 7.

[383] Tr. XVI at 3311 (Mr. Phillips acknowledging that he does not know the capacity performance rules, and confirming that his statement on page 7, line 12 was "made . . . without consideration at all to the capacity performance product offered by PJM"). Mr. Phillips's lack of knowledge about the operation of generating facilities and their dispatch was made clear repeatedly during cross-examination. *See, e,g.*, *id.* at 3292-93 (no knowledge about the rate at which different power plants can ramp up and down); *id.* at 3367 (Mr. Phillips was not involved with dispatch of generating units, and has "no idea how Sammis and Davis-Besse would compare in terms of prices or where the generation might be coming from"); *id.* at 3312 ("I have not kept up or involved myself with the capacity products since that's -- would affect the generation side of the business and the transmission would be details that I would be working with or involved with").

[384] Lanzalotta Suppl. at 9, 10.

Mr. Phillips also raises concerns about the distance between generation sources and the Companies' load, warning of "significant reliability and economic risk for Ohio in entrusting system reliability to out-of-state generators."[385] Here again, these claims are without merit. First, to the best of Mr. Phillips's knowledge, PJM has not identified this proximity issue as a concern.[386] Second, as Mr. Phillips conceded, PJM "maintain[s] reliability irrespective of the distance between generation centers and the load."[387] Third, the support that Mr. Phillips musters for this claim is contradicted by the record evidence. Mr. Phillips claims that "Ohio is a large net importer of power," with the deficit "trending upward."[388] But the very EIA spreadsheet that Mr. Phillips cites in his testimony demonstrates that Ohio has been a net importer of electric power every year since at least 1990 (the earliest year available).[389] And for at least 13 of those years, Ohio had a larger deficit than it did in 2013, the most recent year for which data is available.[390] Fourth, Mr. Phillips's claim is further undermined by the development of multiple new combined cycle plants, which are scheduled to go into service over the next several years.[391] Because it lacks evidentiary support, and because PJM would ensure reliability regardless of the distance between generation and load, Mr. Phillips's proximity argument should be rejected.

2. FirstEnergy's Economic Development Analysis is Fundamentally Flawed.

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[385] Phillips Suppl. at 7.

[386] Tr. XVI at 3295-96.

[387] *Id.* at 3297 (agreeing with Attorney Examiner Price's question).

[388] Phillips Suppl. at 6.

[389] OCC Ex. 14; Tr. XVI at 3301.

[390] OCC Ex. 14; Tr. XVI at 3301.

[391] *See, e.g.*, Comings Third Suppl. at 11, Tbl. 2

FirstEnergy also tried to justify Rider RRS by citing to the supposed "economic development and job retention" benefits of the rider.[392] Under this theory, the Companies can claim that all of the economic activity associated with Sammis and Davis-Besse are "benefits" of Rider RRS because the rider would purportedly prevent the plants from retiring. This argument is wrong for multiple reasons. As an initial matter, as explained in Sections VI.A and VI.B above, there is no evidence that the plants will suddenly retire in the absence of Rider RRS. For this reason alone, these claimed benefits of the rider are completely illusory.

Even if this flawed premise were accepted, FirstEnergy's economic impacts argument would still be without merit. In support of this argument, FirstEnergy has offered the testimony of Sarah Murley Brammer, who prepared reports discussing the "economic and revenue impacts provided by the Plants."[393] Using the IMPLAN model, Ms. Murley came up with estimates of jobs, income, and taxes generated by Sammis and Davis-Besse.[394] In her supplemental testimony, Ms. Murley also included a pair of reports that purport to show the impacts that would occur if these plants retired.[395] These studies are flawed and incomplete for multiple reasons.

First, these studies fail to provide a realistic assessment of economic impacts because they ignore the opportunity costs of spending. At the hearing, Ms. Murley indicated her familiarity with the notion of opportunity costs – namely, that spending on one activity (such as generating electricity from Sammis or Davis-Besse) forecloses the ability to spend that money on another activity that could provide economic benefits – and conceded that her analyses "do not

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[392] Mikkelsen Fifth Suppl. at 9; Stipulation at 18.

[393] Co. Ex. 35, Murley Direct at 2.

[394] *See generally id.*, Atts. SM-1, -2; Co. Ex. 36, Murley Suppl., Atts. SM-1, -2.

[395] Murley Suppl., Atts. SM-3, -4.

factor in opportunity costs in any way."[396] Instead, her analysis assumes that money can be spent on a particular economic activity, and generate economic benefits, without having any offsetting economic costs.

The failure to consider opportunity costs means that these economic impact reports present a woefully incomplete picture of the economic impacts of Sammis and Davis-Besse, and of Rider RRS. For example, Ms. Murley's analysis failed to account for the economic impacts of the Companies' customers paying higher electric bills Rider RRS. Under FirstEnergy's own estimates, customers would pay $363 million of charges, on a net present value basis, during the first 31 months of Rider RRS.[397] And, as explained above in Section II, there is a strong likelihood that the actual charges would be much higher. Although such charges would directly affect the finances of the Companies' customers – and would necessarily mean that Ohio ratepayers have less money to spend on other things – the economic analyses sponsored by FirstEnergy ignore these costs. By presenting a one-dimensional study that considers benefits but not costs, FirstEnergy has failed to provide a thorough picture of Rider RRS's economic impact.[398]

Second, Ms. Murley's studies disregard the likely consequences of a plant retirement. If Sammis and Davis-Besse did suddenly retire – a scenario that runs counter to the evidence in this case – those generating units could be replaced by new generation, transmission upgrades, or some combination of the two. And, as Ms. Murley acknowledged at the hearing, there would be

[396] Tr. XV at 3081.

[397] SC Ex, 89.

[398] As Mr. Comings noted, "[i]f Rider RRS were approved and the Companies proceed with the proposed transaction, rate impacts of operating Sammis or Davis-Besse that are passed on to ratepayers may be higher or lower than alternative sources. An economic impact analysis can account for such an impact, since ratepayers would have more or less money to spend elsewhere in the state's economy." Comings Suppl. at 34-35. He recommended that such impacts should have been factored into Ms. Murley's analysis. *Id.* at 35.

economic impacts associated with the development of new generation or transmission.[399] But although such development would result in economic activity, and those impacts could have been evaluated through the IMPLAN model,[400] the studies sponsored by FirstEnergy ignored these potential economic impacts.[401] By assuming that Sammis and Davis-Besse would retire, but that no new transmission or replacement generation would be built in lieu of them, these studies overinflate the likely economic impacts of a plant retirement. Put simply, Ms. Murley's reports do not, in any realistic sense, "show[] the economic impact which would be lost if the Plants retired."[402] Because these studies present a misleading, one-sided picture of the potential effects of a plant retirement, the Commission should disregard them.

Even setting aside the overarching flaws described above, those studies suffer from many other shortcomings. For example, the studies were performed using general IMPLAN multipliers, and Ms. Murley did not independently verify the actual economic impacts of Sammis and Davis-Besse. For example, the "direct output" listed for Sammis in Ms. Murley's testimony "is not based on the actual costs of coal burned at the Sammis plant," and Ms. Murley did not "evaluate whether the IMPLAN assumption about the coal costs at Sammis were consistent with actual coal costs at Sammis."[403] Nor did she know what level of profits the Sammis plant was assumed to produce as part as part of the plant's direct output, or whether the

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[399] Tr. XV at 3079 (conceding that "[i]f there were a need to build new generation in response to the retirement of, say, the Sammis plant, . . . that new generation would have an economic impact"); *id.* at 3077 (acknowledging that "spending on transmission system upgrades would create economic impact").

[400] Tr. XV at 3077, 3079.

[401] *Id.* at 3077-78 (conceding that these economic impacts estimates "do not factor in any economic impact of any transmission system upgrades that might be needed to allow for such retirement[s]"); *id.* at 3079-80 (conceding that the "estimates of the economic impacts of the retirement of the [plants] do not factor in any economic impacts of replacing the power from [the plants]");*see also* Comings Suppl. at 34.

[402] Murley Suppl. at 2.

[403] Tr. XV at 3064, 3065. Although this issue was discussed in the context of Ms. Murley's testimony, the same holds true with respect to her supplemental testimony. *Id.* at 3069; *see also id.* at 3075.

"assumption for profits included in the IMPLAN model is consistent with the level of profits the Sammis plant actually generated."[404] Ms. Murley also did not conduct a plant-specific analysis to determine what proportion of Sammis's supply purchases came from the local geographic area, relying instead on the model's general multipliers.[405] In sum, the economic impact analyses sponsored by FirstEnergy lack important plant-specific data, which further diminishes the relevance of these reports.[406] The Commission should disregard these studies, because they have no bearing on the true costs and benefits associated with Rider RRS.

3. FirstEnergy's "resource diversity" argument does not justify Rider RRS.

FirstEnergy's claim that Rider RRS would help preserve "resource diversity" by preventing the retirement of Sammis and Davis-Besse is similarly unavailing. This vaguely-defined notion of resource or fuel diversity is one of FirstEnergy's main justifications for Rider RRS, which its witnesses have repeatedly invoked throughout this case.[407] But like the illusory

[404] Tr. XV at 3062-63; *cf.id.* at 3061 (confirming that IMPLAN's definition of output includes the wages of the people that work in the Sammis plant, the costs of the inputs needed to produce power at the plant, and profits from the plant). Although this issue was discussed in the context of Ms. Murley's testimony, the same holds true with respect to her supplemental testimony. *Id.* at 3069; *see also id.* at 3075.

[405] Tr. XV at 3070-72.

[406] The lack of plant-specific data included in these economic impact reports is compounded by shortcomings with the IMPLAN multipliers themselves. The studies presented by Ms. Murley used less-sophisticated economic impact multipliers that fail to distinguish between different types of fossil generation. As Mr. Comings explained, "using the 'fossil fuel generation' sector for the Sammis plant's operations is overly simplistic. This methodology effectively treats Sammis as an agglomeration of coal, natural gas and oil plant operations in Ohio." Comings Suppl. at 36:12-14. At the hearing, Ms. Murley acknowledged that, outside of the analyses she did for the Sammis plant, she has "never carried out an economic impact analysis for a coal-fired power plant." Tr. XV at 3059.

[407] *See, e.g.*, Mikkelsen Direct at 3:13; 27:18, 29:19-21; Mikkelsen Second Suppl. at 4:13-5:10, 7:1-3; Ruberto Direct at 8:18-19; Co. Ex. 28, Moul Direct at 2:22-3:2, 6:6-8, 6:10-7:2, 7:5-8:21; Moul Suppl. at 7:19-8:19; Strah Direct at 4:8-10; Makovich Suppl. at 3:4-11, 4:6-11, 12:13-19, 13:14-15:8; Co. Ex. 32, Harden Direct at 9:9-16. *See also, e.g.*, Tr. I at 96, 154; Tr. II at 415, 447. The foregoing list of citations is by no means exhaustive: FirstEnergy's witnesses touted this "resource diversity" benefit at nearly every opportunity they could get.

reliability and economic benefits discussed above, FirstEnergy's resource diversity argument is a red herring.

First and foremost, these resource diversity claims are premised on the erroneous assumption that Sammis and Davis-Besse would retire in the absence of Rider RRS.[408] As explained above in Sections VI.A and VI.B, this assumption is false: there is no evidence in the record that these plants would retire if Rider RRS is rejected. For this reason alone, FirstEnergy's resource diversity argument should be disregarded in its entirety.

Even assuming – purely for the sake of argument, and contrary to the record evidence – that the plants would retire without Rider RRS, FirstEnergy's resource diversity claims would still be meritless. Although each witness phrases the argument a little differently, at bottom, all of FirstEnergy's witnesses make essentially the same argument: that Sammis and Davis-Besse are important for preserving fuel/resource diversity within Ohio, and that the replacement of these coal and nuclear units with other resources, such as natural gas, would lead to less reliable electric service. This argument is flawed in multiple respects.

First, despite repeatedly touting the benefits of fuel diversity, and warning of the loss of coal and nuclear generation, not a single FirstEnergy witness could identify what the optimal generation mix would be. FirstEnergy's main witness on this topic, Mr. Moul, did not quantify what percentage of Ohio coal would be needed in order to have sufficient resource diversity, and does not know what amount of gas generation would (in his opinion) be too high.[409] Mr. Moul also acknowledged that he is not offering any opinion about what the optimal resource mix

[408] *See, e.g.*, Moul Direct at 2 (claiming that Rider RRS will provide stable revenues to Sammis and Davis-Besse, "thereby permitting these plants to stay in operation, which in turn, promotes fuel diversity and certainty"); Strah Direct at 7 (claiming that Rider RRS "will promote stability and certainty . . . by keeping baseload generating plants open in the face of extensive planned retirements in the near future").

[409] Tr. XI at 2254, 2312. Nor did he analyze Ohio's gas infrastructure for purposes of this proceeding. *Id.* at 2312.

would be.[410] Likewise, although FirstEnergy witness Strah warned that baseload plant retirements would threaten "the stability and security of the Companies' delivery system," he could not identify what level of coal generation in Ohio "would threaten the stability and security of the companies' delivery system."[411] Nor could he identify any such level for PJM more generally.[412] Though Dr. Makovich made numerous claims about "power supply diversity," he also did not evaluate what the optimal mix of generation sources is for PJM.[413]

Some of FirstEnergy's witnesses testified about resource diversity without even knowing the current generation mix. Mr. Strah did not know what the current generation mix was in either Ohio or in PJM generally.[414] And Mr. Moul did not know how the retirement of Sammis and Davis-Besse would affect the generation mix in Ohio or PJM generally, nor did he know what percentage of the generation mix currently serving Ohio is coal-based.[415]

In truth, the generation mix in both Ohio and across PJM is predominantly coal and nuclear. According to EIA data available on the Commission's website, coal and nuclear collectively provided 80% of Ohio's generation output in 2014.[416] And as Mr. Moul's testimony demonstrates, the generation mix within PJM in 2013 consisted of 79.5% coal and nuclear.[417]

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[410] *Id.* at 2311.

[411] Strah Direct at 4; Tr. IV at 752.

[412] *Id.* at 752-53. Similarly, Mr. Ruberto was also unable to identify what proportion of natural gas in the generation mix would (in his opinion) be too much. Tr. XIII at 2840-41.

[413] Tr. XVII at 3506.

[414] Tr. IV at 752. Moreover, Mr. Strah did not analyze what impact the closing of Davis-Besse and Sammis would have on the fuel mix within either PJM or the ATSI zone. *Id.* at 785-86.

[415] Tr. X at 2194; Tr. XI at 2312-13. Similarly, when the EDU Team was negotiating the proposed transaction, it did not look at Ohio's current generation mix. The Team also did not calculate how much natural gas would be in the mix if Sammis and Davis-Besse retired. Tr. XIII at 2840.

[416] SC Ex. 7.

[417] Moul Direct at 9; Tr. XI at 2313, 2403. Dr. Makovich noted that coal currently makes up 41% of installed capacity in PJM. Tr. XVII at 3502.

Under questioning from Attorney Examiner Price, Dr. Makovich also acknowledged that the retirement of Sammis would represent a small proportion of PJM's currently installed capacity.[418] Given that Ohio's and PJM's generation mix is dominated by coal and nuclear, the "counterfactual" discussed in Dr. Makovich's report – a power supply portfolio with zero nuclear or coal generation[419] – is precisely that: it's a scenario that will not occur within the foreseeable future.[420] For this reason, his report – which predates the Companies' ESP Application and includes no specific analysis of Ohio or the issues in this case – should be given no credence.[421]

Second, FirstEnergy's claims about the superior reliability of coal and nuclear versus other resources are seriously overblown. Coal-fired units can certainly face reliability problems, and indeed, the Sammis plant's equivalent forced outage rate in recent years demonstrates that these units are frequently unavailable. As of October 2015, Sammis's year-to-date EFOR was 17%.[422] [redacted].[423] Moreover, although FirstEnergy's witnesses question the reliability of natural gas generation, including gas plants that have contracted for firm delivery, PJM treats gas plants with firm deliverability as Capacity Performance products, with no discount vis-à-vis coal or

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[418] *See generally* Tr. XVII at 3502-04.

[419] *See generally* Makovich Suppl., Att. LM-2.

[420] Even Dr. Makovich admitted that it is unlikely that coal would be eliminated from PJM's generation within the next ten years, or that nuclear would be eliminated from the mix in the next five years. *See* Tr. XVII at 3501.

[421] The only mention of "Ohio" in Dr. Makovich's report is a misstatement: he mistakenly refers to the "Hatfield's Ferry plant in Ohio." Makovich Suppl., Att. LM-2 at 29.

[422] Tr. XXXII at 6550-51.

[423] SC Ex. 37c, Att. 1 at 35. Moreover, nuclear generating units must undergo lengthy, periodic refueling outages that reduce their availability. Davis-Besse undergoes a refueling every two years, Harden Direct at 3, and these refueling outages necessarily reduce its capacity factor. *See also* Conf. Tr. XII at 2705 ([redacted]).

nuclear.[424] In fact, one of the reasons why PJM proposed the Capacity Performance product was to encourage natural gas plants to acquire reliable gas supplies. As FERC noted in its order approving PJM's proposal

> PJM shows that its existing rules also limit the seller's opportunity to recover, as a capacity resource, the costs it must incur to improve the performance capability of its resource. Specifically, PJM's currently-effective offer cap for existing generators . . . skews investment decisions toward capital procurement and does not allow sellers to include in their sell offers costs attributable to other means of securing reliable fuel, such as natural gas firm transportation arrangements or priority fuel procurement contracts.[425]

Likewise, as OCC witness James Wilson explained in his testimony, although there were problems during the Polar Vortex for gas plants with interruptible fuel supply, under PJM's capacity performance proposal, "in the future gas-fired power plants needed for reliability will have firm fuel arrangements."[426]

Indeed, FirstEnergy's own witnesses have also acknowledged the reliability of gas plants with firm deliverability. Although he tried to backtrack at the hearing, Mr. Moul conceded that a gas plant with firm pipeline transportation and a long-term supply contract can operate as reliable

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[424] Tr. X at 2217. Although all of FirstEnergy's witnesses' criticisms of natural gas are unpersuasive, Mr. Strah's criticisms are also uninformed. Although he testified at length about the supposed unreliability of gas plants, *e.g.*, Tr. IV at 758-59, and suggested that even gas plants with firm deliverability are unreliable, *id.* at 767-68, Mr. Strah lacks knowledge about the proportion of gas plants in Ohio or PJM that have contracted for firm gas delivery. *Id.* at 768. He also did not know whether natural gas plants are "less likely to be interrupted if they have firm pipeline transportation." *Id.* at 788.

[425] *PJM Interconnection LLC,* Docket Nos. ER15-623-000 et al., 151 FERC ¶ 61,208, Order on Proposed Tariff Revisions, ¶ 46 (June 9, 2015).

¶ 46 (June

[426] Wilson Direct at 53-54.

baseload generation.[427] He also conceded that [redacted].[428]

In opining about resource diversity, FirstEnergy's witnesses also improperly discount other resources. None of FirstEnergy's witnesses consider wind power to be a valuable contributor to resource diversity,[429] and yet, as Mr. Strah conceded, "wind had a positive impact on the reliability of the system during the polar vortex."[430] FirstEnergy's witnesses also ignored demand-side resources, such as energy efficiency and demand response.[431] This oversight is particularly glaring given that demand response outperformed expectations during the polar vortex. As PJM noted, demand response "assisted in maintaining the reliability of the system," and "the total amount of demand response provided was larger than most generating stations."[432]

In a final effort to shore up their discredited resource diversity claims, the Companies submitted supplemental testimony from Dr. Makovich. In his testimony, Dr. Makovich endorses

[427] Tr. X at 2217-18.

[428] Conf. Tr. XI at 2413-14. Moreover, although Mr. Moul opines about gas infrastructure in his testimony, Moul Direct at 10, he did not personally evaluate Ohio's gas transportation infrastructure for purposes of this proceeding. Tr. XI at 2312.

[429] *See, e.g.*, Tr. IV at 874. (Mr. Strah testifying that only coal and nuclear are "essential generation"); Makovich Suppl. at 4 (stating that wind and solar are not "equivalent power supply sources"); Tr. XI at 2401 (Mr. Moul discussing his omission of wind from a resource diversity discussion).

[430] Tr. IV at 772-73. As PJM stated in a May 2014 report: "PJM also saw up to 4,000 MW produced by wind power during the peak load periods of January 6-7. . . . The wind power produced had a positive impact on supply and contributed to PJM's ability to maintain reliability." SC Ex. 8 at 21; *see also* Tr. XI at 2401-02 (Mr. Moul conceding that wind outperformed expectations during the Polar Vortex).

[431] Tr. XI at 2253 (Mr. Moul's testimony does not "contain any analysis of how [demand] side resources might be able to provide resource diversity"); *id.* at 2245-46; *id.* at 2250, 2252 (Mr. Moul did not discuss with anyone representing FES or the Companies the possibility of using demand side resources to provide resource diversity); Tr. XVII at 3539 (Dr. Makovich acknowledging that his testimony does not address demand-side resources and reliability). The EDU Team likewise did not consider demand response and energy efficiency to be part of resource diversity. Tr. XIII at 2841-42.

[432] SC Ex. 8 at 20.

Rider RRS, and makes sweeping claims about Sammis and Davis-Besse, but this testimony is based on virtually no knowledge about the plants, the proposed transaction, or Rider RRS.

At the time he submitted his testimony, Dr. Makovich had not reviewed the term sheet for the proposed transaction, Mr. Ruberto's direct testimony, Mr. Lisowski's direct testimony, Mr. Rose's direct testimony, or Mr. Moul's supplemental testimony.[433] Although Dr. Makovich claimed that Sammis and Davis-Besse are "exceptional assets from an operations perspective," he made those claims based entirely on Mr. Moul's direct testimony.[434] He also claimed that one of Rider RRS's benefits is providing "system reliability,"[435] but here again he relied on Mr. Moul's direct testimony for his opinions, without reviewing any specific data regarding those plants' reliability.[436] He further opined that Sammis and Davis-Besse are "economic because the cost of continued operation is below the cost of closing the plants and replacing them with the lowest-cost source of equivalent power supply."[437] But despite this bold statement about the economics of these plants, he did not review any cost or revenue estimates for the plants, with his opinion based entirely on Mr. Moul's direct testimony.[438] Likewise, although he claimed that Sammis and Davis-Besse's cost of continued operation is below the cost of replacing them with "the lowest-cost source of equivalent power supply,"[439] Dr. Makovich failed to perform a specific assessment to determine which resource would be the lowest-cost source of equivalent

[433] Tr. XVII at 3463-66. The same was true at the time of his May 27, 2015 deposition: he had not reviewed any of these documents. *Id.*

[434] Tr. XVII at 3466-67, 3470; *see also* Makovich Suppl. at 12.

[435] Makovich Suppl. at 12.

[436] Tr. XVII at 3471-73.

[437] *Id.* at 3475 (citing Makovich Suppl. at 15).

[438] *Id.* at 3475-78. And again, he did not even review the testimony of Mr. Rose, Mr. Lisowski, or Mr. Ruberto before making this statement.

[439] Makovich Suppl. at 15.

power supply.[440] And as explained above in Section VI.A, Dr. Makovich's opinion that Sammis and Davis-Besse are at risk of retirement was offered without any first-hand knowledge.[441]

Dr. Makovich's other claims about Sammis and Davis-Besse are also based on minimal information. In touting the benefits of Rider RRS, he states that "when PJM capacity and energy cash flows increase in future years to cover the costs of a diverse power supply portfolio, then customers will be further benefitted from the Economic Stability Program in place."[442] But Dr. Makovich confirmed that he is not offering any specific opinion that energy or capacity cash flows will increase in future years.[443] Dr. Makovich also claims that Sammis provides "environmental impact management," which he describes as a "system benefit."[444] But he did not review any specific information about Sammis's environmental controls, nor did he review any specific information about emissions from the plant.[445] In short, although Dr. Makovich makes numerous claims about the supposed benefits of Sammis and Davis-Besse, his opinions about these plants are based on minimal knowledge, and should not be credited by the Commission.

More generally, Dr. Makovich's claims about the "missing money" problem – and the benefits of having ratepayers cover all of the costs of FES's generating plants (plus a return on

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[440] Tr. XVII at 3481. Moreover, although his opinions about Sammis are premised on notion that there is no generation surplus, Makovich Suppl. at 4, 15, he did not analyze whether a subset of the Sammis units could be retired without requiring an equivalent power supply. Tr. XVII at 3481.

[441] Indeed, although Dr. Makovich claims that the Sammis plant is at risk of retirement, he has not put a probability on the likelihood of retirement, does not have an opinion about whether some Sammis units are more likely to retire, and has not been privy to any discussions regarding the possible retirement of Sammis. Tr. XVII at 3482. His opinion that Davis-Besse is at risk of retirement is simply based on Mr. Moul's direct testimony. *Id.* at 3487.

[442] Makovich Suppl. at 15-16.

[443] Tr. XVII at 3488.

[444] *Id.* at 3490-91 (discussing Makovich Suppl. at 4, 14-15).

[445] *Id.* at 3491.

equity) – are contradicted by facts on the ground. In his testimony, Dr. Makovich presents a calculation of costs for a new combined-cycle power plant that purportedly demonstrate the shortfalls resulting from the "missing money" problem.[446] But although Dr. Makovich suggests that the construction of new combined-cycle gas plants is a money-losing proposition, the market says otherwise. Currently, there are five combined-cycle plants being developed in Ohio.[447] Moreover, although Dr. Makovich criticizes the adequacy of capacity payments made by PJM, this is an issue that PJM has already addressed, most recently through its Capacity Performance product.[448] This further underscores the irrelevance of Dr. Makovich's testimony to the issues in this case.

VII. Rider RRS does not satisfy the non-binding factors set forth in the AEP ESP III Order.

For the reasons discussed above, Rider RRS should be rejected by the Commission, both because it is not authorized by R.C. 4928.143, and because the proposed Rider is unjust and unreasonable, and would not provide a significant benefit to customers. Likewise, because the Stipulation does not benefit ratepayers or the public interest, and violates important regulatory principles, the Stipulation should be rejected.[449] Rider RRS's failure to satisfy these legal

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[446] Makovich Suppl. at 11-12.

[447] *See* Comings Third Suppl. at 11, Tbl. 2; *see also* Kalt Suppl. at 22-23 (discussing new generation in PJM). Notably, Dr. Makovich could not support many of the underlying numbers used for this calculation. For example, with respect to the 14% carrying charge rate assumed in the calculation, he was unable to explain either the depreciation schedule or the cost of debt that was assumed for that figure. Tr. XVII at 3438-39, 3515. Likewise, the $1400/kW upfront capital cost assumed in his calculation – which has a direct impact on the assumed fix cost rate of $196/kW – is also likely an overestimate. Indeed, FirstEnergy witness Judah Rose directly contradicted Dr. Makovich's cost assumption. *See* Tr. XXXV at 7244-46 (testifying that the upfront capital cost for a new combined cycle plant in Ohio would be approximately $1,000/kW); *see also* Co. Ex. 20c (Rose Public Workpapers, "ICF Base Case New Plant Capital Costs (2013$/summer kW-yr) - ATSI & AEP/Dayton").

[448] *See generally* Kalt Suppl. at 21-22.

[449] *See, e.g.*, FE ESP III Order at 24 (referencing three-part stipulation test).

requirements is dispositive of this case. But even if FirstEnergy's proposal were considered under the non-binding criteria set forth in the Commission's Order from the AEP ESP III case,[450] Rider RRS should still be rejected.

In the AEP ESP III Order, the Commission created a placeholder PPA rider (with an initial value of zero), and identified several factors that it stated it would balance, but not be bound by, in considering future PPA rider proposals:

> financial need of the generating plant; necessity of the generating facility, in light of future reliability concerns, including supply diversity; description of how the generating plant is compliant with all pertinent environmental regulations and its plan for compliance with pending environmental regulations; and the impact that a closure of the generating plant would have on electric prices and the resulting effect on economic development within the state.[451]

The Commission also identified several issues that a rider proposal must address, namely, such proposal must "provide for rigorous Commission oversight of the rider, including a proposed process for a periodic substantive review and audit; commit to full information sharing with the Commission and its Staff; and include an alternative plan to allocate the rider's financial risk between both the Company and its ratepayers."[452]

If the proposed Rider RRS and the Stipulation were evaluated under these criteria, it would fail. As explained below, FirstEnergy's proposal does not satisfy any of the four non-binding factors, does not provide for rigorous review of Rider RRS, and does not properly allocate risk between FirstEnergy and ratepayers. With regard to the first criterion, FES's generating units are not in financial need. As explained above in Section V.B, for the entire

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[450] AEP ESP III Order at 25. Note: Sierra Club disagrees with the Order's conclusion that PPA riders are permissible under Ohio law, and Sierra Club does not concede that the AEP ESP III Order identifies the appropriate criteria for evaluating FirstEnergy's proposed ESP, Rider RRS, or the Stipulation.

[451] *Id.*

[452] *Id.*

eight-year term of Rider RRS, using FirstEnergy's own projections, [redacted].[453]

Consideration of AEP ESP III Order's second criterion, "necessity of the generating facility, in light of future reliability concerns, including supply diversity,"[454] also tilts against approval of Rider RRS. For one thing, the purported reliability benefits of Rider RRS are illusory because Sammis and Davis-Besse are not at risk of retirement.[455] Moreover, as explained above in Section VI.C.1, the transmission upgrade cost estimate presented in FirstEnergy witness Phillips's testimony is based on a study that used outdated information and unrealistic assumptions.[456] And, as explained above in Section VI.C.3, the testimony of FirstEnergy's witnesses regarding resource and fuel diversity is vague, unsupported, and unpersuasive. The second criterion therefore cuts against FirstEnergy's proposal.

The AEP ESP III Order's third criterion, "description of how the generating plant is compliant with all pertinent environmental regulations and its plan for compliance with pending environmental regulations," also weighs against approval of Rider RRS. As explained above in

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[453] SC Ex. 90c. As FirstEnergy witness Moul testified, [redacted]. Conf. Tr. XI at 2432-33; *see also id.* at 2445. Because FirstEnergy's projection of the revenues and costs from the OVEC entitlement [redacted].

[454] AEP ESP III Order at 25.

[455] There is also no reliable evidence in the record that the OVEC plants are at risk of retirement. *See, e.g.*, Tr. II at 404-05.

[456] These problems were compounded by the fact that the study was directed by FirstEnergy, rather than an independent consultant. Dr. Choueiki noted this deficiency in explaining why Rider RRS does not satisfy the conditions set forth in the AEP ESP III Order. Choueiki Pre-filed at 12; *see also* Tr. XXX at 6311, 6318.

See AEP ESP III Order at 25 ("reserv[ing] the right to require a study by an independent third party, selected by the Commission, of reliability and pricing issues as they relate to the application").

Section II.E, the Sammis plant faces regulatory risk – and potential unanticipated costs – due to U.S. EPA's recently-adopted Coal Combustion Residuals rule and Effluent Limitations Guidelines rule. Put simply, the future environmental compliance risks faced by Sammis supports rejection of Rider RRS.

The fourth AEP ESP III Order factor, "the impact that a closure of the generating plant would have on electric prices and the resulting effect on economic development within the state," also cuts against approval of Rider RRS. As noted above, Sammis and Davis-Besse are not at risk of retirement. Because there is no realistic risk that the plants would close during the eight-year term of Rider RRS, there is likewise no serious risk that a closure would affect electric prices. To the extent the Commission does consider that unrealistic scenario, the evidence demonstrates that FirstEnergy's transmission upgrade cost estimate is overinflated.[457] Likewise, FirstEnergy's testimony on the purported economic development benefits of Rider RRS – benefits which are premised on the erroneous notion that the plants will retire – is flawed for the reasons explained in Section VI.C.2 above. Consequently, this factor, when viewed in light of the record evidence, weighs against the approval of Rider RRS.

FirstEnergy's proposal not only fails to satisfy the four non-binding factors listed in the AEP ESP III Order, the proposal fails to meet other relevant factors identified in the AEP ESP III Order. In particular, the audit process proposed by FirstEnergy does not "provide for rigorous Commission oversight of the rider."[458] As discussed above in Section III.C.1, the proposed audit process is both procedurally and substantively flawed. Among other deficiencies, the audit process would exclude a large category of costs – the legacy cost components – from Commission review. Finally, the Stipulation lacks an alternative plan that fairly allocates Rider

[457] *See* Section VI.C.1 *supra.*

[458] *See* AEP ESP III Order at 25.

RRS's financial risk between FirstEnergy and ratepayers.[459] As explained above in Section III.C.2, the "risk-sharing" provision set forth in the Stipulation offers few protections to the Companies' customers and does not allocate any risk to FES.[460]

In sum, the AEP ESP III Order's non-binding factors, as well as the other conditions described in that Order, all weigh against the approval of Rider RRS. Accordingly, to the extent the Commission considers these criteria in evaluating the Companies' proposal here, these criteria further support rejection of Rider RRS

VIII. The Stipulation's "Resource Diversification" Provisions are Ineffective and Unenforceable.

In the Stipulation, FirstEnergy makes much of its supposedly robust "resource diversification" initiatives. Using language that can only be described as hyperbolic, the Companies tout their "environmental stewardship" through an "unprecedented commitment" to reduce CO2 emissions, a "robust" energy efficiency initiative, and a renewable energy provision.[461] But in truth, these provisions are toothless: each provision is either subject to contingencies, or entirely unenforceable. Because these stipulation provisions would do little to achieve their self-announced goal of "resource diversification," these provisions should be disregarded by the Commission.

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[459] *See id.*

[460] Dr. Choueiki recommended that, if the Commission were inclined to approve Rider RRS, the Companies and FES should be required to "develop a sharing mechanism whereby *FES* commits to be responsible for a portion of the costs associated with Rider RRS in exchange for a portion of the revenues associated with Rider RRS." Choueiki Pre-filed at 16-17 (emphasis added). The risk-sharing provision included in the Stipulation fails this test.

[461] Stipulation at 2, 11-12.

Under Section V.E.1, FirstEnergy Corp. would purportedly "establish a goal to reduce CO2 emissions by at least 90% below 2005 levels by 2045."[462] This provision is so weak as to be almost meaningless. By its terms, this provision is not a commitment – rather, it merely establishes a goal. And the company that would supposedly meet this goal is not a signatory to the Stipulation, and is not subject to the Commission's jurisdiction. In any event, this provision is also completely unenforceable, because nothing in the Stipulation establishes a penalty for the failure to meet this CO2 emission reduction goal.[463]

The Stipulation's energy efficiency provision is also deeply flawed. First, the language is misleading: Although the provision is presented as an unconditional commitment – that "[t]he Companies *will* reactivate in 2017 all programs suspended in their EE/PDR Portfolio Plan in Case No. 12-2190-EL-POR"[464] – in truth, the Companies will only reactive those specific programs that are approved by the Commission.[465] Moreover, the Companies "have not committed to propose any minimum level of funding for these energy efficiency programs," and rather than committing to achieve at least 800,000 MWh of energy savings annually, the Companies have instead only promised they would "strive to achieve" such savings.[466] The Companies are therefore not required to achieve that level of energy savings.[467]

[462] *Id.* at 11.

[463] Stipulation at 11; *see also* Tr. XXXVI at 7532 (Ms. Mikkelsen conceding that the Stipulation "does not include explicit language with respect to a penalty associated with the failure to meet the CO-2 emission reduction goal").

[464] Stipulation at 11 (emphasis added).

[465] Tr. XXXVI at 7533. This holds true for the entire eight-year term of the proposed ESP; only programs approved by the Commission through an EE/PDR Portfolio Plan would be implemented. *Id.* at 7534. In this sense, the extent of the Companies' commitment is somewhat circumscribed: They are not committing to *implement* these energy efficiency programs. Rather, they are merely committing to *propose* to implement such programs. *Id.*

[466] *Id.* at 7534; Stipulation at 11.

[467] Tr. XXXVI ay 7535.

Moreover, the Companies are already forecasted to achieve much of the energy savings promised in this Stipulation provision. At the hearing, Ms. Mikkelsen confirmed that the 800,000 MWh of savings are not in addition to the forecasted levels of energy efficiency and demand response identified in the Companies' 2015 Electric Long-Term Forecast Report, which was issued in April 2015, many months before the Stipulation was filed.[468] In that report, the forecasted combined annual incremental energy savings for the Companies for each of the years 2021, 2022, 2023, and 2024 is greater than 800,000 MWh.[469] This means that, according to FirstEnergy's April 2015 forecast, the Companies were already expecting to achieve the 800,000 MWh in energy savings for at least the last 3½ years of the ESP. This underscores the toothlessness of the commitments in V.E.3 of the Stipulation.

The Stipulation's renewable energy provision is equally problematic. This provision does not include a firm commitment to procure 100 MW of wind or solar energy.[470] Rather, this provision is saddled with so many conditions it is difficult to envision it ever leading to the development of new renewable resources: First, the State or federal government would need to issue a future law or rule for which new renewable resources would be helpful for compliance; this provision would not be triggered by any state or federal law or rule currently in existence.[471] Second, Staff would need to determine that the future law or rule had not fostered the development of new renewable resources.[472] Third, the Companies would then make a filing at Staff's request, and the Commission would need to approve the Companies' proposal.[473] At that

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[468] *Id.* at 7536-37; SC Ex. 93.

[469] SC Ex. 94 at 39, column 5b; Tr. XXXVI at 7537-40.

[470] Stipulation at 12.

[471] *Id*.

[472] *Id.*; Tr. XXXVI at 7541.

[473] Stipulation at 12.

point, the Companies would then seek to procure 100 MW of wind or solar, subject to a critical limitation: the renewables procurement would not last for any period of time after May 31, 2024.[474]

Given the numerous conditions that would need to be satisfied before the Companies actually began seeking renewable resources, and given the end-point included in this provision, the time period in which renewables development could occur is vanishingly small. Even if the many conditions embedded in this provision were satisfied, the chances of the Companies successfully procuring 100 MW of renewable resources in such a tight timeframe is not realistic, as a wind or solar developer would not be interested in a project where the procurement would only last a couple of years.

In sum, neither the CO2 reduction provision, nor the energy efficiency provision, nor the renewable energy provision offers a meaningful commitment that should be considered by the Commission in evaluating the Stipulation.

IX. Approval of Rider RRS is Preempted by the Federal Power Act.

Commission approval of Rider RRS would constitute an impermissible intrusion into federal regulation of wholesale energy markets and as such is preempted by the Federal Power Act ("FPA"). The Federal Energy Regulatory Commission ("FERC") oversees PJM's operation of wholesale energy and capacity markets. Rider RRS would encroach on FERC's and PJM's exclusive control in this area by providing an out-of-market supplement to the wholesale energy and capacity prices that FES would otherwise receive for operation of Davis-Besse, Sammis, and the OVEC entitlement. Such out-of-market subsidies effectively supplant the PJM wholesale

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[474] *Id.*

price for FES, eliminate the price signals wholesale markets are intended to send to market participants, and limit the effectiveness of PJM's recent capacity market reforms.

Congress, in enacting the FPA, gave FERC jurisdiction over wholesale sales of electricity in interstate commerce.[475] In this area, "if FERC has jurisdiction over a subject, the States cannot have jurisdiction over the same subject."[476] The federal scheme thus "leaves no room either for direct state regulation of the prices of interstate wholesales of [energy], or for state regulations which would indirectly achieve the same result."[477] "Even where state regulation operates within its own field, it may not intrude indirectly on areas of exclusive federal authority."[478]

Here, the Commission cannot lawfully approve Rider RRS "because it functionally sets the rate that [FES] receives for its sales in the PJM auction."[479] Like the Maryland program at issue in *PPL EnergyPlus*, the Rider RRS "scheme thus effectively supplants the rate generated by the auction with an alternative rate preferred by [FES and] the state."[480] And it is no defense that the Rider does not directly upset any PJM market transaction as, under the FPA, each "state [is] required to treat the utility's FERC-mandated payments as 'reasonably incurred operating expenses for the purpose of setting' the utility's retail rates."[481] Ohio may not therefore

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[475] *Fed. Power Comm'n v. S. Cal. Edison Co.*, 376 U.S. 205, 215-16 (1964).; *see also, e.g., EPSA*, 136 S. Ct. at 767 (discussing FPA's regulatory scheme)

[476] *Miss. Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354, 377 (1988) (Scalia, J., concurring).

[477] *N. Natural Gas Co. v. State Corp. Comm'n of Kansas,* 372 U.S. 84, 91 (1963) (citation omitted).

[478] *Pub. Utils. Comm'n of State of Cal. v. FERC*, 900 F.2d 269, 274 n.2 (D.C. Cir. 1990) (internal quotation marks omitted).

[479] *See PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467, 476 (4th Cir. 2014).

[480] *Id*.

[481] *Id*. "Wholesale energy prices 'fixed by FERC must be given binding effect by state authorities' even 'in areas subject to state jurisdiction.'" *Id.* at 478 (quoting *California ex rel. Lockyer v. Dynegy, Inc.*, 375 F.3d 831, 851 (9th Cir. 2004) (internal quotation marks omitted)).

determine by fiat that FES should be made whole in the PJM marketplaces for the next eight years.

These out-of-market subsidies provided by Rider RRS have the potential "to seriously distort the PJM auction's price signals," thus interfering with FERC's chosen method to achieve federal policy goals.[482] PJM's price signals are intended to "promote a variety of objectives," especially price-driven construction of new generation and expansion of existing generation. As the *PPL EnergyPlus* court explained, "[m]arket participants necessarily rely on these signals in determining whether to construct new capacity or expand existing resources. The signals appear to be serving their purpose; according to FERC, the evidence 'suggests that [the Reliable Pricing Model] has in fact succeeded in securing sufficient capacity to meet reliability requirements for the PJM region.'"[483]

As demonstrated by testimony submitted in this proceeding, Rider RRS intrudes upon FERC's and PJM's regulation of wholesale markets in at least three ways. First, Rider RRS nullifies price signals by removing the effect of PJM capacity prices on any decision to continue to operate or to expand Sammis and Davis-Besse.[484] Commission approval of Rider RRS eliminates the price signal sent by PJM's market prices, and such price signals are a fundamental aspect of FERC's and PJM's regulation of the wholesale markets. As the PJM Independent Market Monitor Joseph E. Bowring explained, "[t]he proposed Rider RRS would constitute a subsidy analogous to the subsidies proposed in New Jersey and Maryland, both of which were

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[482] *PPL EnergyPlus*, 753 F.3d at 478-79.

[483] *Id*.

[484] IMM Ex. 2, Bowring First Suppl. at 5 ("A sustainable market design means a market design that results in appropriate incentives to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market.").

found to be inconsistent with competition in wholesale power markets."[485] Rider RRS's subsidies would undermine the operation of PJM's wholesale markets by rewarding inefficient plants and correspondingly punishing more-efficient plants that do not receive subsidies.[486]

Second, Rider RRS would create an incentive for FirstEnergy to present a "zero offer" in the PJM capacity markets to maximize the revenue offset to the customers, which will have price-suppressive effects and make it more difficult for generating units without subsidies to compete in the PJM capacity market. As the PJM Independent Market Monitor observed:

> The logical offer price for these resources in the PJM Capacity Market . . . would be zero. A zero offer would be rational because this would maximize the revenue offset to customers . . . . Offers at or near zero would have an anti-competitive, price suppressive effect . . . as would any offers at less than the competitive offer level. . . . Such effects would make it difficult or impossible for generating units without subsidies to compete in the market.[487]

As a result of Rider RRS, signals intended to incent new construction may break down if new entrants are forced to compete against existing generation that is immune from price signals – subsidies to existing generation "would negatively affect the incentives to build new generation in Ohio."[488]

Third, Rider RRS would directly harm the effectiveness of PJM's recent capacity market reforms that are intended to increase reliability by punishing generators that do not perform when called upon. Rider RRS would shield FES from those non-performance penalties and thus eliminate FES's incentive to assure that the Rider RRS Plants perform as expected under PJM's requirements. As RESA witness Stephen E. Bennett explained, "[a]s currently proposed, Rider RRS would transfer the entire risk of Capacity Performance non-performance to [FirstEnergy's]

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[485] *Id.* at 4.

[486] *See* RESA Ex. 6, Bennett Stipulation Direct at 2.

[487] IMM Ex. 2 at 5.

[488] *Id.*

customers. . . . Transferring this risk away from FES, removes the strong incentive that was expressly structured to insure maximum reliability."[489] Elimination of the strong incentives created by the PJM's Capacity Performance product would directly conflict with FERC's and PJM's regulation of wholesale markets.

If Ohio wishes, as a matter of industrial policy, to provide a subsidy to FirstEnergy or FES, there are methods that the State could employ (such as tax breaks) to achieve such a policy goal that do not harm wholesale power markets and therefore violate federal law. The Commission may not, however, provide such subsidies to FES by directly intruding upon FERC's regulation of wholesale energy markets. For this reason, in addition to the numerous other reasons listed above, the Commission should reject Rider RRS.

CONCLUSION

For the foregoing reasons, Sierra Club respectfully requests that the Commission: (i) conclude that Rider RRS is not permissible under R.C. 4928.143; (ii) find that Rider RRS, and the Stipulation, are harmful to the Companies' customers, and are not just and reasonable; (iii) find that Rider RRS, and the Stipulation, are not more favorable in the aggregate as compared to a market rate offer; and (iv) hold that Rider RRS is otherwise impermissible under State and federal law.

[489] RESA Ex. 6 at 3; *see* IMM Ex. 2 at 3-4; *see also* Dynegy Ex. 1, Ellis Direct at 9 ("In addition to exposing customers to the risk of being required to foot the bill for FirstEnergy's failure to perform, allowing a pass through of penalty costs makes the Companies indifferent to unit reliability at best, and certainly does not provide the incentives contemplated by the Capacity Performance market design approved by [FERC].").

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CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing public version of the Initial Post-Hearing Brief of the Sierra Club has been served upon the following parties via electronic mail on February 16, 2016:

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