O L S O N, B Z D O K & H O W A R D

January 21, 2020

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

Via E-filing

RE: MPSC Case No. U-20591

Dear Ms. Felice:

The following is attached for paperless electronic filing:

Public Direct Testimony of Tyler Comings on behalf of Sierra Club and Exhibits SC-1 through SC-12

Proofs of Service

*The CONFIDENTIAL VERSION will be served only to those with a signed NDA on file.

Sincerely,

Digitally signed by Lydia Barbash-Riley
Date: 2020.01.21 16:49:15 -05'00'

Lydia Barbash-Riley
lydia@envlaw.com

xc: Parties to Case No. U-20591

BEFORE THE
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of Indiana Michigan Power Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief	**))))**	**Case No. U-20591**

DIRECT TESTIMONY OF TYLER COMINGS

ON BEHALF OF

SIERRA CLUB

PUBLIC VERSION

January 21, 2020

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I. INTRODUCTION AND SUMMARY OF TESTIMONY

Q. Please state your name, business address, and position.

A. My name is Tyler Comings. I am a Senior Researcher at Applied Economics Clinic, located at 1012 Massachusetts Avenue, Arlington, Massachusetts.

Q. Please describe Applied Economics Clinic.

A. The Applied Economics Clinic is a 501(c)(3) non-profit consulting group housed at Tufts University's Global Development and Environment Institute. Founded in February 2017, the Clinic provides expert testimony, analysis, modeling, policy briefs, and reports for public interest groups on the topics of energy, environment, consumer protection, and equity, while providing on-the-job training to a new generation of technical experts.

Q. Please summarize your work experience and educational background.

A. I have 14 years of experience in economic research and consulting. At Applied Economics Clinic, I focus on energy system planning, costs of regulatory compliance, wholesale electricity markets, utility finance, and economic impact analyses. I have provided testimony on these topics in Colorado, the District of Columbia, Hawaii, Indiana, Kentucky, Maryland, Michigan, New Jersey, New, Mexico, Ohio, Oklahoma, West Virginia, and Nova Scotia (Canada). I am also a Certified Rate of Return Analyst (CRRA) and member of the Society of Utility and Regulatory Financial Analysts (SURFA).

I have provided expertise for many public-interest clients including: American Association of Retired Persons (AARP), Appalachian Regional Commission, Citizens Action Coalition of Indiana, City of Atlanta, Consumers Union, District of Columbia Office of the People's Counsel, District of Columbia Government, Earthjustice, Energy Future Coalition, Hawaii Division of Consumer Advocacy, Illinois Attorney General, Maryland Office of the People's Counsel, Massachusetts Energy Efficiency Advisory Council, Michigan Agency for Energy, Montana Consumer Counsel, Mountain Association for Community Economic Development, Nevada State Office of Energy, New Jersey Division of Rate Counsel, New York State Energy Research and Development, Nova Scotia Utility and Review Board Counsel, Rhode Island Office of Energy Resources, Sierra Club, Southern Environmental Law Center, U.S. Department of Justice, Vermont Department of Public Service, West Virginia Consumer Advocate Division, and Wisconsin Department of Administration.

I was previously employed at Synapse Energy Economics, where I provided expert testimony and reports on coal plant economics and utility system planning. Prior to that, I performed research on consumer finance and behavioral economics at Ideas42 and conducted economic impact and benefit-cost analysis of energy and transportation investments at EDR Group.

I hold a B.A. in Mathematics and Economics from Boston University and an M.A. in Economics from Tufts University.

My full resume is attached as Exhibit SC-1.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of Sierra Club.

Q. Have you testified before the Michigan Public Service Commission previously?

A. Yes, on two occasions in 2018. I submitted testimony on the Consumers Energy Company 2018 Integrated Resource Plan (IRP) in Case No. U-20165 and on the Consumers Energy Company 2018 rate case in Case No. U-20134.

Q. What is the purpose of your testimony?

A. My testimony primarily addresses Indiana Michigan Power Company's (I&M or Company) treatment of its coal-fired power plants, including Rockport units 1 and 2 and the Company's share of the output from Kyger Creek and Clifty Creek. I also discuss the Company's modeling of new resources in the IRP.

Q. Please summarize your findings.

A. Based on my review of the Company's filing and data responses in this case, I conclude that:

1. The environmental compliance obligations for the Rockport units have changed since the IRP analysis was conducted, due to a July 2019 modification to a Consent Decree in federal district court. Both units will require enhanced dry sorbent injection (DSI) by 2020 and have an annual 10,000 ton sulfur dioxide (SO_2) cap from 2021 to 2028, which drops to 5,000 tons annually in 2029. Also, Rockport unit 1 must retire by no later than December 31, 2028.

2. In light of the modified Consent Decree, I&M's plan to retire Rockport unit 1 in 2028 and let the lease at Rockport unit 2 expire in 2022 is still justified when compared to continued operation of the units. However, I find that

retirement of Rockport unit 1 in 2025 would save [[[redacted]]], compared to 2028 retirement. I also estimate that the expiration of the lease at Rockport 2 in 2022 will save over [[[redacted]]] Both savings estimates are conservative given that they do not include the costs of operating new enhanced DSI at the Rockport units.

3. I&M's own modeling shows that adding more renewables than are included in its preferred plan would produce substantially lower costs. The Company has not justified bypassing the significant savings associated with more renewable capacity. Instead, it has opted for significant new natural gas capacity in its preferred plan.

4. In 2010, I&M re-signed a contract with the Ohio Valley Electric Corporation (OVEC) that requires the Company to purchase a share of output from OVEC's Kyger Creek and Clifty Creek coal units until 2040. This major transaction was never approved by the Commission and has cost I&M and its ratepayers: generating $40 million in losses from 2016 through 2018 alone. Despite these losses and the lack of Commission approval, I&M has also not investigated any alternatives to locking in these units in its plan until 2040.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

SC-1: Resume

SC-2: Fifth Joint Modification to Consent Decree, U.S. District Court for the Southern District of Ohio, Eastern Division, Civil Action Nos. C2-99-1182/1250 (cons.), C2-04-1098, and C2-05-360, July 17, 2019.

SC-3: Response to Data Request No. SC 3-3

SC-4: Response to Data Request No. SC 3-4

SC-5: Response to Data Request No. SC 3-6

SC-6: Response to Data Request No. SC 3-7

SC-7: Response to Data Request No. Staff 5-7

SC-8: Response to Data Request No. Staff 3-4

SC-9: Case No. U-20359 Response to Data Request No. SC 1-5 and Attachment 1

SC-10: Case No. U-20359 Response to Data Request No. SC 1-6 and Attachment 1

SC-11: Case No. U-20359 Response to Data Request No. SC 1-7

SC-12: Kentucky Public Service Commission, Case No. 2018-00294, Attachment to Response to SC-1 Question No. 13, Ohio Valley Electric Corporation Minutes of Special Meeting of the Board of Directors held December 1, 2015

II. SUMMARY OF I&M'S IRP ANALYSIS

Q. Please describe the cases modeled by I&M in this IRP.

A. I&M modeled a total of 23 cases, most of which assumed retirement of Rockport 1 in 2028 and the expiration of the Rockport 2 lease in 2022—as shown in Table 1. Cases 6 through 8 modeled alternative retirement assumptions for the Rockport units:

- Cases 6 and 6A: Rockport 1 would have a Flue Gas Desulfurization (FGD) system installed by January 2026 and retire in 2044, while the lease for Rockport 2 would expire in 2022. As I will discuss below, this case is no longer relevant (shown as lightly shaded in Table 1 below).

- Cases 7 and 7A: Rockport 1 would have an FGD system installed by January 2029 and retire in 2044, while the lease for Rockport 2 would expire in 2022.

As I will discuss below, this case is also no longer relevant (shown as lightly shaded in Table 1 below).

- Cases 8 and 8A: Rockport 1 would retire in 2025, while the lease for Rockport 2 would be extended and the unit would have an FGD system installed by January 2029 and retire in 2048. As I will discuss below, this case is no longer relevant as the FGD is no longer required on Rockport 2.

Table 1 also shows the amount of added capacity for several resource types, including natural gas combined cycle (NGCC), natural gas combustion turbine (NGCT), solar photovoltaic (PV) and wind.

I&M case	Scenario	Rockport 1 retirement	Rockport 2 expiration	Rockport 1 FGD?	Rockport 2 FGD?	NGCC Capacity in 2038 (MW)	NGCT Capacity in 2038 (MW)	Solar Capacity in 2038 (MW)	Wind Capacity in 2038 (MW)	System Cost (CPW, $2018 mil)
Case 1	Base	2028	2022	N	N	2,695	-	865	258	$11,958
Case 2	High	2028	2022	N	N	2,695	-	865	258	$12,040
Case 3	Low	2028	2022	N	N	3,080	-	865	55	$11,798
Case 4	No Carbon	2028	2022	N	N	3,080	-	865	55	$11,541
Case 5A	No Carbon	2028	2022	N	N	3,080	-	865	92	$11,509
Case 6	Base	2044	2022	2026	N	1,540	-	865	221	$12,849
Case 6A	No Carbon	2044	2022	2026	N	1,540	-	865	129	$12,439
Case 7	Base	2044	2022	2029	N	1,540	-	865	240	$12,774
Case 7A	No Carbon	2044	2022	2029	N	1,540	-	865	129	$11,664
Case 8	Base	2025	2048	N	2029	1,155	-	865	240	$13,374
Case 8A	No Carbon	2025	2048	N	2029	1,540	-	865	148	$12,239
Case 9*	Base	**2028**	**2022**	**N**	**N**	2,695	-	865	240	**$11,992**
Case 10	Base	2028	2022	N	N	2,310	248	865	258	$12,201
Case 11	Base	2028	2022	N	N	1,155	1,240	865	258	$12,473
Case 12	Base	2028	2022	N	N	-	1,240	1,729	517	$11,485
Case 12a	Base	2028	2022	N	N	1,540	-	1,729	517	$11,058
Case 13	Base - Low Load	2028	2022	N	N	2,310	-	865	258	*
Case 14	Base - High Load	2028	2022	N	N	3,080	-	865	258	*
Case 15	Low Band - Low Load	2028	2022	N	N	2,310	-	865	74	*
Case 16	High Band - High Load	2028	2022	N	N	3,080	-	865	258	*
Case 17	Base	2028	2022	N	N	*	*	*	*	*
Case 18	Base - Unconstrained Wind and Solar Additions	2028	2022	N	N	*	*	*	*	*
Case 19	Base - Reserve Margin Constraint with Unconstrained Renewables	2028	2022	N	N	*	*	*	*	*

Table 1: I&M IRP Cases (Original, Uncorrected CPW Results)[1]

Q. What did I&M choose as its preferred plan?

A. The Company chose Case 9 as its preferred plan, which includes the following:

- Rockport 1 retirement in 2028 and Rockport 2 lease expiration in 2022;
- Nearly 2,700 MW of new natural gas combined cycle capacity by 2038; and
- 865 MW of solar photovoltaic (PV) and 240 MW of wind capacity by 2038 (both are in terms of firm capacity).

[1] I&M 2018-19 Integrated Resource Plan – Exhibit IM-2 (JFT-2), pp. 117-129. Solar and wind MW's are firm capacity. *Note that, according to the Company, Case 9 (the preferred plan) is the same as Case 5 (not shown). CPW for Cases 13 through 19 was not provided by I&M. Buildout for Cases 16 through 19 was not provided by I&M.

Q. Of the cases where the costs were not provided by I&M (cases 13-19), was the assumed retirement of Rockport 1 and 2 the same as in their preferred plan (Case 9)?

A. Yes. Cases 13 through 19 assumed the same retirement years for the Rockport units as in the preferred plan (Case 9). These other cases included changes in load, fuel and energy prices, and constraints on renewable resources.

Q. Did the Company conduct a risk analysis of select cases?

A. Yes. I&M conducted a risk analysis on Case 9 (the preferred plan) as well as Cases 1, 7, and 12 in order to provide "insight as to the risk or probability of a higher cost (revenue requirement) relative to the expected outcome."[2] The Company used "a stochastic, or 'Monte Carlo' modeling technique" to evaluate the risk associated with the preferred plan with respect to the alternative cases listed above. Combinations of variables or risk factors (natural gas prices, Rockport coal prices, CO_2 prices, and electricity market prices) were generated for 100 random iterations for each case.[3] Thus, there were 100 estimates of cost for each case.

Q. Have the environmental compliance obligations for I&M's coal units changed since it conducted the IRP analysis?

A. Yes. On July 17, 2019, the U.S. District Court for the Southern District of Ohio entered modifications to a 2007 Consent Decree between American Electric Power (AEP, I&M's parent company) and several parties, including several state attorneys general, the U.S. EPA and Department of Justice, and environmental advocacy

[2] I&M 2018-19 Integrated Resource Plan – Exhibit IM-2 (JFT-2), p. 137.
[3] I&M 2018-19 Integrated Resource Plan – Exhibit IM-2 (JFT-2), pp.137-8.

groups.[4] While the initial 2007 agreement covered many coal units owned by AEP, the modifications entered on July 17, 2019 were specific to the Rockport units and provided as follows:

- Rockport unit 1 would install enhanced dry sorbent injection (DSI) by December 31, 2020; and retire by no later than December 31, 2028.
- Rockport unit 2 would install enhanced dry sorbent injection (DSI) by June 1, 2020.
- Both units must maintain a sulfur dioxide (SO_2) emission rate of 0.15 lb/MMBtu on a 30-day rolling average basis starting in 2021; and meet an annual SO_2 tonnage cap of 10,000 tons from 2021-2028 and a 5,000 ton cap for every year thereafter.[5]

Q. Have the costs of enhanced DSI, now required of both Rockport units in 2020, been included in the IRP analysis by I&M?

A. No.[6] If included, these controls would increase costs for both units starting in 2020, for all cases modeled in the IRP but not all equally. These costs would be higher in cases where the Rockport units operated longer. The Company did not run the IRP cases with enhanced DSI, but it conducted a separate modeling exercise with these additions.[7] [[[redacted]

[4] Exhibit SC-2 (Fifth Joint Modification to Consent Decree, U.S. District Court for the Southern District of Ohio, Eastern Division, Civil Action Nos. C2-99-1182/1250 (cons.), C2-04-1098, and C2-05-360, July 17, 2019).

[5] *Id*. at pp. 12 and 16.

[6] Exhibit SC-3 (Response to Data Request No. SC 3-3(c)).

[7] Exhibit SC-3 (Response to Data Request No. SC 3-3(d)); Response to Data Request No. SC 3-3d, SC 3-3d Confidential Attachment 1.xlsx.

[redacted]]] All else equal, this would mean [[[redacted]]]

Q. How should one interpret the IRP results given the requirement for the Rockport units in the modified Consent Decree, discussed above?

A. Apart from not including the costs of enhanced DSI, some of the IRP cases are rendered moot or in need of updating due to the recent modifications to the Consent Decree. I&M's Cases 6, 6A, 7, and 7A are no longer relevant as each case assumes that Rockport unit 1 operates past 2028, which is prohibited under the newly modified Consent Decree. I&M's cases 8 and 8A, where Rockport unit 2 is assumed to operate until 2048 and install an FGD by 2029, are no longer relevant because (as of now), under the modified Consent Decree, an FGD is not required if I&M extends the lease and the unit were continue to operate.

III. Retiring Rockport 1 Soon and Letting the Lease for Rockport 2 Expire in 2022 Will Save Ratepayers

Q. Please summarize this section.

A. This section focuses on the Company's plan to retire Rockport 1 in 2028 and let the lease for Rockport unit 2 expire in 2022.

First, both I&M's and my analyses show that letting the lease expire on Rockport 2 is the best path forward. After applying the following: 1) I&M's corrections and updates provided after the filing of its IRP; and 2) some of the new compliance obligations in light of the modified Consent Decree: I show that the expiration of the

[8] *Id.* [[[redacted]]]

lease for Rockport 2 in 2022 would save nearly [[[redacted]]], compared to continued operation through the 2040s.

Second, I show how retirement of Rockport 1 in 2025 is lower-cost than the Company's planned 2028 retirement—saving [[[redacted]]] from retiring three years earlier.

Third, I discuss reasons why 2025 retirement of Rockport 1 and 2022 lease expiration at Rockport 2 would likely produce more savings than what I have estimated. My estimates rely on modifications to I&M's preferred plan (Case 9) which includes significant natural gas replacement capacity. But given that I&M's modeling produced lower-cost cases with more replacement renewable capacity (e.g. Case 12A) and has new environmental compliance obligations that are unaccounted for, the savings from earlier retirement of Rockport 1 and lease expiration at Rockport 2 are more substantial.

A. <u>I&M's Modeling Shows that Letting the Lease on Rockport 2 Expire in 2022 is Lower-Cost Than Extension</u>

Q. Did you estimate the savings from retirement of Rockport unit 1 and the expiration of the Rockport unit 2 lease using I&M's IRP modeling?

A. Yes. I&M provided corrections and updates to its modeling—as I will discuss in more detail. Using these new figures, I estimated the relative savings of the base cases where only one of the Rockport units comes off-line early (Cases 6, 7, and 8) compared to the Company's base cases of Case 9, I&M's preferred plan, where both units come off-line early. [[[redacted]]

[redacted]]]

Q. Do these updated results account for the July 2019 modification to the Consent Decree?

A. No. The results above merely correct and update the data used in I&M's original cases. But, as I mentioned previously, the compliance requirements for both Rockport units have since changed in light of the July 2019 modification to the Consent Decree. First, both units will install enhanced DSI in 2020, the costs of which were not included in any of the cases modeled by I&M. Second, Rockport 1 must retire by December 31, 2028; thus Cases 6 and 7 are now moot because they assume the unit operates until 2044. Third, Rockport 2 would no longer need an FGD in 2029; thus, the costs of the FGD should be removed from Case 8.

Q. How did you modify the IRP analysis to account for the Consent Decree modifications?

A. I took Cases 6 and 7 out of consideration, as they were no longer legally relevant, and I removed the capital costs of the Rockport 2 FGD from Case 8, as it was no

[9] Response to Data Request No. SC 1-8, SC 1-8 Confidential CORRECTED Attachment_Case_6; Response to Data Request No. SC 1-8, SC 1-8 Confidential CORRECTED Attachment_Case_7; Response to Data Request No. SC 1-8, SC 1-8 Confidential CORRECTED Attachment_Case_8; Response to Data Request No. SC 1-8, SC 1-8 Confidential Attachment_Case_9; Response to Data Request No. SC 2-3, SC 2-3 Confidential CORRECTED Attachment_1.

longer needed. The updated results below in Table 3 reflect these changes. The removal of the Rockport 2 FGD capital costs from Case 8 reduces the savings of this case relative to I&M's preferred plan (Case 9).

[redacted]]]

Q. Were you able to address all changes from the Consent Decree modifications?

A. No. Ideally, all cases would: 1) include the costs of enhanced DSI starting in 2020 for both Rockport units and 2) exclude all costs associated with an FGD at Rockport 2 in Case 8. I was only able to remove the capital costs of the Rockport 2 FGD. Sierra Club asked the Company to break down fixed O&M and variable O&M costs associated with the FGD but I&M would not provide these costs.[11] Also, the Company did not provide fixed O&M costs associated with the enhanced DSI.[12]

Q. Please explain the fixed cost errors you found in I&M's modeling.

A. In reviewing the Company's workpapers, I found that in the cases where either one of the Rockport units was expected to operate until the 2040's (Cases 6 through 8A),

[10] Response to Data Request No. SC 1-8, SC 1-8 Confidential CORRECTED Attachment_Case_7; Response to Data Request No. SC 1-8, SC 1-8 Confidential CORRECTED Attachment_Case_8; Response to Data Request No. SC 1-8, SC 1-8 Confidential Attachment_Case_9; Response to Data Request No. SC 2-3, SC 2-3 Confidential CORRECTED Attachment_1.

[11] Exhibit SC-4 (Responses to Data Request Nos. SC 3-4(b) and 3-4(c)).

[12] Exhibit SC-3 (Responses to Data Request Nos. SC 3-3(e) and SC 3-3(f)).

the fixed operations and maintenance (O&M) costs, on-going capital expenditures, and lease payments (for Rockport 2) were missing for nine or ten years of the units' operations:[13]

- In Cases 6, 6A, 7, and 7A where Rockport 1 was assumed to operate until 2044, there was $0 in fixed O&M costs and on-going capital spending from 2036 through 2044.
- In Cases 8 and 8A where the lease for Rockport 2 was assumed to extend to 2048, there was $0 in fixed O&M costs, ongoing capital spending, and lease payments from 2039 through 2048.

The cost of cases where one of the Rockport units continued to operate through the 2040s were significantly understated due to I&M's errors. Thus, after remedying these errors, the relative savings from retirement of each of the Rockport units would increase—all else equal.

Q. Did I&M address these errors after you identified them?

A. Yes, to an extent. I&M addressed the errors by issuing new modeling output workbooks for Cases 6 through 8A, which now included on-going capital costs and fixed O&M costs occurring during all years of the units' operation. [[redacted]]

[13] Exhibit SC-5 (Response to Data Request No. SC 3-6); Exhibit SC-6 (Response to Data Request No. SC 3-7).

[14] See: Response to Data Request No. SC 2-3, SC_2-3_Confidential CORRECTED Attachment_1, "OGC Summary" tab and SC 1-8 Confidential CORRECTED Attachments, "RP Costs" tab.

Q. With these corrections, when the lease for Rockport 2 was assumed to extend to 2048, did I&M include lease payments for all years?

A. No. In Cases 8 and 8A, I&M kept the lease payments for Rockport 2 at $0 for 2039 through 2048. The Company's justification for having no lease costs was that it assumed it would acquire the unit for $0 in 2039.[15] The assumption that the unit could be acquired for free means that the costs of Cases 8 and 8A are likely understated. For instance, the Company may have to pay $0 or more to acquire the plant; but in either case, ownership of the plant would mean taking on future environmental compliance obligations, other future liabilities, or other ownership costs.

Q. Did you correct the Company's assumption that it could acquire Rockport 2 for free in 2039?

A. No. I did not speculate on a specific purchase price of Rockport 2 in 2039. But if the purchase price were above $0, as seems likely, then I&M's assumption would be biased in favor of continued operation. Thus, my results should be viewed as understating the savings from I&M declining to extend its lease of Rockport 2 beyond 2022. Notably, if the unit were given away for free in 2039, then it would be worthless (by definition) and could be retired and replaced around that time. Such a case has not been modeled by I&M, however.

Q. [[redacted]

A. [redacted]

[15] Exhibit SC-5 (Response to Data Request No. SC 3-6(c)). The response says that the cost will be "relative [*sic*] low" but there is no purchase price included.

[redacted]]]

B. I&M Should Retire Rockport 1 in 2025 and Let the Lease on Rockport 2 Expire in 2022

Q. Did you estimate the savings from retiring Rockport 1 in 2025 and letting the lease for Rockport 2 expire in 2022?

A. Yes. I constructed a case ("AEC"[17]) that included retirement of Rockport 1 in 2025 (as in I&M Case 8) and expiration of the lease at Rockport 2 in 2022 (as in Case 9). [[[redacted]

[16] All Response to Data Request No. SC 1-8 Confidential and CORRECTED attachments and Response to Data Request No. SC 2-3 Confidential CORRECTED Attachment_1. Cases 6 and 7 are lightly shaded as they are no longer relevant.

[17] AEC denotes Applied Economics Clinic.

[redacted]]]

The AEC case allows for a direct estimate of retirement savings for each unit. I&M only modeled 2025 retirement of Rockport 1 in Case 8, where Rockport 2's lease was extended. This was also the only case where I&M modeled Rockport 2 to operate until 2048. But comparing the AEC case to I&M's Case 8 (excluding the Rockport 2 FGD) isolates the impact of Rockport 2 lease expiration because Rockport 1's future is the same in both cases. Similarly, comparing the AEC case to Case 9 isolates the impact of 2025 Rockport 1 retirement, relative to 2028, because the future of Rockport 2 is the same in both of those cases.

Q. How was the AEC case constructed?

A. The AEC case relies largely on I&M's preferred plan (Case 9) as well as the aforementioned corrections and updates by I&M. I removed the fuel costs, O&M costs and energy revenues associated with Rockport 1's operations in 2026, 2027,

[18] Response to Data Request No. SC 1-8, SC 1-8 Confidential CORRECTED Attachment_Case_7; Response to Data Request No. SC 1-8, SC 1-8 Confidential CORRECTED Attachment_Case_8; Response to Data Request No. SC 1-8, SC 1-8 Confidential Attachment_Case_9; Response to Data Request No. SC 2-3, SC 2-3 Confidential CORRECTED Attachment_1.

and 2028 from Case 9, and then replaced the updated capital costs for Rockport 1 with those from Case 8. I also removed Rockport 1's capacity (MW's) and replaced it with contracted capacity, using I&M's base case PJM capacity price forecast as a proxy for contracted capacity cost. Importantly, I am not advocating for contracted capacity as the only replacement option. I&M should issue an all-resource request for proposals (RFP) in anticipation of other units' retirement, which would provide a market-based, possibly lower-cost replacement solution.

Q. Did you correct the Company's assumption that it could purchase Rockport 2 for free in 2039 in estimating savings from early lease termination?

A. No. If the Company were to purchase the unit in 2039, I did not want to speculate on the price of that purchase. However, I maintain that $0 is too low, unless the unit is worthless (by definition) at the time of purchase. The unit could also be retired at that time or in another year prior to 2048 but such a scenario was not modeled by I&M.

Q. Were the costs of the enhanced DSI included in your retirement savings estimates?

A. No. As discussed previously, the fixed and variable costs of both Rockport units will increase as a result of installing enhanced DSI in 2020, and these costs have not been included in I&M's IRP modeling. My estimate of savings from 2025 retirement of Rockport 1 is understated as enhanced DSI costs for 2026, 2027, and 2028 would also be avoided with 2025 retirement. [[[redacted]]]

Q. Did you modify I&M's new resources added in Case 9?

A. I only added a capacity purchase replacement for Rockport 1's earlier retirement for 2026 and 2027.[19] However, I&M's new resources in Case 9 were untouched.

Q. What do you conclude based on I&M's modeling and your modifications to its preferred plan?

A. Clearly, the early retirement of Rockport 1 and lease expiration of Rockport 2 is favorable to ratepayers—the question is only a matter of when Rockport 1 retirement provides the most value to customers. I&M's modeling shows that its preferred retirement of Rockport 1 in 2028 and expiration of the lease at Rockport 2 in 2022 was a low-cost solution. But my modifications to this plan demonstrate that retirement of Rockport 1 in 2025 and the same lease expiration at Rockport 2 is even lower-cost than I&M's plan. Importantly, the above comparisons use I&M's replacement resources in these cases, which are heavily-reliant on new natural gas. As I discuss below, substitution of renewable resources for new natural gas would produce substantially more savings from taking the Rockport units off-line.

C. <u>I&M's Modeling Shows that Adding More Renewable Resources Lowers Cost</u>

[19] [[redacted]]

Q. Did I&M model cases with more renewable replacement resources than in its preferred plan?

A. Yes. In most cases, I&M limited the amount of wind and solar built to 300 MW of wind and 300 MW of solar annually, which helped lead to the selection of significant new gas combined-cycle capacity in 2028 as the assumed replacement for the retiring Rockport unit 1.[20] However, the Company modified the renewable limit in several cases, allowing for double the maximum level of annual renewable replacement (High RE[21]) in Cases 12 and 12A, as well as effectively unconstrained renewable replacement in Cases 18 and 19. [22]

By 2038, Cases 12 and 12A both include double the capacity of solar and slightly more than double the capacity of wind, compared to Case 9 (as set by I&M): 1,729 MW of firm solar capacity (instead of 865 MW); and 517 MW of firm wind capacity (instead of 240 MW). The results from I&M's modeling show that adding double the renewable capacity saves between $507 and $924 million compared to the Company's preferred plan—shown in Table 6. Case 12 also included gas combustion turbine (peaking) capacity, which was not included in Case 9. For Cases 18 and 19 (no constraint on the solar and wind added), the results were not reported by I&M.

[20] I&M 2018-19 Integrated Resource Plan – Exhibit IM-2 (JFT-2), pp. 104, 107.
[21] *Id.*, p. 126.
[22] *Id.*, p. 130.

I&M case	Rockport 1 retirement	Rockport 2 expiration	Cost relative to I&M Case 9
Case 9	2028	2022	$0
Case 12 (High RE, Peaking)	2028	2022	-$507
Case 12A (High RE)	2028	2022	-$934
Case 18 (Unconstrained RE)	2028	2022	?
Case 19 (Unconstrained RE, reserve margin limit)	2028	2022	?

Table 6: Savings from High Renewable Replacement (CPW, $2018 mil)[23]

Q. Were Cases 12 and 12A, with higher renewable capacity, the two lowest-cost plans reported by I&M?

A. Yes. Case 12A was the lowest-cost plan reported and Case 12 was the second lowest-cost plan (see Table 1).

Q. Was Case 12 the lowest-cost plan in a majority of the risk analysis runs conducted by I&M?

A. Yes. I&M conducted a Monte Carlo risk analysis for a select number of cases: 1, 7, 9, and 12. This analysis allowed for variation in fuel, electricity and carbon prices, producing a sample of 100 runs for each case. I&M then reported various percentiles for each case: for instance, the 95th percentile of Case 9 is the 95th most expensive of the 100 runs conducted. In I&M's updated risk analysis, comparing the results of the 100 runs for each case shows that Case 12 is lower-cost than Case 9 in 71 percent of the runs conducted.[24] It does not appear that I&M conducted this type of analysis for Case 12A, the lowest-cost plan. Because case 12A is significantly cheaper than Case 12, if I&M had included it the result would have likely shown that Case 12A was lower-cost than Case 9 in more than 71 percent of the runs.

[23] *Id.*, p. 128. See "Total Utility Cost, Net CPW". Corrections to capital costs affected Cases 9, 12, and 12A equally. Therefore, the differences in cost between them did not change.

[24] Exhibit SC-7 (Response to Data Request No. Staff 5-7).

Q. Why were Cases 12 or 12A not chosen as I&M's preferred plan, despite being the lowest-cost plans in terms of CPW and Case 12 being lowest-cost in 71 percent of the risk analysis runs?

A. I&M's extensive modeling and risk analysis both point to a High RE buildout as lower-cost than I&M's preferred plan. The Company falls back on the higher-cost Case 9 as its preferred plan, yet does not adequately justify this decision. This is problematic due to the over $900 million in savings from a higher renewable buildout (compared to the preferred plan), which is substantial enough that it should not be dismissed without strong, quantitative justifications. Second, I&M contends that the High RE buildout "may not be practical" but will consider a higher amount of renewables in its future plans.[25] I&M's treatment of the High RE buildout raises two questions: 1) Why was the High RE buildout modeled in the first place if it was not seen as practical?; and 2) Given the substantial savings of the High RE buildout, if it were indeed impractical, why not investigate a buildout that was <u>in between</u> High RE and that in the preferred plan? Surely, the feasibility of the plan could have been determined before the modeling was conducted. Moreover, I&M could have modeled a trajectory higher than Case 9 and lower than Cases 12 and 12A.

Second, I&M points to the 20-year CPW of Case 12 compared to Case 9 as part of its justification for choosing Case 9.[26] This comparison is problematic for two reasons: 1) the IRP uses a 30-year analysis period, not 20, and also includes the "end effects" which accounts for costs incurred after the 30-year period; and 2) if the 20-

[25] I&M 2018-19 Integrated Resource Plan – Exhibit IM-2 (JFT-2), p. 126.
[26] *Id*., p. 144.

year CPW measure were important, then I&M should have reported the result for Case 12A, which had a 20-year CPW that was $84 million <u>less</u> than that of Case 9.[27]

Q. Does your testimony address all critical issues regarding new resources used in I&M's modeling?

A. No. Sierra Club witness Anna Sommer addresses the validity of costs of new resources, limitations of renewable buildout and demand-side resources. My testimony takes I&M's costs of new resources as-read. If the costs of renewable resources employed by I&M were too high or the constraints on new renewable builds found to be invalid, then the High RE path would be even more attractive than what I&M's modeling already shows. For cases that include battery storage, the Company has only included 50 MW of total new battery storage through 2038; but it is possible that more storage capacity would be cost-effective.[28]

Q. What do you conclude regarding new resources modeled in the IRP?

A. While I find the Company has clearly justified abandonment of the Rockport units, it has not justified its choice of new capacity in its preferred plan. Plans that include High RE, Cases 12 and 12A, are clearly lower-cost plans, saving between $507 and $934 million compared to I&M's preferred plan (Case 9). This level of quantified and substantial savings should not be discarded due to qualitative and unsubstantiated arguments by I&M.

[27] *Id.*, p. 128. See "Utility CPW 2019-2038". Corrections to capital costs affected Cases 9, 12, and 12A equally. Therefore, the differences in cost between them did not change.
[28] *Id.*, pp. 122, 124, and 127.

IV. I&M'S SHARE OF OVEC HAS NOT BEEN JUSTIFIED AS PART OF THE PREFERRED PLAN

Q. What is OVEC?

A. Ohio Valley Electric Corporation (OVEC) is an independent power producer that is owned as a joint venture between various utilities, including AEP, the largest shareholder. OVEC owns two coal-fired power plants built in the 1950's—Clifty Creek in Indiana and Kyger Creek in Ohio.

Q. Does I&M include a share of the Kyger Creek and Clifty Creek coal plants' output in its IRP modeling?

A. Yes. Under an Amended and Restated Inter-Company Power Agreement ("ICPA" or "OVEC Agreement") between load-serving entities and OVEC, I&M is a "Sponsoring Company" that is responsible for a lifetime share of the costs associated with owning and running these plants. Specifically, I&M is contractually responsible for 7.85% of the "benefits and requirements" of OVEC—under the contract this percentage is referred to as a Power Participation Ratio. This means that I&M is entitled to 7.85% of the energy, capacity, and ancillary services from the OVEC units and, in turn, is responsible for 7.85% of total OVEC's costs, including debt and decommissioning costs.[29]

Q. Did I&M assume that all of these units would operate through 2040, in every case it modeled?

A. Yes. These units are assumed to operate for another 20 years in every case modeled in the IRP. I&M stated that it is "contractually required to purchase a share of the

[29] See Amended and Restated Inter-Company Power Agreement, September 10, 2010, available at https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12594881.

output of the OVEC plants through 2040."[30] The ICPA, signed in 1953, was originally set to terminate in 2006, as the federal atomic energy program for which the plants had been built had ended. In 2004, the OVEC parties extended the ICPA by 20 years, from March 2006 to March 2026. On September 10, 2010, the OVEC owners once again extended the ICPA, this time to 2040. I&M claims that another amendment to the OVEC Agreement would need consent from all parties that have signed the existing OVEC Agreement, and approval from FERC.[31]

Q. Was signing this amendment, which locked in I&M to purchase output from the OVEC units for 30 more years, deemed prudent by this Commission?

A. No. The Commission has not made a ruling on I&M's re-signing of the OVEC contract in 2010.

Q. Have the OVEC units generated positive value in the last three years?

A. No. I estimate that the units have cost I&M $40 million more than the value provided to I&M from 2016 through 2018; the annual costs and value are shown below in Figure 1. Note this is for I&M's share only (7.85%); a 100% share would mean losses of over $500 million for OVEC as a whole.

[30] Exhibit SC-8 (Response to Data Request No. Staff 3-4(b)).

[31] Exhibit SC-8 (Response to Data Request No. Staff 3-4(a)).

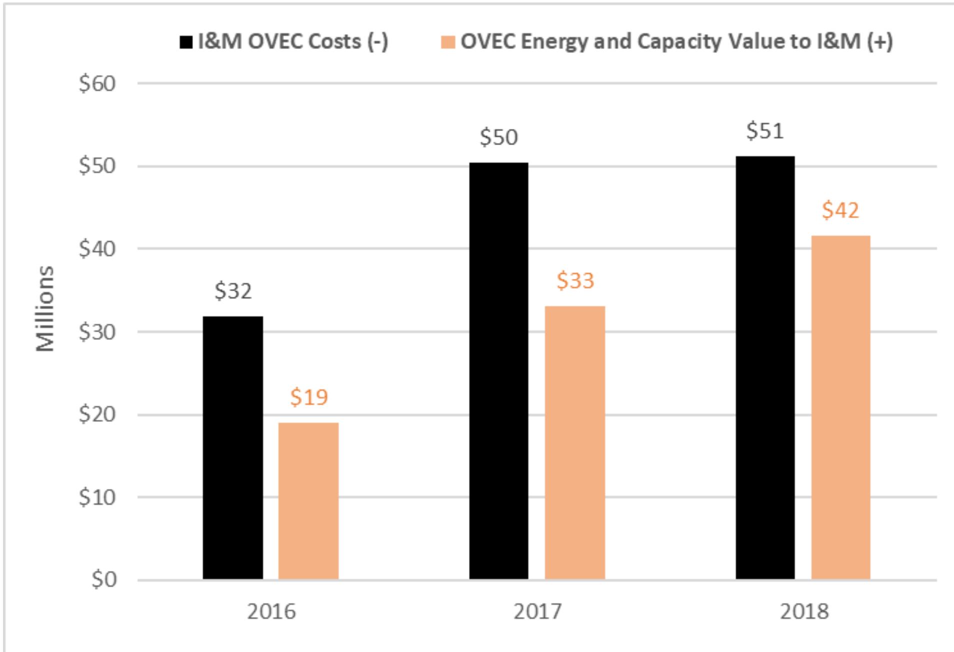

Figure 1: Costs and Value of OVEC Units to I&M ($mil)[32]

The losses shown above represent total costs and value to I&M produced by the OVEC units between May 2016 and December 2018 (when all necessary data was made available). The total costs to I&M in 2016, 2017, and 2018 are the sum of energy, demand, and transmission charges under the OVEC Agreement as well as PJM expenses and fees.[33] The value to I&M is comprised of energy, capacity, and ancillary services during the same period. Energy and ancillary services revenue were reported by I&M.[34] I calculated the capacity value by multiplying I&M's share of

[32] Exhibit SC-9 (Case No. U-20359 Response to Data Request No. SC 1-5 and Attachment 1); Exhibit SC-10 (Case No. U-20359 Response to Data Request No. SC 1-6 and Attachment 1); Exhibit SC-11 (Case No. U-20359 Response to Data Request No. SC 1-7(a-c)).

[33] Exhibit SC-9 (Case No. U-20359 Response to Data Request No. SC 1-5 and Attachment 1).

[34] Exhibit SC-11 (Case No. U-20359 Response to Data Request No. SC 1-7(a-c)).

OVEC ICAP (given in MW)[35] by the RTO clearing price (given in $/MW-day) from PJM's Base Residual Auction in each relevant delivery year for capacity.[36]

Q. Did the Company provide any economic support for the continued operation of the OVEC plants?

A. No. The Company has not evaluated any alternative to keeping the OVEC until 2040 as part of its IRP process. Every case modeled in the IRP assumes the OVEC units operate until 2040. In discovery, the Company provided two assessments of OVEC's going-forward economics conducted in 2015 and 2016.[37]

Q. Does the most recent economic analysis of the OVEC units provided by I&M show that the plants were not expected to cover their costs in most years?

A. [[[redacted]

[35] Exhibit SC-10 (Case No. U-20359 Response to Data Request No. SC 1-6 and Attachment 1).

[36] PJM capacity results: https://www.pjm.com/markets-and-operations/rpm.aspx under "Delivery Years".

[37] Responses to Data Requests Nos. SC 3-1 and SC 3-2.

[redacted]]]

Q. Is it reasonable to assume that all of the OVEC units will run until 2040?

A. No. The units are currently 64 and 65 years old, which makes them approximately 20 years older than the average coal unit still operating in the U.S. today (the average coal plant in 2018 was 45 years old).[38] The OVEC units are in the 90th percentile of existing U.S. coal units, in terms of age.[39] If they were to run for another 20 years, as I&M assumes in its IRP, they would retire at age 85: 30 years more than the average coal unit age at retirement (55 years).[40] Indeed, of those units that have retired since

[38] U.S. Energy Information Administration, 2018 Form EIA-860 Data.

[39] *Id.*

[40] *Id.*

2010, only <u>one</u> coal unit had run for more than 85 years.[41] It is highly unlikely that all of the OVEC units will operate as long as I&M assumes.

Q. Has I&M shown that investment in the OVEC units is prudent?

A. No. I&M has not shown that its 2010 signing of the amended ICPA with OVEC was prudent, and the Company has failed to assess any alternative to including these units in its planning through 2040. Meanwhile, the OVEC coal units appear to be uneconomic by producing losses for the Company and costing its ratepayers. Moreover, if the units were to face more environmental compliance obligations, then I&M and its ratepayers would be on the hook for their share of those costs.[42] If the Commission were to approve of the OVEC transaction and/or the inclusion of the OVEC units in I&M's preferred plan, it would saddle the Company and ratepayers with these costly resources for up to another 20 years—or as long the units continue operating.

V. RECOMMENDATIONS

Q. What do you recommend to the Commission?

A. Based on my findings, I recommend that the Commission do the following:

1. Approve of retirement of Rockport 1 in 2025. If not, then approve of I&M's plan to retire the unit in 2028.
2. Approve of I&M's plan to let the lease at Rockport 2 expire in 2022.

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[41] *Id.*

[42] Exhibit SC-12 (Kentucky Public Service Commission, Case No. 2018-00294, Attachment to Response to SC-1 Question No. 13, Ohio Valley Electric Corporation Minutes of Special Meeting of the Board of Directors held December 1, 2015).

3. Ask I&M to update its preferred plan to address the lack of justification for its resource additions.
4. Encourage I&M to issue an all-resource RFP prior to Rockport 2 lease expiration and Rockport 1 retirement to foster market-based, low-cost replacement resources.
5. Not approve of I&M's contract with OVEC or the inclusion of the OVEC units through 2040 in I&M's plan.

Q. Does this conclude your testimony?

A. Yes.

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PROFESSIONAL EXPERIENCE

Applied Economics Clinic, Arlington, MA. *Senior Researcher*, June 2017 – Present.

Provides technical expertise on electric utility regulation, energy markets, and energy policy. Clients are primarily public service organizations working on topics related to the environment, consumer rights, the energy sector, and community equity.

Synapse Energy Economics Inc., Cambridge, MA. *Senior Associate*, July 2014 – June 2017, Associate, July 2011 – July 2014.

Provided expert testimony and reports on energy system planning, coal plant economics and economic impacts. Performed benefit-cost analyses and research on energy and environmental issues.

Ideas42, Boston, MA. *Senior Associate*, 2010 – 2011.

Organized studies analyzing behavior of consumers regarding finances, working with top researchers in behavioral economics. Managed studies of mortgage default mitigation and case studies of financial innovations in developing countries.

Economic Development Research Group Inc., Boston, MA. *Research Analyst*, *Economic Consultant*, 2005 – 2010.

Performed economic impact modeling and benefit-cost analyses using IMPLAN and REMI for transportation and renewable energy projects, including support for Federal stimulus applications. Developed a unique web-tool for the National Academy of Sciences on linkages between economic development and transportation.

Harmon Law Offices, LLC., Newton, MA. *Billing Coordinator, Accounting Liaison,* 2002 – 2005.

Allocated IOLTA and Escrow funds, performed bank reconciliation and accounts receivable. Projected legal fees and costs.

Massachusetts Department of Public Health, Boston, MA. *Data Analyst* (contract), 2002.

Designed statistical programs using SAS based on data from health-related surveys. Extrapolated trends in health awareness and developed benchmarks for performance of clinics for a statewide assessment.

EDUCATION

Tufts University, Medford, MA
Master of Arts in Economics, 2007

Boston University, Boston, MA
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**IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION**

UNITED STATES OF AMERICA Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Consolidated Cases: Civil Action No. C2-99-1182 Civil Action No. C2-99-1250 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Kimberly A. Jolson
OHIO CITIZEN ACTION, ET AL., Plaintiffs, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. C2-04-1098 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Kimberly A. Jolson
UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. C2-05-360 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Kimberly A. Jolson

ORDER

This matter came before the Court on the Parties' Joint Motion to Enter the Fifth Joint Modification of Consent Decree (ECF No.). Having reviewed the submissions of all Parties and being fully advised of the positions therein, the Court hereby **GRANTS** the Joint Motion and **ORDERS** that the following Paragraphs of the Consent Decree entered in this case are modified as set forth herein.

IT IS SO ORDERED.

7-17-2019
DATE

EDMUND A. SARGUS, JR.
CHIEF UNITED STATES DISTRICT JUDGE

FIFTH JOINT MODIFICATION TO CONSENT DECREE WITH ORDER MODIFYING CONSENT DECREE

WHEREAS, On December 10, 2007, this Court entered a Consent Decree in the above-captioned matters (Case No. 99-1250, Docket # 363; Case No. 99-1182, Docket # 508).

WHEREAS, Paragraph 199 of the Consent Decree provides that the terms of the Consent Decree may be modified only by a subsequent written agreement signed by the Plaintiffs and Defendants. Material modifications shall be effective only upon written approval by the Court.

WHEREAS, pursuant to Paragraph 87 of the Consent Decree (Case No. 99-1250, Docket # 363), as modified by a Joint Modification to Consent Decree With Order Modifying Consent Decree filed on April 5, 2010 (Case No. 99-1250, Docket # 371), as modified by a Second Joint Modification to Consent Decree with Order Modifying Consent Decree filed on December 28, 2010 (Case No. 99-1250, Docket # 372), as modified by a Third Joint Modification With Order Modifying Consent Decree filed on May 14, 2013 (Case No. 99-1182, Docket # 548), and as modified by an Agreed Entry Approving Fourth Joint Modification to Consent Decree filed on January 23, 2017 (Case No. 99-1182, Docket # 553), no later than December 31, 2025, the American Electric Power (AEP) Defendants are required, *inter alia*, to install and continuously operate a Flue Gas Desulfurization (FGD) system on, or Retire, Refuel, or Re-Power one Unit at the Rockport Plant, and no later than December 31, 2028, the AEP Defendants are required to install and continuously operate a FGD system on, or Retire, Refuel, or Re-Power the second Unit at the Rockport Plant.

WHEREAS, the AEP Defendants filed a Motion for Fifth Modification of Consent Decree in Case No. 99-1182 on July 21, 2017 (Case No. 99-1182, Docket # 555) and in the related cases seeking to further modify the provisions of Paragraph 87 and make other changes.

WHEREAS, the United States, the States, and Citizen Plaintiffs filed memoranda in opposition to the motion by the AEP Defendants (Case No. 99-1182, Docket # 571 and 572, and Case No. 99-1250, Docket # 405) on September 1, 2017.

WHEREAS, the Parties made additional supplemental filings and engaged in settlement discussions and have reached agreement on a modification to the Consent Decree as set forth herein.

WHEREAS, the Parties have agreed, and this Court by entering this Fifth Joint Modification finds, that this Fifth Joint Modification has been negotiated in good faith and at arm's length; that this settlement is fair, reasonable, and in the public interest, and consistent with the goals of the Clean Air Act, 42 U.S.C. §7401, *et seq.*; and that entry of this Fifth Joint Modification without further litigation is the most appropriate means of resolving this matter.

WHEREAS, the Parties agree and acknowledge that final approval of the United States and entry of this Fifth Joint Modification is subject to the procedures set forth in 28 CFR § 50.7, which provides for notice of this Fifth Joint Modification in the *Federal Register*, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Fifth Joint Modification is inappropriate, improper, or inadequate. No Party will oppose entry of this Fifth Joint Modification by this Court or challenge any provision of this Fifth Joint Modification unless the United States has notified the Parties, in writing, that the United States no longer supports entry of the Fifth Joint Modification.

NOW THEREFORE, for good cause shown, without admission of any issue of fact or law raised in the Motion or the underlying litigation, the Parties hereby seek to modify the Consent Decree in this matter, and upon the filing of a Motion to Enter by the United States, move that the Court sign and enter the following Order:

Modify the provisions of the Consent Decree, as amended by the first four modifications, as follows:

Add a new Paragraph 5A that states:

5A. A "30-Day Rolling Average Emission Rate" for Rockport means, and shall be expressed as, lb/mmBTU and calculated in accordance with the following procedure: first, sum the total pounds of the pollutant in question emitted from the combined Rockport stack during a Day which is an Operating Day for either or both Rockport Units, and the previous twenty-nine (29) such Days; second, sum the total heat input to both Rockport Units in mmBTU during the Day which was an Operating Day for either or both Rockport Units, and the previous twenty-nine (29) such Days; and third, divide the total number of pounds of the pollutant emitted during the thirty (30) Days which were Operating Days for either or both Rockport Units by the total heat input during the thirty such Days. A new 30-Day Rolling Average Emission Rate shall be calculated for each new Day which is an Operating Day for either or both Rockport Units. Each 30-Day Rolling Average Emission Rate shall include all emissions that occur during all periods of startup, shutdown, and Malfunction within an Operating Day, except as follows:

a. Emissions and BTU inputs from both Rockport Units that occur during a period of Malfunction at either Rockport Unit shall be excluded from the calculation of the 30-Day Rolling Average Emission Rate if Defendants provide notice of the Malfunction to EPA in accordance with Paragraph 159 in Section XIV (Force Majeure) of this Consent Decree;

b. Emissions of NOx and BTU inputs from both Rockport Units that occur during the fifth and subsequent Cold Start Up Period(s) that occur at a single Rockport Unit during any 30-Day period shall be excluded from the calculation of the 30-Day Rolling Average Emission Rate if inclusion of such emissions would result in a violation of any applicable 30-Day Rolling Average Emission Rate and Defendants have installed, operated, and maintained the SCR at the Unit in question in accordance with manufacturers' specifications and good engineering practices. A "Cold Start Up Period" occurs whenever there has been no fire in the boiler of a Unit (no combustion of any Fossil Fuel) for a period of six (6) hours or more. The NOx emissions to be excluded during the fifth and subsequent Cold Start Up Period(s) at a single unit shall be the lesser of (i) those NOx emissions emitted during the eight (8) hour period commencing when the Unit is synchronized with a utility electric distribution system and concluding eight (8) hours later, or (ii) those NOx emissions emitted prior to the time that the flue gas has achieved the minimum SCR operational temperature specified by the catalyst manufacturer; and

c. For SO_2, shall include all emissions and BTUs commencing from the time a single Rockport Unit is synchronized with a utility electric distribution system through the time that both Rockport Units cease to combust fossil fuel and the fire is out in both boilers.

Paragraph 14 is replaced in its entirety and now reads as follows:

14. "Continuously Operate" or "Continuous Operation" means that when an SCR, FGD, DSI, Enhanced DSI, ESP or other NOx Pollution Controls are used at a Unit, except during a Malfunction, they shall be operated at all times such Unit is in operation, consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for such equipment and the Unit so as to minimize emissions to the greatest extent practicable.

Add a new Paragraph 20A that states:

20A. "Enhanced Dry Sorbent Injection" or "Enhanced DSI" means a pollution control system in which a dry sorbent is injected into the flue gas prior to the NOx and particulate matter controls in order to provide additional mixing and improved SO_2 removal as compared to Dry Sorbent Injection.

Paragraph 67 is replaced in its entirety and now reads as follows:

67. Notwithstanding any other provisions of this Consent Decree, except Section XIV (Force Majeure), during each calendar year specified in the table below, all Units in the AEP Eastern System, collectively, shall not emit NOx in excess of the following Eastern System-Wide Annual Tonnage Limitations:

Calendar Year	**Eastern System-Wide Annual Tonnage Limitations for NOx**
2009	96,000 tons
2010	92,500 tons
2011	92,500 tons
2012	85,000 tons
2013	85,000 tons
2014	85,000 tons
2015	75,000 tons
2016-2017	72,000 tons per year
2018-2020	62,000 tons per year
2021-2028	52,000 tons per year
2029 and each year thereafter	44,000 tons per year

Paragraph 68 is replaced in its entirety and now reads as follows:

68. No later than the dates set forth in the table below, Defendants shall install and

Continuously Operate SCR on each Unit identified therein, or, if indicated in the table, Retire, Retrofit, or Re-Power such Unit:

Unit	NOx Pollution Control	Date
Amos Unit 1	SCR	January 1, 2008
Amos Unit 2	SCR	January 1, 2009
Amos Unit 3	SCR	January 1, 2008
Big Sandy Unit 2	SCR	January 1, 2009
Cardinal Unit 1	SCR	January 1, 2009
Cardinal Unit 2	SCR	January 1, 2009
Cardinal Unit 3	SCR	January 1, 2009
Conesville Unit 1	Retire, Retrofit, or Re-Power	Date of Entry of this Consent Decree
Conesville Unit 2	Retire, Retrofit, or Re-Power	Date of Entry of this Consent Decree
Conesville Unit 3	Retire, Retrofit, or Re-Power	December 31, 2012
Conesville Unit 4	SCR	December 31, 2010
Gavin Unit 1	SCR	January 1, 2009
Gavin Unit 2	SCR	January 1, 2009
Mitchell Unit 1	SCR	January 1, 2009
Mitchell Unit 2	SCR	January 1, 2009
Mountaineer Unit 1	SCR	January 1, 2008
Muskingum River Units 1-4	Retire, Retrofit, or Re-Power	December 31, 2015
Muskingum River Unit 5	SCR	January 1, 2008
Rockport Unit 1	SCR	December 31, 2017
Rockport Unit 2	SCR	June 1, 2020
Sporn Unit 5	Retire, Retrofit, or Re-Power	December 31, 2013
A total of at least 600 MW from the following list of Units: Sporn Units 1-4, Clinch River units 1-3, Tanners Creek Units 1-3 and/or Kammer Units 1-3	Retire, Retrofit, or Re-Power	December 31, 2018

Add a new Paragraph 68A that reads as follows:

68A. <u>30-Day Rolling Average NO_x Emission Rate at Rockport.</u> Beginning on the thirtieth Day which is an Operating Day for either one or both Rockport Units in calendar year 2021, average

NOx emissions from the Rockport Units shall be limited to 0.090 lb/mmBTU on a 30-day Rolling Average Basis at the combined stack for the Rockport Units. Emissions shall be calculated in accordance with the provisions of Paragraph 5A and reported in accordance with the requirements of Paragraph J in Appendix B.

Add a new Paragraph 68B that reads as follows:

68B. Informational NOx Monitoring. During the ozone seasons (May 1 – September 30) in each of calendar years 2019 and 2020, prior to the effective date of the 30-Day Rolling Average NOx Rate at the Rockport Units in Paragraph 68A, the AEP Defendants shall provide an estimate of the 30-day rolling average NOx emissions from Rockport Unit 1, based on NOx concentrations and percent CO_2 measured at an uncertified NOx monitor in the duct from Unit 1 before the flue gases from Rockport Units 1 and 2 combine at the common stack. Hourly NOx rates shall be calculated for each hour for which valid data is available, using the following equation:

$$\text{NOx lb/mmBtu} = [(1.194 \times 10^{-7}) \times \text{NOx ppm} \times 1840 \text{ scf } CO_2 \text{ per mmBtu} \times 100]/\% \, CO_2$$

The monitor shall be calibrated daily and maintained in accordance with good engineering and maintenance practices. If valid NOx or CO_2 data is not available for any hour, that hour shall not be used in the calculation of the informational data provided to Plaintiffs, including periods of monitor downtime, calibrations, and maintenance. For informational purposes only, NOx emission rate data for Rockport Unit 1 on a 30-Day Rolling Average Basis for May – June shall be reported to Plaintiffs by July 30, and NOx emission rate data for Rockport Unit 1 on a 30-Day Rolling Average Basis for July – September shall be reported to Plaintiffs by October 30. Nothing in this Paragraph shall be construed to establish a Unit-specific NOx Emission Rate for Rockport Unit 1, and these interim reporting obligations are not required to be incorporated into the Title V permit for the Rockport Plant.

Paragraph 86 is replaced in its entirety and now reads as follows:

86. Notwithstanding any other provisions of this Consent Decree, except Section XIV (Force Majeure), during each calendar year specified in the table below, all Units in the AEP Eastern System, collectively, shall not emit SO_2 in excess of the following Eastern System-Wide Annual Tonnage Limitations:

Calendar Year	**Eastern System-Wide Annual Tonnage Limitations for SO2**
2010	450,000 tons
2011	450,000 tons
2012	420,000 tons
2013	350,000 tons
2014	340,000 tons
2015	275,000 tons
2016	145,000 tons
2017	145,000 tons
2018	145,000 tons
2019-2020	113,000 tons per year
2021-2028	94,000 tons per year
2029, and each year thereafter	89,000 tons per year

Paragraph 87 is replaced in its entirety and now reads as follows:

87. No later than the dates set forth in the table below, Defendants shall install and Continuously Operate an FGD, Dry Sorbent Injection, or Enhanced Dry Sorbent Injection system on each Unit identified therein, or, if indicated in the table, Cease Burning Coal, Retire,

Retrofit, Re-power, or Refuel such Unit:

Unit	SO_2 Pollution Control	Date
Amos Unit 1	FGD	February 15, 2011
Amos Unit 2	FGD	April 2, 2010
Amos Unit 3	FGD	December 31, 2009
Big Sandy Unit 2	Retrofit, Retire, Re-Power or Refuel	December 31, 2015
Cardinal Units 1 and 2	FGD	December 31, 2008
Cardinal Unit 3	FGD	December 31, 2012
Conesville Units 1 and 2	Retire, Retrofit, or Re-power	Date of Entry
Conesville Unit 3	Retire, Retrofit, or Re-power	December 31, 2012
Conesville Unit 4	FGD	December 31, 2010
Conesville Unit 5	Upgrade existing FGD and meet a 95% 30-day Rolling Average Removal Efficiency	December 31, 2009
Conesville Unit 6	Upgrade existing FGD and meet a 95% 30-day Rolling Average Removal Efficiency	December 31, 2009
Gavin Units 1 and 2	FGD	Date of Entry
Mitchell Units 1 and 2	FGD	December 31, 2007
Mountaineer Unit 1	FGD	December 31, 2007
Muskingum River Units 1-4	Retire, Retrofit, or Re-power	December 31, 2015
Muskingum River Unit 5	Cease Burning Coal and Retire Or Cease Burning Coal and Refuel	December 15, 2015 December 31, 2015, unless the Refueling project is not completed in which case the Unit

Unit	SO_2 Pollution Control	Date
		will be taken out of service no later than December 31, 2015, and will not restart until the Refueling project is completed. The refueling project must be completed by June 30, 2017.
Rockport Unit 1	Dry Sorbent Injection and Enhanced DSI, and beginning in calendar year 2021 meet an Emission Rate of 0.15 lb/mmBTU of SO_2 on a 30-Day Rolling Average Basis at the Rockport combined stack And Retrofit, Refuel, or Re-Power, but must satisfy the provisions of Paragraphs 133 and 140	April 16, 2015 December 31, 2020 December 31, 2028
Rockport Unit 2	Dry Sorbent Injection and Enhanced DSI, and beginning in calendar year 2021 meet an Emission Rate of 0.15 lb/mmBTU of SO_2 on a 30-Day Rolling Average Basis at the Rockport combined stack	April 16, 2015 June 1, 2020
Sporn Unit 5	Retire, Retrofit, or Re-power	December 31, 2013
A total of at least 600 MW from the following list of Units: Sporn Units 1-4, Clinch River Units 1-3,	Retire, Retrofit, or Re-power	December 31, 2018

Unit	SO_2 Pollution Control	Date
Tanners Creek Units 1-3, and/or Kammer Units 1-3		

Paragraph 89A is replaced in its entirety and now reads as follows:

89A. Plant-Wide Annual Tonnage Limitation and 30-Day Rolling Average Emission Rate for SO_2 at Rockport. For each of the calendar years set forth in the table below, AEP Defendants shall limit their total annual SO_2 emissions from Rockport Units 1 and 2 to the Plant-Wide Annual Tonnage Limitation for SO_2 as follows:

Calendar Years	Plant-Wide Annual Tonnage Limitation for SO2
2016-2017	28,000 tons per year
2018-2019	26,000 tons per year
2020	22,000 tons per year
2021-2028	10,000 tons per year
2029, and each year thereafter	5,000 tons per year

In addition to the Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport, beginning on the thirtieth Day which is an Operating Day for either or both Rockport Units in calendar year 2021, SO_2 emissions from the Rockport Units shall be limited to 0.15 lb/mmBTU on a 30-Day Rolling Average Basis at the Rockport combined stack (30-Day Rolling Average Emission Rate for SO_2 at Rockport). Emissions shall be calculated in accordance with the provisions of Paragraph 5A and reported in accordance with the requirements of Paragraph J in Appendix B. Nothing in this Consent Decree shall be construed to prohibit the AEP Defendants from further optimizing the Enhanced DSI system, utilizing alternative sorbents, or upgrading the SO_2 removal technology at the Rockport Units so long as the Units maintain compliance with the 30-day Rolling Average Emission Rate for SO_2 at Rockport and the 30-day Rolling Average Emission Rate for NO_x at Rockport.

Paragraph 127 is replaced in its entirety and now reads as follows:

127. The States, by and through their respective Attorneys General, shall jointly submit to Defendants Projects within the categories identified in this Subsection B for funding in amounts not to exceed $4.8 million per calendar year for no less than five (5) years following the Date of Entry of this Consent Decree beginning as early as calendar year 2008, and for an additional amount not to exceed $6.0 million in 2013. The funds for these Projects will be apportioned by and among the States, and Defendants shall not have approval rights for the Projects or the apportionment. Defendants shall pay proceeds as designated by the States in accordance with the Projects submitted for funding each year within seventy-five (75) days after being notified by the States in writing. Notwithstanding the maximum annual funding limitations above, if the total costs of the projects submitted in any one or more years is less than the maximum annual amount, the difference between the amount requested and the maximum annual amount for that year will be available for funding by the Defendants of new and previously submitted projects in the following years, except that all amounts not requested by and paid to the States within eleven (11) years after the Date of Entry of this Consent Decree shall expire.

Pursuant to the Fifth Joint Modification Indiana Michigan Power Company ("I&M") will provide as restitution or as funds to come into compliance with the law $4 million in additional funding for the States to support projects identified in Section VIII, Subsection B during the period from 2019 through 2021. I&M shall provide the funding within seventy-five (75) days of receipt of a written request for payment and in accordance with instructions from counsel for the States.

Paragraph 128B is replaced in its entirety and now reads as follows:

128B. Citizen Plaintiffs' Mitigation Projects. I&M will provide $2.5 million in mitigation funding as directed by the Citizen Plaintiffs for projects in Indiana that include diesel retrofits, health and safety home repairs, solar water heaters, outdoor wood boilers, land acquisition projects, and small renewable energy projects (less than 0.5 MW) located on customer premises that are eligible for net metering or similar interconnection arrangements on or before December 31, 2014. I&M shall make payments to fund such Projects within seventy-five (75) days after being notified by the Citizen Plaintiffs in writing of the nature of the Project, the amount of funding requested, the identity and mailing address of the recipient of the funds, payment instructions, including taxpayer identification numbers and routing instructions for electronic payments, and any other information necessary to process the requested payments. Defendants shall not have approval rights for the Projects or the amount of funding requested, but in no event shall the cumulative amount of funding provided pursuant to this Paragraph 128B exceed $2.5 million.

In addition to the $2.5 million provided in 2014, pursuant to the Fifth Joint Modification I&M will provide as restitution or as funds to come into compliance with the law $3.5 million in funding for Citizen Plaintiffs to support projects that will promote energy efficiency, distributed generation, and pollution reduction measures for nonprofits, governmental entities, low income residents and/or other entities selected by Citizen Plaintiffs. I&M shall provide the $3.5 million in funding within seventy-five (75) days of the Date of Entry of the Fifth Joint Modification of the Consent Decree by the Court in accordance with instructions from counsel for Citizen Plaintiffs.

Paragraph 133 is replaced in its entirety and now reads as follows:

133. Claims Based on Modifications after the Date of Lodging of This Consent Decree. Entry of this Consent Decree shall resolve all civil claims of the United States against Defendants that

arise based on a modification commenced before December 31, 2018, or, solely for Rockport Unit 1, before December 31, 2028, or, solely for Rockport Unit 2, before June 1, 2020, for all pollutants, except Particulate Matter, regulated under Parts C or D of Subchapter I of the Clean Air Act, and under regulations promulgated thereunder, as of the Date of Lodging of this Consent Decree, and:

a. where such modification is commenced at any AEP Eastern System Unit after the Date of Lodging of the original Consent Decree; or

b. where such modification is one this Consent Decree expressly directs Defendants to undertake.

With respect to Rockport Unit 1, the United States agrees that the AEP Defendants' obligation to Retrofit, Re-Power, or Refuel Rockport Unit 1 would be satisfied if, by no later than December 31, 2028, the AEP Defendants Retrofit Rockport Unit 1 by installing and commencing continuous operation of FGD technology consistent with the definition in Paragraph 56 of the Third Joint Modification of the Consent Decree, Re-Power the Unit consistent with the definition in Paragraph 54 of the Consent Decree, or Refuel the Unit consistent with the provisions of Paragraph 53A of the Third Joint Modification of the Consent Decree. If the AEP Defendants elect to Retire Rockport Unit 1 by December 31, 2028, that would also satisfy the requirements of this Paragraph and fulfill the AEP Defendants' obligations with regard to Rockport Unit 1 under this Consent Decree. The term "modification" as used in this paragraph shall have the meaning that term is given under the Clean Air Act and under the regulations in effect as of the Date of Lodging of this Consent Decree, as alleged in the complaints in *AEP I* and *AEP II*.

Paragraph 140 is replaced in its entirety and now reads as follows:

140. With respect to the States and Citizen Plaintiffs, except as specifically set forth in this Paragraph, the States and Citizen Plaintiffs expressly do not join in giving the Defendants the

covenant provided by the United States in Paragraph 133 of this Consent Decree, do not release any claims under the Clean Air Act and its implementing regulations arising after the Date of Lodging of the original Consent Decree, and reserve their rights, if any, to bring any actions against Defendants pursuant to 42 U.S.C. §7604 for any claims arising after the Date of the Lodging of the original Consent Decree. AEP, the States, and Citizen Plaintiffs also recognize that I&M informed state regulators in its most recent base rate proceedings that the most realistic date through which Rockport Unit 1 can be expected to be in operation with any reasonable degree of certainty is December 2028, and the Indiana Utility Regulatory Commission and the Michigan Public Service Commission have approved depreciation rates for I&M's share of Rockport Unit 1 to be consistent with the retirement of Unit 1 in December 2028. Notwithstanding the existence of any other compliance options in Paragraphs 87 and 133, AEP Defendants must Retire Rockport Unit 1 by no later than December 31, 2028. AEP Defendants and the States and Citizen Plaintiffs agree that Paragraph 140 prevails in any conflict between it and Paragraphs 87 and/or 133.

a. On or before March 31, 2025, AEP Defendants shall submit to PJM Interconnection, LLC, or any other regional transmission organization with jurisdiction over the Rockport Units, notification of the planned retirement of Rockport Unit 1 by no later than December 31, 2028, and a request for such regional transmission organization to evaluate and identify any reliability concerns associated with such retirement.

Paragraph 180 is replaced in its entirety and now reads as follows:

180. Within one (1) year from commencement of operation of each pollution control device to be installed, upgraded, and/or operated under this Consent Decree, Defendants shall apply to include the requirements and limitations enumerated in this Consent Decree into federally-enforceable non-Title V permits and/or site-specific amendments to the applicable state

implementation plans to reflect all new requirements applicable to each Unit in the AEP Eastern System, the Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River, the Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer, and the Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport.

Paragraph 182 is replaced in its entirety and now reads as follows:

182. Prior to termination of this Consent Decree, Defendants shall obtain enforceable provisions in their Title V permits for the AEP Eastern System that incorporate (a) any Unit-specific requirements and limitations of this Consent Decree, such as performance, operational, maintenance, and control technology requirements, (b) the Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River, the Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer, and the Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport, and (c) the Eastern System-Wide Annual Tonnage Limitations for SO_2 and NO_x. If Defendants do not obtain enforceable provisions for the Eastern System-Wide Annual Tonnage Limitations for SO_2 and NO_x in such Title V permits, then the requirements in Paragraphs 86 and 67 shall remain enforceable under this Consent Decree and shall not be subject to termination.

Paragraph 188 is modified as follows to update the information required in order to provide required notices under the Consent Decree:

188.

As to the United States:

Case Management Unit
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, DC 20044-7611
DJ# 90-5-2-1-06893
eescdcopy.enrd@usdoj.gov

Phillip Brooks
Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [Mail Code 2242A]
1200 Pennsylvania Avenue, N.W.
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Brooks.phillip@epa.gov

Sara Breneman
Air Enforcement & Compliance Assurance Branch
U.S. EPA Region 5
77 W. Jackson Blvd.
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Chicago, IL 60604
Breneman.sara@epa.gov

and

Carol Amend, Branch Chief
Air, RCRA & Toxics Branch (3ED20)
Enforcement & Compliance Assurance Division
U.S. EPA, Region 3
1650 Arch Street
Philadelphia, PA 19103-2029
Amend.carol@epa.gov

For all notices to EPA, Defendants shall register for the CDX electronic system and upload such notices at https://cdx.gov/epa-home.asp.

As to the State of Connecticut:

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Office of the Attorney General
Environment Department
55 Elm Street
P.O. Box 120
Hartford, CT 06141-0120
Lori.dibella@ct.gov

As to the State of Maryland:

Frank Courtright
Program Manager
Air Quality Compliance Program

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and

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Christophe.courchesne@state.ma.us

As to the State of New Hampshire:

Director, Air Resources Division
New Hampshire Department of Environmental Services
29 Hazen Dive
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and

K. Allen Brooks
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As to the State of New Jersey:

Section Chief
Environmental Enforcement
Dept. of Law & Public Safety
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As to the State of New York:

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Environmental Protection Bureau
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As to the Citizen Plaintiffs:

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Natural Resources Defense Council, Inc.
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Margrethe Kearney
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and

Shannon Fisk
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As to AEP:

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Vice President, Environmental Services
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As to Gavin Buyer:

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karl.karg@lw.com

and

Alexandra Farmer
Kirkland & Ellis LLP
1301 Pennsylvania Avenue, N.W.
Washington, DC 20004
alexandra.farmer@kirkland.com

Add a new Paragraph 205A that reads as follows:

205A. 26 U.S.C. Section 162(f)(2)(A)(ii) Identification. For purposes of the identification requirement of Section 162(f)(2)(A)(ii) of the Internal Revenue Code, 26 U.S.C. § 162(f)(2)(A)(ii), with respect to obligations incurred under this Fifth Joint Modification, performance of Section II (Applicability), Paragraph 3; Section IV (NO_x Emission Reductions and Controls), Paragraphs 67, 68, 68A, and 68B; Section V (SO_2 Emission Reductions and Controls), Paragraphs 86, 87, and 89A; Section VII (Prohibition on Netting Credits or Offsets from Required Controls), Paragraph 117; Section XI (Periodic Reporting), Paragraphs 143 – 147; Section XII (Review and Approval of Submittals), Paragraphs 148 and 149 (except with respect to dispute resolution); Section XVI (Permits), Paragraphs 175, 177, 179, and 180 – 183; Section XVII (Information Collection and Retention), Paragraphs 184 and 185; Section XXIII (General Provisions), Paragraph 207; and Appendix B; is restitution or required to come into compliance with law.

Modify Appendix B (Reporting Requirements) as follows:

Section I Paragraph O is replaced in its entirety and now reads as follows:

O. Plant-Wide Annual Tonnage Limitation and Emission Rate for SO_2 at Rockport.

Beginning March 31, 2017, and continuing annually thereafter, Defendants shall report: (a) the actual tons of SO_2 emitted from Units 1 and 2 at the Rockport Plant for the prior calendar year; (b) the Plant-Wide Annual Tonnage Limitation for SO_2 at the Rockport Plant for the prior calendar year as set forth in Paragraph 89A of the Consent Decree; and (c) for the annual reports for calendar years 2015 - 2020, Defendants shall report the daily sorbent deliveries to the Rockport Plant by weight. Beginning in calendar year 2021, the annual reports shall report the 30-day rolling average SO_2 Emissions Rate at the Rockport stack as required under Section I, Paragraph J of Appendix B, and reporting of daily sorbent deliveries will no longer be required.

Section I Paragraph S. is replaced in its entirety and now reads as follows:

S. Notification of Retirement of Rockport Unit 1.

AEP Defendants shall provide to the Plaintiffs a copy of the notification submitted to PJM Interconnection, LLC, or any other regional transmission organization pursuant to Paragraph 140.a, and a copy of any response received from PJM Interconnection, LLC, or any other the regional transmission organization.

Delete Paragraphs T and U from Section I of Appendix B.

Except as specifically provided in this Order, all other terms and conditions of the Consent Decree remain unchanged and in full effect.

SO ORDERED, THIS 17th DAY OF July, 2019.

HONORABLE EDMUND A. SARGUS, JR.
UNITED STATES DISTRICT JUDGE

**SIGNATURE PAGE FOR THE
FIFTH JOINT MODIFICATION OF THE CONSENT DECREE**

in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR THE UNITED STATES

Myles E. Flint, II

Myles E. Flint, II
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FOR THE UNITED STATES

Rosemarie A. Kelley
Rosemarie A. Kelley
Director
Office of Civil Enforcement
United States Environmental Protection Agency

Phillip A. Brooks
Director, Air Enforcement Division
Office of Civil Enforcement
United States Environmental Protection Agency

Sabrina Argentieri
Sabrina Argentieri
Attorney-Advisor
Office of Civil Enforcement
Civil Enforcement Division
United States Environmental Protection Agency

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FOR THE STATE OF CONNECTICUT

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Lori D. DiBella
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FOR THE STATE OF MARYLAND:

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**SIGNATURE PAGE FOR THE
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in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR THE COMMONWEALTH OF
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**SIGNATURE PAGE FOR THE
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United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

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in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR THE STATE OF NEW JERSEY

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____
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**SIGNATURE PAGE FOR THE
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United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR THE STATE OF NEW YORK

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ATTORNEY GENERAL

Michael J. Myers
Senior Counsel
Environmental Protection Bureau
New York State Attorney General
The Capitol
Albany, NY 12224

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in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR THE STATE OF RHODE ISLAND

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Gregory S. Schultz
Special Assistant Attorney General
150 South Main Street
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SIGNATURE PAGE FOR THE
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in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR THE STATE OF VERMONT

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**SIGNATURE PAGE FOR THE
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in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR NATURAL RESOURCES DEFENSE
COUNCIL, INC.

Nancy S Marks

Nancy S. Marks
Natural Resources Defense Council, Inc.
40 West 20th Street
New York, NY 10011

**SIGNATURE PAGE FOR THE
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in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR SIERRA CLUB

Kristin A. Henry

Kristin Henry
Sierra Club
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Oakland, CA 94612

**SIGNATURE PAGE FOR THE
FIFTH JOINT MODIFICATION OF THE CONSENT DECREE**

in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR OHIO CITIZEN ACTION, CITIZENS ACTION COALITION OF INDIANA, HOOSIER ENVIRONMENTAL COUNCIL, OHIO VALLEY ENVIRONMENTAL COALITION, WEST VIRGINIA ENVIRONMENTAL COUNCIL, CLEAN AIR COUNCIL, IZAAK WALTON LEAGUE OF AMERICA, ENVIRONMENT AMERICA, NATIONAL WILDLIFE FEDERATION, INDIANA WILDLIFE FEDERATION, AND LEAGUE OF OHIO SPORTSMEN

Margrethe K. Kearney

Margrethe Kearney
Environmental Law and Policy Center
35 East Wacker Drive, Suite 1600
Chicago, IL 60601-2110

**SIGNATURE PAGE FOR THE
FIFTH JOINT MODIFICATION OF THE CONSENT DECREE**

in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR THE AEP COMPANIES

David M. Feinberg
American Electric Power
1 Riverside Plaza
Columbus, OH 43215

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 3
CASE NO. U-20591

DATA REQUEST NO. 3-3-SIERRA CLUB

Request

Per the Fifth Joint Modification of Consent Decree ordered by the U.S. District Court on July 17, 2019, the Company will be required to install "enhanced" dry sorbent injection (DSI) at Rockport units 1 and 2 in 2020 and meet an SO2 emission rate of 0.15 lb/mmBtu on a 30-day rolling average basis at the Rockport combined stack beginning in calendar year 2021.

a. Identify each change that has been or will need to be made to install enhanced DSI on each of Rockport Units 1 and 2.

b. Identify each operational or other change that you anticipate will need to be made to Rockport Units 1 and/or 2, or to the plant as a whole, in order to meet the 0.15 lb/mmBtu emission limit established in the Fifth Joint Modification

c. Confirm or deny that costs for enhanced DSI are not included in any of the cases modeled for the IRP in this docket.

i. If denied, please identify which cases include enhanced DSI at both Rockport units that are operational in 2020.

d. Has the Company conducted (or does it plan to conduct) economic modeling that includes the costs of enhanced DSI at both Rockport units that are operational in 2020?

i. If so, please explain the results of such modeling, and provide the inputs and outputs for this modeling, preferably in Excel formal.

ii. If not, please explain why not.

e. Please provide the capital costs and associated annual capital revenue requirements of enhanced DSI for each Rockport unit for the IRP analysis period. Explain how such costs and revenue requirements were calculated or determined, and produce any documents or workpapers reflecting or supporting such calculations or determinations.

f. Please provide the annual fixed O&M costs of enhanced DSI for each Rockport unit for the IRP analysis period, and for all cases of Rockport units' retirement modeled in the IRP. Explain how such costs were calculated or determined, and produce any documents or workpapers reflecting or supporting such calculations or determinations.

g. Please provide the annual variable O&M costs of enhanced DSI for each Rockport unit for the IRP analysis period, and for all cases of Rockport units' retirement modeled in the IRP. Explain how such costs were calculated or determined, and produce any documents or workpapers reflecting or supporting such calculations or determinations.

h. Confirm or deny that variable costs per MWh of generation would increase for both units after the enhanced DSI were installed (all else equal).

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 3
CASE NO. U-20591

i. If confirmed, please provide any analyses or documentation produced by the Company on the impact of enhanced DSI installation on variable costs.
ii. If denied, please explain why not.

i. Confirm or deny that the units would operate less often if enhanced DSI were installed and variable costs per MWh were to increase.
i. If confirmed, please provide any analyses or documentation produced by the Company on the impact of enhanced DSI installation on unit operations.
ii. If denied, please explain why not.

Response

a. Enhanced DSI modifications listed at the same for each unit:

- Add a third sodium bicarbonate truck unloading station,
- Relocate the DSI injection points from their current location to a location ahead of the SCR,
- Upgrade control system,
- Install steep angle cones in the base of each DSI silo,
- install pin mixer ash treatment.

b. Enhanced DSI modifications listed at the same for each unit:

- Increase unloading frequency of sodium bicarbonate, Inject at a rate to meet 0.15#/mmBtu.

c. Confirmed.

d. I&M objects to this request the grounds and to the extent the request is vague and ambiguous with respect to the meaning of the term "economic modeling." I&M further objects to the extent this question seeks information that is confidential, proprietary, competitively sensitive and/or trade secret. Without waiving these objections, I&M will provide the requested confidential information subject to the Protective Order issued September 20, 2019 and further please see “SC 3-3d Confidential Attachment 1.xlsx” which provides the enhanced DSI modifications as referenced in question 3 part b. The modeling output is from an 8/22/19 Budget Forecast production costing run produced for I&M.

e. See response to c.

f. See response to c.

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 3
CASE NO. U-20591

g. See response to c.

h. Confirmed. Please see “SC 3-3d Confidential Attachment 1.xlsx.”

i. I&M can neither admit nor deny, and therefore denies. In support of this denial, I&M states that the units' operation is dependent on value of energy at a given time, which is influenced by the weather, natural gas prices, and the availability of cheaper energy.

As to objection
Counsel

Preparer
Kerns
Torpey

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 3
CASE NO. U-20591

DATA REQUEST NO. 3-4-SIERRA CLUB

Request

Refer to Table 17 on page 117 of Ex. IM-2. With regard to each of the modeling portfolios in which you assumed the installation of an FGD on Rockport Unit 1 or 2 (i.e. Cases 6 & 6A, 7 & 7A, and 8 & 8A):

a. Please provide the capital costs and associated annual capital revenue requirements of the FGDs for each Rockport unit for the IRP analysis period.

b. Please provide the annual fixed O&M costs of FGDs for each Rockport unit for the IRP analysis period.

c. Please provide the annual variable O&M costs of FGDs for each Rockport unit for the IRP analysis period.

Response

I&M objects to the extent this question seeks information that is confidential, proprietary, competitively sensitive and/or trade secret. Without waiving these objections, I&M will provide the requested confidential information subject to the Protective Order issued September 20, 2019.

a. Please see “SC 3-4 a Confidential Attachment 1.pdf” and “SC 3-4a Confidential Attachment 2.pdf” for the Rockport FGD capital costs and associated capital revenue requirements used in the IRP analysis.

b. The FGD annual fixed O&M costs are not broken out, but included in the total fixed O&M cost for the units.

c. The FGD annual variable O&M costs are not broken out, but included in the total variable O&M cost for the units.

As to objection
Counsel

Preparer
Torpey

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 3
CASE NO. U-20591

DATA REQUEST NO. 3-6-SIERRA CLUB

Request

Refer to the "RP costs" tab in the Confidential attachments provided in the Company's response to data request Sierra Club 1-8. [[For this question, "retirement case" refers to the four options for Rockport unit retirement that I&M presents in this attachment.

a. Please explain why there are zero fixed O&M costs for Rockport unit 1 in retirement cases 2 and 3 in years prior to its retirement in 2044.
i. If this is an error on the Company's part, please provide corrected numbers for fixed O&M for Rockport unit 1 in retirement cases 2 and 3.

b. Please explain why there are zero fixed O&M costs for Rockport unit 2 in retirement case 4 in years prior to its retirement in 2048.
    i. If this is an error on the Company's part, please provide corrected numbers for fixed O&M for Rockport unit 2 in retirement case 4.

c. Please explain why there is zero lease payment for Rockport 2 in retirement case 4 starting in 2039 even though the unit is assumed to retire in 2048 for this retirement case.
    i. If this is an error on the Company's part, please provide corrected numbers for lease payments in retirement case 4.

d. Please confirm that the "major capital expenditures" for each Rockport unit are depreciated over a 10-year period
    i. If denied, please provide updated carrying charges for major capital expenditures.

e. Please confirm that the "major capital expenditures" for Rockport 1 and 2 only include the capital costs of FGD installation.
    i. If denied, please provide a breakdown of major capital expenditures for FGD costs compared to non-FGD costs for each Rockport unit.]]

Response

I&M objects to the extent this question seeks information that is confidential, proprietary, competitively sensitive and/or trade secret. Without waiving these objections, I&M will provide the requested confidential information subject to the Protective Order issued September 20, 2019.

a. Please see I&M's 2nd Supplemental response to SC DR 1. In particular, please see the following files:
- SC 1-8 Confidential CORRECTED Attachment_Case_6.xlsx
- SC 1-8 Confidential CORRECTED Attachment_Case_6A.xlsx

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 3
CASE NO. U-20591

- SC 1-8 Confidential CORRECTED Attachment_Case_7.xlsx
- SC 1-8 Confidential CORRECTED Attachment_Case_7A.xlsx

b. Please see I&M's 2nd Supplemental response to SC DR 1. In particular, please see the following files:

- SC 1-8 Confidential CORRECTED Attachment_Case_8.xlsx
- SC 1-8 Confidential CORRECTED Attachment_Case_8A.xlsx

c. For this case it was assumed that the unit would be acquired by I&M at the end of the extended lease term, and that the acquisition cost of the unit, which would be approximately 50 years old in 2039, will be relative low.

d. Confirmed

e. Confirmed

<u>As to objection</u>
Counsel

<u>Preparer</u>
Torpey

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 3
CASE NO. U-20591

DATA REQUEST NO. 3-7-SIERRA CLUB

Request

Refer to the response to data request SC 2-3, Confidential_Attachment_1.[[For this question, "retirement case" refers to the four options for Rockport unit retirement that I&M presents in this attachment.

a. In the "OGC Summary" tab, please explain why there are zero on-going capital expenditures for Rockport unit 1 in retirement cases 2 and 3 in years prior to its retirement in 2044.

i. If this is an error on the Company's part, please provide corrected numbers for on-going capital expenditures for Rockport unit 1 in retirement cases 2 and 3.

b. In the "OGC Summary" tab, please explain why there are zero on-going capital expenditures for Rockport unit 2 in retirement case 4 in years prior to its retirement in 2048.

i. If this is an error on the Company's part, please provide corrected numbers for on-going capital expenditures for Rockport unit 2 in retirement case 4.

c. In each of the "OGC Cost Recovery" tabs, the description at the top of the tab claims that spending though 2030 is recovered over 20 years (and over 15 years thereafter) but the calculations actually show that spending through 2035 is using a 20-year recovery. Please explain which method is correct.

d. In the "OM & Lease Payment Data" tab, please explain why there are no O&M or lease payments provided after 2046.

i. If this is an error, please provide O&M and leases payments for 2047 and 2048.

e. The discount rate of 7.55% used to calculate cost recovery differs from the 7.17% discount rate used in calculating CPW. Please explain why and, if this is an error, please identify which is the correct discount rate to apply.]]

Response

I&M objects to the extent this question seeks information that is confidential, proprietary, competitively sensitive and/or trade secret. Without waiving these objections, I&M will provide the requested confidential information subject to the Protective Order issued September 20, 2019.

a. Please see I&M's supplemental response to SC DR 2, in particular, please see "SC 2-3 Confidential CORRECTED Attachment_1.xlsx."

b. See response to a.

c. See response to a.

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 3
CASE NO. U-20591

d. See response to a for O&M and Company's response to SC 3-6 c for lease payment.

e. The 7.55% weighted average cost of capital (WACC) is the end of year 2017 value and the 7.17% WACC is the end-of-year 2018 value for I&M. Both are correct, the estimated revenue requirement impacts for incremental capital investments were calculated using the 2017 value because that was the value when the IM IRP process began. As the process was extended the CPW WACC or discount rate was updated to reflect the end-or-year 2018 value.

As to objection
Counsel

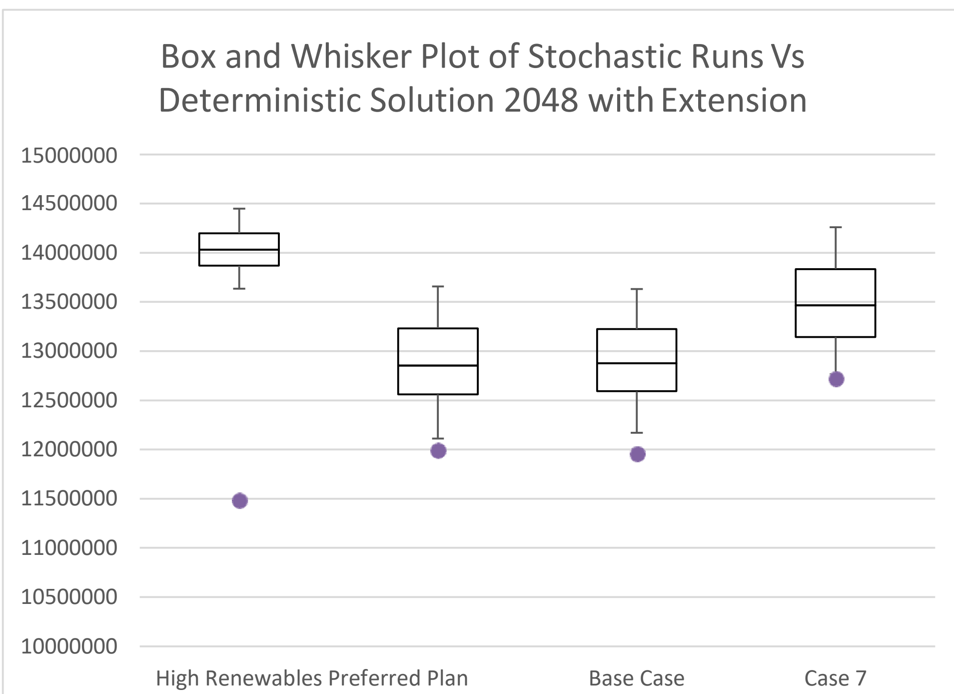
Preparer
Torpey

INDIANA MICHIGAN POWER COMPANY
MICHIGAN PUBLIC SERVICE COMMISSION STAFF
DATA REQUEST SET NO. 5
CASE NO. U-20591

DATA REQUEST NO. 5-7-STAFF

Request

Referencing discovery response ”1-9-STAFF”: Staff followed the instructions laid out. Using the methodology described in the last paragraph of the response “1-9-STAFF,” Staff was able to construct box and whisker plots based off the 100 iterations for each individual plan provided in the “summary tab”. Staff verified that the equation used to develop the “summary tab” was the Excel NPV function with a rate of 7.17% in tabs, “Case 1 Net Cost”, “Case 9 Net Cost”, “Case 12 Plan Net Cost”. Staff was able to reproduce the CPW for Cases 1, 9, 7 and 12 displayed in tables 19, 21 and 25 using this same equation and data from Appendix C. However, when the results from the deterministic runs using information from Appendix C are plotted against the box and whisker plots derived from the stochastic analysis, the deterministic runs fall outside the 5th percentile bounds on the box and whisker plot. It would be expected that the deterministic runs would fall somewhere near the median of the stochastic runs as the mean input in the stochastic runs are the inputs for the deterministic runs. An example of this can be seen below. Please explain this discrepancy.



INDIANA MICHIGAN POWER COMPANY
MICHIGAN PUBLIC SERVICE COMMISSION STAFF
DATA REQUEST SET NO. 5
CASE NO. U-20591

Response

The Company has reviewed Staff's comments on "1-9 STAFF". The Company has re-calculated the risk analysis results expressed in the IRP. Please see the update in “Staff 5-7 Attachment 1.xlsx.” The Company found the results expressed in "Staff 1-9" did not adequately reflect the total net profits for Solar Tier 1 and 2 and Wind Tier 2. This issue impacted all the cases where multiple additions of Solar Tier 1 and 2 and Wind Tier 2 were selected. The workbooks associated with this update can be found on the AEP Citrix server under PLEX_IN_OUT\Stochastic\2-pagers\Update.

Preparer
Torpey

INDIANA MICHIGAN POWER COMPANY
MICHIGAN PUBLIC SERVICE COMMISSION STAFF
DATA REQUEST SET NO. 3
CASE NO. U-20591

DATA REQUEST NO. 3-4-STAFF

Request

Referencing the Company's contract with the Ohio Valley Electric Corporation (OVEC):

a. Does the contract include terms that allow the Company the opportunity to renegotiate the existing contract?

b. Did the Company evaluate a renegotiation of this contract as part of its IRP planning process? If the Company did, please provide the location of this analysis in its IRP or supply any analysis conducted. If the Company did not, please provide a detailed explanation including how the Company determined that this contract was in the best interest of its ratepayers.

c. Please provide the EFORD for this unit on an annual basis the Company utilized as an input assumption into its model. If the EFORD changes over time, please provide an explanation as to why this change is occurring.

d. How did the Company model this resource in its IRP? Please provide details of how the Company modeled:

i. the contracts energy, demand, and transmission charges; and
ii. the inclusion of any expected capital investments related to environmental compliance.

e. What assumptions did the Company make regarding the Company's share of the going-forward costs associated with the advanced billing for debt services as described on page 12 of the

Response

a. The Amended and Restated Inter-Company Power Agreement (ICPA) is a multi-party agreement under which I&M has a commitment to purchase the output. Any amendment would require the agreement of the various parties to the ICPA and would be subject to the review and jurisdiction of the FERC.

b. No. Under the ICPA, into which I&M and the other OVEC sponsoring companies originally entered on July 10, 1953, and most recently amended on September 10, 2010 (see FERC Docket ER11-3181), I&M is contractually required to purchase a share of the

INDIANA MICHIGAN POWER COMPANY
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output of the OVEC plants through 2040. I&M's entitlement under the ICPA therefore cannot be excluded from I&M's generation portfolio in this IRP.

c. The following EFORd values were assumed constant over the planning period:

Clifty Creek Unit 1: 8.703, Unit 2: 7.277, Unit 3: 12.763, Unit 4: 8.486, Unit 5: 8.555, Unit 6: 15.701.

Kyger Creek Unit 1: 8.230, Unit 2: 14.147, Unit 3: 12.599, unit 4: 13.442, unit 5: 11.195.

d. i) The OVEC resources are dispatched in the model using the OVEC-provided energy price. Demand charges are included in the model but do not affect unit dispatch.

ii) The demand charges, which are provided by OVEC, include fixed costs and the costs of any capital investments forecasted by OVEC.

e. See response to d.ii above.

<u>Preparer</u>
Lewis
Torpey

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 1
CASE NO. U-20359

DATA REQUEST NO. 1-5-SC

Request

For each month since January 1, 2013, provide the itemized monthly charge as calculated by OVEC and charged to the Company for the period January 1, 2013 through the date of your response, "itemized" by:
a. energy charge,
b. demand charge,
c. transmission charge (if any), and
d. minimum loading events costs (if any).

Response

Please see "SC 1-05 Attachment 1.xlsx."

Preparer
Stegall

Indiana Michigan Power Company
OVEC Billing Data
January 2013 to July 2019

	Energy Charge	Demand Charge	Transmission Charge	PJM Expenses/Fees	Total Bill
Jan 2013	$2,049,966	$1,626,488	$106,266		$3,782,720
Feb	$1,789,333	$1,986,378	$102,700		$3,878,412
Mar	$1,458,139	$2,242,416	$98,322		$3,798,877
Apr	$1,454,535	$3,096,788	$96,926		$4,648,248
May	$1,837,542	$2,633,022	$103,149		$4,573,714
Jun	$2,336,639	$1,937,124	$109,621		$4,383,384
Jul	$2,536,226	$1,871,042	$111,986		$4,519,254
Aug	$2,117,036	$1,951,189	$106,625		$4,174,851
Sep	$1,755,417	$2,057,689	$101,817		$3,914,923
Oct	$2,206,050	$2,502,011	$107,807		$4,815,869
Nov	$1,881,544	$2,572,956	$103,142		$4,557,642
Dec	$2,235,204	$2,504,466	$110,253		$4,849,923
Jan 2014	$2,506,101	$1,500,861	$115,395		$4,122,357
Feb	$2,390,789	$1,769,031	$113,014		$4,272,835
Mar	$2,357,287	$2,028,630	$112,167		$4,498,084
Apr	$1,464,012	$2,391,845	$98,824		$3,954,681
May	$1,561,715	$2,097,283	$100,400		$3,759,398
Jun	$2,020,747	$1,681,400	$108,857		$3,811,004
Jul	$2,226,123	$1,638,739	$110,246		$3,975,108
Aug	$2,104,602	$1,750,930	$107,746		$3,963,278
Sep	$2,189,949	$1,853,251	$108,545		$4,151,746
Oct	$1,320,808	$2,181,359	$97,669		$3,599,836
Nov	$1,757,492	$1,863,656	$103,658		$3,724,806
Dec	$2,158,926	$2,735,824	$110,026		$5,004,775
Jan 2015	$1,899,272	$1,547,597	$109,246		$3,556,115
Feb	$1,720,027	$1,565,307	$105,027		$3,390,362
Mar	$1,899,161	$1,981,141	$107,897		$3,988,199
Apr	$1,490,052	$2,395,423	$101,130		$3,986,606
May	$1,505,223	$1,842,171	$91,925		$3,439,319
Jun	$1,654,843	$1,691,356	$100,677		$3,446,876
Jul	$1,651,366	$1,965,086	$100,085		$3,716,537
Aug	$1,787,529	$1,871,847	$104,923		$3,764,299
Sep	$1,820,109	$1,847,212	$101,736		$3,769,057
Oct	$1,392,335	$1,968,277	$98,916		$3,459,527
Nov	$811,597	$2,247,303	$89,352		$3,148,253
Dec	$779,366	$2,412,632	$88,226		$3,280,224

	Energy Charge	Demand Charge	Transmission Charge	PJM Expenses/Fees	Total Bill
Jan 2016	$1,515,951	$1,531,039	$1,282,014		$4,329,003
Feb	$1,236,126	$1,617,773	$97,814		$2,951,713
Mar	$773,142	$1,892,817	$92,735		$2,758,695
Apr	$923,902	$2,567,807	$91,412		$3,583,121
May	$1,337,521	$1,986,197	$99,140		$3,422,858
Jun	$2,125,263	$1,524,541	$110,432		$3,760,236
Jul	$2,313,550	$1,712,436	$114,173		$4,140,159
Aug	$2,199,008	$1,796,092	$111,469		$4,106,569
Sep	$2,199,215	$1,683,785	$111,535		$3,994,535
Oct	$1,264,218	$2,203,944	$96,544		$3,564,706
Nov	$1,646,298	$2,151,153	$102,148		$3,899,599
Dec	$2,428,505	$2,415,220	$113,963		$4,957,689
Jan 2017	$1,958,792	$1,756,404	$109,355	$186	$3,824,737
Feb	$2,041,717	$1,925,768	$110,573	$784	$4,078,843
Mar	$2,516,284	$1,998,440	$118,002	$186	$4,632,911
Apr	$1,687,670	$2,442,300	$104,128	$186	$4,234,283
May	$1,254,953	$2,678,596	$96,421	$855	$4,030,825
Jun	$1,934,239	$1,808,936	$108,755	$186	$3,852,116
Jul	$2,146,206	$2,046,243	$113,290	$186	$4,305,923
Aug	$2,091,025	$1,939,160	$111,466	$831	$4,142,482
Sep	$1,318,937	$2,589,294	$98,536	$186	$4,006,953
Oct	$1,636,331	$2,561,559	$103,824	$186	$4,301,900
Nov	$2,003,463	$2,239,373	$110,684	$780	$4,354,300
Dec	$2,480,126	$2,007,877	$118,188	$186	$4,606,376
Jan 2018	$2,201,990	$1,828,115	$115,319	$190	$4,145,614
Feb	$1,891,001	$1,922,764	$106,826	$798	$3,921,390
Mar	$2,038,271	$2,108,377	$114,492	$190	$4,261,331
Apr	$1,588,687	$2,810,074	$106,423	$190	$4,505,375
May	$1,374,834	$2,748,094	$100,280	$806	$4,224,014
Jun	$1,887,062	$2,014,513	$110,091	$190	$4,011,855
Jul	$2,148,571	$2,203,312	$114,368	$190	$4,466,442
Aug	$2,060,939	$2,185,845	$112,573	$1,031	$4,360,388
Sep	$1,729,063	$2,187,940	$103,476	$417	$4,020,897
Oct	$1,276,276	$2,562,668	$99,449	$190	$3,938,583
Nov	$1,988,586	$1,962,812	$110,328	$990	$4,062,716
Dec	$2,228,542	$2,951,098	$95,791	$19,651	$5,295,083
Jan 2019	$2,152,952	$2,094,810	$110,194	-$1,915	$4,356,041
Feb	$1,836,187	$2,034,957	$105,126	$24,981	$4,001,251
Mar	$2,114,271	$2,344,018	$109,083	$13,497	$4,580,869
Apr	$1,136,458	$2,918,177	$92,291	$28,319	$4,175,244
May	$1,608,660	$2,570,080	$98,898	$24,129	$4,301,767
Jun	$1,792,517	$2,029,810	$103,577	$25,653	$3,951,558
Jul	$2,170,400	$2,170,947	$109,947	$23,149	$4,474,442

INDIANA MICHIGAN POWER COMPANY
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DATA REQUEST NO. 1-6-SC

Request

For each month since January 1, 2013, provide the monthly energy received (in MWh) and capacity value (ICAP, in MW) of the OVEC Units to the Company.

Response

Please see "SC 1-06 Attachment 1.xlsx" for the requested data.

Preparer
Stegall

Indiana Michigan Power Company

OVEC ICAP Values (MW)

	2013		2014	2015		2016		2017	2018		
	Jan - Nov	*Dec*	*Jan - Dec*	*Jan - May*	*Jun - Dec*	*Jan - May*	*Jun - Dec*	*Jan - Dec*	*Jan - Aug*	*Sep - Nov*	*Dec*
Total I&M	**165.3**	**165.8**	**165.8**	**165.8**	**166.1**	**166.1**	**163**	**163**	**163**	**171.4**	**174.9**

OVEC Energy Received (MWh) (as reported by PJM)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013	65,346	58,570	47,186	46,637	61,240	79,044	86,197	69,875	56,065	72,079	60,429	78,502
2014	92,964	86,439	86,130	50,367	53,980	74,510	78,830	72,178	74,968	46,538	62,918	75,372
2015	72,360	65,955	71,214	54,344	49,944	55,718	53,749	66,170	62,351	48,167	25,602	22,077
2016	52,456	44,313	29,516	32,016	35,713	80,546	88,142	84,431	84,555	46,861	60,683	91,108
2017	77,915	83,113	103,611	66,155	47,723	78,688	90,408	86,214	52,935	65,446	82,257	103,155
2018	94,970	74,367	92,426	71,592	56,548	81,677	92,665	87,958	68,432	56,741	90,972	90,021
2019	91,218	78,170	87,236	42,097	60,874	72,564	90,014					

NOTE: All values are presented are Total I&M values

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DATA REQUEST NO. 1-7-SC

Request

For each month since January 1, 2013, with respect to the Company's share of the energy, capacity, and ancillary services of the OVEC Units, provide:
a. by month (or year if monthly data is not available) total energy market revenue earned by the Company through sale of its share into PJM markets;
b. by year total capacity market revenue earned by the Company through sale of its share into PJM markets;
c. by year total ancillary market revenue earned by the Company through sale of its share into PJM markets (if any);
d. For any month in which the Company took energy and/or capacity from the OVEC Units but did not sell all of such energy and/or capacity into the PJM markets, describe how such energy and/or capacity was used and the amount(s) for such uses.

Response

I&M objects to the Request to the extent it seeks an analysis, calculation, or compilation which has not already been performed and which I&M objects to performing. In support of this objection, I&M states that the requested data data prior to May 2016 is not in the Company's care, custody or control. Without waiving this response, I&M states:

a.) TABLE SC 1-7a provides the energy revenues associated with energy provided to the Company from OVEC by month as reported by PJM.

TABLE SC 1-7a	
	Energy Revenues
May 2016	$302,747.14
Jun 2016	$2,154,151.21
Jul 2016	$2,831,350.89
Aug 2016	$2,640,777.23
Sep 2016	$2,503,461.16
Oct 2016	$1,377,735.53

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Nov 2016	$1,571,913.99
Dec 2016	$2,889,165.97
Jan 2017	$2,292,946.82
Feb 2017	$2,074,501.83
Mar 2017	$3,180,843.68
Apr 2017	$1,935,621.58
May 2017	$1,430,521.24
Jun 2017	$2,184,186.76
Jul 2017	$2,758,507.76
Aug 2017	$2,373,535.77
Sep 2017	$1,679,230.03
Oct 2017	$1,938,282.40
Nov 2017	$2,385,552.74
Dec 2017	$3,210,924.09
Jan 2018	$4,634,744.00
Feb 2018	$1,970,332.66
Mar 2018	$2,913,590.64
Apr 2018	$2,426,270.46
May 2018	$1,932,982.46
Jun 2018	$2,479,542.68
Jul 2018	$2,939,188.57
Aug 2018	$2,757,436.62
Sep 2018	$2,393,559.71
Oct 2018	$1,972,823.32
Nov 2018	$3,322,595.26
Dec 2018	$2,885,259.27
Total	**$76,344,283.47**

b.)

The Company participates in a Power Coordination Agreement with AEP's other operating companies in PJM (Appalachian Power Co., Kentucky Power Co. and Wheeling Power Co.). Capacity in excess of the four companies' joint FRR obligations can be sold into the capacity auction and the revenues are allocated based on individual operating company capacity

INDIANA MICHIGAN POWER COMPANY
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length. As a result, providing unit specific information on sales would not be meaningful since any of the four companies' resources could be used towards making the sale in the auction.

c.) The table below provides the Company's ancillary revenues from OVEC by month as reported by PJM.

	Ancillary Revenue
May 2016	$0.67
Jun 2016	$197.18
Jul 2016	$231.41
Aug 2016	$660.77
Sep 2016	$468.44
Oct 2016	$315.99
Nov 2016	$59.76
Dec 2016	$95.79
Jan 2017	$500.27
Feb 2017	$173.26
Mar 2017	$821.08
Apr 2017	$258.61
May 2017	$182.56
Jun 2017	$78.73
Jul 2017	$31.29
Aug 2017	$76.60
Sep 2017	$1,552.37
Oct 2017	$11.48
Nov 2017	$66.10
Jan 2018	$13,815.14
Mar 2018	$62.37
Apr 2018	$36.73
May 2018	$39,424.29
Jun 2018	$86.76
Jul 2018	$30.34
Aug 2018	$13.76
Sep 2018	$494.79
Oct 2018	$2,422.64

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Nov 2018	$168.14
Dec 2018	$2,145.26
Total	**$64,482.58**

d. N/A.

As to objection
Counsel

Preparer
Stegall

OHIO VALLEY ELECTRIC CORPORATION

Minutes of Special Meeting of the

Board of Directors held December 1, 2015

A Special Meeting of the Board of Directors of **OHIO VALLEY ELECTRIC CORPORATION** (OVEC) was called to order by Mr. Mark C. McCullough at 1 Riverside Plaza, Columbus, Ohio, on Tuesday, December 1, 2015, at 10:00 a.m., pursuant to notice duly given. On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that in accordance with Article IV, Section 3 of the Code of Regulations of this Corporation, Mr. Mark C. McCullough be elected Chairman of this Meeting on December 1, 2015, in the absence of the President of this Corporation.

Mr. McCullough acted as Chairman of the meeting, and John D. Brodt, Chief Financial Officer, Secretary and Treasurer of the Corporation, acted as Secretary of the Meeting.

Mr. Brodt reported that the following Directors were present for the meeting:

Nicholas K. Akins (Phone)
Thomas Alban
Eric D. Baker (Phone)
Wayne D. Games
James R. Haney
Lana L. Hillebrand
Mark C. McCullough
Mark E. Miller
Donald A. Moul
Steven K. Nelson
Patrick W. O'Loughlin
Paul W. Thompson
John A. Verderame

Mr. Brodt reported that the Minutes of the Special Meeting of the Board of Directors of this Corporation, held on December 5, 2014, have been sent to each of the Directors. He asked that, if there were no corrections, such minutes be approved in the form in which they were circulated. On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that the Minutes of the Special Meeting of the Board of Directors of this Corporation, held on December 5, 2014, are approved.

At the request of Mr. McCullough, Mr. Justin Cooper reported on the 2013 – 2016 LEAN Cost Structure cost profile. Mr. Cooper reviewed the results of the 2015 continuous improvements (LEAN) reductions and the operating, maintenance, and capital cost benchmarking budgets. Mr. Cooper reported that OVEC's operating, maintenance, and capital cost profile was projected to [redacted] in 2016 compared with 2013. The energy cost [redacted] was expected to be [redacted].

Mr. McCullough asked Mr. Robert Osborne to give an update on the boiler floor refractory wastage issue and the replacement of floor tubes. The replacement of floor tubes has occurred on three boilers and four more will be replaced in 2016. Mr. Osborne discussed unit reliability and process health of the units.

Mr. McCullough asked Mr. Clifford Carnes and Ms. Annette Hope to report on operating activities for the Clifty Creek and Kyger Creek Plants, respectively. Mr. Carnes and Ms. Hope reviewed operating statistics and environmental and safety records for 2015 at each plant. Mr. Carnes and Ms. Hope reported on the sustainability of the LEAN process and the Open Book Leadership.

Mr. McCullough asked Mr. Copper to review the 2016 Construction Budget and the 2017-2020 Construction Budget Forecast. Mr. Cooper commented that the 2016 Construction Budget is a [redacted] compared with the [redacted] annual capital spending prior to implementation of OVEC's LEAN initiative. Mr. Cooper reported that the Construction Budget for 2016 indicates estimated total expenditures of [redacted], representing [redacted] and [redacted] On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that the OVEC-IKEC Construction Budget for 2016, indicating estimated total expenditures of [redacted] which totals [redacted], is approved.

Mr. McCullough asked Mr. Brown to give an update on the OVEC and IKEC environmental compliance and to report on future environmental capital projects. Mr. Brown reported on Section 316(b) of the Clean Water Act, Coal Combustion Residual (CCR) Rule, and Effluent Limitations Guidelines compliance. Mr. Brown indicated the estimated cost of compliance may reach [redacted] during the [redacted] time frame. Mr. Brown requested authorization to complete entrainment studies at Kyger Creek and Clifty Creek Stations associated with the initial phase of 316(b) compliance, to perform Phase I engineering studies on the boiler slag complexes and FGD wastewater treatment plant systems, to perform additional analyses using results and findings of Kyger Creek Dry Fly Ash Conversion Project Phase I engineering study, to perform compliance activities and evaluations associated with the CCR Rule at the Kyger Creek and Clifty Creek Stations, and to perform engineering study and capital work associated with modifications to the Kyger Creek Landfill stackout pad and leachate collections systems. On a motion duly made, seconded, and unanimously adopted, it was

RESOLVED, that the Company is authorized to proceed to perform the following environmental compliance activities:

1. Complete entrainment studies and other compliance activities at the Kyger Creek and Clifty Creek Stations associated with the initial phase of 316(b) compliance;
2. Perform Phase I engineering studies on the boiler slag complexes and FGD wastewater treatment plant systems at the Kyger Creek and Clifty Creek Stations to evaluate capital costs and options for compliance with the final version of the Steam Electric Effluent Limitations Guidelines (ELGs);
3. Perform additional analyses using results and findings of Kyger Creek Dry Fly Ash Conversion Project Phase I engineering study relative to the final ELGs;
4. Perform compliance activities and evaluations associated with the CCR Rule at the Kyger Creek and Clifty Creek Stations;
5. Perform engineering study and capital work associated with modifications to the Kyger Creek Landfill stackout pad and leachate collections systems to meet NPDES water quality based limits.

The cost for the scope of work described above is forecasted to be a total of [redacted] for 2016 and 2017 inclusive. The results of these studies will be used to refine future environmental capital project costs prior to requesting the Boards' approval to complete each associated environmental capital project.

At the request of Mr. McCullough, Mr. Ken Tamms of the AEP Service Corporation reviewed the merchant plant analysis. A handout was provided to the Board, which indicated that [redacted]

At the request of Mr. McCullough, Mr. Charles West of the AEP Service Corporation discussed the coal and transportation contracts. A handout was provided to the Board, and a discussion followed describing the fuel supplies currently at each power plant as well as future commitments. Mr. West discussed [redacted] at both plants.

At the request of Mr. McCullough, Mr. Brodt provided information and discussed OVEC's year-to-date power costs estimated for 2015 and projections for 2016-2020. Mr. Brodt stated that based on current estimates OVEC expected to end 2015 with an average power cost of [redacted] and an available power use factor of [redacted]. Mr. Brodt stated that the projected average power cost for OVEC power, delivered under the terms of the Inter-Company Power Agreement, ranges from [redacted] in 2016 to [redacted] in 2020 using an estimated available power use factor of [redacted].

Mr. McCullough asked Mr. Scott Cunningham to report on the OVEC Operating Committee. Mr. Cunningham reported that the PJM pseudo-tie was scheduled to start in June 2016 and that the Operating Committee was studying PJM membership for OVEC.

At the request of Mr. McCullough, Mr. Brodt reviewed the 2015 Service Corporation general expenditures, which were expected to be approximately [redacted]. Mr. Brodt requested authorization for 2016 general expenditures for services from the AEP Service Corporation up to [redacted]. The primary general expenditures are expected to be in the areas of operation and maintenance, environmental activities, fuel procurement, and coal transportation. Mr. Brodt stated that the 2016 Budget is similar to the 2015 Budget except that the 2016 Budget request of [redacted] On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that the officers of Ohio Valley Electric Corporation may request and obligate Ohio Valley Electric Corporation to pay for general services, exclusive of services for specific projects previously approved, under the Agreement among American Gas and Electric Service Corporation (now American Electric Power Service Corporation), Ohio Valley Electric Corporation, and Indiana-Kentucky Electric Corporation dated December 15, 1956, in an amount which, when added to amounts paid for general services by Indiana-Kentucky Electric Corporation, exclusive of services for specific projects previously approved, would aggregate a maximum of [redacted] for calendar year 2016.

At the request of Mr. McCullough, Mr. Brodt reported on the status of the Corporation's finances. Mr. Brodt distributed to all members present a copy of the Treasurer's Report that included the following statistics:

CONFIDENTIAL INFORMATION REDACTED

**OHIO VALLEY ELECTRIC CORPORATION (OVEC)
INDIANA-KENTUCKY ELECTRIC CORPORATION (IKEC)
Treasurer's Report
Boards of Directors' Meeting
December 1, 2015**

	OVEC	IKEC	Consolidated
EQUITY			
Common Stock, 100,000 shares outstanding	$ 10,000,000	$ 3,400,000	$ 10,000,000
Retained Earnings	7,771,843	-	7,771,843
Total Equity at October 31, 2015	$ 17,771,843	$ 3,400,000	$ 17,771,843
(OVEC's ownership of IKEC's Capital Stock (17,000 shares) is eliminated in consolidation.)			
CASH AND INVESTMENTS			
Cash and Short-Term Investments	$ 11,534,278	$ -	$ 11,534,278
Reserve Account - Long Term Investments	78,666,596	-	78,666,596
Total Cash and Investments at October 31, 2015	$ 90,200,874	$ -	$ 90,200,874
DIVIDENDS			
Total 2015 Dividends	$ -	$ -	$ -
LONG-TERM DEBT			
2006 Senior Unsecured Notes, Series A, 5.80%, due February 15, 2026	$ 245,132,192	$ -	$ 245,132,192
2006 Senior Unsecured Notes, Series B, 6.40% due June 15, 2040	58,583,884	-	58,583,884
2007 Senior Unsecured Notes, Series AA, AB & AC, 5.90%, due February 15, 2026	172,329,341	-	172,329,341
2007 Senior Unsecured Notes, Series BA, BB & BC, 6.50% due June 15, 2040	44,425,396	-	44,425,396
2008 Senior Unsecured Notes, Series A, 5.92%, due February 15, 2026	35,718,051	-	35,718,051
2008 Senior Unsecured Notes, Series B & C, 6.71%, due February 15, 2026	141,148,369	-	141,148,369
2008 Senior Unsecured Notes, Series D & E, 6.91% due June 15, 2040	85,617,277	-	85,617,277
2013 Senior Unsecured Notes, Series A, Floating Rate, due February 15, 2018	100,000,000	-	100,000,000
2009 Tax Exempt Bonds, $100M Series A-D, Floating Rate, due February 1, 2026	100,000,000	-	100,000,000
2009 Tax Exempt Bonds, $100M Series E, 5.625%, due October 1, 2019	100,000,000	-	100,000,000
2010 Tax Exempt Bonds, $100M Series A & B, Floating Rate, due February 1, 2040	100,000,000	-	100,000,000
2012 Tax Exempt Bonds, $200M Series A, 5%, due June 1, 2039	200,000,000	-	200,000,000
2012 Tax Exempt Bonds, $100M Series B & C, Floating Rate, due June 1, 2040	100,000,000	-	100,000,000
Total Long-Term Debt Outstanding at October 31, 2015	$ 1,482,954,510	$ -	$ 1,482,954,510
SHORT-TERM DEBT			
Total Short-Term Debt Outstanding at October 31, 2015	$ 20,000,000	$ -	$ 20,000,000
EMPLOYEE BENEFIT PLAN ASSETS			
Pension Plan			$ [redacted]
Supplemental Pension & Savings Plan			
Union Retiree Medical VEBA Trust			
Retiree Medical VEBA Trust			
Retiree Life Insurance VEBA Trust			
401(h) - Retiree Medical			
Total Benefit Plan Assets at October 31, 2015			$ [redacted]
PLANT DECOMMISSIONING & DEMOLITION (D&D) FUND			
Total D&D Assets at October 31, 2015	$ 18,155,970	$ 25,042,284	$ 43,198,254

Mr. McCullough asked Mr. Brodt to discuss the OVEC 2015 financing plan. Mr. Brodt reported that OVEC's investment grade ratings of Baa3 (Moodys), BBB- (S&P), and BBB- (Fitch) had been affirmed with stable outlooks. Mr. Brodt stated that [redacted]

Mr. McCullough introduced Mr. Bob Bitter of Deloitte & Touche. Mr. Bitter reported that Deloitte & Touche just began its audit to certify the 2015 Financial Statements that would be finalized in April 2016.

Mr. McCullough asked Mr. Brown to discuss the Department of Energy (DOE) Arranged Power Agreement. Mr. Brown stated that DOE is working with a Sponsoring Company to provide power to DOE and end the Arranged Power Agreement with OVEC.

The Board moved to an Executive Session to hear the Human Resources Committee report.

There being no further business to come before the Board, the meeting was adjourned.

Secretary
OHIO VALLEY ELECTRIC CORPORATION

CONFIDENTIAL
INFORMATION
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OHIO VALLEY ELECTRIC CORPORATION
Minutes of Special Meeting of the
Board of Directors held December 1, 2016

A Special Meeting of the Board of Directors of **OHIO VALLEY ELECTRIC CORPORATION** (OVEC) was called to order by the President at 1 Riverside Plaza, Columbus, Ohio, on Thursday, December 1, 2016, at 10:00 a.m., pursuant to notice duly given.

Nicholas K. Akins, President of the Corporation, acted as Chairman of the meeting, and John D. Brodt, Chief Financial Officer, Secretary and Treasurer of the Corporation, acted as Secretary of the Meeting.

Mr. Brodt reported that the following Directors were present for the meeting:

Nicholas K. Akins	Mark E. Miller
Thomas Alban	Donald A. Moul
Eric D. Baker	Patrick W. O'Loughlin
Wayne D. Games	Julie Sloat (Phone)
Lana L. Hillebrand	Paul W. Thompson
Mark C. McCullough	John A. Verderame

Mr. Brodt reported that the Minutes of the Special Meeting of the Board of Directors of this Corporation, held on December 1, 2015, have been sent to each of the Directors. He asked that, if there were no corrections, such minutes be approved in the form in which they were circulated. On a motion duly made, seconded, and unanimously adopted, it was

RESOLVED, that the Minutes of the Special Meeting of the Board of Directors of this Corporation, held on December 1, 2015, are approved.

At the request of Mr. Akins, Mr. Brodt reviewed the 2016 Service Corporation general expenditures, which were expected to be approximately [redacted]. Mr. Brodt requested authorization for 2017 general expenditures for services from the AEP Service Corporation up to [redacted]. The primary general expenditures are expected to be in the areas of operation and maintenance, environmental activities, fuel procurement, and coal transportation. Mr. Brodt stated that the 2017 Budget is similar to the 2016 Budget except that the 2017 Budget request of [redacted]. The [redacted] in the 2017 Budget is related to [redacted]

[redacted]. On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that the officers of Ohio Valley Electric Corporation may request and obligate Ohio Valley Electric Corporation to pay for general services, exclusive of services for specific projects previously approved, under the Agreement among American Gas and Electric Service Corporation (now American Electric Power Service Corporation), Ohio Valley Electric Corporation, and Indiana-Kentucky Electric Corporation dated December 15, 1956, in an amount which, when added to amounts paid for general services by Indiana-Kentucky Electric Corporation, exclusive of services for specific projects previously approved, would aggregate a maximum of [redacted] for calendar year 2017.

Mr. Akins asked Mr. Mike Brown to give an update on the OVEC and IKEC environmental compliance status and to report on the work to develop cost estimates for future environmental capital projects. Mr. Brown reported on the status of developing cost estimates to comply with Effluent Limitations Guidelines, which include the construction of two closed loop boiler slag systems, two FGD wastewater ABMet and MBR treatment systems, and Kyger Creek dry fly ash conversion. In addition, Mr. Brown provided an update on cost estimates to comply with Section 316(b) and the Coal Combustion Residual (CCR) rule. OVEC's current environmental capital investment "best-case" cost estimate for these projects is [redacted], and the current "worst-case" cost estimate is [redacted]. An investment decision for additional funding for conceptual engineering and design will be required by year-end 2017.

At the request of Mr. Akins, Mr. Justin Cooper reported on the 2013 – 2017 LEAN Cost Structure cost profile. Mr. Cooper reviewed the results of the 2016 continuous improvements (LEAN) reductions and the operating, maintenance, and capital cost benchmarking budgets. Mr. Cooper reported that OVEC's operating, maintenance, and capital cost profile was projected to [redacted] in 2017 compared with 2013. The energy cost [redacted].

Mr. Akins asked Mr. Cooper to review the 2017 Construction Budget and the 2018-2021 Construction Budget Forecast. Mr. Cooper commented that the 2017 Construction Budget is a [redacted] with the original 2017 budget forecast with prioritization of economic benefit, risk, and fiscal impact. Mr. Akins requested that a list of future high-risk capital budget items be provided at the next meeting. Mr. Cooper reported that the Construction Budget for 2017 indicates estimated total expenditures of [redacted], representing [redacted] clair On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that the OVEC-IKEC Construction Budget for 2017, indicating estimated total expenditures of [redacted]

Mr. Akins asked Mr. Osborne to report on operating activities for the Clifty Creek and Kyger Creek plants. Mr. Osborne reviewed the operating statistics and discussed how the Open Book Leadership scoreboard is being used to track key areas of concern. Mr. Osborne also reviewed the 2016 safety performance statistics and the need to focus on recognizing hazards.

At the request of Mr. Akins, Mr. Ken Tamms of the AEP Service Corporation reviewed the merchant plant analysis. A handout was provided to the Board, which indicated that [redacted].

At the request of Mr. Akins, Mr. Brodt provided information and discussed OVEC's year-to-date power costs estimated for 2016 and projections for 2017-2021. Mr. Brodt stated that based on current estimates OVEC expected to end 2016 with an average power cost of [redacted] and an available power use factor of [redacted]. Mr. Brodt stated that the projected average power cost for OVEC power, delivered under the terms of the Inter-Company Power Agreement, ranges from [redacted] to [redacted] using an estimated available power use factor of [redacted].

Mr. Akins asked Mr. Scott Cunningham to report on the OVEC Operating Committee. Mr. Cunningham reported that the Operating Committee recommended a fuel cost policy revision to use replacement fuel cost versus weighted cost of inventory. This revision is expected to be made during the first quarter 2017. The Operating Committee made no recommendation to the Board to proceed with the integration of the OVEC-IKEC transmission system into PJM.

At the request of Mr. Akins, Mr. Brodt reported on the status of the Corporation's finances. Mr. Brodt distributed to all members present a copy of the Treasurer's Report that included the following statistics:

CONFIDENTIAL INFORMATION REDACTED

OHIO VALLEY ELECTRIC CORPORATION (OVEC)
INDIANA-KENTUCKY ELECTRICCORPORATION (IKEC)
Treasurer's Report
Boards of Directors' Meeting
December 1, 2016

	OVEC	IKEC	Consolidated
EQUITY			
Common Stock, 100,000 shares outstanding	$ 10,000,000	$ 3,400,000	$ 10,000,000
Retained Earnings	8,653,536	-	8,653,536
Total Equity at October 31, 2016	$ 18,653,536	$ 3,400,000	$ 18,653,536
(OVEC's ownership of IKEC's Capital Stock (17,000 shares) is eliminated in consolidation.)			
CASH AND INVESTMENTS			
Cash and Short-Term Investments	$ 46,793,706	$ -	$ 46,793,706
Employee PRB Benefits Reserve Account	77,697,759	-	77,697,759
Total Cash and Investments at October 31, 2016	$ 124,491,465	$ -	$ 124,491,465
DIVIDENDS			
Total 2016 Dividends	$ -	$ -	$ -
LONG-TERM DEBT			
2006 Senior Unsecured Notes, Series A, 5.80%, due February 15, 2026	$ 227,600,578	$ -	$ 227,600,578
2006 Senior Unsecured Notes, Series B, 6.40% due June 15, 2040	57,576,242	-	57,576,242
2007 Senior Unsecured Notes, Series AA, AB & AC, 5.90%, due February 15, 2026	160,320,832	-	160,320,832
2007 Senior Unsecured Notes, Series BA, BB & BC, 6.50% due June 15, 2040	43,682,246	-	43,682,246
2008 Senior Unsecured Notes, Series A, 5.92%, due February 15, 2026	33,231,642	-	33,231,642
2008 Senior Unsecured Notes, Series B & C, 6.71%, due February 15, 2026	131,104,353	-	131,104,353
2008 Senior Unsecured Notes, Series D & E, 6.91% due June 15, 2040	84,231,146	-	84,231,146
2013 Senior Unsecured Notes, Series A, Floating Rate, due February 15, 2016	100,000,000	-	100,000,000
2009 Tax Exempt Bonds, $100M Series A-D, Floating Rate, due February 1, 2026	100,000,000	-	100,000,000
2009 Tax Exempt Bonds, $100M Series E, 5.625%, due October 1, 2019	100,000,000	-	100,000,000
2010 Tax Exempt Bonds, $100M Series A & B, Floating Rate, due February 1, 2040	100,000,000	-	100,000,000
2012 Tax Exempt Bonds, $200M Series A, 5%, due June 1, 2039	200,000,000	-	200,000,000
2012 Tax Exempt Bonds, $100M Series B & C, Floating Rate, due June 1, 2040	100,000,000	-	100,000,000
Total Long-Term Debt Outstanding at October 31, 2016	$ 1,437,747,039	$ -	$ 1,437,747,039
SHORT-TERM DEBT			
Total Short-Term Debt Outstanding at October 31, 2016	$ 85,000,000	$ -	$ 85,000,000
EMPLOYEE BENEFIT PLAN ASSETS			
Pension Plan			$ [redacted]
Supplemental Pension & Savings Plan			[redacted]
Union Retiree Medical VEBA Trust			[redacted]
Retiree Medical VEBA Trust			[redacted]
Retiree Life Insurance VEBA Trust			[redacted]
401(h)			[redacted]
Total Benefit Plan Assets at October 31, 2016			$ [redacted]
PLANT DECOMMISSIONING & DEMOLITION (D&D) FUND			
Total D&D Assets at October 31, 2016	$ 19,001,239	$ 26,239,806	$ 45,241,045

Mr. Akins introduced Mr. Bob Bitter of Deloitte & Touche. Mr. Bitter reported that Deloitte & Touche just began its audit to certify the 2016 Financial Statements that would be finalized in April 2017.

The Board moved to an Executive Session.

There being no further business to come before the Board, the meeting was adjourned.

Secretary
OHIO VALLEY ELECTRIC CORPORATION

OHIO VALLEY ELECTRIC CORPORATION
Minutes of Special Meeting of the
Board of Directors' Meeting via Teleconference
January 30, 2017

A Special Meeting of the Board of Directors of **OHIO VALLEY ELECTRIC CORPORATION** (OVEC) via teleconference was called to order by the President on Monday, January 30, 2017, at 8:45 a.m., pursuant to notice duly given.

Nicholas K. Akins, President of the Corporation, acted as Chairman of the meeting, and John D. Brodt, Chief Financial Officer, Secretary and Treasurer of the Corporation, acted as Secretary of the meeting.

Mr. Brodt reported that the following Directors were present for the meeting:

Nicholas K. Akins	Mark E. Miller
Thomas Alban	Steven K. Nelson
Eric D. Baker	Patrick W. O'Loughlin
Lee E. Barrett	David W. Pinter
Wayne D. Games	Julie Sloat
Mark C. McCullough	Paul W. Thompson

John N. Voyles, Jr.

Mr. Akins advised that Donald A. Moul would be resigning from the OVEC and IKEC Boards of Directors and as a member of both Executive Committees, pending the election of his replacement. Mr. Akins recommended that Mr. David W. Pinter, Executive Director, Business Development for FirstEnergy Corp., be nominated to succeed Mr. Moul on both the OVEC and IKEC Boards of Directors and be appointed to the Executive Committees of both OVEC and IKEC. Mr. Akins also recommended that Lee E. Barrett be appointed to the OVEC Executive Committee. On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that subject to any necessary action by the Federal Energy Regulatory Commission under Section 305 of the Federal Power Act, Mr. David W. Pinter be elected a Director and appointed a member of the Executive Committee of this Corporation; and further
>
> **RESOLVED**, that subject to any necessary action by the Federal Energy Regulatory Commission under Section 305 of the Federal Power Act, Mr. Lee E. Barrett be appointed a member of the Executive Committee of this Corporation.

Mr. Akins asked Mr. Justin Cooper to review the handout, "OVEC in PJM Cost/Benefit Analysis," prepared by the OVEC Operating Committee. Mr. Cooper reported that a [redacted]

[redacted]. He also stated that some costs are approximations and difficult to quantify at this time. The Board provided feedback to Mr. Cooper for OVEC to review the possible additional benefit from energy value from changing the delivery point.

At the request of Mr. Akins, Mr. Brian Chisling, with Simpson Thacher & Bartlett LLP, highlighted the plan of OVEC moving forward with the process of applying for membership in PJM. The motion was duly made and seconded. The resolution was adopted based upon a vote of [redacted]. The motion was approved as

> **RESOLVED**, that Ohio Valley Electric Corporation is to move forward with the process of applying for membership in PJM to further validate assumptions prior to a final Board vote to join PJM.

There being no further business to come before the Board, the meeting was adjourned.

Secretary
OHIO VALLEY ELECTRIC CORPORATION

OHIO VALLEY ELECTRIC CORPORATION

Minutes of Special Meeting of the

Board of Directors held December 8, 2017

A Special Meeting of the Board of Directors of **OHIO VALLEY ELECTRIC CORPORATION** (OVEC) was called to order by the President at 1 Riverside Plaza, Columbus, Ohio, on Friday, December 8, 2017, at 2:00 p.m., pursuant to notice duly given.

Nicholas K. Akins, President of the Corporation, acted as Chairman of the meeting, and John D. Brodt, Chief Financial Officer, Secretary and Treasurer of the Corporation, acted as Secretary of the Meeting.

Mr. Brodt reported that the following Directors were present for the meeting:

Nicholas K. Akins	Mark C. McCullough
Thomas Alban	Steven K. Nelson
Lonnie E. Beller	Patrick W. O'Loughlin
Wayne D. Games	David W. Pinter (Phone)
James R. Haney (Phone)	Paul W. Thompson
Lana L. Hillebrand	John A. Verderame

Mr. Brodt reported that the Minutes of the Special Meeting of the Board of Directors of this Corporation, held on December 1, 2016, have been sent to each of the Directors. He asked that, if there were no corrections, such minutes be approved in the form in which they were circulated. On a motion duly made, seconded, and unanimously adopted, it was

RESOLVED, that the Minutes of the Special Meeting of the Board of Directors of this Corporation, held on December 1, 2016, are approved.

At the request of Mr. Akins, Mr. Brodt reviewed the 2017 Service Corporation general expenditures, which were expected to be approximately [redacted]. Mr. Brodt requested authorization for 2018 general expenditures for services from the AEP Service Corporation up to [redacted]. The primary general expenditures are expected to be in the areas of operation and maintenance, environmental activities, fuel procurement, and coal transportation. Mr. Brodt stated that the 2018 Budget is similar to the 2017 Budget except that the 2018 Budget request of [redacted] the 2017 Budget request of [redacted]. The [redacted]

[redacted]. On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that the officers of Ohio Valley Electric Corporation may request and obligate Ohio Valley Electric Corporation to pay for general services, exclusive of services for specific projects previously approved, under the Agreement among American Gas and Electric Service Corporation (now American Electric Power Service Corporation), Ohio Valley Electric Corporation, and Indiana-Kentucky Electric Corporation dated December 15, 1956, in an amount which, when added to amounts paid for general services by Indiana-Kentucky Electric Corporation, exclusive of services for specific projects previously approved, would aggregate a maximum of [redacted] for calendar year 2018.

At the request of Mr. Akins, Mr. Justin Cooper reported on the 2018 LEAN demand costs. Mr. Cooper reviewed the results of the 2017 continuous improvements (LEAN) reductions and the operating, maintenance, and capital cost benchmarking budgets. Mr. Cooper reported that OVEC's operating, maintenance, and capital cost profile was projected to [redacted] in 2018 compared with 2013. The energy cost [redacted].

Mr. Akins asked Mr. Mike Brown to give an update on the OVEC and IKEC environmental compliance status and to report on the work to develop cost estimates for future environmental capital projects. Mr. Brown reported that the OVEC and IKEC 2017 ozone season NO_x performance was better than expected. The 2017 ozone season NO_x emissions were reduced by approximately [redacted] at Kyger Creek and [redacted] at Clifty Creek compared with the 2012-2016 average. Mr. Brown reported on the status of developing cost estimates to comply with Effluent Limitations Guidelines, [redacted], and Kyger Creek dry fly ash conversion. In addition, Mr. Brown provided an update on cost estimates to comply with Section 316(b) and the Coal Combustion Residual (CCR) rule. OVEC's current environmental capital investment "best-case" cost estimate for these projects is [redacted], and the current "worst-case" cost estimate is [redacted]. An investment decision for additional funding for conceptual engineering and design will be required by mid-year 2019 to mid-year 2020.

Mr. Akins asked Mr. Cooper to review the 2018 Construction Budget and the 2019-2022 Construction Budget Forecast. Mr. Cooper commented that the 2018 Construction Budget is a [redacted] compared with the original 2018 budget forecast with prioritization of economic benefit, risk, and fiscal impact. Mr. Cooper reported that the Construction Budget for 2018 indicates estimated total expenditures of [redacted], representing [redacted] On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that the OVEC-IKEC Construction Budget for 2018, indicating estimated total expenditures of [redacted]

Mr. Akins asked Mr. Osborne to report on operating activities for the Clifty Creek and Kyger Creek plants. Mr. Osborne reviewed the operating statistics and the results of the 2017 Culture Survey. Mr. Osborne recognized that the Clifty Creek employees completed one year without a recordable injury. Mr. Osborne asked Clifty Creek Plant Manager Cliff Carnes and Kyger Creek Plant Manager Annette Hope to report on the 2017 Strategic Plan for each respective location highlighting three areas of success and three areas of opportunities.

Mr. Akins asked Mr. Scott Cunningham to report on the OVEC Operating Committee. Mr. Cunningham reviewed a projected OVEC-PJM integration timeline of the basic steps OVEC intends to pursue regarding full integration into PJM.

At the request of Mr. Akins, Mr. Brodt reported on the status and timeline of the Corporation's finance activities. Mr. Brodt distributed to all members present a copy of the Treasurer's Report that included the following statistics:

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INFORMATION
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OHIO VALLEY ELECTRIC CORPORATION (OVEC)
INDIANA-KENTUCKY ELECTRIC CORPORATION (IKEC)
Treasurer and Finance Report
Boards of Directors' Meeting
December 8, 2017

	OVEC	IKEC	Consolidated
CASH AND INVESTMENTS			
Cash and Short-Term Investments	$ 53,878,779		$ 53,878,779
Employee PRB Benefits Reserve Account	71,625,576		71,625,576
Debt Reserve Account	20,306,082		20,306,082
Total Cash and Investments at October 31, 2017	$ 145,810,437		$ 145,810,437
PLANT DECOMMISSIONING & DEMOLITION (D&D) FUND			
Total D&D Assets at October 31, 2017	$ 21,892,091	$ 30,195,452	$ 52,087,543
EMPLOYEE BENEFIT PLAN ASSETS			
Pension Plan			$ [redacted]
Supplemental Pension & Savings Plan			
Union Retiree Medical VEBA Trust			
Retiree Medical VEBA Trust			
Retiree Life Insurance VEBA Trust			
Retiree Medical 401(h)			
Total Benefit Plan Assets at October 31, 2017			$
EQUITY			
Common Stock, 100,000 shares outstanding	$ 10,000,000	$ 3,400,000	$ 10,000,000
Retained Earnings	9,893,759	-	9,893,759
Total Equity at October 31, 2017	$ 19,893,759	$ 3,400,000	$ 19,893,759
(OVEC's ownership of IKEC's Capital Stock (17,000 shares) is eliminated in consolidation.)			
LONG-TERM DEBT			
2006 Senior Unsecured Notes, Series A, 5.80%, due February 15, 2026	$ 209,037,387		$ 209,037,387
2006 Senior Unsecured Notes, Series B, 6.40% due June 15, 2040	56,503,080		56,503,080
2007 Senior Unsecured Notes, Series AA, AB & AC, 5.90%, due February 15, 2026	147,593,370		147,593,370
2007 Senior Unsecured Notes, Series BA, BB & BC, 6.50% due June 15, 2040	42,890,007		42,890,007
2008 Senior Unsecured Notes, Series A, 5.92%, due February 15, 2026	30,595,859		30,595,859
2008 Senior Unsecured Notes, Series B & C, 6.71%, due February 15, 2026	120,374,809		120,374,809
2008 Senior Unsecured Notes, Series D & E, 6.91% due June 15, 2040	82,747,579		82,747,579
2017 Senior Unsecured Notes, Series A, Floating Rate, due August 4, 2022	100,000,000		100,000,000
2009 Tax Exempt Bonds, $100M Series A-D, Floating Rate, due February 1, 2026	75,000,000		75,000,000
2009 Tax Exempt Bonds, $100M Series E, 5.625%, due October 1, 2019	100,000,000		100,000,000
2010 Tax Exempt Bonds, $100M Series A & B, Floating Rate, due February 1, 2040	100,000,000		100,000,000
2012 Tax Exempt Bonds, $200M Series A, 5%, due June 1, 2039	200,000,000		200,000,000
2012 Tax Exempt Bonds, $100M Series B & C, Floating Rate, due June 1, 2040	100,000,000		100,000,000
Total Long-Term Debt Outstanding at October 31, 2017	$ 1,364,742,091		$ 1,364,742,091
SHORT-TERM DEBT			
$200M Revolving Credit Facility (extension date November 14, 2019)			
Total Short-Term Debt Outstanding at October 31, 2017	$ 85,000,000		$ 85,000,000
CORPORATE UNSECURED CREDIT RATINGS			
Standard & Poor's (rating affirmed February 13, 2017)	BBB-, Stable Outlook		
Fitch (rating affirmed November 14, 2017)	BBB-, Negative Outlook		
Moody's (rating downgrade December 20, 2016)	Ba1, Negative Outlook		

FINANCE WORKING GROUP

[redacted]

At the request of Mr. Akins, Mr. Brodt provided information and discussed OVEC's year-to-date power costs estimated for 2017 and projections for 2018-2022. Mr. Brodt stated that based on current estimates OVEC expected to end 2017 with an average power cost of [redacted] and an available power use factor of [redacted]. Mr. Brodt stated that the projected average power cost for OVEC power, delivered under the terms of the Inter-Company Power Agreement, ranges from [redacted] in 2018 to [redacted] in 2022 using an estimated available power use factor of [redacted].

Mr. Akins introduced Mr. Bob Bitter of Deloitte & Touche. Mr. Bitter reported that Deloitte & Touche just began its audit to certify the 2017 Financial Statements that would be finalized in April 2018.

The OVEC and IKEC Boards of Directors recognized John D. Brodt for his contributions to the corporations upon his upcoming January 1, 2018, retirement from the Company. On a motion duly made, seconded, and unanimously adopted

> **WHEREAS**, John D. Brodt has provided exemplary leadership and guidance to OVEC-IKEC during a period of unprecedented change in the electric utility industry throughout his career; and
>
> **WHEREAS**, John D. Brodt has drawn upon the wisdom and experience he has gained as Secretary and Treasurer/Chief Financial Officer, which enabled him to provide dedicated and effective service to the Company, to the electric utility industry and to his community during a tenure as Secretary and Treasurer/Chief Financial Officer that began in 1988.
>
> **NOW, THEREFORE BE IT**
>
> **RESOLVED**, that John D. Brodt is recognized by the Directors of OVEC and IKEC for his steadfast commitment and superb judgment throughout his years of illustrious service to the Company; and further
>
> **RESOLVED**, that the Directors of OVEC and IKEC hereby acknowledge the important contributions made by John D. Brodt to the success, growth and well-being of the Company during a most challenging period in his history; and further
>
> **RESOLVED**, that the Directors of OVEC and IKEC thank John D. Brodt for his 41 years of service and extend their best wishes upon his upcoming retirement from the Company, along with their sincere desire that his retirement years will be long, enjoyable and fulfilling; and further
>
> **RESOLVED**, that a copy of these resolutions and their preambles shall be delivered to John D. Brodt as an expression of the deep appreciation and hearty good wishes of the Directors of OVEC and IKEC upon his retirement.

The Board moved to an Executive Session.

There being no further business to come before the Board, the meeting was adjourned.

Secretary
OHIO VALLEY ELECTRIC CORPORATION

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **INDIANA MICHIGAN POWER COMPANY** for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief.	Case No. U-20591 ALJ Jonathan Thoits

PROOF OF SERVICE

On the date below, an electronic copy of **Direct Testimony of Tyler Comings on behalf of Sierra Club and Exhibits SC-1 through SC-12** were served on the following:

Name/Party	E-mail Address
Administrative Law Judge Jonathan Thoits	thoitsj@michigan.gov
Counsel for Indiana Michigan Power Company Richard J. Aaron John A. Janiszewski Jason Hanselman Indiana Michigan Power Company 1 of 3 Indiana Michigan Power Company 2 of 3 Indiana Michigan Power Company 3 of 3	raaron@dykema.com jjaniszewski@dykema.com jhanselman@dykema.com ajwilliamson@aep.com msmckenzie@aep.com mgobrien@aep.com
Counsel for MPSC Staff Spencer A. Sattler Nicholas Q. Taylor Benjamin J. Holwerda Anna Schiller	sattlers@michigan.gov taylorn10@michigan.gov holwerdab@michigan.gov schillerA3@michigan.gov
Counsel for Citizens Against Rate Excess John Liskey	john@liskeypllc.com
Counsel for Great Lakes Renewable Energy Association Don L. Keskey Brian W. Coyer	donkeskey@publiclawresourcecenter.com bwcoyer@publiclawresourcecenter.com
Counsel for Environmental Law & Policy Center Margrethe Kearney Nikhil Vijaykar Constance D. Groh	mkearney@elpc.org nvijaykar@elpc.org cdgroh@liskeypllc.com

The statements above are true to the best of my knowledge, information and belief.

OLSON, BZDOK & HOWARD, P.C.
Counsel for Sierra Club

Date: January 21, 2020

Digitally signed by Karla Gerds
DN: cn=Karla Gerds, o=Olson, Bzdok & Howard, P.C., ou, email=karla@envlaw.com, c=US
Date: 2020.01.21 16:49:58 -05'00'

By: ______________________________

Kimberly Flynn, Legal Assistant
Karla Gerds, Legal Assistant
Breanna Thomas, Legal Assistant
420 E. Front St.
Traverse City, MI 49686
Phone: 231/946-0044
Email: kimberly@envlaw.com
karla@envlaw.com
breanna@envlaw.com

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **INDIANA MICHIGAN POWER COMPANY** for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief.	Case No. U-20591 ALJ Jonathan Thoits

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CONFIDENTIAL PROOF OF SERVICE

On the date below, an electronic copy of the **CONFIDENTIAL Direct Testimony of Tyler Comings on behalf of Sierra Club** was served on the following:

Name/Party	E-mail Address
Administrative Law Judge Jonathan Thoits	thoitsj@michigan.gov
Counsel for Indiana Michigan Power Company Richard J. Aaron John A. Janiszewski Jason Hanselman Indiana Michigan Power Company 1 of 3 Indiana Michigan Power Company 2 of 3 Indiana Michigan Power Company 3 of 3	raaron@dykema.com jjaniszewski@dykema.com jhanselman@dykema.com ajwilliamson@aep.com msmckenzie@aep.com mgobrien@aep.com
Counsel for Environmental Law & Policy Center Margrethe Kearney Nikhil Vijaykar	mkearney@elpc.org nvijaykar@elpc.org
Counsel for MPSC Staff Spencer A. Sattler Nicholas Q. Taylor Benjamin J. Holwerda Anna Schiller	sattlers@michigan.gov taylorn10@michigan.gov holwerdab@michigan.gov schillerA3@michigan.gov

The statements above are true to the best of my knowledge, information and belief.

OLSON, BZDOK & HOWARD, P.C.
Counsel for Sierra Club

Date: January 21, 2020

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