BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan.	)))))))	Case No. 23-301-EL-SSO

INITIAL BRIEF
SUBMITTED ON BEHALF OF THE STAFF OF THE PUBLIC UTILITIES COMMISSION OF OHIO

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I. INTRODUCTION AND SUMMARY OF STAFF RECOMMENDATIONS

The Public Utilities Commission of Ohio should approve a fifth electric security plan ("ESP V") for the FirstEnergy Companies,[1] consistent with the Commission Staff's recommendations. These recommendations improve upon the Companies' proposed ESP by making it more affordable for ratepayers and more consistent with state policies and Commission precedent. Staff's recommendations also support the Companies' ability to provide reliable service to customers while maintaining the utilities' financial stability. As demonstrated through Staff's testimony, rather than a $110 million increase as the Companies proposed, Staff's recommendations would result in a **<u>$52 million rate reduction</u>** in the first year of ESP V as compared to current rates.

The Commission will hear from numerous parties in this case: the utilities, residential and nonresidential customer advocates, retail energy suppliers, environmental advocates, and others,

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[1] The Companies are, collectively, The Cleveland Electric Illuminating Company ("CEI"), Ohio Edison Company ("OE"), and The Toledo Edison Company ("TE").

each with differing perspectives and different financial interests. In developing its recommendations, Staff carefully considered the impacts on all stakeholders and evaluated the positions set forth in Company and intervenor testimony, many of which Staff agreed with, in whole or in part. Staff evaluated each issue on its individual merits and also considered the cumulative impact of Staff's various recommendations. Ten Staff witnesses testified, all of whom are seasoned regulatory professionals, and all of whom were supported behind the scenes by numerous other Staff subject matter experts. Given Staff's consummate expertise and unique ability to balance the interests of all parties, the Commission should give Staff's recommendations substantial weight.

Among other things, and as described more thoroughly below, Staff recommends the following improvements to ESP V:

Distribution Capital Recovery Rider ("DCR"). The Commission should allow the Companies to continue Rider DCR on an interim basis only, to be reevaluated in their upcoming 2024 base distribution rate case (the "2024 Rate Case"). The annual cap should be no more than $360 million in the first year of ESP V—a $30 million reduction from the current $390 million cap—with modest annual increases while the 2024 Rate Case is pending. Further, the Companies' current Rider DCR is substantially out of line with what the Commission has approved for other Ohio utilities. Rider DCR should be modified to be more consistent with other Ohio utilities' similar riders, as explained by Staff witness Mackey.

Standard Service Offer ("SSO") Auctions. Despite recent spikes in generation prices, the Companies' SSO Auctions have served ratepayers well, on the whole, for more than a decade. Consistent with the Commission's recent ruling in Case No. 23-781-EL-UNC, the Companies' auctions should include a capacity proxy price as necessary. But currently, there is no need to extensively modify the fundamental nature of Ohio's SSO auctions, which utilize a slice of system model and place the risk of customer migration on SSO suppliers.

ESP Term Length. ESP V should be approved for a six-year term, rather than the Companies' proposed eight-year term. A six-year term provides stability and certainty without locking in the terms of ESP V for an unduly long time.

Vegetation Management. The Companies should be allowed to recover some vegetation management costs through the Vegetation Management Cost Recovery Rider ("VMC"). Recovery should be capped at an amount sufficient for the Companies to meet their regulatory requirements—an average of about $26 million per year (subject to adjustment after the 2024 Base Rate Case). The Commission should not adopt the Companies' proposal, which would include rider charges averaging $68 million per year.

Economic Load Reduction ("ELR") Program. The Commission should approve continuation of the Companies' ELR program, which supports reliability and economic development in Ohio. Staff's recommended changes to the program make it (i) more affordable, by gradually phasing down charges that nonparticipants pay for the program, (ii) more equitable, by opening up the program to new participants, and (iii) more competitive, by requiring participants to engage in PJM capacity markets on their own rather than through their distribution utility.

Storm Cost Recovery Rider ("SCR"). The Commission should approve a rider to collect storm costs. But only storms that meet the definition of a "major event" under the Commission's rules should be eligible for recovery, consistent with what is allowed for other Ohio utilities. Further, the Commission should not approve recovery of the Companies' existing storm cost deferral balance until a full audit of all costs incurred through May 31, 2024 is completed.

Energy Efficiency and Demand Response. Consistent with Commission precedent, the Commission should approve a total budget of about $15.7 million per year for the Companies' proposals for a low-income energy efficiency program, energy education, and residential demand response.

Transmission Charges. PJM transmission charges incurred by the Companies should generally be passed through to customers. The Commission should adopt Staff witness Baas's recommended changes to the Companies' transmission rider ("Rider NMB"), which more closely track PJM's own allocations.

Shareholder Funding. The Commission should approve the Companies' proposal to commit $52 million in shareholder funding (*i.e.*, without any recovery now or in the future from ratepayers) for ratepayer benefit. In doing so, it should adopt Staff's recommendations that the Companies collaborate with stakeholders to ensure that these funds are put to the best use.

With these changes and those described below, Staff respectfully requests that the Commission approve ESP V.

II. RECOMMENDATIONS AND ARGUMENT

A. The Delivery Capital Recovery Rider should be approved on an interim basis only while the 2024 Rate Case is pending and should be modified to lower the rate impact on customers and to be more consistent with Commission precedent.

The Companies' Rider DCR was implemented in 2012.[2] Its fundamental purpose is to "maintain[] the reliability of the distribution grid."[3] Reliability of the distribution grid is maintained primarily through investments in distribution plant, which are found in FERC

[2] Co. Ex. 3 (Direct Testimony of Brandon McMillen) at 3 (Apr. 5, 2023).
[3] Staff Ex. 8 (Direct Testimony of Devin Mackey) at 7 (Oct. 30, 2023).

Accounts 360-374.[4] Ohio's other electric distribution utilities (AEP Ohio, Duke Energy Ohio, and AES Ohio) have distribution investment riders that allow them to recover only investments in those FERC accounts.[5] The Companies, on the other hand, have been allowed to recover other investments through Rider DCR. This includes transmission plant, general plant, intangible plant, and service company plant, which are in other FERC accounts.[6] These types of investments have at best an indirect impact on reliability and thus would be more appropriately recovered through other mechanisms, including base rates.[7]

The Companies' proposal for Rider DCR is essentially to leave Rider DCR unchanged, other than to increase the annual rider cap by $15 to $21 million per year.[8] Staff, however, recommends changes to Rider DCR to bring the Companies' Rider DCR back to its core purpose of supporting reliability, consistent with similar riders for Ohio's other electric distribution utilities.

As a starting point, Staff recommends that the Commission approve the DCR on an interim basis for the period June 1, 2024 through the effective date of new base rates in the Companies' 2024 rate case (referred to as the "Bridge Period"). Any further continuation of Rider DCR should be addressed in that rate case. If FirstEnergy fails to file a base distribution rate case in May 2024, Rider DCR should be set to zero as of June 1, 2024 and not be increased

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[4] *Id.* at 7.
[5] *Id.* at 7-8.
[6] *Id.* at 6.
[7] *See id.* at 7 (plant "in accounts outside of 360-374 are more appropriately recovered through other cost recovery mechanisms, including base rates"); Tr. Vol. XIV at 2408 (Staff witness Mackey testifying that "investments in the accounts outside of the distribution accounts 360 to 374, if they impact the distribution system, are more indirect impacts and not direct impacts" on reliability).
[8] *See generally* Co. Ex. 3 at 3-9. The increase would be $21 million if each of the three Companies meets both their SAIFI and CAIDI standards, $19 million if they meet five of six, $17 million if they meet four of six, and $15 million if they meet three or fewer. *See id.* at 5.

for the duration of ESP V.[9] Staff explained that although the Companies are already required by Commission Order to file a rate case in May 2024, this added penalty would give them an additional incentive to comply with the Commission's Order.[10]

During the Bridge Period, consistent with all other Ohio electric distribution utilities' similar riders,[11] the Companies should be allowed to recover only distribution plant investments in FERC Accounts 360-374.[12] Specifically, Staff testified (based on the Companies' data) that removing plant from other accounts would lower the current $390 million cap by about $51 million to a total of $339 million.[13] Staff recommends that while the 2024 Rate Case is pending, the cap could increase modestly by $15 million to $21 million annually to account for new investments, tied to meeting reliability metrics (using the methodology proposed by the Companies). These new investments would be limited to those properly placed in FERC Accounts 360-374. Thus, in the first year of ESP V (June 1, 2024 – May 31, 2025), Staff recommends an initial DCR cap of between $354 and $360 million. This is based on a starting point of $339 million, which accounts for the removal of plant outside of FERC Accounts 360-374, plus the $15-21 million annual increase.[14]

Staff's recommendation that the Commission approve an initial DCR cap of no more than $360 million, with annual increases of $15-21 million during the Bridge Period, allows for reasonable recovery of reliability-focused investments, which is the purpose of the DCR. Staff's recommendation is that the Commission not approve charges under Rider DCR beyond the

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[9] If Rider DCR is set to zero and there is a final reconciliation from ESP IV that requires a credit to customers as a result of overcollection, the rider should be populated as a credit. But if the final reconciliation would result in a charge, the charge should be disallowed, and the rider should remain at zero. *See* Staff Ex. 10 at 9, fn. 6.

[10] Staff Ex. 10 (Direct Testimony of Christopher Healey) at 9 (Oct. 30, 2023).

[11] Staff Ex. 8 (Mackey Testimony) at 5 (citing Commission rulings approving the other utilities' riders).

[12] *Id.*

[13] Staff Ex. 10 at Attachment CH-1 (adopting the Companies' analysis of the expected Rider DCR revenue requirement based on only investments in FERC Accounts 360-374).

[14] Staff Ex. 10 (Healey Testimony) at 10.

Bridge Period at this time. Instead, this should be assessed as part of the 2024 Rate Case. Stakeholders (including intervenors, the Companies, and Staff) would reserve all rights to take any position in the 2024 Rate Case regarding Rider DCR. If the Commission does not make a ruling in the 2024 Rate Case affirmatively ordering continuation of Rider DCR beyond the Bridge Period, then Rider DCR would be set to zero when new base rates become effective.[15]

Staff's proposal that Rider DCR only be approved for the Bridge Period, with reevaluation in the 2024 Rate Case, is fair and reasonable. Likewise, for Staff's recommended caps during the Bridge Period. The reduced cap sets more appropriate boundaries for what should be recovered through a distribution investment rider and ends the practice—unique in Ohio to FirstEnergy—of allowing recovery of investments outside FERC Accounts 360-374.[16] By deferring consideration of a longer-term Rider DCR until the 2024 Rate Case, parties and the Commission can weigh in on the appropriateness of the rider based on the comprehensive record established in the rate case.[17] And by eliminating the non-FERC Account 360-374 investments from the rider during the Bridge Period, ratepayers could save $45 million or more as compared to ESP IV and $75 million or more as compared to the Companies' Application.[18]

If the Commission does not adopt Staff's recommendation to approve Rider DCR only for the Bridge Period (*e.g.*, if the Commission rules that Rider DCR should be approved for the duration of ESP V), then Staff witness Devin Mackey provided a recommendation for Rider DCR caps beyond the Bridge Period.[19] In that instance, the Commission should approve $15-21 million increases as annual caps for the full ESP V term, using Staff's starting point of $339

[15] *Id.*
[16] *See* Staff Ex. 10 (Healey Testimony) at 10-11.
[17] *Id.* at 11.
[18] *Id.* at 11-12.
[19] Staff Ex. 8 (Mackey Testimony) at 2-4.

million. The following table compares Staff's recommended caps (minimum and maximum based on whether the Companies meet their reliability standards) with the Companies':[20]

Year	Companies proposed minimum	Companies proposed maximum	Staff's recommendation minimum	Staff's recommendation maximum
June 1, 2024, to May 31, 2025	$405,000,000	$411,000,000	$354,000,000	$360,000,000
June 1, 2025, to May 31, 2026	$420,000,000	$432,000,000	$369,000,000	$381,000,000
June 1, 2026, to May 31, 2027	$435,000,000	$453,000,000	$384,000,000	$402,000,000
June 1, 2027, to May 31, 2028	$450,000,000	$474,000,000	$399,000,000	$423,000,000
June 1, 2028, to May 31, 2029	$465,000,000	$495,000,000	$414,000,000	$444,000,000
June 1, 2029, to May 31, 2030	$480,000,000	$516,000,000	$429,000,000	$465,000,000
Cumulative cap totals over ESP	$2,655,000,000	$2,781,000,000	$2,349,000,000	$2,475,000,000

As this table demonstrates, Staff's recommended caps could save customers more than $300 million over six years as compared to the Companies' proposed caps.[21]

Regardless of whether the Commission approves Rider DCR for only the Bridge Period or for some longer duration, additional changes to the rider are necessary. Effective June 1, 2024 (the start of ESP V), the Commission should adopt the following Staff recommendations regarding Rider DCR:

1. As explained above, the Companies should only be allowed to include in Rider DCR those investments that are properly placed in FERC Accounts 360-374. The Companies should no longer be allowed to include Transmission Plant, General Plant, Intangible Plant, or Service Company Plant.[22]

2. The Companies should not be allowed to include projected plant-in-service in the rider. Currently under ESP IV, the Companies can recover investments before they are even made because the Companies file quarterly updates to Rider DCR

[20] Staff Ex. 8 (Mackey Testimony) at 5.
[21] *Id*. Note that this is based on a six-year ESP term, which is one of Staff's recommendations discussed later in this brief.
[22] Staff Ex. 8 (Mackey Testimony) at 7-8.

based on expected, rather than actual, plant investments. Quarterly updates already allow for near-immediate recovery, and the Companies' projected plant investments have been inaccurate in the past.[23] No other electric utility has enjoyed the benefit of recovering projected plant; the Commission should end this practice for FirstEnergy.

3. Currently, if the Companies are under the cap in one year, they can roll the unused cap space over to the next year, thereby increasing the next year's cap. Likewise, if the Companies go over their approved cap, they can carry the overage to the next year and recover it if it falls under the next year's cap.[24] None of Ohio's other electric utilities are allowed to do either of these things.[25] The Companies' Rider DCR should therefore be modified. If the Companies are under their cap in one year, it should have no impact on the following year's cap. And if the Companies are over the cap, the amount over the cap should not be rolled forward and should be excluded from the DCR.

4. Upon approval of rates in any future base rate case, the Companies should be required to update the DCR with any inputs (*e.g.*, rate of return, class allocation) updated in the rate case. The inputs are currently tied to the Companies' 2007 base rate case, making them outdated.[26]

5. The Companies should be required to add a revenue true-up schedule to the DCR. Currently, the only true-up is to reconcile the prior filing's estimated revenue requirement with the actual revenue requirement in the filing.[27] Because Staff is recommending hard caps and elimination of projected plant, the Companies need to track the revenue recovered from prior Rider DCR filings and true it up to the revenue requirement that was in effect for that filing.[28] As with many of Staff's other recommendations, this would bring FirstEnergy's Rider DCR in line with other Ohio electric utilities.[29]

6. Currently, the allocation and rate design for Rider DCR is unnecessarily convoluted, requiring each Company to allocate its revenue requirement and develop rates using forecasted sales and forecasted billing units, with each rate class paying a different rate based on kWh, kW, or kVa.[30] The Rider DCR rate should be simplified and charged as a percentage of base distribution revenues.[31] This is more sensible because it mirrors the payment of base distribution revenues, and Rider DCR is a capital rider.[32]

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[23] *Id.* at 8.
[24] *Id.* at 9-10.
[25] *Id.* at 9, fn. 10, 11, and 12.
[26] *Id.* at 10.
[27] *Id.* at 11.
[28] *Id.*
[29] *Id.*
[30] *Id.* at 11-12. *See also* Delivery Capital Recovery Rider Tariff Sheet 124.
[31] Staff Ex. 8 (Mackey Testimony) at 12.
[32] *Id.*

7. The Companies should be ordered to file their proposed DCR rates at least 60 days prior to the effective date, which they have not consistently done in the past.[33] If they don't, the rider should be set to zero three months after the effective date of the prior quarterly filing and remain at zero until the Companies meet the 60-day deadline on a future Rider DCR filing.[34] Any foregone revenues resulting from the rider being temporarily set to zero shall be permanently foregone—the Companies should not be allowed to increase future rider charges to account for these foregone revenues.[35]

8. Currently, the Companies' quarterly Rider DCR filings have dates certain at the end of February, May, August, and November. Each of these should be pushed back one month so that the last filing has a date certain of December 31.[36] This would simplify the annual review process because the Rider DCR filings would correspond with the Companies' FERC Form 1 filing, which uses plant balances through December 31.[37]

9. Historically, when the Companies have exceeded their annual Rider DCR cap, they have reduced the revenue requirement for just one of the three operating Companies to get below the cap.[38] To avoid this arbitrary result, the Companies should be required to reduce each of the three Companies' revenue requirements proportionately to get down to the overall revenue cap.[39]

10. In addition to the overall Rider DCR cap, each of the Companies has historically had its own sub-cap. FirstEnergy proposes that these sub-caps continue, with a cap of 70% for CEI, 50% for OE, and 30% for TE.[40] Staff recommends that these caps be modified to more closely reflect the allocation of plant investments among the three Companies. The Companies should be required to modify the individual Company revenue caps to 60% for CEI, 65% for OE, and 15% for TE. Staff's proposed caps would still provide the Companies with flexibility to spend on each of the three Companies as needed.[41]

11. If the Companies make any changes to their capitalization policy, they should be required to notify Staff of the change and provide documentation and an explanation of the new or revised policy.[42]

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[33] *Id.* at 12-13.
[34] *Id.* at 13.
[35] *Id.*
[36] *Id.* at 14.
[37] *Id.*
[38] *Id.* at 15.
[39] *Id.*
[40] Co. Ex. 3 (McMillen Testimony) at 5.
[41] Staff Ex. 8 (Mackey Testimony) at 16.
[42] *Id.* at 16.

In short, these Staff recommendations are important because they make the Companies' Rider DCR fairer, simpler, more reasonable, and more consistent with Commission precedent. If implemented, the Companies would still benefit from accelerated recovery of and on their capital investments, while ratepayers would receive greater protection in the form of more reasonable caps and more appropriate limits on rider mechanics and recovery. Staff's recommendations balance these competing interests.

B. The Commission should approve a Storm Cost Recovery Rider to recover prudently-incurred costs for Major Events that occur during ESP V.

The Companies' current ESP IV does not include a rider for storm costs. Instead, the Companies collect some storm costs through base rates and have been deferring additional storm costs since 2009.[43] The Companies now propose a new Storm Cost Recovery Rider ("Rider SCR").

As proposed by the Companies, Rider SCR would serve two purposes.[44] First, it would include recovery of deferred storm costs through May 31, 2024 over a five-year period.[45] Second, it would allow recovery of new storm costs incurred during ESP V, above those already collected through base rates. Staff recommends approval of Rider SCR but with modifications to the Companies' proposals.

First, Staff recommends that the Commission not allow recovery of the deferral balance at this time. The audit of the deferral balance should be completed in a separate proceeding, either in the 2024 Rate Case or a standalone proceeding.[46] In this future proceeding, Staff or its

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[43] Staff Ex. 2 (Direct Testimony of Jonathan J. Borer) at 3 (Oct. 30, 2023).
[44] *See generally* Co. Ex. 7 (Direct Testimony of Juliette Lawless) at 2-7 (Apr. 5, 2023).
[45] *Id.* at 6.
[46] Staff Ex. 2 (Borer Testimony) at 18.

designee would complete a comprehensive review of the deferral through May 31, 2024. During this review, Staff or its designee would be permitted to evaluate any and all aspects of the deferral that Staff or its designee deem appropriate. In addition to auditing the deferred expenses and determining the amount to be recovered, Staff recommends that all other aspects of the deferral be addressed, including the recovery period.[47] Staff further recommends that the Companies' existing deferral authority cease at the time ESP V becomes effective.[48]

Second, regarding storm costs incurred during ESP V, Staff recommends that Rider SCR only include incremental, prudently-incurred expenses related to storms that are "Major Events" as defined by Ohio Administrative Code 4901:1-10-01(T). As Staff witness Borer explained, limiting the rider to Major Events would be consistent with storm riders in place for other Ohio electric utilities.[49]

More importantly, Staff's proposal to use the Ohio Administrative Code definition of "Major Event" will increase certainty regarding which costs are recoverable. FirstEnergy's proposal is to allow recovery of any "event that is anticipated to last longer than twelve (12) hours (using local only crews)."[50] But this definition is impossibly vague. If Rider SCR is allowed to include expenses related to non-Major Events, it would be difficult to ensure that expenses are related to storms as opposed to routine maintenance that occurred around the same time as the storm.[51] This could lead to double recovery. Likewise, the Companies' definition "creates complications with providing assurance of proper cost assignments," including whether a particular cost was related to a specific storm.[52]

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[47] *Id.* at 19-20.
[48] *Id.* at 7.
[49] *Id.* at 6-7.
[50] Co. Ex. 7 (Lawless Testimony) at 3.
[51] Staff Ex. 2 (Borer Testimony) at 7-8.
[52] *Id*. at 8.

Further, the scope of eligible storms is vastly larger under FirstEnergy's proposal. Based on Staff's analysis, the number of eligible storms could increase by more than 300% using the Companies' definition as compared to Staff's.[53]

Limiting recovery to costs for Major Events is also appropriate because they are highly unpredictable and have the potential to cause significant financial harm to a utility. Non-Major Events, in contrast, should be recovered through base distribution rates.[54]

Third, the Companies proposed annual recovery caps for Rider SCR of $16 million for OE, $17 million for CEI, and $2 million for TE.[55] These caps are based on the *maximum* storm damage cost that the Companies incurred in the past eight years.[56] Furthermore, these caps would only apply to new storm costs incurred during ESP V; charges for the deferral balance through May 31, 2024 would be on top of these caps. If the Commission adopts Staff's recommendation to limit Rider SCR to only include recovery of Major Events, the proposed recovery caps would be unnecessary. Applying the Major Event criteria is itself a limit on recovery, as it restricts the costs to a limited number of storms each year. If, however, the Commission does not adopt Staff's recommendation to limit Rider SCR to only include recovery of Major Events, a cap would then be necessary. In that case, annual caps should be determined at the time the Companies file for recovery in a separate proceeding.[57]

Fourth, Rider SCR should not include any costs for straight-time (*i.e.,* non-overtime) labor. If the Companies' internal straight-time labor costs are included in the rider, there could be

[53] *Id.* at 8-9 (Staff's preliminary analysis showing that there were 50 storms per year under the Companies' definition but only 12 storms per year when limiting them to Major Events).
[54] *Id.* at 9-10.
[55] Co. Ex. 7 (Lawless Testimony) at 5.
[56] Staff Ex. 2 (Borer Testimony) at 9-10.
[57] *Id.* at 11.

double-recovery because straight-time labor is typically included in base rates.[58] This, too, would be consistent with other utilities' storm riders.[59]

Fifth, any straight-time labor costs that the Companies incur when providing mutual assistance should be credited to Rider SCR. At times, utilities offer other utilities resources, labor, and equipment to perform storm restoration outside the utility's service territory.[60] The other utility reimburses the utility providing mutual assistance. Without Staff's proposed credit, the Companies could be paid twice for their employee straight-time labor, once through base rates, and once through mutual assistance payments from the other utility.

Sixth, Staff recommends slight changes to the Companies' proposed process for annual rider updates. The Companies propose a May 1 filing each year, with rates automatically going into effect June 1, and then a separate filing by August 31 for an audit.[61] To simplify the process and to allow rates to include only actual incurred expenses, the Companies should make a single filing in August of each year that includes actual costs for the prior June 1 through May 31 period. Those rates would go into effect automatically after 60 days (subject to the Commission ruling otherwise), and the audit would occur in the same proceeding.[62]

Finally, because there is minimal regulatory lag associated with the Companies' recovery of storm costs incurred during ESP V, there should be no carrying charges applied to the Major Event expense.[63]

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[58] *Id.* at 12-13.
[59] *Id.* at 13, fn. 8.
[60] *Id.* at 14.
[61] *Id.* at 15.
[62] *Id.*
[63] *Id.* at 16. For clarity, Staff is not taking any position at this time regarding carrying charges on the deferral balance incurred from 2009 through May 31, 2024. This would be addressed in a future proceeding under Staff's proposal.

C. The Commission should approve a Vegetation Management Cost Recovery Rider to incur prudently-incurred vegetation management costs in an amount that allows the Companies to meet their regulatory requirements.

The Companies propose to establish a Vegetation Management Cost Recovery Rider ("Rider VMC") "for the recovery of incremental vegetation [operations and maintenance (O&M) expenses] compared to the baseline recovered in base distribution rates."[64] The Company states that Rider VMC will help to ensure that customers are only paying the actual expense incurred from vegetation management, with timely reconciliation and carrying charges, subject to annual audit and regulatory review.[65] The current baseline for O&M expense is around $30 million.[66]

The Companies' vegetation management proposal has two components. First, the Companies propose $460 million in spending over eight years, which they state is necessary to meet their minimum regulatory requirements.[67] This includes the $30 million currently in base rates, so rider charges for this portion would be about $220 million over eight years. Second, the Companies propose an additional $300 million over eight years for an "enhanced vegetation management program."[68] The following table summarizes the Companies' proposed spending:

	Base Rates[69]	**Add'l to Meet Regulatory Requirements**[70]	**Enhanced Program**[71]
Year 1	$29.6M	$22.1M	$46.8M
Year 2	$29.6M	$23.7M	$47.8M
Year 3	$29.6M	$25.3M	$48.9M
Year 4	$29.6M	$26.9M	$50.0M

[64] Co. Ex. 3 (McMillen Testimony) at 19.
[65] *Id*.
[66] *Id*.
[67] *See* Co. Ex. 8 (Direct Testimony of Shawn Standish) at 12 (Apr. 5, 2023).
[68] *Id.*at 9-12.
[69] *See* Co. Ex. 3, Attachment BSM-4 at 1 ($29,596,811 currently included in base rates). This amount will be updated as part of the 2024 Rate Case.
[70] *See* Co. Ex. 8 at 12, Table 3 (Minimum Regulatory Requirements column, minus the $29.6 million currently in base rates).
[71] Co. Ex. 8 at 12, Table 3 (Additional Reliability Improvements column).

Year 5	$29.6M	$28.6M	$26.0M
Year 6	$29.6M	$30.4M	$26.4M
Year 7	$29.6M	$32.2M	$26.8M
Year 8	$29.6M	$34.0M	$27.3M

Staff supports approval of Rider VMC at the start of the proposed ESP V but recommends that the Commission approve caps lower than the ones proposed by the Companies. Staff proposes Rider VMC caps equal to the amounts in the table above in the column marked Additional to Meet Regulatory Requirements for years one through six.[72]

If Staff's proposal were adopted, the Companies could charge ratepayers up to $334.6 million over a six-year period through base rates and Rider VMC.[73] This is a significant reduction from the Companies proposal for up to $759.8 million in charges over an eight-year ESP term.

Based on Staff's review of the Companies' recent historical vegetation management spending and reliability performance, the Companies' cost estimates for vegetation management spending to meet their regulatory requirements are reasonable. The caps should be reset in the 2024 Rate Case, where a new baseline will be set based on a holistic view of vegetation management spending.[74]

Staff also recommends that rates for Rider VMC become effective 60 days after filing, as opposed to the Companies' proposal that rates go into effect on June 1 after a May filing. The current deadline does not provide sufficient time for Staff to identify issues that may prompt the Commission to pause the updated rates.[75] Further, Staff recommends that no carrying charges be

[72] *See* Staff Ex. 1 (Direct Testimony of Natalia Messenger) at 6 (Oct. 30, 2023).
[73] *Id*. Staff's recommendation is based on a six-year term because Staff is recommending six years for ESP V instead of the Companies' proposed eight-year term.
[74] Tr. Vol. XI at 2067.
[75] Staff Ex. 1 (Messenger Testimony) at 8.

applied to Rider VMC rates; there is minimal regulatory lag because the rider is updated annually and would go into effect 60 days after filing under Staff's proposal.[76]

D. To provide for continued reliability and economic development benefits, the Commission should approve continuation of the Economic Load Reduction program but with lower credits to reduce charges paid by nonparticipants.

1. The Commission should adopt Staff's proposed ELR credits: $5 in year one, $4 in years two through four, and $3 in years five and six.

The Companies' Economic Load Reduction ("ELR") program should continue but with some modifications. The ELR program is a form of demand response that is designed to improve reliability.[77] The Commission has also found that the program and others like it support economic development.[78] It provides credits to participating nonresidential customers who agree to reduce their demand for electricity when called upon, specifically at times when the grid is stressed. Currently, the program is limited to twenty-four customers. These customers receive credits in the amount of $10/kW-month. During the first seven years of ESP IV, participating customers received, in the aggregate, between $55.1 million and $67.5 million per year—a total of more than $430 million.[79]

Staff, the Companies, and several intervening parties—Ohio Energy Group ("OEG"), Ohio Energy Leadership Council ("OELC"), and Nucor Steel Marion—filed testimony in

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[76] *Id.*
[77] Staff Ex. 10 (Healey Testimony) at 16.
[78] *See, e.g., In re Application of [FirstEnergy] 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, Opinion & Order at 94 (Mar. 31, 2016). *See also In re Application of Ohio Power Co. for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143, in the Form of an Electric Security Plan,* Case No. 13-2385-EL-SSO, Opinion & Order at 40 (Feb. 25, 2015) (finding that AEP Ohio's similar program "offers numerous benefits, including the promotion of economic development and the retention of manufacturing jobs").
[79] Staff Ex. 10 (Healey Testimony) at 17. This would be in addition to amounts they received or will yet receive in year 8 of ESP IV, and more than $170 million they received from the program before ESP IV. *See* RESA Ex. 8 (Companies' response to RESA Set 02, INT-005).

support of continuing the ELR program, though there are differing opinions regarding the details. The following table summarizes these parties' proposed ELR credits:

Year	FE[80]	Staff[81]	OEG[82]	OELC[83]	Nucor[84]
1	$10	$5	$10	$10	$10
2	$9	$4	$9	$10	$10
3	$8	$4	$8	$10	$10
4	$7	$4	$7	$10	$10
5	$6	$3	$7	$10	$10
6	$5	$3	$7	$10	$10
7	$4		$7	$10	$10
8	$3		$7	$10	$10

As this table demonstrates, there is disagreement among these parties regarding how much ELR participants should be paid.[85] Staff considered various quantitative and qualitative factors in recommending its proposed credits. The starting point for Staff's analysis was market pricing. The ELR program is closely tied to PJM's demand response market. Staff analyzed PJM demand response clearing prices over the last decade and found that they averaged around $3.40/kW-month.[86] The current $10/kW-month credit—nearly three times the average market price and around ten times the current market price—if continued, would result in undue subsidies paid by nonparticipating customers.[87]

Staff considered other factors in arriving at its proposed credits. While at first glance, a reduction from $10/kW-month to $5/kW-month might seem large, this is not an apples-to-apples comparison. Under the current ESP IV program, FirstEnergy serves as the curtailment service

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[80] Co. Ex. 3 (McMillen Testimony) at 12-13.
[81] Staff Ex. 10 (Healey Testimony) at 24. Because Staff is recommending a six-year ESP, it did not provide a recommended credit for years 7 and 8.
[82] OEG Ex. 3 (Direct Testimony of Kevin Murray) at 17-18 (Oct. 23, 2023).
[83] OELC Ex. 32 (Direct Testimony of Matthew Brakey) at 46 (Oct. 23, 2023).
[84] Nucor Ex. 1 (Direct Testimony of Dennis Goins) at 11 (Oct. 23, 2023).
[85] OMAEG believes the program should end unless it is completely overhauled but did not propose any specific amount for ELR credits. *See* OMAEG Ex. 1 (Direct Testimony of John Seryak) at 12 (Oct. 23, 2023).
[86] Staff Ex. 10 (Healey Testimony) at 24.
[87] *Id.*

provider ("CSP"). This means that FirstEnergy bids the ELR participants' demand response into PJM and receives revenues from PJM, which are credited to nonparticipating customers. Under Staff's proposal, however, ELR participants would engage their own CSP, and the *participants themselves* would get to keep any PJM revenues.[88] This new revenue stream would make up some or even all of the difference between the current $10 credit and Staff's recommended credits.[89] Staff's credits, when combined with the opportunity for ELR participants to earn market-based revenues on their own, are consistent with the principle of gradualism and mitigate concerns about rate shock for ELR participants.[90]

Staff also considered the impact on nonparticipants. While the program does result in reliability and economic development benefits, those benefits come at a cost in the form of rider charges for nonparticipating customers.[91] The Commission should seek to maximize participation in the program while minimizing the costs paid by nonparticipants. Staff's recommendations achieve the proper balance. Indeed, as Staff testified, lower credits would not be expected to result in lower participation in the program.[92] Citing AEP Ohio as an example, the credits for that utility have been *less than a dollar* in recent years, yet that program remains highly subscribed with customers asking to increase participation in the program.[93] Thus, any claim that lowering credits to Staff's proposed levels will cause current participants to drop out

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[88] Staff Ex. 10 (Healey Testimony) at 21-24. The Companies proposed the change whereby participants would hire their own CSP rather than using FirstEnergy as CSP. Staff agrees with this proposal and incorporated it into its recommendations.
[89] Tr. Vol. VIII at 1680 (OEG witness Murray testifying that PJM revenues could be greater than the reduction in credits). *See also* OELC Ex. 32 at 50 (OELC witness Brakey testifying that periods of low capacity prices can be followed by periods of much higher prices).
[90] Staff Ex. 10 (Healey Testimony) at 25 ("Staff's proposed ELR credits are reasonable because they avoid rate shock for participating customers and move Ohio toward a more market-based approach."). *See also* Tr. at 2538.
[91] Staff Ex. 10 (Healey Testimony) at 26.
[92] Tr. Vol. XIV at 2588.
[93] *Id.*

of the program is not indicative of what has occurred in the AEP program. In other words, Staff's proposed credits are expected to provide the same reliability benefits at a lower cost.

In contrast to Staff, the ELR participants' primary position is that the credits they receive should be as high as possible. OELC and Nucor take a particularly rigid stance, demanding that the credit remain at $10/kW-month—an amount that was approved as part of a larger stipulation in ESP IV—for the entire ESP V term with no reduction.[94] OEG, to its credit, concedes to a reduction over time, with payments staying at $10 in the first year and then decreasing by $1 per year until they reach $7, where they would remain for the duration of ESP V.[95] None of these parties provided a quantitative justification for their proposed credits. They discuss the benefits of the ELR program—reliability and economic development—which Staff broadly agrees with. But there is no tie in these intervenors' proposals to these benefits and the higher credits that they propose.[96]

To be fair, Staff's proposed credits are not entirely derived from a strict quantitative analysis. The economic development benefits of the program, while real, are difficult to quantify, and none of the Companies, Staff, OEG, OELC, or Nucor was able to quantify them. And reliability benefits can be quantified in part by reference to PJM capacity prices, but the program also supports local reliability, which again, neither Staff nor any other party specifically quantified.[97] Ultimately, when deciding the appropriate level of credits, the Commission will

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[94] *See* OELC Ex. 32 (Brakey Testimony) at 46; Nucor Ex. 1 (Goins Testimony) at 11.
[95] OEG Ex. 3 (Murray Testimony) at 17-18.
[96] For clarity, Staff understands that stakeholders intervene in cases to pursue their own interests, financial or otherwise. There is nothing wrong with these parties advocating for higher credits for the benefit of their clients. But when deciding what level of credits to approve, the Commission must consider the broader public interest and the interests of nonparticipants, not just these parties' desire for greater financial compensation under the program.
[97] Tr. Vol. XIV at 2591 (Staff witness Healey testifying that there are local reliability benefits in addition to reliability derived from PJM demand response events).

need to rely on parties' expert judgment and determine which party—Staff, the Companies, or intervenors—best balanced all the competing factors.

2. The Commission should gradually and modestly open the ELR program up to new participants.

When determining the proper size of the ELR program, there are competing interests. Staff generally supports competition and open access to participation in utility programs. But Staff also generally supports caps on participation in utility programs to mitigate the bill impacts for nonparticipating customers.[98] To balance these interests, Staff recommends that the ELR program be increased by 50MW each year for five years, beginning June 1, 2025.[99] It should be open to new participants on a first-come-first-served basis, with the same per-kW credit amounts and requirements as current participants. If new participants do not fill the entire new 50MW (after being given a reasonable open enrollment period), then current ELR participants could be offered an opportunity to increase their interruptible load.[100]

This modest annual increase (10% of the current approximately 500 MW participating in the program[101]) will allow new customers to participate and benefit from the program. And coupled with Staff's recommended reduction in credits, nonparticipants will pay less under Rider ELR than they do currently, even with the additional 50MW of participation.[102]

In contrast, the Companies propose no new additions to the program.[103] And on the opposite end of the spectrum, OELC recommends unlimited participation in the program with no

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[98] Staff Ex. 10 (Healey Testimony) at 26.
[99] *Id.* Thus, in year six of ESP V, an additional 250MW will have been made available to new participants.
[100] *Id.* at 27.
[101] *See* Tr. Vol. XIV at 2520 (average ELR load of approximately 500 MW).
[102] Staff Ex. 10 (Healey Testimony) at 17, 27 ($27 million per year under Staff's proposal compared to ESP IV charges of around $60 million per year).
[103] *See* Co. Ex. 10 (Direct Testimony of Edward Stein) at 7 (Apr. 5, 2023).

cap whatsoever on charges to nonparticipants.[104] The Commission should reject the Companies' proposal because it unfairly limits the program to only those who currently participate in the program, and current participants' eligibility was based on a stipulation in ESP IV.[105] And the Commission should reject OELC's proposal because it makes no attempt to consider nonparticipant rate impacts.

3. The Commission should adopt Staff's additional ELR recommendations, which simplify cost recovery and make the program more market based.

Staff recommends several changes to FirstEnergy's recovery of costs for the ELR program.[106] The Companies currently recover the costs of the program through two different riders, Rider DSE1 and Rider EDR. To simplify cost recovery, Staff recommends that all ELR program costs be recovered through Rider EDR.[107] What was formerly recovered through Rider DSE1 should be added as a new component of Rider EDR, with the same allocation currently being used under Rider DSE1. The allocations and calculation of per kWh rates for Rider EDR(e)-1 and Rider EDR(e)-2 should continue without modification. Then, all three per kWh rates should be included in the overall Rider EDR rate. This will simplify the recovery of costs for the ELR program. It has the added benefit of allowing Rider DSE to be removed from the Companies' tariffs once there is a final reconciliation of Rider DSE2.[108]

Staff also supports the Companies' proposal to no longer serve as the CSP for the ELR program.[109] Allowing large nonresidential customers to participate in demand response programs

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[104] *See* Tr. Vol. IX at 1776 (OELC witness Brakey testifying, "I don't think there should be a cap" on the amount that other customers pay to fund the program).
[105] *See* Case No. 14-1297-EL-SSO, Opinion & Order (Mar. 31, 2016).
[106] Staff Ex. 10 (Healey Testimony) at 19-20.
[107] *Id.*
[108] *Id.*
[109] *See* Co. Ex. 10 (Stein Testimony) at 4-5; Staff Ex. 10 (Healey Testimony) at 21.

on their own is a more market-based approach. Further, as described above, if FirstEnergy is no longer the CSP, participating customers would be allowed to keep any PJM revenues that they derive from their participation. This will allow FirstEnergy to reduce the credits paid to participants, lowering the amount that other customers pay for the program while giving participants a new revenue stream not currently available to them *and* maintaining the program's reliability benefits.[110]

E. The Commission should approve a $15.7 million annual budget for energy education, low-income energy efficiency, and demand response for residential customers.

The Companies proposed a four-year energy efficiency plan with four residential programs (Residential Rebates, Energy Education, Low Income Energy Efficiency, and Demand Respond) and one program for Commercial and Industrial programs called Energy Solutions for Business.[111] Their proposed budget is approximately $72.1 million per year over the proposed four-year term. The Companies state that at the conclusion of the four-year term, they will determine whether they will seek approval to extend, modify, or terminate the programs.[112]

Consistent with recent Commission precedent, Staff supports the Residential Energy Education, Low Income Energy Efficiency, and Demand Response programs, but not Residential Rebates and Energy Solutions for Business programs.[113] If the Commission approves Staff's recommendation for a six-year ESP term, Staff recommends that the programs be approved for three years. Then, at the end of the three-year term, the Companies be permitted to request a

[110] Staff Ex. 10 (Healey Testimony) at 21.
[111] Staff Ex. 3 (Direct Testimony of Kristin Braun) at 2 (Oct. 30, 2023).
[112] Co. Ex. 5 (Direct Testimony of Edward Miller) at 4 (Apr. 5, 2023).
[113] *See In the Matter of the Application of Columbia Gas of Ohio, Inc. For Authority to Amend its Filed Tariffs to Increase the Rates and Charges for Gas Services and Related Matters*, Case No. 21-0637-GA-AIR, et al., Opinion & Order, at 56 (Jan. 26, 2023) ("It is time to look to competitive markets to play a more significant role in the provision of energy efficiency services in this state.").

modification, extension, or termination of those programs.[114] Unless the program is extended, Staff recommends that only the costs within that three-year period should be recovered through the Energy Efficiency Cost ("EEC") Recovery Rider.

In regard to the cost recovery mechanism for the Companies' proposed EEC Recovery Rider, Staff recommends the following modifications to the Companies' proposal:

(1) The Companies should only be authorized to recover expenses through the rider that are known, measurable, and already incurred;

(2) The Companies should not be allowed to defer recovery of prudently incurred expenses over an eight-year period;

(3) The Companies should not be allowed to receive carrying charges on expenses in the rider;

(4) The Companies should only be eligible to recover expenses incurred in the first three years of this ESP; and

(5) The Companies should docket the annual EEC Rider filing at least 60 days in advance of its effective date.[115]

Staff recommends that the Companies only be allowed to recover expenses that are already incurred, known, and measurable. Staff does not believe Companies should utilize projected expenses in the calculation of the rider.[116]

Based on the Companies' proposal to defer recovery of prudently incurred expenses over an eight-year period, Staff estimates that deferral will cost residential customers around $39.8 million,[117] which is approximately a 30% increase above the residential program costs.[118] In this case, Staff finds that a delay in recovering those costs will cost customers substantially more if the Commission approves carrying charges on the unrecovered expense balance. As such, Staff

[114] Staff Ex. 3 (Braun Testimony) at 3.
[115] Staff Ex. 8 (Mackey Testimony) at 22.
[116] Tr. Vol. XIV at 2435-2436.
[117] Staff Ex. 8 (Mackey Testimony) at 22.
[118] *Id*. at 23.

recommends that the Companies not be allowed to benefit and accrue carrying charges for deferring recovery of expenses that could have been recovered in a prior EEC filing.[119]

Staff requests that the annual EEC Rider filing be docketed at least 60 days prior to its effective date to give Staff sufficient time to complete an initial review of the rider before its effective date.[120]

If the Commission adopts Staff's recommendations, the annual program budget should be $15,663,202 per year.[121] Staff's recommendations to modify the Companies' proposed programs are aligned with recently approved energy efficiency programs[122] while taking into account programs that are appropriate in size and scale to allow the Companies to provide customers with energy efficiency and demand response services.[123]

F. The Commission should approve continuation of the Companies' current SSO auction procedures, modified to include a capacity proxy price mechanism.

The Companies propose several changes to their current SSO competitive bidding process. Broadly speaking, the Companies propose to continue the declining clock auction structure and the laddering and staggering of auction dates and terms that, when blended, form the basis of the SSO rate.[124] Staff supports this. As Staff witness Benedict testified, this auction structure has been adopted by each of the Ohio electric distribution utilities and has proven to be an effective mechanism to leverage competitive forces and allow wholesale market conditions to

[119] *Id*.
[120] Staff Ex. 3 (Braun Testimony) at 24.
[121] *Id*. at 4.
[122] *See In the Matter of the Application of Columbia Gas of Ohio, Inc. For Authority to Amend its Filed Tariffs to Increase the Rates and Charges for Gas Services and Related Matters*, Case No. 21-0637-GA-AIR, et al., Opinion & Order, at 56 (Jan. 26, 2023) ("It is time to look to competitive markets to play a more significant role in the provision of energy efficiency services in this state.").
[123] Staff Ex. 3 (Braun Testimony) at 5.
[124] *See generally* Co. Ex. 6 (Direct Testimony of Robert Lee) (Apr. 5, 2023).

determine the rate for default service.[125] Furthermore, having an SSO rate that is competitively determined also serves to discipline the retail marketplace by providing customers with a rate for default generation service to compare with other retail offerings.[126]

1. The Companies' SSO auctions should include a capacity proxy price mechanism.

The Companies propose the addition of a capacity proxy price mechanism.[127] Where the PJM capacity price is unknown for the delivery period of a certain auction, a capacity proxy price would be set, and then once actual capacity prices are known, the SSO price will be updated to charge customers the actual price.[128] The Commission recently ordered all Ohio utilities to utilize a capacity proxy price for SSO auctions for years in which no price has been set by PJM.[129] And indeed, in this very case, the Commission has ordered FirstEnergy to include a capacity proxy price in its upcoming spring auction.[130]

2. The Commission should not adopt the Companies' proposal for a volumetric risk cap.

The Companies also propose the use of a "volumetric risk cap" to address concerns that might arise when significant load migrates from shopping for generation back to the SSO. Under the Companies' proposal, a benchmark level would be set at the Peak Load Contribution ("PLC") per tranche as of the first day of each SSO delivery period (*i.e.*, beginning June 1 each year). Then, the volumetric risk cap would be set at 20MW above the benchmark. In other words,

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[125] Staff Ex. 6 (Direct Testimony of Timothy Benedict) at 2 (Oct. 30, 2023).
[126] *Id.* at 2-3.
[127] Co. Ex. 6 (Lee Testimony) at 11.
[128] *Id.* at 11-13.
[129] *In re Proposed Modifications to the Electric Distribution Utilities' Standard Service Offer Procurement Auctions*, Case No. 23-781-EL-UNC, Finding & Order (Dec. 13, 2023).
[130] Entry at 5 (Jan. 10, 2024).

winning SSO bidders would be required to supply up to 20 MW above the benchmark.[131] If the load exceeds this limit, it would be supplied by the Companies at real-time market prices.[132]

Staff recommends that the Commission not adopt the Companies' proposal for a volumetric risk cap. There are several concerns with the proposal.

First, it is true that at least in theory, a volumetric risk cap might result in slightly lower SSO bid prices because suppliers could include lower risk premiums in their bids.[133] All else equal, this would seem to benefit ratepayers in the form of lower SSO prices. At the same time, however, SSO customers would now be exposed to the risk of paying market prices, which during periods of high demand can be extraordinarily high (up to $4/kWh, which is nearly <u>*four thousand times*</u> as high as current SSO prices).[134] So the question the Commission must ask itself is whether reducing risk premiums to theoretically lower SSO prices is worth exposing SSO customers to real-time market pricing. In a recent decision involving another EDU, the Commission stated that it was "not prepared, at this time, to adopt any mechanism that shifts migration risk from wholesale suppliers to consumers in this state."[135]

Another problem with the Companies' volumetric risk cap proposal is that it is based on an unusual calculation of PLC values. At PJM, each customer has a fixed PLC that is determined prior to the delivery year.[136] *If* a volumetric risk cap were to be adopted, the cap should be based on the aggregate PLCs of all SSO customers. In other words, when a customer migrates to or from the SSO, its fixed PLC tag should go with it. Each day, the Companies would look at the

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[131] Co. Ex. 6 (Lee Testimony) at 6-7.
[132] *Id.*
[133] *See* Staff Ex. 6 (Benedict Testimony) at 3 (the Companies' proposal "should *theoretically* translate into lower risk premiums in SSO auction bids and therefore lower SSO auction clearing prices") (emphasis added).
[134] *Id.* at 3-4 (SSO ratepayers "would now be exposed to market prices rather than a fixed auction price"). Tr. Vol. IV at 729-30 ($4/kWh real-time market prices).
[135] *In re The Dayton Power and Light Company d/b/a AES Ohio*, Case No. 22-900-EL-SSO, et al., Opinion and Order at ¶ 247 (Aug. 9, 2023).
[136] Tr. Vol. XIII at 2375.

total PLC values for all SSO customers and determine whether it exceeds the risk cap. Thus, the only way that the volumetric risk cap would be triggered would be through customer migration.[137] Increased *usage* on a single day (for example, based on weather) would not change any customer's PLC, so it would not impact whether the cap is triggered.[138]

The Companies' proposal, however, appears to define PLC differently. Rather than set each customer's PLC in advance of the delivery year as is done at PJM, the Companies propose that they recalculate a PLC value for SSO load on a daily basis. This is based on kilowatt hour energy usage during each hour for non-shopping load.[139] Thus, under the Companies' proposal, PLC values can change irrespective of load migration, and the volumetric risk cap could be triggered without any migration at all.[140] Allowing the volumetric risk cap to be triggered on a daily basis based on changes in usage resulting from, for example, the weather, would expose customers to risk of paying market prices for reasons other than customer load migration.

If, despite these concerns, the Commission nevertheless concludes that the above tradeoff is in the public interest, Staff would make the following recommendations. First, the Companies should publish the daily PLC value for non-shopping load on their auction website as expeditiously as possible so interested parties can evaluate migration levels and determine whether the cap is likely to be exceeded during a delivery year. Staff would also recommend that for two-year products, the cap be reset at the start of the second delivery year based upon the

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[137] *Id.*
[138] *Id.* at 2375-76.
[139] Tr. Vol. IV at 719.
[140] Tr. Vol. IV at 771-72. Indeed, it is not clear whether FirstEnergy's proposal is clear at all. It appears that FirstEnergy witness Lee testified that the cap could be triggered by increased usage resulting from, for example, changes in weather. *Id.* But FirstEnergy witness Stein seemed to believe that PLCs should change only based on migration. *See* Tr. Vol. VII at 1516-17. This apparent contradiction and uncertainty alone should give the Commission pause in approving any volumetric risk cap, given that the details of what the Commission would be approving might be vague and ambiguous.

actual tranche PLC at that time. This would effectively reset the cap based upon the migration levels that were observed at the start of year two.

Further, Staff recommends that, should the cap be exceeded, the Commission initiate a process to evaluate whether it is prudent to continue with real-time market purchases or to consider alternative procurement strategies.[141] Staff agrees with the Companies that it should be their responsibility, at least initially, for procuring any load in excess of the cap.

3. Staff does not oppose the Companies' proposal to eliminate 36-month contracts from its SSO auctions.

Staff does not oppose the Companies' proposal to eliminate 36-month contracts. As Staff witness Benedict testified, shorter terms present reduced risk to potential suppliers and therefore may result in lower risk premiums being incorporated into bids.[142] While this modification may slightly increase volatility, it may also cause SSO rates to be more closely in alignment with current market conditions.[143]

4. The Commission should not adopt the Companies' proposal to restrict bidding eligibility based on credit metrics.

Staff opposes the Companies' proposal to modify the credit-based tranche caps for potential SSO suppliers. This proposal would reduce the maximum initial bidding eligibilities for certain qualified bidders based upon their credit ratings. As explained by Staff witness Benedict, this proposal has not been adequately justified by the Companies.[144] Staff recommends not only that the Commission reject the Companies' proposed changes, but also that the Commission should keep the credit-based tranche caps unchanged from the previous ESP. Initial bidding

[141] Staff Ex. 6 (Benedict Testimony) at 5.
[142] *Id.*
[143] *Id.*
[144] *Id.* at 7.

eligibilities should be as accommodating as is reasonable to allow for robust participation in SSO auctions by a diverse range of qualified suppliers.

5. At this time, the Commission should not adopt intervenor proposals to hold separate SSO auctions by class.

Currently, Ohio's SSO auctions use a slice-of-system approach, where customers in all rate classes pay the same SSO rate. Several intervenors, however, have proposed that the Companies hold separate auctions for different classes.[145]

Staff has concerns about proposals to hold separate auctions by customer class. While Staff recognizes that mass-market residential or small commercial loads and larger commercial or industrial loads have differing characteristics and present different risks to suppliers, each supplier may value these risks differently. Consequently, there is no guarantee that separating products by customer class will produce a lower auction price. Combining these mixed loads into a single product that is as broadly defined as possible actually mitigates the idiosyncrasies of serving any customer class in isolation, to the benefit of all customers.[146] As the Commission stated in a recent decision involving another utility, "we are not persuaded that separating the auctions into auctions for residential customers and non-residential customers will result in aggregate savings to consumers in this state."[147]

G. The Commission should approve a six-year ESP term length.

The Companies proposed an eight-year ESP term.[148] Staff recommends a six-year ESP term instead (June 1, 2024 through May 31, 2030). The Commission has typically approved

[145] *See* Constellation Ex. 11 (Direct Testimony of Muralikrishna Indukuri) at 25-26 (Oct. 23, 2023); OCC Ex. 2 (Direct Testimony of James F. Wilson) at 10-18 (Oct. 23, 2023).
[146] *Id.* at 9.
[147] *In re The Dayton Power and Light Company d/b/a AES Ohio*, Case No. 22-900-EL-SSO, et al., Opinion and Order at ¶ 247 (Aug. 9, 2023).
[148] Co. Ex. 2 (Direct Testimony of Santino Fanelli) at 2 (Apr. 5, 2023).

ESPs of lengths between three and six years,[149] with a few outliers.

There are pros and cons to different ESP term lengths. A shorter ESP term allows greater flexibility to account for changes in market conditions, which can include geopolitical changes, new and emerging technologies, inflation, recessions, modifications to wholesale market processes, and new laws and regulations. A shorter term is therefore beneficial because it gives the Commission a better opportunity to revisit a utility's SSO based on the most current information and make changes that are in the public interest. On the other hand, a longer ESP term can be beneficial because it provides certainty and stability for the utility, ratepayers, and other stakeholders.[150] Staff's recommended six-year terms balances the benefits of both.

H. The Commission should approve the Companies' proposal to spend $52 million in shareholder funds for the benefit of customers while requiring the Companies to work with stakeholders to put those funds to their best possible use.

The Companies propose $52 million in shareholder funding for the benefit of customers.[151] This includes (i) $20 million for bill payment assistance, (ii) $16 million for a low-income senior citizen bill discount program, (iii) $12 million for electric vehicle ("EV") related initiatives, and (iv) $4 million for grid innovation investments.[152] Although the Companies are offering this shareholder money voluntarily, FirstEnergy witness Fanelli confirmed that because it is part of their Application, it would be a binding regulatory commitment if approved.[153] Staff supports the use of shareholder funds for the benefit of ratepayers and recommends that the Commission approve $52 million in shareholder commitments. Staff, however, proposes that the

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[149] Staff Ex. 10 (Healey Testimony) at 3-4.
[150] *Id.*
[151] Co. Ex. 2 (Fanelli Testimony) at 8.
[152] *Id.* at 8-9.
[153] Tr. Vol. I at 61.

Companies work with stakeholders to ensure that these shareholder funds are put to their best use.

Staff witness Krystina Schaefer addressed the Companies' proposal to provide $12 million of shareholder funds to support the EV transition and $4 million in grid resilience and innovation.[154]

The $12 million to support the EV transition includes a commercial web application, marketing, and communications campaigns around the EV transition and potential benefits ($0.5-$0.7 million annually), financial assistance for customers to support grant writing to obtain government funding ($0.4-$0.6 million annually), educational toolkits for auto dealerships ($0.1 million annually), and financial assistance for customers to obtain fleet advisory services ($0.3-$0.5 million annually).[155]

According to Ms. Schaefer, there is value in electric distribution utilities exploring the impacts associated with the EV transition to help inform distribution system planning and, ideally, to develop rate design options to support the efficient use of the distribution system in accordance with state policy as set forth in R.C. 4928.02(A).[156] Moreover, these investments are consistent with the state policy contained in R.C. 4928.02 11(J) and (N) to "provide coherent, transparent means of giving appropriate incentives to technologies that can adapt successfully to potential environmental mandates while also facilitating the state's effectiveness in the global economy."[157]

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[154] Staff Ex. 4 (Direct Testimony of Krystina Schaefer) at 4 (Oct. 30, 2023).
[155] *Id.*
[156] *Id.* at 5
[157] *In the Matter of the Commission's Investigation into Electric Vehicle Charging Service in the State,* Case No. 20-434-EL-COI, Finding & Order, at 2 (July 1, 2020).

Staff therefore recommends that the Companies' proposal to provide at least $12 million in shareholder funds to support the EV transition be approved, subject to certain modifications. Specifically, Staff recommends that the Companies modify the program design so that their associated activities are limited to those directly related to providing distribution service. This could include customer education about rate options for EVSE site hosts, shareholder funded credits to encourage charging during times of low localized distribution system demand, or improvements to the siting and interconnection process for EVSE. To develop a modified EV transition program, the Companies should meet with interested parties within 90 days of an Opinion and Order in the current case to discuss how the money should best be spent. For any shareholder-funded EV transition programs, the Companies should file annual status updates in the current case to detail progress and associated spending each year.[158]

The $4 million grid investment proposal was related to the U.S. Department of Energy Grid Innovation Program ("GIP").[159] The Companies, however, were not among the applicants selected to receive funding under the first funding opportunity for the program.[160] Therefore, Staff supports the Companies' proposal to reallocate the $4 million towards the other shareholder-funded EV and low-income programs included in the Application. But if the Companies pursue and receive approval through future funding opportunities, then Staff recommends that the Companies' proposal to provide $4 million in support of the proposed project be approved.[161] Staff further recommends that any plant-in-service or operations and maintenance expenses associated with the GIP project that are funded through Federal funding or shareholder funds, if applicable, be excluded from distribution rates for the life of the assets.

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[158] Staff Ex. 4 (Schaefer Testimony) at 6.
[159] Co. Ex. 2 (Fanelli Testimony) at 10.
[160] *Id.* at 6.
[161] *Id.* at 7.

Staff witness Craig Smith presented Staff's position regarding the Companies' proposed stewardship assistance for low-income and senior customers. Mr. Smith noted that Staff has concerns regarding the proposed bill assistance as well as the senior discount. As Mr. Smith explained, the Companies' proposal is modeled on their existing bill assistance program that was initiated from their last ESP.[162] FirstEnergy is proposing $20 million in bill payment assistance or $2.5 million per year of the proposed ESP. One change from the current bill payment assistance is a new administrator through a competitive process and availability to customers of all three Companies instead of only a single company. Mr. Smith noted that Staff has monitored and reviewed the current bill assistance program throughout the duration of the current ESP and has observed mixed results.[163]

Based on its monitoring of the program, Staff has some recommendations regarding the proposed bill assistance.[164] Staff supports the continued funding of the OPAE bill assistance program. Staff, however, does not support the second proposed bill assistance program based on the results of the existing program. The Companies should designate some bill assistance towards customers at risk of disconnection including customers above the 175% of the Federal income guidelines and not just low-income. Staff recommends that the Companies expand the funding and eligibility for the three emergency hardship funds (Project REACH, Community Outreach Opportunity Program, and Neighbors helping Neighbors) administered by the Salvation Army.[165]

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[162] Staff Ex. 7 (Direct Testimony of Craig Smith) at 9 (Oct. 30, 2023).
[163] *Id.*
[164] *Id*. at 10-11.
[165] *Id*.

Staff recommends that the Companies develop and fund an internal bill assistance program like AEP's neighbor to neighbor program[166] to assist customers in crisis of disconnection and who may be above the 175% threshold for low-income assistance.

Bill assistance should be available to customers first at risk of disconnection including customers above 175% of the Federal income Guidelines. Staff recommends that customers under 300% of the Federal income Guidelines be eligible for bill assistance.[167] There are few programs or assistance for customers just above the federal income guidelines yet many of these customers face the same affordability burdens. In addition, for customers having difficulty navigating the income assistance process or who otherwise might not be eligible, an additional resource to prevent disconnection is helpful.

Staff further recommends that the Companies engage with customers at resource fairs and community events, particularly in conjunction with Community Action Agencies and municipal and county governments to educate customers on available resources for assistance, and to directly assist customers with applications for assistance enrolling in payment plans during those events. FirstEnergy should continue to educate customers regarding the price of SSO generation service and the impact that has on their bills.[168]

Mr. Smith also explained Staff's concerns regarding the $5 senior credit proposed by the Companies.[169] FirstEnergy is proposing to credit $5 per bill for customers 65 and older to be funded through $16 million in shareholder money at $2 million per year.[170] While Staff generally is neutral or silent regarding the use of shareholder money as these funds are outside the purview

[166] *Id.* at 11.
[167] *Id.*
[168] *Id.* at 11-12.
[169] *Id*. at 12-13.
[170] Co. Ex. 2 (Fanelli Testimony) at 9.

of rates, FirstEnergy has included the programs within its Application. Staff supports the Companies' efforts at stewardship regarding bill assistance. However, Staff does have concerns with providing some customers such as seniors with a reduced cost to serve that is not tied to any causation, need, or risk.[171] Although customers over 65 would certainly appreciate a $5 bill credit from the applicant's shareholders, so would other customers who are struggling to pay their bills.

Regarding low-income programs, Staff therefore recommends that the Companies direct the $16 million toward seniors at risk of disconnection as bill assistance instead of a $5 monthly credit for all residential customers over 65.[172] The Companies should create an internal bill assistance program to assist customers that might not have other options and are at immediate risk of disconnection, or add to the existing hardship emergency funding and eligibility if necessary.[173]

Finally, Staff recommends that the Companies provide Staff with annual accountings for each of the bill assistance programs. Annual reporting to Staff on the results of each of the bill assistance programs is beneficial in evaluating and monitoring the programs. The annual disclosures during the current ESP regarding the assistance programs have been valuable to Staff.[174]

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[171] Staff Ex. 7 (Smith Testimony) at 12.
[172] *Id*. at 13.
[173] *Id.*
[174] *Id.*

I. Because transmission costs are intended to be a pass-through to customers, the Commission should modify the Companies' transmission rider (Rider NMB) to more closely align with PJM's transmission cost allocations.

1. Background on Current Transmission Rates and the Companies' Proposal

Currently, customers pay for transmission through the Companies' Non-Market Based Services Rider ("Rider NMB"). Rider NMB is a pass-through mechanism designed to recover from FirstEnergy's customers the costs billed to FirstEnergy by the regional transmission organization, PJM, for transmission service.[175] The rider is non-bypassable, except for a limited number of customers participating in a Rider NMB Transmission Pilot Program ("Pilot"). Pilot customers shop for transmission service through a CRES.

PJM charges FirstEnergy for transmission based on specific costs known as Billing Line Items ("BLIs").[176] PJM allocates each BLI using one of several methodologies, including MWh, 1 Coincident Peak ("CP") Net Service Peak Load ("NSPL"), or 12 CP.[177] In contrast, at the retail level, transmission costs that are not directly billed are allocated to each of the three Companies based on the Company's previous month's load share (*i.e.*, the percentage of MWh used by each of the three Companies).[178] Each Company then allocates its share of transmission costs to its customer classes based on the most recent four summer peak months, calculating a demand allocation factor for each class.[179]

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[175] Staff Ex. 9 (Direct Testimony of Annie Baas) at 2 (Oct. 30, 2023).
[176] *Id*. at 3.
[177] *Id.* at 4.
[178] *Id.* at 3-4.
[179] *Id.* at 4-5.

Because Pilot customers do not pay Rider NMB, their demand and billing determinants must be removed when performing these allocations. Currently, the Companies use a 5CP methodology to remove Pilot customers from Rider NMB.[180]

The Companies have proposed changes to Rider NMB. The Companies propose the creation of two different rate designs for commercial and industrial customers within Rider NMB. The first rate (NMB 1) will keep the current Rider NMB rate allocations and rate design. The second rate (NMB 2) will apply to commercial and industrial customers with an interval or advanced meter, and those customers will be billed based on their 5CP NSPL.[181] If a customer on the NMB 1 rate receives a new interval or smart meter, the customer would be switched immediately to NMB 2.[182] The NMB 2 rate will be the same for all customers for all three Companies.[183] Under the Companies' proposal, the Pilot will end, and Pilot customers will be moved to either NMB 1 (if they don't have an interval or smart meter) or NMB 2 (if they do have such a meter).

2. Staff's Recommended Allocations

To follow PJM's allocation, any cost not directly billed should be allocated to each individual Company using the same methodologies that PJM uses. For example, costs assigned by PJM based on 1CP NSPL would similarly be allocated to each Company based on 1CP NSPL. Likewise, costs assigned by PJM based on energy (MWh) would then be allocated to each Company by MWh.[184] Once costs are allocated to each Company, the Company should allocate costs to each customer class, again based on the same allocation factors that PJM uses.[185] These

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[180] *Id.* at 7.
[181] *Id.* at 8.
[182] *Id.* at 9.
[183] *Id.* at 8-9.
[184] *Id.* at 4-6.
[185] *Id.* at 6.

changes would apply to all costs flowing through Rider NMB. These changes to the NMB allocations will mitigate cost shifting among the FirstEnergy Companies and customer classes.

Changes to allocations will impact customer bills, although the magnitude of Staff's recommended changes to the NMB Rider's allocations is unknown. Staff therefore recommends that the Commission require the Companies to provide bill impacts with compliance tariffs in this case. If the bill impacts reveal unreasonable increases to customer bills, then it may be necessary to phase in the changes to the allocations over time to implement the changes gradually.[186] Although ESP V will take effect June 1, 2024, Staff's proposed allocation changes for Rider NMB would not go into effect until April 2025; thus, there is sufficient time to address this issue, if necessary, after compliance tariffs are filed.[187]

3. Staff's Recommendations for the Pilot

Staff supports the Companies' proposal to eliminate the NMB Pilot, provided that certain modifications are made to the Companies' proposed NMB 2 rate. First, the Commission should reject the Companies' proposal for a single uniform rate for all commercial and industrial customer classes paying under NMB 2. The Companies' proposed unified rate design for NMB 2 rates would cause interclass and intraclass cost shifts because it does not align with PJM's cost allocation.[188] Instead, separate NMB 2 rates should be calculated for each Company and each customer class.[189]

[186] *Id.* at 7.
[187] *See* Tr. Vol. XIV at 2453.
[188] Staff Ex. 9 (Baas Testimony) at 11.
[189] *Id.* at 12.

Second, for customers in the GS class, NMB 2 should be optional. Eligible customers (*i.e.* those with smart or interval meters) should have to opt in to the program so that they do not suffer undue bill impacts, especially on short notice after installation of a new meter.[190]

Third, customers should not be immediately moved to Rider NMB 2 after installation of a new internal or smart meter. Instead, the switch should only be made once a year in April at the time of the annual rider review.[191]

Fourth, the Companies would need to work with Staff to review bill impacts that include actual NSPL data with the allocation changes compared to the current NMB rates. These bill impacts should be broken out by each EDU and customer class and should include customers that will be switching rates from the current NMB rates to NMB 2 rates. It should also include an analysis of customers switching rates from the current NMB rates to NMB 1 rates.[192]

Fifth and finally, the Companies should work with Staff after the Commission Order to structure the mechanics of the rider before the annual filing is made. The NMB 2 rate would be effective in April of 2025 after the annual review has been completed.[193]

If these five recommendations are adopted, and if allocations to each Company and customer class are modified to follow PJM allocations, Staff recommends eliminating the current Pilot at the time the new NMB 1 and NMB 2 rates take effect. If these Staff recommendations are not adopted, however, the Pilot program should continue and the proposed NMB 2 rate should not be adopted. Regardless of whether the Pilot program is continued, however, the allocation recommendations to the Companies and customer classes would still need to mirror PJM's allocation methodology to mitigate cost shifting. If the Pilot program remains, it should be

[190] *Id.* at 13.
[191] *Id.*
[192] *Id.* at 12.
[193] *Id.* at 13.

gradually extended and made available to all customers within the GS, GP, GSU, and GT classes. Additionally, participants' costs removed from the NMB should be changed to mirror PJM's allocation for each BLI. This would eliminate the interclass and intraclass cost shifting currently caused by this program.[194]

J. ESP V, with Staff's recommended changes, complies with R.C. 4928.143(B)(2)(h) because customers' and the Companies' expectations are aligned and the Companies are placing sufficient emphasis on and dedicating sufficient resources to reliability.

The Companies have consistently met or exceeded their reliability standards.[195] There have only been two recent instances when the Companies have not met their Customer Average Interruption Duration Index ("CAIDI") standards—in 2019 for CE and in 2022 for CEI.[196] The Companies, however, are projected to miss their CAIDI standards in 2023 for CEI and TE.[197] The Companies have consistently met or outperformed their System Average Interruption Frequency Index ("SAIFI") for the last five years for all operating companies.

When considering whether a utility is meeting or exceeding its reliability standards, Staff evaluates customer perception surveys. During these evaluations, Staff conducts an analysis to determine what customers perceive as acceptable values for CAIDI and SAIFI. Based on this analysis, Staff testified that the Companies' and customers' expectations are aligned. The Companies are placing sufficient emphasis on the reliability of its distribution systems and are dedicating sufficient resources to maintain that reliability.[198] Commission approval of ESP V, with Staff's recommendations, is consistent with R.C. 4928.143(B)(2)(h).[199]

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[194] *Id.* at 14-15.
[195] Co. Ex. 9 (Direct Testimony of Amanda Richardson) at 2 (Apr. 5, 2023).
[196] *Id.* at 5.
[197] Tr. Vol. VII at 1381.
[198] Staff Ex. 5 (Direct Testimony of Jacob Nicodemus) at 6 (Oct. 30, 2023).
[199] *See, e.g., In re Application of the Dayton Power & Light Co. to Establish a Standard Service Offer in the Form of the Electric Security Plan*, Case No. 16-395-EL-SSO, Opinion and Order, at ¶ 113-16 (Oct. 20, 2017).

K. The Commission should modify the Advanced Metering Infrastructure / Modern Grid Rider to be more consistent with Commission precedent.

The Companies propose to continue the Advanced Metering Infrastructure / Modern Grid Rider ("Rider AMI") without modification.[200] They do not propose any additional charges under Rider AMI in this proceeding. Rather, additional charges under Rider AMI are being proposed in a separate proceeding, Case No. 22-704-EL-UNC. Nevertheless, because Rider AMI itself is part of the Companies' ESP, Staff proposes the following modifications to the rider:[201]

1. Like Rider DCR, the Companies should be required to eliminate the use of projected PIS and expenses from the rider. This would increase accuracy and make Rider AMI more like similar riders approved for other utilities.[202]

2. The Companies should not be allowed to recover any additional costs associated with the Ohio Site Deployment Pilot in the AMI Rider and should remove the Provisions section from the AMI Rider tariff because in Case No. 09-1820-EL-ATA, the Commission only approved recovery of such costs through June 1, 2019.[203]

3. Upon approval of new rates in the Companies' 2024 Rate Case, the Companies should not be allowed to recover Ohio Site Deployment Pilot or Grid Mod Phase 1 PIS or expenses in the AMI Rider. The Companies have had sufficient time to complete these investments and indeed are no longer making Phase I capital investments.[204]

4. Consistent with Commission and Ohio Supreme Court precedent, the rate of return for the rider should be the same as the rate of return approved in the Companies' most recent base rate case.[205]

5. To allow Staff sufficient time for review, the Companies should be required to file each quarterly AMI Rider filing at least 60 days in advance of the effective date of the tariff.[206]

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[200] Co. Ex. 1 (Fanelli Testimony), Attachment SLF-1.
[201] Staff Ex. 8 (Mackey Testimony) at 16-21.
[202] *Id.* at 18.
[203] *Id.* at 18-19.
[204] *Id.* at 19.
[205] *See, e.g., In re Application of East Ohio Gas Co.*, 2023 WL 6131618 (Sept. 20, 2023).
[206] Staff. Ex. 8 (Mackey Testimony) at 20.

6. The annual AMI Rider audit may be completed by a third-party auditor, with the costs of such audit paid for by the Companies but eligible for recovery in the AMI Rider.[207]

7. Upon Commission approval of any future base rate case, the Companies should update the rider with any inputs from the rate case, including but not limited to the authorized rate of return and depreciation rates.[208]

L. The Companies should engage with stakeholders to find ways to improve their time varying rate offerings.

There are currently several options for customers seeking time varying rates.[209] These include Rider CPP, Rider RTP, Rider RCP, and Rider HLF, which are all voluntary time-variable options available to SSO customers, in lieu of the rates available under the standard generation service rider.[210]

Staff generally supports the implementation of time-differentiated pricing to encourage innovation and market access for cost-effective supply and demand side retail electric service, consistent with state policy as set forth in R.C. 4928.02(D).[211] However, there has been little to no participation under any of the current riders during the last ESP term, so it is unlikely that any significant benefits have accrued.[212]

To encourage greater participation, Staff recommends that the Companies meet with interested intervening parties within 90 days of an Opinion and Order in this case to discuss their experience with the riders and to discuss opportunities to improve the rider design.[213] Potential improvements could include increasing customer education around rate options, providing customers with bill information detailing money saved (or lost) on the voluntary time varying

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[207] *Id.* at 21.
[208] *Id.*
[209] Staff Ex. 4 (Schaefer Testimony) at 9.
[210] *Id.*
[211] *Id.* at 12.
[212] *Id.*
[213] *Id.*

rates compared to the standard generation service rider, or providing a rate calculator for customers to estimate potential savings/costs associated with enrolling in a time varying rate.[214] Based on these discussions, the Companies should file an application to update the riders within 120 days of an Opinion and Order in the current case.[215]

M. The Commission should approve the Companies' proposal to eliminate inactive riders.

The Companies propose to eliminate 12 riders that are currently inactive/expired but which have outstanding balances. These riders would have a final reconciliation through Rider VMC in the first year of ESP V.[216]

Staff verified the authority for each deferral as well as the unrecovered balance of each.[217] The Companies' proposal should be approved.

N. The Commission should reserve the right to address certain riders in a future proceeding.

FirstEnergy proposes the continuation of certain riders without modification, many of which are not addressed by FirstEnergy in its Application or testimony, other than being identified in a list attached to witness Fanelli's testimony.

Many of these riders are not part of FirstEnergy's electric security plan because they are required or authorized under other statutes. This includes the Conservation Support Rider (a decoupling rider approved as part of House Bill 6 but which has now been set to zero); the Consumer Rate Credit (a rider providing credits to customers as a result of a settlement in a recent significantly excessive earnings test case); the County Fairs and Agricultural Societies

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[214] *Id.*
[215] *Id.* at 12-13.
[216] Co. Ex. 3 (McMillen Testimony) at 15.
[217] Staff Ex. 1 (Messenger Testimony) at 9.

Rider (a special rate approved under House Bill 6); the Delta Revenue Recovery Rider (a rider that allows FirstEnergy to recover delta revenues resulting from things like reasonable arrangements); the Phase-in Recovery Rider (approved under R.C. 4928.231); the Net Energy Metering and Hospital Net Energy Metering tariffs (required under R.C. 4928.67); the Solar Generation Fund Rider (required under R.C. 3706.46); the Business Distribution Credit (approved in the Companies' last base distribution rate case); and the School Distribution Credit (costs recovered through base distribution rates). So, as Staff witness Healey explained, their "continuation" should be considered mere acknowledgement that they are not being modified and not an affirmative Commission ruling that they are being continued as part of ESP V.[218]

If the Commission were to make any changes to these riders, it would be done in a different proceeding.[219] Thus, Staff is not taking any position on these riders and reserves the right to address them in a future proceeding as appropriate.

There are, however, at least two riders that might be deemed to be part of ESP V, if approved.[220] The first is the Residential Non-Standard Credit Provision found under subsection (a) of the Economic Development Rider, and the second is the "Additional Provision" under the Residential Generation Credit Rider ("RGC"). These provisions are related, with the Residential Non-Standard Credit Provision providing credits to certain SSO customers on special all-electric rates, and the Additional Provision under Rider RGC providing similar credits to shopping customers on those same all-electric rates. These legacy credits have been in place for more than ten years without being substantively addressed in a Commission proceeding. Staff recommends

[218] Staff Ex. 10 (Healey Testimony) at 13.
[219] *Id*. at 14.
[220] *Id*.

that these credits continue for now but that the Commission preserve the issue for further review, either in the 2024 Rate Case or in a separate docket.[221]

O. The Commission should maintain the status quo with respect to unaccounted for energy.

FirstEnergy is proposing a change to the way unaccounted for energy ("UFE") is addressed. According to FirstEnergy witness Stein, UFE is currently the responsibility of suppliers, but the Companies propose that it instead be charged to customers on a non-bypassable basis through their transmission rider, Rider NMB.[222]

Staff recommends that the Commission maintain the status quo and not adopt the Companies' proposal at this time.[223] According to the Companies, UFE will be less volatile once they install more smart meters because one contributor to UFE is the need to mathematically derive customer hourly load data where the customer does not have a smart meter. The Commission might reconsider the proposed change to UFE in a future case when FirstEnergy has completed or is closer to completing its smart meter rollout. No other Ohio utility addresses UFE in the way that FirstEnergy proposes.[224] Thus, this further supports maintaining the current process for now.

P. ESP V, with Staff's proposed modifications, is more favorable in the aggregate than a market rate offer.

The ESP, as modified by Staff's recommendation, is more favorable in the aggregate than a market rate offer ("MRO"). In assessing the differences between ESP V (with Staff's modifications) and a hypothetical MRO, Staff considered quantitative and qualitative factors.

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[221] Staff Ex. 10 (Healey Testimony) at 15.
[222] Co. Ex. 10 (Stein Testimony) at 8-9.
[223] Staff Ex. 10 (Healey Testimony) at 15-16.
[224] *Id.*

A quantitative benefit to using an ESP, as opposed to an MRO, is that ESP has shareholder-funded programs which provides benefits to customers without an added cost to those customers.[225] An MRO does not require these types of programs.

Qualitative factors considered from the Application, subject to Staff's modifications, provide low-income assistance programs, limit bill impacts to customers, and establish riders which promote transparency with annual audits.[226] Staff's proposals for the Storm Cost Recover Rider and the Vegetation Management Recovery rider limit the recovery of incremental spending until the Companies come back in for a base distribution rate case and can provide for an annual prudence audit. Thus, when compared to a hypothetical MRO, ESP V is more favorable in the aggregate.

III. SUMMARY AND CONCLUSION

Staff's recommendations represent a reduction in charges to FirstEnergy customers as of the start of ESP V, both compared to what they currently pay under ESP IV and compared to what they would pay under the Companies' proposed ESP V.[227] Even with new riders for vegetation management, storm costs, and energy efficiency/demand response, if the Commission were to adopt all of Staff's recommendations, then in the first year of ESP V, customers should see around $52 million in annual rate decreases compared to current ESP IV rates.[228] In contrast, the Companies are proposing a rate increase of more than $110 million in the first year of ESP V.[229]

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[225] Staff Ex. 1 (Messenger Testimony) at 4.
[226] *Id.* at 15-18.
[227] Staff Ex. 10 (Healey Testimony) at 28.
[228] *Id*. at 31; *see generally* pages 28-31.
[229] *Id.* at 31; Tr. Vol. XIV at 2518.

The Commission should adopt Staff's recommendations because they best balance numerous interests. Each of Staff's recommendations stands on its own merits, while the cumulative impact of Staff's proposals is just and reasonable, allowing the Companies to continue offering market-based generation and to provide reliable service to customers at fair prices.

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PROOF OF SERVICE

I hereby certify that a true copy of the foregoing **Initial Brief**, Submitted on Behalf of The Staff of The Public Utilities Commission of Ohio, was served via electronic mail upon the following parties of record, this 19th day of January 2024.

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