STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA FOR APPROVAL OF A FUEL COST FACTOR FOR ELECTRIC SERVICE DURING THE BILLING MONTHS OF SEPTEMBER 2022 THROUGH NOVEMBER 2022, IN ACCORDANCE WITH THE PROVISIONS OF I.C. 8-1-2-42, AND CONTINUED USE OF RATEMAKING TREATMENT FOR COSTS OF WIND POWER PURCHASES PURSUANT TO CAUSE NOS. 43485 AND 43740, AND CONTINUED RECOVERY OF THE COSTS OF THE FUEL HEDGING PLAN PURSUANT TO I.C. 8-1-2-42.	)	**CAUSE NO. 38703 FAC 136**

APPLICANT'S SUBMISSION OF DIRECT TESTIMONY OF
NATALIE HERR COKLOW

Indianapolis Power & Light Company d/b/a AES Indiana ("AES Indiana", "IPL", "Company", or "Applicant"), by counsel, hereby submits the direct testimony and attachments of Natalie Herr Coklow.

Respectfully submitted,

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D/B/A AES INDIANA

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing was served this 17th day of June, 2022, by email transmission, hand delivery or United States Mail, first class, postage prepaid to:

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ATTORNEYS FOR APPLICANT
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D/B/A AES INDIANA
DMS 22936384v1

VERIFIED TESTIMONY OF NATALIE HERR COKLOW
MANAGER IN REGULATORY ACCOUNTING

Q1. Please state your name, employer, and business address.

A1. My name is Natalie Herr Coklow. I am employed by AES US Services, LLC ("the Service Company"), which is the Service Company that serves Indianapolis Power & Light Company d/b/a AES Indiana ("AES Indiana", "IPL" or the "Applicant"). The Service Company is located at One Monument Circle, Indianapolis, Indiana 46204. The Service Company provides accounting, legal, human resources, information technology and other corporate services to the businesses owned by The AES Corporation in the United States of America, including AES Indiana.

Q2. What is your position with the Service Company?

A2. I am a Manager in the Regulatory Accounting department.

Q3. Please summarize your work experience with the Service Company.

A3. I began employment with the Service Company in July 2013. During my tenure with the Service Company, I have worked in Regulatory Accounting on various AES Indiana and Dayton Power & Light Company d/b/a AES Ohio ("AES Ohio" or "DP&L") regulatory filings and the associated accounting entries for both companies. I am responsible for the various general ledger entries, the reconciliation of regulatory asset and liability accounts, the computation and tracking of various costs for regulatory filings, and the preparation of supporting schedules for these filings. These regulatory filings for AES Indiana have included filings related to the Fuel Adjustment Clause ("FAC") (Cause No. 38703-FAC XX), AES Indiana's most recent basic rate cases (Cause Nos. 44576 and 45029), the

Environmental Compliance Cost Recovery Adjustment ("ECCRA") (Cause No. 42170-ECR XX) and the Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") (Cause No 45264-TDSIC XX).

Q4. Please summarize your prior work experience.

A4. Prior to the Service Company, I was employed by London Witte Group, LLC ("LWG") for seven years. LWG is a certified public accounting firm that provides an array of accounting and consulting services to public utility, private and governmental clients. At LWG, I worked on the review of Gas Cost Adjustments filed with this Commission by various Indiana utilities, performed financial statement audits for predominately gas and electric utility clients, completed rate design for municipally owned utilities, and completed or reviewed financial statements and tax returns.

Q5. Please summarize your educational qualifications.

A5. I hold a Bachelor of Science Degree in Accounting from Indiana University.

Q6. Have you previously testified before this Commission?

A6. Yes. I have submitted testimony on behalf of AES Indiana in previous FAC proceedings as well as ECCRA and TDSIC proceedings. I also submitted testimony in AES Indiana's basic rates case, Cause No. 45029.

Q7. What are your responsibilities in connection with the Applicant's fuel cost filings?

A7. The data is assembled and the actual calculations of the fuel cost credit or charge are made under my supervision and direction. In this case, I am presenting the calculated ("unmitigated") fuel cost charge as well as a reduced fuel charge ("mitigated factor" or "mitigated FAC factor") the Company proposes to place into effect, subject to reconciliation and true-up, in a future FAC filing or upon resolution of the Eagle Valley forced outage matters pending in the subdocket in FAC 133 S1.

Q8. Have you reviewed the testimony and attachments of the Applicant's other witnesses in this Cause?

A8. Yes.

Q9. Are you sponsoring any attachments?

A9. Yes. I am sponsoring the following attachments, which were prepared or assembled by me or under my direction and supervision:

- Attachment NHC-l is a copy of the Verified Application filed in this proceeding, including Schedules 1 through 7 thereto which reflect the proposed mitigated factor.
- Attachment NHC-1-A is the proposed tariff sheets revised to reflect the fuel cost adjustment requested herein.
- Attachment NHC-2 is a Statement of Jurisdictional Electric Operating Income for the Twelve Months Ended July 31, 2022.
- Attachment NHC-3 is a Determination of Authorized Return for the Twelve Months Ended July 31, 2022.
- Attachment NHC-4 is an Earnings Test Summary.
- Attachment NHC-5 is the calculation of the unmitigated FAC factor.

Q10. Is the information set forth in Attachments NHC-l through NHC-5 and Attachment NHC-1-A true and correct?

A10. Yes, to the best of my knowledge.

Q11. Are you filing any workpapers in this proceeding?

A11. Yes. I have included Excel workbooks that support the calculations of Attachments NHC-1 through Attachment NHC-5. These workpapers were prepared or assembled by me or under my direction and supervision.

Q12. Why is AES Indiana proposing a mitigated FAC factor in this proceeding?

A12. As discussed in FAC 134-135 and FAC 133S1, the Company completed its analysis of the estimated impact of the Eagle Valley outage on the FAC during the outage period (April 2021 through March 2022) and modeled an estimate of the variances that were the result of issues independent of the Eagle Valley outage (commodity price and volume variances), which are included for recovery in this proceeding. The Company is including the variances not related to the Eagle Valley outage for recovery in order to recognize the impact of increased natural gas and coal prices on overall fuel costs. Recognizing these increases in fuel costs in the proposed fuel factor will allow the price for the electric service to more timely reflect the actual cost of service.

Q13. Please elaborate further why you are making this proposal.

A13. As stated in prior FAC filings, AES Indiana has been experiencing rising commodity prices like other utilities in the state. This proposal allows the Company to appropriately reflect the cost of service in customer rates by including the non-outage portion of the variances in the FAC factor.

Q14. Please explain the Company's proposal that the mitigated factor be approved on an interim basis subject to reconciliation and true-up in a future FAC filing or upon resolution of the Eagle Valley forced outage matters pending in the subdocket in FAC 133 S1.

A14. As explained above, the mitigated factor recovers estimated fuel costs unrelated to the Eagle Valley forced outage matters pending in the subdocket. The proposed factor is based on an estimate of the costs not attributable to the forced outage. The Company recognizes that all these costs remain subject to review. The Company is not seeking to finalize the amount of costs attributable to the forced outage in this FAC 136 but, as explained above, believes it is appropriate to recover costs estimated not related to the forced outage. Therefore, to balance the consumer and Company interests and the need for timely cost recovery, the Company proposes the mitigated factor be approved on an interim basis.

Q15. How was the mitigated FAC factor proposed in this proceeding calculated?

A15. As discussed in more detail by AES Indiana Witness Jackson, output from Open Access Technology International, Inc. ("OATI") was used to model the portion of the variances not related to the Eagle Valley Outage. The resulting price per Mills/kWh model output for each month was then compared to billed sales to determine the revised FAC variance if Eagle Valley had been running.

The difference between the mitigated factor calculated on Attachment NHC-1, Schedule 1 and Attachment NHC-5 is that the mitigated factor includes the estimated non-outage portion of the variances for the FAC 136 reconciliation period of February through April 2022. The total variance for February through April 2022 is $24,404,647. After subtracting the estimated Eagle Valley outage impact of $6,350,096[1] the variance for the FAC 136 reconciliation period totals $18,054,561. The remaining 50% variance approved for recovery in FAC 135 of $34,140,968 was then added to the FAC 136 variance of

[1] See Attachment DJ-6 for detail calculation.

$18,054,561 for a total variance of $52,195,529 to be collected in this FAC factor. This adjustment is reflected on Attachment NHC-1, Schedule 1, Line 35.

Witness Jackson further details the cost impact of the Eagle Valley outage for the reconciliation period which impacted the FAC 136 reconciliation months of February and March 2022. This mitigated factor would follow the normal reconciliation process and would be reconciled and trued-up as part of the FAC 138 and 139 filing. To the extent that the amount attributable to the outage differs upon the subdocket outcome, these factors would be subject to further true-up in a future FAC filing upon resolution of the subdocket.

Q16. What accounting treatment is being sought for the variances excluded from this filing?

A16. AES Indiana is excluding from the mitigated factor, outage related variances for FAC 136 of $6,350,096 and is seeking authority to continue to defer as a regulatory asset this balance for recovery pending conclusion of the FAC 133 subdocket. AES Indiana is not seeking to recover carrying charges on the regulatory asset.

Q17. Why is the mitigated factor calculation reasonable?

A17. The mitigated factor is reasonable because it is using a forecast generated using the same methods as reviewed and approved in previous FACs and reflects our estimated fuel costs and forecasted unit availability for the rate period. In addition, AES Indiana is not including recovery of the estimated variance related to the Eagle Valley outage and has addressed it as part of the FAC 133 subdocket. As stated in the prior FAC and discussed further by Witness Jackson, utilities are experiencing increased commodity prices which is a key driver for the larger variances.

Q18. What is the difference between the proposed mitigated factor and the unmitigated calculated factor?

A18. The proposed mitigated FAC factor in this proceeding for the months of September through November 2022 is $0.037858 per kwh on <u>Attachment NHC-1</u>, Schedule 1 as compared to the unmitigated factor on <u>Attachment NHC-5</u> of $0.039970 for a difference of -$0.002112 per kWh.

FAC Rate Comparison Between FAC 136 Mitigated Factor and Unmitigated Factor			
	FAC 136 Mitigated Factor <u>Attachment NHC-1</u>, Schedule 1, Line 39	FAC 136 Unmitigated Factor <u>Attachment NHC-5</u>, Line 39	Difference
Fuel Cost Charge per kWh	$0.037858	$0.039970	-$0.002112

Q19. Have you reviewed the Commission's June 1, 2005 Order in Cause No. 42685 ("June 1, 2005 Order") and June 30, 2009 Phase II Order in Cause No. 43426 ("Phase II Order") regarding changes in operations as a result of the Midcontinent Independent System Operator Inc.'s ("MISO") implementation of energy markets and for determination of the manner and timing of recovery costs resulting from the implementation of standard market design mechanisms and participation in the ancillary services market?

A19. Yes.

Q20. Is AES Indiana's filing in this proceeding consistent with your understanding of these two orders?

A20. Yes, AES Indiana's filing in this proceeding is consistent with my understanding of the Commission's June 1, 2005 Order and Phase II Order.

Q21. Over what months has the Applicant estimated its fuel costs in <u>Attachment NHC-1</u> for the purpose of its proposed fuel cost factor for electric service?

A21. <u>Attachment NHC-1</u> estimates fuel costs over the months of September through November 2022.

Q22. In making such estimate, were actual fuel costs reconciled with estimated fuel costs for any period?

A22. Yes, actual fuel costs for the months of February through April 2022 were reconciled with the estimated fuel costs for the same period. As mentioned previously, these variances are shown for reference in the unmitigated FAC factor calculated on <u>Attachment NHC-5</u> but the non-outage portion is included in the mitigated factor calculated on <u>Attachment NHC-1</u>, Schedule 1.

Q23. Have calculations been made applying the Purchased Power Daily Benchmarks established pursuant to the methodology approved in Cause No. 43414?

A23. Yes. As described in the testimony of Witness Jackson, the applicable Purchased Power Daily Benchmarks are set forth in <u>Attachment DJ-1</u> and have been done in conformity with the Commission's Order in Cause No. 43414.

Q24. Is AES Indiana seeking to recover the costs of any individual purchased power transactions used to serve jurisdictional retail customers in excess of the applicable Purchased Power Daily Benchmarks?

A24. Yes, for the non outage portion of the purchased power over the benchmark. Company Witness Jackson describes further the calculation of the purchased power costs in excess of the applicable Purchased Power Daily Benchmarks and the amount that is recoverable based on the currently approved calculation methodology. However, AES Indiana is only including the estimated non-outage portion in the mitigated FAC factor. $498,872 is the total purchased power over the benchmark for FAC 136, of which $293,356 is estimated to be attributable to the Eagle Valley outage and therefore included in the total variance of $6,350,096 that is deferred pending the outcome of the FAC 133 subdocket. The remaining purchased power over the benchmark of $205,516 is included in the purchased power impacting the remaining variances included in the proposed mitigated FAC factor in this proceeding.

A summary of the purchased power volumes, costs, the total hourly purchased power costs above the applicable Purchased Power Daily Benchmarks for February through April 2022 and the reasons for the purchases at-risk after consideration of MISO economic dispatch, is set forth in Attachment DJ-2 to Witness Jackson's testimony.

Q25. Did AES Indiana include in this filing the fuel cost and fuel revenues associated with sales from its public electric vehicle charging stations during the February through April 2022 period?

A25. Yes. AES Indiana determined the fuel cost for its public electric vehicle charging stations by multiplying the total public electric vehicle charging station kWh sales by the average cost of fuel per kWh for each period. AES Indiana calculated the fuel portion of electric vehicle revenues by multiplying the total public electric vehicle charging station kWh sales under Rate EVP by the applicable fuel factor in effect. The amounts accounted for as fuel costs are reflected on Attachment NHC-1, Schedule 4, Line 4, columns C and D. The amounts accounted for as fuel recovery, when received, are reflected on Attachment NHC-1, Schedule 4, Line 4, columns E and F. The recovery represents a reduction in the fuel costs being collected through this FAC filing.

Q26. Did AES Indiana incur any realized gain or losses associated with financial hedges or transactional fees for the hedging program?

A26. No. There were no financial hedges settled or transactional fees incurred during the historical FAC period of February through April 2022, as shown on Attachment NHC-5, Schedule 5, Line 20. As I explained in my testimony in FAC 122, physical hedges do not receive mark-to-market accounting treatment and thus there are no recognized gains or losses on physical hedges. See Witness Jackson's testimony for a discussion of the result of any physical hedges.

Q27. Are you familiar with the Applicant's estimated and actual fuel costs for the months of February through April 2022?

A27. Yes. As shown in Attachment NHC-l, Schedule 5 (Page 4 of 4), the estimated fuel cost for those months was $0.037474 per kWh and the actual cost for the same period averaged $0.045561 per kWh, which represents an underestimate of 17.75%. While AES Indiana has calculated this difference, as previously stated, AES Indiana has not included fuel cost variances for the portion attributable to the Eagle Valley outage at this time in the mitigated factor calculation proposed in this proceeding. The variances are due to multiple factors as described further by Witness Jackson including rising commodity pricing and the Eagle Valley outage.

Q28. Based on such costs, in your opinion, are Applicant's estimated average fuel costs for the months of September through November 2022, as set forth in Attachment NHC-1, reasonable in amount?

A28. Yes. The estimated fuel costs for those months reflect the expected costs from contract sources. The Company has also included forecasted costs associated with participation in

MISO, spot purchases of fuel, and purchased power from Rate REP customers. Also included are the estimated credits to customers for the off-system sales margins related to the Lakefield Wind power purchase agreement ("PPA") as required per the Commission's Order in Cause No. 43740, as well as any realized gains or losses for financial hedges (including any associated transactional costs) from natural gas hedging per the Commission's Orders in Cause Nos. 38703 FAC 122 and FAC 126.

Q29. When was the last Order of the Commission approving Applicant's basic electric rates and charges?

A29. On October 31, 2018, the Commission issued an order in Cause No. 45029 (the "2018 Base Rate Order") approving new basic rates and charges based on Applicant's test year operating expenses and operating income for the twelve months ended June 30, 2017. AES Indiana implemented these new base rates on a service rendered basis effective December 5, 2018. The 2018 Base Rate Order established an annual level of operating income of $220,076,000.

Q30. Please explain Attachments NHC-2, NHC-3, and NHC-4.

A30. Attachment NHC-2 contains a comparison of AES Indiana's electric retail operating results per books for the twelve months ended April 30, 2022, with the electric operating results applicable to jurisdictional retail customers for the same period. Attachment NHC-2 calculates the result of the "operating expense" test of I.C. § 8-1-2-42(d)(2). This attachment also calculates the I.C. § 8-1-2-42(d)(3) test, to determine if the Applicant's actual return applicable to jurisdictional retail customers for the twelve months ended April 30, 2022 was higher than the authorized net electric operating income during the same period. Attachment NHC-3 calculates AES Indiana's authorized return. That total authorized return was $228,291,000. In accordance with 170 IAC 4-6-21 and the Commission's Orders in Cause Nos. 42170 and 45264, AES Indiana added the return on its Qualified Pollution Control Property ("QPCP") of $1,528,000 and the return on its Transmission, Distribution and Storage System Improvement Charge Property ("TDSIC") of $6,687,000 for a total of $8,215,000, to its authorized net operating income of $220,076,000. AES Indiana's TDSIC charge began on November 1, 2020. Attachment NHC-4 reflects the earnings bank total for the relevant period and calculates the differential between the determined return and the authorized return.

Q31. Based on the calculation on Attachment NHC-2, has AES Indiana passed "operating expense" test of I.C. § 8-1-2-42(d)(2)?

A31. Yes. As shown on Attachment NHC-2, the total jurisdictional operating expenses excluding fuel costs have increased as compared to the last basic rate case. Therefore, the Commission should find that the (d)(2) test is satisfied.

Q32. Based on the calculation on Attachment NHC-2, Attachment NHC-3 and Attachment NHC-4 has AES Indiana passed the I.C. § 8-1-2-42(d)(3) test?

A32. Yes. The Company's actual return applicable to jurisdictional retail customers for the twelve months ended April 30, 2022 was $223,712,000, while the authorized net electric operating income during the same period was $228,291,000. While the sum of AES Indiana's differentials for the relevant period is greater than zero, Applicant's actual return was less than its authorized return for the twelve months ended April 30, 2022. See Attachment NHC-4. Accordingly, no reduction in the fuel factor is required and the Commission should find that the "return" test of I.C. § 8-1-2-42.3 is satisfied.

Q33. Were there any revenue and/or expenses eliminated or excluded from total electric operating income for the twelve months ended April 30, 2022 in the preparation of Applicant's <u>Attachment NHC-2</u>?

A33. No. AES Indiana did not eliminate or exclude any revenue and/or expenses from the total electric income for the twelve months ended April 30, 2022.

Q34. What was the source of the data contained in <u>Attachment NHC-2</u>?

A34. All the accounting figures and other financial data contained in <u>Attachment NHC-2</u> were derived from AES Indiana's books of account and accounting records.

Q35. Is AES Indiana including any proposed adjustments in this FAC filing?

A35. Yes. As mentioned previously, AES Indiana has included the remaining uncollected portion of the FAC 133 through FAC 135 estimated non Eagle Valley outage variances totaling $34,140,968 (<u>Attachment NHC-1</u>, Schedule 1, Line No. 34, Column D) which was approved for recovery in FAC 135. Furthermore, the Company is proposing to defer in this FAC the total fuel cost variance for the reconciliation period of February through April 2022 attributable to the Eagle Valley outage equaling an estimated $6,350,096. The adjustment is included on <u>Attachment NHC-1</u>, Schedule 1, Line 33, Column D. As stated previously in my testimony, the result is a reduction between the unmitigated FAC factor and the proposed mitigated factor of -$0.002112 per kWh. These remaining variances were addressed in the FAC 133 subdocket.

Q36. What is the Applicant's estimated average cost of fuel for September through November 2022 as included in the proposed mitigated factor?

A36. The Applicant's estimated average cost of fuel for the months of September through November 2022, after taking into consideration the reconciliation of its estimated and actual fuel costs, is estimated to be $0.07796 per kWh as shown on Attachment NHC-1, Schedule 1, Page 1 of 1, line 37. This represents an increase of $0.037858 per kWh from the base cost of fuel approved in the 2018 Base Rate Order of $0.032938 per kWh.

Q37. What effect will the proposed mitigated factor have on an average residential customer using 1,000 kWh per month?

A37. In relation to the FAC 135 factor from the IURC 30-day filing for the URT repeal, the mitigated factor will result in an increase of $24.39 or 18.90% for an average residential customer using 1,000 kWh per month. The majority of this increase is due to the increase in the forecasted costs. As previously stated in my testimony, the estimated Eagle Valley outage impact has not been included in this FAC factor calculation and thus is not contributing to the FAC factor increase. The forecast costs have risen from the prior FAC filing mostly due to forecasted gas prices. See Company Witness Jackson's testimony for further discussion on commodity pricing for the forecast period (Q/A 18) and the shift in timing of a planned outage at Petersburg that will benefit ratepayers during the forecast period via reduced fuel costs as well as additional off system sales ("OSS") margins that will flowback 100% to customers via the OSS rider (Q/A 19).

Q38. What effect would the unmitigated fuel cost factor have had on an average residential customer using 1,000 kWh per month?

A38. In relation to the FAC 135 factor from the IURC 30-day filing for the utility receipts tax ("URT") repeal, the unmitigated factor would result in an increase of $26.50 or 20.53% for the average residential customer using 1,000 kWh per month.

Q39. If approved by the Commission, when does the Applicant propose to make effective for electric service the mitigated fuel cost factor requested in this proceeding?

A39. The Applicant seeks to make the fuel cost factor shown in Attachment NHC-1, Schedule l, line 41 effective for all bills rendered for electric services beginning with the first billing cycles for the September 2022 billing month (Regular Billing District 41 and Special Billing District 01, which begins August 30, 2022). Such adjustment factor, upon becoming effective, shall remain in effect for approximately three (3) months or until replaced by a different adjustment factor. A copy of the proposed tariff is set forth in Attachment NHC-1-A, attached hereto and made a part hereof.

Q40. Does that conclude your prefiled direct testimony?

A40. Yes.

Verification

I, Natalie Herr Coklow, Manager in Regulatory Accounting for AES US Services, LLC, affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

Dated this 16th day of June 2022.

Natalie Herr Coklow

Natalie Herr Coklow

Attachment NHC-1

[Verified Application – Not Duplicated Herein]

AES INDIANA
Statement of Jurisdictional Electric Operating Income for the Twelve Months Ended April 30, 2022
(In $000's except where otherwise stated)

Line No.	Description	Total Electric For the Twelve Months Ended April 30, 2022	MISO Attachment GG	Applicable to Jurisdictional Retail Customers	Line No.
		Per Books For The Twelve Months Ended April 30, 2022			
1	Operating Revenues	$ 1,505,140	$ 2,643	$ 1,502,497	1
2	Operating Expenses:				2
3	Operation and Maintenance Expenses	$ 937,899	$ 954	$ 936,945	3
4	Depreciation and Amortization	260,874	379	260,495	4
5	Taxes Other than Income Taxes:	44,459	75	44,384	5
6	Income Taxes:	37,269	308	36,961	6
7	Total Operating Expenses	$ 1,280,501	$ 1,716	$ 1,278,785	7
8	Operating Income	$ 224,639	$ 927	$ 223,712	8

(d)(2) Test (In $000's)
Summary of Increase in Operating Expenses Applicable to Jurisdictional Retail Customers
For the Twelve Months Ended April 30, 2022

		Per Cause Nos. 45029	Per Books April 30, 2022	Increase (Decrease)	
9	Operating Expenses Excluding Fuel Costs	$ 756,890	$ 804,276	$ 47,386	9
10	Fuel Costs ***	436,216	474,509	38,293	10
11	Total Operating Expenses **	$ 1,193,106	$ 1,278,785	$ 85,679	11

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(d)(3) Test (In $'s)

12	Jurisdictional Retail Electric Operating Income (April 30, 2022)	$ 223,712,000	12
13	Total Authorized Operating Income (1)	228,291,000	13
14	Excess/(Deficiency)	$ (4,579,000)	14

(1) Calculated on Applicant's Exhibit 3.

AES INDIANA
Determination of Authorized Return
For the Twelve Months Ended April 2022

Line No.				Line No.
1	Operating Income per Cause No. 45029		$220,076,000	1
2	Effective for March 2021 - February 2022			2
3	Allowed Return on CCT Utility Plant per Cause No. 42170-ECR34 [(2)]	1,541,335		3
4	Jurisdictional Portion	100.00%		4
5	Jurisdictional Total for Cause No. 42170-ECR34	1,541,335		5
6	Proration for Cause No. 42170-ECR34	304/365		6
7	Total for Cause No. 42170-ECR34		1,284,000	7
8	Effective for February 2021 - October 2021			8
9	Allowed Return on TDISC-1 Distribution Utility Plant per Cause No. 45264-TDSIC-1 [(2)]	2,551,960		9
10	Jurisdictional Portion	100.00%		10
11	Jurisdictional Total for Cause No. 45264-TDSIC-1	2,551,960		11
12	Proration for Cause No.45264-TDSIC-1	184/365		12
13	Total for Cause No. 45264-TDSIC-1		1,286,000	13
14	Effective for February 2021 - October 2021			14
15	Allowed Return on TDISC-1 - Transmission Utility Plant per Cause No. 45264-TDSIC-1 [(2)]	530,592		15
16	Jurisdictional Portion	100.00%		16
17	Jurisdictional Total for Cause No. 45264-TDSIC-1	530,592		17
18	Proration for Cause No.45264-TDSIC-1	184/365		18
19	Total for Cause No. 45264-TDSIC-1		267,000	19
20	Effective for November 2021 - April 2022			20
21	Allowed Return on TDISC-3 Distribution Utility Plant per Cause No. 45264-TDSIC-3 [(2)]	8,370,218		21
22	Jurisdictional Portion	100.00%		22
23	Jurisdictional Total for Cause No. 45264-TDSIC-3	8,370,218		23
24	Proration for Cause No.45264-TDSIC-3	181/365		24
25	Total for Cause No. 45264-TDSIC-3		4,151,000	25
26	Effective for November 2021 - April 2022			26
27	Allowed Return on TDISC-3 - Transmission Utility Plant per Cause No. 45264-TDSIC-3 [(2)]	1,982,306		27
28	Jurisdictional Portion	100.00%		28
29	Jurisdictional Total for Cause No. 45264-TDSIC-3	1,982,306		29
30	Proration for Cause No.45264-TDSIC-3	181/365		30
31	Total for Cause No. 45264-TDSIC-3		983,000	31
32	Effective for March 2022 - April 2022			32
33	Allowed Return on CCT Utility Plant per Cause No. 42170-ECR35 [(2)]	1,458,112		33
34	Jurisdictional Portion	100.00%		34
35	Jurisdictional Total for Cause No. 42170-ECR35	1,458,112		35
36	Proration for Cause No. 42170-ECR35	61/365		36
37	Total for Cause No. 42170-ECR35		244,000	37
26	Total Authorized Operating Income		$228,291,000	26

[(2)] The Commission requires that, for purposes of computing the authorized net operating income for IC 8-1-2-42(d)(2) and IC 8-1-2-42(d)(3), the jurisdictional portion of the increased return shall be phased-in over the appropriate period of time that the Applicant's net operating income is affected by this earnings modification resulting from the Commission's approval of the QPCP Construction Cost Rider. The following example may be helpful in implementing the appropriate phase-in: Assume a ECCRA Order is effective and implemented Feb. 1, 2015. Assume the test period for the first FAC filing after the ECCRA Order covers the twelve months ended March 31, 2015. The increase to net operating income resulting from the ECCRA Order should be 59/365 of the total additional earnings authorized by the Commission's Order in the ECCRA. Assuming all things remain constant, the next FAC filing would reflect 150/365 of the total additional ECCRA earnings.

AES INDIANA
Earnings Test Summary

FAC No.	Reporting Period	Determined Return	Authorized Return	Differential
136	4/30/2022	$223,712,000	$228,291,000	($4,579,000)
135	1/31/2022	227,360,000	226,529,000	$831,000
134	10/31/2021	226,080,000	224,682,000	$1,398,000
133	7/31/2021	219,585,000	223,889,000	(4,304,000)
132	4/30/2021	232,893,000	223,097,000	9,796,000
131	1/31/2021	227,171,000	222,310,000	4,861,000
130	10/31/2020	229,881,000	221,451,000	8,430,000
129	7/31/2020	242,467,000	221,368,000	21,099,000
128	4/30/2020	236,917,000	221,285,000	15,632,000
127	1/31/2020	234,075,000	221,201,000	12,874,000
126	10/31/2019	230,875,000	218,710,000	12,165,000
125	7/31/2019	229,431,000	206,716,000	22,715,000
124	4/30/2019	217,179,000	194,654,170	22,524,830
123	1/31/2019	212,078,000	182,107,612	29,970,388
122	10/31/2018	201,730,000	172,128,000	29,602,000
121	7/31/2018	190,971,000	171,399,000	19,572,000
120	4/30/2018	180,892,000	170,247,000	10,645,000
119	1/31/2018	177,867,000	169,205,000	8,662,000
118	10/31/2017	180,108,000	168,291,000	11,817,000
117	7/31/2017	185,397,000	167,012,000	18,385,000
				$252,096,218

AES INDIANA
Determination of Fuel Cost Adjustment
Beginning with November 2022 Based on the Estimated
Three Months Average of September, October, and November 2022

Line No.	Description	(A) Estimated Month of: September	(B) Estimated Month of: October	(C) Estimated Month of: November	(D) Total	(E) Estimated Three Month Average	Line No.
	kWh Source (000's)						
1	Coal and Oil Generation	720,972	857,188	927,139	2,505,299	835,100	1
2	Nuclear Generation	-	-	-	-	-	2
3	Hydro Generation	-	-	-	-	-	3
4	Other Generation - Internal Combustion	-	-	-	-	-	4
5	Gas Generation	729,222	792,634	711,016	2,232,872	744,291	5
	Purchases through MISO:						
6	Wind Purchase Power Agreement Purchases	38,119	64,703	76,987	179,809	59,936	6
7	Non-Wind PPA Market Purchases	13,792	-	-	13,792	4,597	7
8	Other	-	-	-	-	-	8
9	Purchased Power other than MISO	16,366	13,526	10,260	40,152	13,384	9
	LESS:						
10	Energy Losses and Company Use	50,080	47,264	47,773	145,117	48,372	10
11	Inter-System Sales through MISO	430,459	701,175	687,517	1,819,151	606,384	11
12	Inter-System Sales other than MISO	-	-	-	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	-	-	-	13
14	**Sales (S)**	1,037,932	979,612	990,112	3,007,656	1,002,552	14
	Fuel Cost ($)						
15	Coal and Oil Generation	17,401,721	19,651,559	20,958,787	58,012,067	19,337,356	15
16	Nuclear Generation	-	-	-	-	-	16
17	Hydro Generation	-	-	-	-	-	17
18	Other Generation - Internal Combustion	-	-	-	-	-	18
19	Gas Generation	50,447,177	55,571,828	50,616,983	156,635,988	52,211,996	19
	Purchases through MISO:						
20	Wind Purchase Power Agreement Purchases	4,913,364	6,972,374	8,119,302	20,005,040	6,668,347	20
21	Non-Wind PPA Market Purchases	860,689	-	-	860,689	286,896	21
22	Other	-	-	-	-	-	22
23	MISO Components of Cost of Fuel	1,523,685	1,438,070	1,453,485	4,415,240	1,471,747	23
24	Purchased Power other than MISO	2,669,023	2,165,444	1,863,671	6,698,138	2,232,713	24
	Less:						
25	Inter-System Sales through MISO	19,505,443	31,233,351	29,321,470	80,060,264	26,686,755	25
26	Inter-System Sales other than MISO	- -	-	-	-	-	26
27	Non-Jurisdictional Retail Sales	- -	-	-	-	-	27
28	Transmission Losses	677,260	628,360	608,064	1,913,684	637,895	28
29	Lakefield PPA Adjustment	1,093,588	1,297,812	1,525,783	3,917,183	1,305,728	29
30	**Total Fuel Cost (F)**	$ 56,539,368	$ 52,639,752	$ 51,556,911	$ 160,736,031	$ 53,578,677	30
31	**F ÷ S (Line 30 ÷ Line 14) (Mills/kWh)**					53.442	31

Line No.	Description	Months to be Reconciled: February	Months to be Reconciled: March	Months to be Reconciled: April	Total		Line No.
32	Fuel Cost Variance - FAC 136	$ 11,488,761	$ 889,428	$ 12,026,467	$ 24,404,656		32
33	Estimated Eagle Valley Outage Impact FAC 136 (1)						33
34	50% Fuel Cost Variance Not Attributable to Eagle Valley Outage as Calculated in FAC 135				34,140,968		34
35	Total Fuel Cost Variance Included in this Filing					$ 58,545,624	35
	(Mills/kWh)						
36	Variance Charge (Line 32 Total divided by estimated Indiana jurisdictional sales of		3,007,656	kWh (000's)		19.466	36
37	Adjusted Fuel Cost Charge (Line 31 + Line 33)					72.908	37
38	Less: Base Cost of Fuel Included in Rates					32.938	38
39	Fuel Cost Charge					39.970	39