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 JUNE 2022 THROUGH AUGUST 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 AUTHORITY TO RECOVER COSTS OF THE FUEL HEDGING PLAN PURSUANT TO I.C. 8-1-2-42.	**CAUSE NO. 38703 FAC 135**

APPLICANT'S SUBMISSION OF DIRECT TESTIMONY OF
<u>NATALIE HERR COKLOW</u>

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,

Teresa Morton Nyhart (No. 14044-49)
Jeffrey M. Peabody (No. 28000-53)
Barnes & Thornburg LLP
11 South Meridian Street
Indianapolis, Indiana 46204
Nyhart Telephone: (317) 231-7716
Peabody Telephone: (317) 231-6465
Facsimile: (317) 231-7433
Nyhart Email: tnyhart@btlaw.com
Peabody Email: jpeabody@btlaw.com

ATTORNEYS FOR APPLICANT
INDIANAPOLIS POWER & LIGHT COMPANY
D/B/A AES INDIANA

CERTIFICATE OF SERVICE

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

Lorraine Hitz
Office of Utility Consumer Counselor
115 W. Washington Street, Suite 1500 South
Indianapolis, Indiana 46204
infomgt@oucc.in.gov
lhitz@oucc.in.gov

Gregory T. Guerrettaz
Financial Solutions Group, Inc.
2680 East Main Street, Suite 223
Plainfield, Indiana 46168
greg@fsgcorp.com
fsg@fsgcorp.com

A Courtesy Copy to:
Anne E. Becker
Lewis & Kappes
One American Square, Suite 2500
Indianapolis, Indiana 46282
abecker@lewis-kappes.com

and a courtesy copy to:
ATyler@lewis-kappes.com
ETennant@Lewis-kappes.com

Jeffrey M. Peabody

Teresa Morton Nyhart (No. 14044-49)
Jeffrey M. Peabody (No. 28000-53)
Barnes & Thornburg LLP
11 South Meridian Street
Indianapolis, Indiana 46204
Nyhart Telephone: (317) 231-7716
Peabody Telephone: (317) 231-6465
Facsimile: (317) 231-7433
Nyhart Email: tnyhart@btlaw.com
Peabody Email: jpeabody@btlaw.com

ATTORNEYS FOR APPLICANT
INDIANAPOLIS POWER & LIGHT COMPANY
D/B/A AES INDIANA

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 January 31, 2022.
- Attachment NHC-3 is a Determination of Authorized Return for the Twelve Months Ended January 31, 2022.
- Attachment NHC-4 is an Earnings Test Summary.
- Attachment NHC-4a is the Calculated Reduction for the Earnings Test.
- Attachment NHC-5 is the calculation of the unmitigated FAC factor.
- Attachment NHC-6 calculates a true-up to the October 2021 variance as a result of a tie-line meter read issue which I describe further in my testimony.

Q10. Is the information set forth in Attachments NHC-l through NHC-6 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-6.

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

A12. As discussed in my testimony for FAC 134, the Company was working to confirm and verify modeled impacts related to the Eagle Valley outage. The Company has completed its analysis of the estimated impact of the Eagle Valley outage on the variances from FAC 133 through FAC 135 and is now able to model an estimate of the variances that were the result of issues independent of the Eagle Valley outage (commodity price and volume variances) which are now 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. Also, the continued deferral of large variances results in a strain on the Company's cash flow as discussed further below. That said, in an effort to mitigate the rate impact to customers, the Company also proposes to spread the variances over two FAC filings.

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

A13. As previously stated in FAC 134, 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 a portion of the variances in the

FAC factor. In addition, this proposal will help to mitigate cash flow issues that can negatively impact the Company. By deferring large variance amounts, AES Indiana is not receiving the associated cashflow which pressures the Company's liquidity as it must use other sources of funding to make up for the shortfall in cashflow. AES Indiana is currently satisfying this shortfall by borrowing on its short-term revolving credit facility, incurring additional interest expense as a result. The borrowing capacity on the revolving credit facility is not unlimited, and the continued deferral of the variance amount limits the Company's financial flexibility and uses available liquidity that would otherwise primarily be used to finance capital expenditures and supporting working capital needs. Additionally, AES Indiana issues long-term debt from time to time. The continued deferral of these variances (and future variance amounts) may require the issuance of long-term debt earlier than planned and/or in an amount greater than expected.

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 135 but, as explained above, believes it is appropriate to begin 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 resulting variance after subtracting the amount already collected from FAC 133 is shown on Line 40 of Attachment NHC-1, Schedule 1 and is detailed in Chart 1 below.

The difference between the mitigated factor calculated on Attachment NHC-1, Schedule 1 and Attachment NHC-5 (unmitigated FAC 135 factor if filed for the usual forecast and reconciliation periods), is that the mitigated factor includes all of the estimated non outage portion of the variances that have not yet been collected for the FAC 133 through FAC 135 reconciliation period of May 2021 through January 2022. This total variance is then divided over two FAC periods. The total variance is $75,123,747. After subtracting the 50% variance already collected from FAC133 of $6,841,811, the net total variance is $68,281,936. The Company is then proposing to collect this remaining total over two FAC periods. Total fuel cost variances for the reconciliation periods after dividing in half is $34,140,968. This adjustment is reflected on Attachment NHC-1, Schedule 1, Line 41 and detailed in Chart 1 below.

<u>Chart 1</u>[1]

	As Filed Variance	Non Outage Actuals (2)	Eagle Valley Impact
FAC133	$ 13,683,621	$ 7,032,886	$ (6,650,735)
FAC134 (1)	$ 32,281,690	$ 27,356,531	$ (4,925,159)
FAC135	$ 64,326,816	$ 40,734,330	$ (23,592,486)
		$ 75,123,747	$ (35,168,380)
less 50% FAC133 already recovered		$ 6,841,811	
		$ 68,281,936	
50% of Variance		$ 34,140,968	

(1) As filed variances of $29,879,749 plus October tie line correction of $2,401,941
(2) Actuals if EV had been in service

Excluding the Eagle Valley outage portion of the variances totaling $35,168,380 and collecting the remaining variance over two FAC periods mitigates the rate impact for customers. Witness Jackson further details the cost impact of the Eagle Valley outage for the reconciliation period. This mitigated factor would follow the normal reconciliation process and would be reconciled and trued-up as part of the FAC 137 and 138 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 133 through 135 of $35,168,380 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.

[1] See Attachment DJ-5 for detail calculation.

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 has not included recovery of the estimated variance remaining from FAC 133 through FAC 135 related to the Eagle Valley outage at this time and is proposing to address it as part of the FAC 133 subdocket. Furthermore, AES Indiana is proposing to split the remaining non outage variance over two FAC periods which helps to further mitigate the rate increase to customers. 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. The mitigated factor proposed results in a charge to the average residential customer using 1,000 kWh per month that is -$8.19 or -5.96% lower than the calculated unmitigated factor.

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 June through August 2022 is $0.013673 per kwh on Attachment NHC-1, Schedule 1 as compared to the unmitigated factor on Attachment NHC-5 of $0.021857 for a difference of -$0.008184 per kwh.

FAC Rate Comparison Between FAC 135 Mitigated Factor and Unmitigated Factor			
	FAC 135 Mitigated Factor Attachment NHC-1, Schedule 1, Line 46	FAC 135 Unmitigated Factor Attachment NHC-5, Line 39	Difference
Fuel Cost Charge per kWh	$0.013673	$0.021857	-$0.008184

Q19. You mentioned previously a meter read error impacting the October 2021 variance as previously filed in FAC 134. Please describe this error further.

A19. It was discovered during January 2022 that Duke Energy had provided incorrect meter readings to MISO at a substation where AES Indiana has tie-lines. This impacts the October 2021 variance from what was previously filed in FAC 134. The original variance included in FAC 134 for October 2021 was $16,883,428 and the revised variance is $19,285,369 for a difference of $2,401,941. To correct the data, the corrected meter readings were entered into the Company's energy accounting system and resulted in changes to MWH purchased from MISO, wholesale sales, and MISO fuel-like charges impacting FAC variances. The correct figures are reflected in the schedules presented in this FAC proceeding for the months of November and December and the October change is presented as part of Attachment NHC-6. Once MISO re-settles the market for these days, AES Indiana will receive refunds and MISO fuel-like charges will be lower in future months. These credits will be reflected in the FAC in the months they are received (anticipated to be January through March 2022) and are expected to total approximately $7.9 million.

Q20. 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?

A20. Yes.

Q21. Is AES Indiana's filing in this proceeding consistent with your understanding of these two orders?

A21. 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.

Q22. 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?

A22. <u>Attachment NHC-1</u> estimates fuel costs over the months of June through August 2022.

Q23. In making such estimate, were actual fuel costs reconciled with estimated fuel costs for any period?

A23. Yes, actual fuel costs for the months of November 2021 through January 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 only a portion is included in the mitigated factor calculated on <u>Attachment NHC-1</u>, Schedule 1.

Q24. Have calculations been made applying the Purchased Power Daily Benchmarks established pursuant to the methodology approved in Cause No. 43414?

A24. 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.

Q25. 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?

A25. Yes, for the non outage portion of the purchased power over the benchmark. Chart 2 below calculates the purchased power over the benchmark not attributable to the Eagle Valley outage.

Chart 2

	Total Purchased Power over Benchmark		Non Outage Purchases over Benchmark		Eagle Valley Impact	
FAC133	$	1,198,183	$	161,097	$	(1,037,085)
FAC134 (1)	$	1,183,609	$	133,349	$	(1,050,260)
FAC135	$	2,487,937	$	273,441	$	(2,214,496)
	$	4,869,729	$	567,887	$	(4,301,842)

(1) FAC 134 total of $1,271,874 plus October tie line true-up of ($88,265)
Source: Attachment DJ-5

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. $4,869,729 is the total purchased power over the benchmark for FAC 133 through FAC 135 of which $4,301,842 is estimated to be attributable to the Eagle Valley outage and therefore included the total variance of $35,168,380 that is deferred pending the outcome of the FAC 133 subdocket. The remaining purchased power over the benchmark of $567,887 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 November 2021 through January 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.

Q26. 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 November 2021 through January 2022 period?

A26. 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.

Q27. Did AES Indiana incur any realized gain or losses associated with financial hedges or transactional fees for the hedging program?

A27. Yes. There was one financial power hedge settled during the historical FAC period of November 2021 through January 2022. The realized loss of $482,546 is reflected on Attachment NHC-1, Schedule 5, Page 2, Line 20. Since the hedge is the result of the Eagle Valley outage, it has not been included in the variances requested in this filing and instead is included in the portion that is being deferred for the FAC 133 subdocket. As discussed previously in FAC 133 and 134, there were power financial hedge realized gains during the reconciliation periods of June through October 2021 totaling $7,226,446. The net of the realized gains and loss totaling $6,743,900 are not included in the variances requested in this filing and are included in the portion that is being deferred for the FAC 133 subdocket. AES Indiana did not incur any transactional fees associated with these power hedge transactions. 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.

Q28. Are you familiar with the Applicant's estimated and actual fuel costs for the months of November 2021 through January 2022?

A28. Yes. As shown in <u>Attachment NHC-1</u>, Schedule 5 (Page 4 of 4), the estimated fuel cost for those months was \$0.033879 per kWh and the actual cost for the same period averaged \$0.053988 per kWh, which represents an underestimate of 37.25%. 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, Petersburg coal strategy, and the Eagle Valley outage.

Q29. Based on such costs, in your opinion, are Applicant's estimated average fuel costs for the months of June through August 2022, as set forth in <u>Attachment NHC-1</u>, reasonable in amount?

A29. Yes. The estimated fuel costs for those months reflect the expected costs from contract sources. We have also included forecasted costs associated with our participation in MISO, spot purchases of fuel, and purchased power from Rate REP customers. In addition, we have included 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.

Q30. When was the last Order of the Commission approving Applicant's basic electric rates and charges?

A30. 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.

Q31. Please explain Attachments NHC-2, NHC-3, and NHC-4.

A31. Attachment NHC-2 contains a comparison of AES Indiana's electric retail operating results per books for the twelve months ended January 31, 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 January 31, 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 $226,529,000. 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 $1,537,000 and the return on its Transmission, Distribution and Storage System Improvement Charge Property ("TDSIC") of $4,916,000 for a total of $6,453,000, 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.

Q32. Based on the calculation on Attachment NHC-2, has AES Indiana passed "operating expense" test of I.C. § 8-1-2-42(d)(2)?

A32. 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.

Q33. Based on the calculation on Attachment NHC-3 and Attachment NHC-4a has AES Indiana passed the I.C. § 8-1-2-42(d)(3) test?

A33. No. The Company's actual return applicable to jurisdictional retail customers for the twelve months ended January 31, 2022 was $227,361,000, while the authorized net electric operating income during the same period was $226,529,000. In addition, the sum of AES Indiana's differentials for the relevant period is greater than zero. See Attachment NHC-4. Accordingly, a reduction in the fuel factor was calculated as both the current period and the sum of the differentials for the relevant period result in an amount greater than zero.

Q34. Please explain how the Company determined the reduction amount on Attachment NHC-4a.

A34. Attachment NHC-4a shows the calculation of the reduction in the current FAC period. Ind. Code §8-1-2-42.3(d) defines the calculation of the reduction amount in an instance where both the current period and the sum of the differentials for the relevant period result in an amount greater than zero.

> Consistent with subsection (b), the amount of reduction shall be determined by dividing the lesser of:
>
> (1) The amount determined under subsection (c); or
>
> (2) The amount by which the return in the current application before the commission was more than the authorized return;
>
> by the total number of applications filed during the twelve (12) month test period considered in the current application before the commission.

As shown on Line 1 of Attachment NHC-4a, the current period ended January 31, 2022 results in a positive differential of $832,000, which is the same differential reflected on Attachment NHC-2, line 14. The sum of the differentials totaling $275,608,218 is listed on Line 2 and reflects the relevant statutory period from April 2017 (FAC 116) through January 2022 (FAC 135). This amount is the same as the total reflected on Attachment NHC-4. Line 3 determines the basis for the reduction, which is the lesser of Line 1 and Line 2. In this instance, the current period differential listed on Line 1 is the lesser amount. This amount is multiplied by 25% on Line 4, which reflects the total number of applications filed during the twelve-month period in the current application (AES Indiana files four applications per year). The resulting amount of $208,000, listed on Line 5, represents the basis for the reduction for the current FAC period. Line 6 reflects the revenue conversion factor utilized in IPL's last base rate case (Cause No. 45029, Petitioner's Exhibit No. REVREQ2-T), with adjustments for the applicable Indiana state income tax rate, the utility receipts tax rate, and the Public Utility Fee rate. The reduction amount on Line 5 is grossed up for taxes by multiplying the conversion factor on Line 6 in a manner identical to the treatment in IPL's last base rate case to determine the pre-tax reduction on Line 7. This reduction amount totals $282,364 and is included as a reduction to fuel costs recoverable in the current FAC period as shown on Attachment NHC-1, Schedule 1, Lines 32 and 33.

Q35. Were there any revenue and/or expenses eliminated or excluded from total electric operating income for the twelve months ended January 31, 2022 in the preparation of Applicant's Attachment NHC-2?

A35. Yes. Because IPL anticipated that the earnings bank would be depleted during the fourth quarter of 2021, IPL began recording the estimated liability that would result from the earnings test for FAC 135 in November 2021 through January 2022. IPL excluded both the reduction to revenue and the associated tax impact as a result of these entries from net operating income for the twelve months ending January 31, 2022 earnings calculation presented on Attachment NHC-2 because it would be inappropriate to reduce the earnings in this current FAC period before the adjustment is able to be reflected as a reduction to rates on Attachment NHC-1, Schedule 1. These adjustments to per books net operating income are shown on the twelve-month net operating income statement worksheet that is included in the FAC audit packet. Both the reduction to revenue and the associated tax impact will be reflected in the earnings test in the next FAC.

Q36. What was the source of the data contained in Attachment NHC-2?

A36. All the accounting figures and other financial data contained in Attachment NHC-2 were derived from AES Indiana's books of account and accounting records.

Q37. Is AES Indiana including any proposed adjustments in this FAC filing?

A37. Yes. As mentioned previously, AES Indiana has included the remaining uncollected portion of the FAC 133 through FAC 135 variances totaling $68,281,936 (Attachment NHC-1, Schedule 1, Line No. 40, Column D) and is proposing to spread the recovery over two FAC periods. Furthermore, the Company is proposing to defer in this FAC the total fuel cost variance for the reconciliation period of May 2021 through January 2022 attributable to the Eagle Valley outage equaling an estimated $35,168,380. The adjustment is included on Attachment NHC-1, Schedule 1, Line 39, Column D. As stated previously in my testimony, the result is a reduction between the unmitigated FAC factor and the proposed mitigated factor of -$0.008184 per kWh. These remaining variances will be addressed in the FAC 133 subdocket.

Q38. What is the Applicant's estimated average cost of fuel for June through August 2022 as included in the proposed mitigated factor?

A38. The Applicant's estimated average cost of fuel for the months of June through August 2022, after taking into consideration the reduction for the earnings test, is estimated to be $0.046410 per kWh as shown on Attachment NHC-1, Schedule 1, line 43. This represents an increase of $0.013673 per kWh, after being adjusted for Indiana Utility Receipts Tax, from the base cost of fuel approved in the 2018 Base Rate Order of $0.032938 per kWh.

Q39. What effect will the proposed mitigated factor have on an average residential customer using 1,000 kWh per month?

A39. In relation to the factor currently in effect, the mitigated factor will result in an increase of $6.25 or 5.08% for an average residential customer using 1,000 kWh per month.

Q40. What effect would the unmitigated fuel cost factor have had on an average residential customer using 1,000 kWh per month?

A40. In relation to the factor currently in effect, the unmitigated factor would result in an increase of $14.44 or 11.74% for the average residential customer using 1,000 kWh per month.

Q41. 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?

A41. The Applicant seeks to make the fuel cost factor shown in Attachment NHC-1, Schedule 1, line 41 effective for all bills rendered for electric services beginning with the first billing cycles for the June 2022 billing month (Regular Billing District 41 and Special Billing District 01, which begins May 31, 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.

Q42. Does that conclude your prefiled direct testimony?

A42. 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 17th day of March 2022.

Natalie Herr Coklow

Natalie Herr Coklow

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 JUNE 2022 THROUGH AUGUST 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 AUTHORITY TO RECOVER COSTS OF THE FUEL HEDGING PLAN PURSUANT TO I.C. 8-1-2-42.	)	**CAUSE NO. 38703 FAC 135**

VERIFIED APPLICATION

TO THE INDIANA UTILITY REGULATORY COMMISSION:

INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA (hereinafter called "Applicant" or "IPL" or "AES Indiana") respectfully represents and shows this Commission:

1. Applicant is an electric generating utility and is a corporation organized and existing under the laws of the State of Indiana having its principal office at Indianapolis, Indiana. It is engaged in rendering electric public utility service in the State of Indiana and owns and operates, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such service to the public. Applicant is subject to the jurisdiction of this Commission in the manner and to the extent provided by the Public Service Commission Act, as amended, and other laws of the State of Indiana.

ELECTRIC SERVICE

2. With respect to electric service, this Application is filed pursuant to Ind. Code § 8-1-2-42 for the purpose of securing approval of a new fuel cost factor for electric service for the billing months of June through August 2022.

3. AES Indiana is requesting recovery of projected fuel-related costs attributable to Applicant accepting transmission service from the Midcontinent Independent System Operator, Inc. ("MISO") for the period of June through August 2022. The Company's filing also reflects a true-up of fuel-related MISO costs and revenues for the period of November 2021 through January 2022. As discussed further in the Company's testimony, the Company is proposing to reconcile in the mitigated factor the non-outage related costs from the FAC 133 through FAC 135 historical periods. The data and calculations supporting such estimated fuel cost and fuel cost factor are set forth in Schedules 1-7 attached hereto and made a part hereof.

4. Applicant represents that (i) Applicant has made every reasonable effort to acquire fuel and to generate and/or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible; (ii) the actual increases in fuel cost through the latest month for which actual fuel costs are available since the last order of the Commission approving Applicant's basic rates have not been offset by actual decreases in Applicant's other operating expenses; (iii) Applicant has performed the calculations required under Ind. Code § 8-1-2-42.3 and determined that the fuel factor (including interim factor) should be reduced by $282,364; and (iv) the estimate of Applicant's prospective average fuel costs for the FAC period are reasonable after taking into consideration the reconciliation of Applicant's actual fuel cost recoveries for the reconciliation period.

5. In Cause No. 43414, Applicant and Indiana Office of Utility Consumer Counselor ("OUCC") agreed upon a "Benchmark" triggering mechanism for the judgment of the

reasonableness of purchased power costs. Each day, a Benchmark is established based upon a generic Gas Turbine ("GT") with a generic GT heat rate of 12,500 btu/kWh, using the day ahead natural gas prices for the NYMEX Henry Hub, plus $0.60/mmbtu gas transport charge for a generic gas-fired GT. The Benchmark methodology was approved in Cause No. 43414 on April 23, 2008 ("Purchased Power Daily Benchmark(s)"). As explained by Applicant's witness David Jackson, Applicant continues to follow the guidelines and procedures established in Cause No. 43414. The Purchased Power Daily Benchmarks for November 2021 through January 2022 are set forth in Attachment DJ-1.

6. Applying the Purchased Power Daily Benchmarks set forth above to individual power purchase transactions included in this proceeding, shows $2,487,937 of purchased power costs in excess of the applicable Purchased Power Daily Benchmarks incurred in November 2021 through January 2022. A summary of the purchased power volumes, costs, the total of hourly purchased power costs above the applicable Purchased Power Daily Benchmarks for November 2021 through January 2022 and the reasons for the purchases at-risk after consideration of MISO economic dispatch, is set forth in Attachment DJ-2. As explained by Witness Jackson, Applicant is proposing to include only the non-outage portion of the total FAC 133, 134, and 135 purchases over the benchmark, totaling $567,887, in this proceeding. The forced outage related purchases over the benchmark will be considered in the resolution of the pending subdocket in FAC 133.

7. Consistent with the Commission's Orders in Cause Nos. 43485 and 43740, Applicant continues to apply ratemaking treatment to recover the purchased power costs incurred under the Hoosier Wind Park and Lakefield Wind Park purchase power agreements.

8. The books and records of Applicant supporting the data and calculations set forth herein are available for inspection and review by the OUCC and this Commission. Applicant is

contemporaneously prefiling with the Commission its direct testimony, attachments, and workpapers in support of this Application.

9. The names and addresses of Applicant's duly authorized representatives, to whom all correspondence and communications concerning this Application should be sent, are as follows:

Teresa Morton Nyhart (No. 14044-49)
Jeffrey M. Peabody (No. 28000-53)
Barnes & Thornburg LLP
11 South Meridian Street
Indianapolis, Indiana 46204
Nyhart Telephone: (317) 231-7716
Peabody Telephone: (317) 231-6465
Facsimile: (317) 231-7433
Nyhart Email: tnyhart@btlaw.com
Peabody Email: jpeabody@btlaw.com

10. Applicant's average cost of fuel for the months of June through August 2022, after taking into consideration its estimated and actual fuel costs for the months of November 2021 through January 2022, is estimated to be $0.054473 per kWh for the unmitigated factor and $0.046410 for the proposed interim factor.

11. As more fully illustrated on Schedule 1, taking into account the projected fuel costs and fuel variance, the resulting unmitigated fuel factor, as modified to recover Indiana Utility Receipts Tax, would be $0.021857 per kWh. This factor would represent an increase from the basic rates otherwise anticipated to be applicable during the billing cycles for the months of June through August 2022.

12. As discussed by Witness Coklow, Applicant has completed its analysis of the estimated impact of the Eagle Valley outage on the variances from FAC 133 through FAC 135 and is now able to model the estimate of the variances that were the result of issues independent of the Eagle Valley outage (commodity price and volume variances), which are now included for recovery in this proceeding. Applicant 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.

13. To mitigate the rate impact on cutomers, Applicant proposes to spread the variances over two FAC filings. Applicant is requesting that the Commission authorize the Company to place into effect a reduced fuel factor of $0.013673 per kWh on an interim basis subject to reconciliation and true-up in a future FAC filing or pending resolution of the Eagle Valley forced outage matters in the subdocket established in FAC 133. To the extent that the amount attributable to the outage differs upon the subdocket outcome, these rates would be further trued-up in a future filing upon resolution of the subdocket. AES Indiana is also seeking authority to continue to defer as a regulatory asset the outage related variances calculated for FAC 133 through 135 for recovery pending conclusion of the FAC 133 subdocket.

14. A copy of the proposed Tariff is set forth in Attachment NHC-1-A, attached hereto and made a part hereof.

15. Applicant requests that the Commission approve a procedural schedule agreed to by the Applicant and the OUCC in lieu of conducting a prehearing conference. The agreed schedule is as follows:

Date	**Event**
April 21, 2022	OUCC/Intervenors File Case-in-Chief
May 2, 2022	Petitioner's Rebuttal Testimony
May 12 or 13, or Week of May 16, 2022	Hearing

16. Applicant seeks to make the fuel cost factor requested herein effective for all bills rendered for electric services beginning with the first billing cycle for June 2022 (Regular Billing District 41 and Special Billing District 01), which begins May 31, 2022. Such fuel cost factor,

upon becoming effective, shall remain in effect for approximately three (3) months or until replaced by a different fuel cost factor.

WHEREFORE, Applicant respectfully requests that the Commission:

(i) approve this Application and the fuel cost factor requested herein as set forth in and supported by Schedules 1-7;

(ii) authorize Applicant to make such fuel cost factor effective on an interim basis subject to reconciliation and true-up in a future FAC filing or pending resolution of the Eagle Valley forced outage matters in the FAC 133 subdocket;

(iii) grant to Applicant deferral accounting authority as requested in Paragraph 13;

(iv) approve the proposed Tariff attached hereto as Attachment NHC-1-A;

(v) authorize AES Indiana to recover costs, gains, or losses, including any associated transactional costs, associated with the hedging plan through the fuel adjustment clause in accordance with the review of the reasonableness of the transaction(s) as described herein; and

(vi) grant to Applicant all other appropriate relief.

INDIANAPOLIS POWER & LIGHT COMPANY
D/B/A AES INDIANA

Chad A. Rogers
Senior Manager, Regulatory Affairs and RTO Policy

Teresa Morton Nyhart (No. 14044-49)
Jeffrey M. Peabody (No. 28000-53)
Barnes & Thornburg LLP
11 South Meridian Street
Indianapolis, Indiana 46204

Nyhart Telephone:	(317) 231-7716
Peabody Telephone:	(317) 231-6465
Facsimile:	(317) 231-7433
Nyhart Email:	tnyhart@btlaw.com
Peabody Email:	jpeabody@btlaw.com

ATTORNEYS FOR APPLICANT

Verification

I affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

Dated this 17th day of March, 2022.

Natalie Herr Coklow

Natalie Herr Coklow

Attachment NHC-1-A

Indianapolis Power & Light Company | I.U.R.C. No. E-18 | 154th Revised No. 157
d/b/a AES Indiana | | Superseding
One Monument Circle, Indianapolis, Indiana | | 14~~3~~th Revised No. 157

STANDARD CONTRACT RIDER NO. 6
FUEL COST ADJUSTMENT
(Applicable to Rates RS, UW, CW, SS, SH, OES, SL, PL, PH, HL, MU-1, APL, and EVX)

In addition to the rates and charges set forth in the above mentioned Rates, a fuel cost adjustment applicable for approximately three (3) months or until superseded by a subsequent factor shall be made in accordance with the following provisions:

A. The fuel cost adjustment shall be calculated by multiplying the KWH billed by an Adjustment Factor per KWH established according to the following formula:

$$\text{Adjustment Factor} = \frac{F}{S} - \$0.032938$$

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the month of ~~March~~ June 2022 and consisting of the following costs:

   (a) The average cost of fossil and nuclear fuel consumed in the Company's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants including, as to fossil fuel, only those items listed in Account 151 and as to nuclear fuel only those items listed in Account 518 (except any expense for fossil fuel included in Account 151) of the Federal Energy Regulatory Commission's Uniform System of Accounts for Public Utilities and Licensees;

   (b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below;

   (c) The net energy cost, exclusive of capacity or demand charges, of energy purchased on an economic dispatch basis, and energy purchased as a result of a scheduled outage, when the costs thereof are less than the Company's fuel cost of replacement net generation from its own system at that time; less

   (d) The cost of fossil and nuclear fuel recovered through intersystem sales including fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

2. "S" is the estimated kilowatt-hour sales for the same estimated period set forth in "F", consisting of the net sum in kilowatt-hours of:

   (a) Net Generation,
   (b) Purchases and
   (c) Interchange-in, less
   (d) Inter-system Sales,
   (e) Energy Losses and Company Use.

Effective ~~February 28~~May 31, 2022

Indianapolis Power & Light Company
d/b/a AES Indiana
One Monument Circle, Indianapolis, Indiana

I.U.R.C. No. E-18

~~14th~~ 15th Revised No. 158
Superseding
~~13th~~ 14th Revised No. 158

STANDARD CONTRACT RIDER NO. 6 (Continued)

B. The Adjustment Factor as computed above shall be further modified to allow the recovery of Utility Receipts taxes and other similar revenue-based tax charges occasioned by the fuel adjustment revenues.

C. The Adjustment Factor may be further modified to reflect the difference between incremental fuel cost billed and the incremental fuel cost actually experienced during the months of ~~August~~ November 2021 through ~~October 2021~~January 2022.

D. The Adjustment Factor to be effective for all bills rendered for electric service beginning with the first billing cycles for ~~March~~ June 2022 (Regular Billing District 41 and Special Billing Route 01) will be $~~0.007418~~ 0.013673 per KWH.

Effective ~~February 28~~May 31, 2021

STANDARD CONTRACT RIDER NO. 6
FUEL COST ADJUSTMENT
(Applicable to Rates RS, UW, CW, SS, SH, OES, SL, PL, PH, HL, MU-1, APL, and EVX)

In addition to the rates and charges set forth in the above mentioned Rates, a fuel cost adjustment applicable for approximately three (3) months or until superseded by a subsequent factor shall be made in accordance with the following provisions:

A. The fuel cost adjustment shall be calculated by multiplying the KWH billed by an Adjustment Factor per KWH established according to the following formula:

$$\text{Adjustment Factor} = \frac{F}{S} - \$0.032938$$

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the month of June 2022 and consisting of the following costs:

    (a) The average cost of fossil and nuclear fuel consumed in the Company's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants including, as to fossil fuel, only those items listed in Account 151 and as to nuclear fuel only those items listed in Account 518 (except any expense for fossil fuel included in Account 151) of the Federal Energy Regulatory Commission's Uniform System of Accounts for Public Utilities and Licensees;

    (b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below;

    (c) The net energy cost, exclusive of capacity or demand charges, of energy purchased on an economic dispatch basis, and energy purchased as a result of a scheduled outage, when the costs thereof are less than the Company's fuel cost of replacement net generation from its own system at that time; less

    (d) The cost of fossil and nuclear fuel recovered through intersystem sales including fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

2. "S" is the estimated kilowatt-hour sales for the same estimated period set forth in "F", consisting of the net sum in kilowatt-hours of:

    (a) Net Generation,
    (b) Purchases and
    (c) Interchange-in, less
    (d) Inter-system Sales,
    (e) Energy Losses and Company Use.

STANDARD CONTRACT RIDER NO. 6 (Continued)

B. The Adjustment Factor as computed above shall be further modified to allow the recovery of Utility Receipts taxes and other similar revenue-based tax charges occasioned by the fuel adjustment revenues.

C. The Adjustment Factor may be further modified to reflect the difference between incremental fuel cost billed and the incremental fuel cost actually experienced during the months of November 2021 through January 2022.

D. The Adjustment Factor to be effective for all bills rendered for electric service beginning with the first billing cycles for June 2022 (Regular Billing District 41 and Special Billing Route 01) will be $0.013673 per KWH.

AES INDIANA
Determination of Fuel Cost Adjustment
Beginning with August 2022 Based on the Estimated
Three Months Average of June, July, and August 2022

Line No.	Description	(A)	(B)	(C)	(D)	(E) Estimated Three Month Average	Line No.
		Estimated Month of:					
	kWh Source (000's)	June	July	August	Total		
1	Coal and Oil Generation	637,289	857,258	836,652	2,331,199	777,066	1
2	Nuclear Generation	-	-	-	-	-	2
3	Hydro Generation	-	-	-	-	-	3
4	Other Generation - Internal Combustion	-	-	-	-	-	4
5	Gas Generation	605,096	719,440	683,319	2,007,855	669,285	5
	Purchases through MISO:						
6	Wind Purchase Power Agreement Purchases	48,142	37,263	40,692	126,097	42,032	6
7	Non-Wind PPA Market Purchases	52,391	14,912	17,294	84,597	28,199	7
8	Other	-	-	-	-	-	8
9	Purchased Power other than MISO	18,112	17,322	16,407	51,841	17,280	9
	LESS:						
10	Energy Losses and Company Use	55,780	63,786	61,069	180,635	60,212	10
11	Inter-System Sales through MISO	149,162	260,380	267,629	677,171	225,724	11
12	Inter-System Sales other than MISO	-	-	-	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	-	-	-	13
14	**Sales (S)**	1,156,088	1,322,029	1,265,666	3,743,783	1,247,926	14
	Fuel Cost ($)						
15	Coal and Oil Generation	16,871,101	20,961,184	19,662,899	57,495,184	19,165,061	15
16	Nuclear Generation	-	-	-	-	-	16
17	Hydro Generation	-	-	-	-	-	17
18	Other Generation - Internal Combustion	-	-	-	-	-	18
19	Gas Generation	21,421,883	27,389,521	25,405,189	74,216,593	24,738,864	19
	Purchases through MISO:						
20	Wind Purchase Power Agreement Purchases	4,940,837	3,831,018	3,499,511	12,271,366	4,090,455	20
21	Non-Wind PPA Market Purchases	2,392,839	626,766	658,357	3,677,962	1,225,987	21
22	Other	-	-	-	-	-	22
23	MISO Components of Cost of Fuel	1,765,347	2,018,739	1,932,675	5,716,761	1,905,587	23
24	Purchased Power other than MISO	3,010,839	2,819,645	2,728,627	8,559,111	2,853,037	24
	Less:						
25	Inter-System Sales through MISO	4,367,277	7,697,815	7,656,369	19,721,461	6,573,820	25
26	Inter-System Sales other than MISO	- -	-	-	-	-	26
27	Non-Jurisdictional Retail Sales	- -	-	-	-	-	27
28	Transmission Losses	487,424	562,813	521,402	1,571,639	523,880	28
29	Lakefield PPA Adjustment	242,955	279,703	230,564	753,222	251,074	29
30	**Total Fuel Cost (F)**	$ 45,305,190	$ 49,106,542	$ 45,478,923	$ 139,890,655	$ 46,630,217	30
31	**F ÷ S (Line 30 ÷ Line 14) (Mills/kWh)**					37.366	31
32	Reduction from Earnings Test				($282,364)		32
33	Reduction in Fuel Factor (Line 32 divided by estimated Indiana jurisdictional sales of		3,743,783	kWh (000's)	(Mills/kWh)	(0.075)	33
		Months to be Reconciled					
		November	December	January	Total		
34	Fuel Cost Variance	$ 36,943,851	$ 14,618,271	$ 12,764,694	$ 64,326,816		34
	(Mills/kWh)						
35	Fuel Cost Variance - FAC 133				$ 13,683,621		35
36	Fuel Cost Variance- FAC 133- 50% Collected				(6,841,811)		36
37	Fuel Cost Variance - FAC 134 (1)				32,281,690		37
38	Subtotal Variances				103,450,316		38
39	Estimated Eagle Valley Outage Impact				(35,168,380)		39
40	Estimated Non Outage Related Fuel Cost Variances not yet Collected				$ 68,281,936		40
41	TOTAL Fuel Cost Variance Included in this Filing- 50% (Mitigated by Collecting over FAC 135 and 136)					$ 34,140,968	41
42	Variance Charge (Line 32 Total divided by estimated Indiana jurisdictional sales of		3,743,783	kWh (000's)		9.119	42
43	Adjusted Fuel Cost Charge (Line 31 + Line 33)					46.410	43
44	Less: Base Cost of Fuel Included in Rates					32.938	44
45	Fuel Cost Charge					13.472	45
46	Fuel Cost Charge Adjusted for Indiana Utility Receipts Tax (2)					13.673	46

(1) As filed variances of $29,879,749 plus October tie line correction of $2,401,941
(2) Line 45 Divided By (1-(1.46% URT Rate/(1-0.04900)))

AES INDIANA
Determination of Net Energy Cost of Purchased Power
For the Estimated Months of June, July, and August 2022

Line No	Supplier	kWh Purchased (000's) (A)	Energy * (B)	Line No
	June			
	Purchases through MISO:			
1	Wind Purchase Power Agreement Purchases	48,142	$ 4,940,837	1
2	Non-Wind PPA Market Purchases	52,391	2,392,839	2
3	Other	-	-	3
4	MISO Components of Cost of Fuel	-	1,765,347	4
5	Purchased Power other than MISO	18,112	3,010,839	5
6	Total	118,645	$ 12,109,862	6
	July			
	Purchases through MISO:			
7	Wind Purchase Power Agreement Purchases	37,263	$ 3,831,018	7
8	Non-Wind PPA Market Purchases	14,912	626,766	8
9	Other	-	-	9
10	MISO Components of Cost of Fuel	-	2,018,739	10
11	Purchased Power other than MISO	17,322	2,819,645	11
12	Total	69,497	$ 9,296,168	12
	August			
	Purchases through MISO:			
13	Wind Purchase Power Agreement Purchases	40,692	$ 3,499,511	13
14	Non-Wind PPA Market Purchases	17,294	658,357	14
15	Other	-	-	15
16	MISO Components of Cost of Fuel	-	1,932,675	16
17	Purchased Power other than MISO	16,407	2,728,627	17
18	Total	74,393	$ 8,819,170	18
19	Total Net Energy Cost of Purchased Power	262,535	$ 30,225,200	19

* Demand Charges have not been estimated.

Cause No. 38703-FAC135

Applicant's Attachment NHC-1
Schedule 3
Page 1 of 1

AES INDIANA
Determination of Fuel Costs Recovered Through
Inter-System and Non-Jurisdictional Retail Sales by Month
For the Estimated Months of June, July, and August 2022

Line No.	Purchaser	kWh Sold (000's) (A)	Fuel Cost * (B)	Line No.
	June			
1	Inter-System Sales through MISO	149,162	$ 4,367,277	1
2	Inter-System Sales other than MISO	-	-	2
3	Non-Jurisdictional Retail Sales	-	-	3
4	Total	149,162	$ 4,367,277	4
	July			
5	Inter-System Sales through MISO	260,380	$ 7,697,815	5
6	Inter-System Sales other than MISO	-	-	6
7	Non-Jurisdictional Retail Sales	-	-	7
8	Total	260,380	$ 7,697,815	8
	August			
9	Inter-System Sales through MISO	267,629	$ 7,656,369	9
10	Inter-System Sales other than MISO	-	-	10
11	Non-Jurisdictional Retail Sales	-	-	11
12	Total	267,629	$ 7,656,369	12
13	Total Inter-System and Non-Jurisdictional Retail Sales	677,171	$ 19,721,461	13

* Demand Charges have not been estimated.

AES INDIANA
Reconciliation of Actual Incremental Cost of Fuel
Incurred to Applicable Incremental Retail Fuel Clause
Revenues for November, 2021

Line No.	Class of Customers	kWh Sales (In 000's) (A)	Base Cost of Fuel Included in Rates 32.938 Mills/kWh (B) (Col A * mills above)	Actual Cost of Fuel Incurred 72.563 Mills/kWh (C) (Col A * mills above)	Actual Incremental Cost of Fuel Incurred (D) (Col C - Col B)	Actual Incremental Cost of Fuel Billed Including Utility Receipts Tx (E)	Actual Incremental Cost of Fuel Billed Excluding Utility Receipts Tx [1] (F)	Fuel Cost [2] Variance From Cause No. 38703-FAC132 (G)	Incremental Fuel Clause Revenues to be Reconciled with Actual Incremental Cost of Fuel Incurred (H) (Col F - Col G)	Fuel Cost Variance (I) (Col D - Col H)	Line No.
1	Total Residential	327,224	$ 10,778,104	$ 23,744,356	$ 12,966,252	$ (10,374)	$ (10,222)				1
2	Total Commercial	118,722	3,910,465	8,614,824	4,704,359	(3,835)	(3,778)				2
3	Total Industrial	453,048	14,922,495	32,874,522	17,952,027	(16,819)	(16,571)				3
4	Total Electric Vehicle Public Charging Stations	3	99	218	119	(0)	-				4
5	Total Lighting	5,958	196,245	432,330	236,085	(127)	(125)				5
6	Total Other										6
7	Total Retail Sales Subject to FAC	904,955	$ 29,807,408	$ 65,666,250	$ 35,858,842	$ (31,155)	$ (30,696)	$ 1,054,313	$ (1,085,009)	$ 36,943,851	7
8	Total Retail Sales NOT Subject to FAC	-									8
9	Total Non-jurisdictional Retail Sales	-									9
10	Sales	904,955									10

(1) Column E Multiplied By (1-(1.4% URT Rate/(1-.05075)))

(2) Column G includes amortization of the prior period (over)/under collections of fuel costs and the NOI credit. FAC 132 included an NOI credit of -$3,330,787 and a fuel cost variance of $12,987,449

AES INDIANA
Reconciliation of Actual Incremental Cost of Fuel
Incurred to Applicable Incremental Retail Fuel Clause
Revenues for December, 2021

Line No.	Class of Customers	kWh Sales (In 000's) (A)	Base Cost of Fuel Included in Rates 32.938 Mills/kWh (B) (Col A * mills above)	Actual Cost of Fuel Incurred 47.423 Mills/kWh (C) (Col A * mills above)	Actual Incremental Cost of Fuel Incurred (D) (Col C - Col B)	Actual Incremental Cost of Fuel Billed Including Utility Receipts Tx (E)	Actual Incremental Cost of Fuel Billed Excluding Utility Receipts Tx [1] (F)	Fuel Cost [2] Variance From Cause No. 38703-FAC132/FAC133 (G)	Incremental Fuel Clause Revenues to be Reconciled with Actual Incremental Cost of Fuel Incurred (H) (Col F - Col G)	Fuel Cost Variance (I) (Col D - Col H)	Line No.
1	Total Residential	459,406	$ 15,131,915	$ 21,786,411	$ 6,654,496	$ 2,457,142	$ 2,420,903				1
2	Total Commercial	147,221	4,849,165	6,981,661	2,132,496	785,318	773,736				2
3	Total Industrial	475,724	15,669,397	22,560,259	6,890,862	2,399,891	2,364,496				3
4	Total Electric Vehicle Public Charging Stations	3	99	142	43	17	17				4
5	Total Lighting	6,380	210,144	302,559	92,415	38,637	38,067				5
6	Total Other										6
7	Total Retail Sales Subject to FAC	1,088,734	$ 35,860,720	$ 51,631,032	$ 15,770,312	$ 5,681,005	$ 5,597,219	$ 4,445,179	$ 1,152,041	$ 14,618,271	7
8	Total Retail Sales NOT Subject to FAC	$ -									8
9	Total Non-jurisdictional Retail Sales	-									9
10	Sales	1,088,734									10

(1) Column E Multiplied By (1-(1.4% URT Rate/(1-.05075)))

(2) Column G includes amortization of the prior period (over)/under collections of fuel costs. Includes FAC 132 fuel cost variance of $12,987,449 and FAC 133 fuel cost variance of $13,683,622.

AES INDIANA
Reconciliation of Actual Incremental Cost of Fuel
Incurred to Applicable Incremental Retail Fuel Clause
Revenues for January, 2022

Line No.	Class of Customers	kWh Sales (In 000's)	Base Cost of Fuel Included in Rates 32.938 Mills/kWh	Actual Cost of Fuel Incurred 45.097 Mills/kWh	Actual Incremental Cost of Fuel Incurred	Actual Incremental Cost of Fuel Billed Including Utility Receipts Tx	Actual Incremental Cost of Fuel Billed Excluding Utility Receipts Tx [1]	Fuel Cost [2] Variance From Cause No. 3703-FAC132/FAC1:	Incremental Fuel Clause Revenues to be Reconciled with Actual Incremental Cost of Fuel Incurred	Fuel Cost Variance	Line No.
		(A)	(B) (Col A * mills above)	(C) (Col A * mills above)	(D) (Col C - Col B)	(E)	(F)	(G)	(H) (Col F - Col G)	(I) (Col D - Col H)	
1	Total Residential	552,387	$ 18,194,523	$ 24,910,997	$ 6,716,474	$ 2,954,438	$ 2,909,081				1
2	Total Commercial	164,049	5,403,446	7,398,118	1,994,672	880,326	866,811				2
3	Total Industrial	491,612	16,192,716	22,170,226	5,977,510	2,673,200	2,632,160				3
4	Total Electric Vehicle Public Charging Stations	3	99	135	36	-	-				4
5	Total Lighting	6,238	205,467	281,315	75,848	37,549	36,973				5
6	Total Other										6
7	Total Retail Sales Subject to FAC	1,214,289	$ 39,996,251	$ 54,760,791	$ 14,764,540	$ 6,545,513	$ 6,445,025	$ 4,445,179	$ 1,999,847	$ 12,764,694	7
8	Total Retail Sales NOT Subject to FAC	-									8
9	Total Non-jurisdictional Retail Sales	-									9
10	Sales	1,214,289									10

(1) Column E Multiplied By (1-(1.46% URT Rate/(1-.049)))

(2) Column G includes amortization of the prior period (over)/under collections of fuel costs. Includes FAC 132 fuel cost variance of $12,987,449 and FAC 133 fuel cost variance of $13,683,622.

Cause No. 38703-FAC135

Applicant's Attachment NHC-1
Schedule 5
Page 1 of 4

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
Reconciliation November, 2021

Line No.	Description	November Actual	November Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	184,482	795,413	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	19	-	4
5	Gas Generation	382,977	378,968	5
	Purchases through MISO:			
6	Wind Purchase Power Agreement Purchases	59,790	72,753	6
7	Non-Wind PPA Market Purchases	427,674	80,527	7
8	Other	19	-	8
9	Purchased Power other than MISO	7,585	11,290	9
	LESS:			
10	Energy Losses and Company Use	52,802	53,512	10
11	Inter-System Sales through MISO	-	294,402	11
12	Inter-System Sales other than MISO	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	13
14	Sales (S)	1,009,744	991,037	14
	Fuel Cost			
15	Coal and Oil Generation	$ 4,974,914	$ 16,027,105	15
16	Nuclear Generation	-	-	16
17	Hydro Generation	-	-	17
18	Other Generation - Internal Combustion	2,954	-	18
19	Gas Generation	24,572,739	9,276,128	19
20	Financial Hedges Gains/Losses & Transactional Fees	-	-	20
	Purchases through MISO:			
21	Wind Purchase Power Agreement Purchases	7,929,986	7,927,735	21
22	Non-Wind PPA Market Purchases	27,481,782	1,908,695	22
23	Other	472	-	23
24	MISO Components of Cost of Fuel	7,081,450	1,246,724	24
25	Purchased Power other than MISO	1,225,785	1,863,671	25
	LESS:			
26	Inter-System Sales through MISO	-	5,925,787	26
27	Inter-System Sales other than MISO	-	-	27
28	Non-Jurisdictional Retail Sales	-	-	28
29	Transmission Losses	-	287,249	29
30	Lakefield PPA Adjustment	69	209,181	30
31	Purchased Power in Excess	-	-	31
32	Total Fuel Costs (F)	$ 73,270,013	$ 31,827,841	32
33	F / S (Mills/kWh)	72.563	32.116	33
	Weighted Average Deviation	-55.74%		

Cause No. 38703-FAC135

Applicant's Attachment NHC-1
Schedule 5
Page 2 of 4

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
Reconciliation December, 2021

Line No.	Description	December Actual	December Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	623,008	940,033	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	15	-	4
5	Gas Generation	211,212	449,911	5
	Purchases through MISO			
6	Wind Purchase Power Agreement Purchases	74,863	73,403	6
7	Non-Wind PPA Market Purchases	226,904	65,136	7
8	Other	14	-	8
9	Purchased Power other than MISO	6,768	5,287	9
	LESS:			
10	Energy Losses and Company Use	56,393	65,277	10
11	Inter-System Sales through MISO	10,527	259,559	11
12	Inter-System Sales other than MISO	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	13
14	Sales (S)	1,075,864	1,208,934	14
	Fuel Cost			
15	Coal and Oil Generation	$ 14,770,615	$ 19,377,649	15
16	Nuclear Generation	-	-	16
17	Hydro Generation	-	-	17
18	Other Generation - Internal Combustion	1,009	-	18
19	Gas Generation	15,481,539	15,790,027	19
20	Financial Hedges Gains/Losses & Transactional Fees	482,546	-	20
	Purchases through MISO			
21	Wind Purchase Power Agreement Purchases	7,483,356	8,101,072	21
22	Non-Wind PPA Market Purchases	9,524,139	1,851,402	22
23	Other	337	-	23
24	MISO Components of Cost of Fuel	2,546,715	1,496,660	24
25	Purchased Power other than MISO	1,112,262	875,857	25
	LESS:			
26	Inter-System Sales through MISO	331,296	6,268,405	26
27	Inter-System Sales other than MISO	-	-	27
28	Non-Jurisdictional Retail Sales	-	-	28
29	Transmission Losses	40,793	420,422	29
30	Lakefield PPA Adjustment	10,114	350,525	30
31	Purchased Power in Excess	-	-	31
32	Total Fuel Costs (F)	$ 51,020,315	$ 40,453,315	32
33	F / S (Mills/kWh)	47.423	33.462	33
	Weighted Average Deviation	-29.44%		

Cause No. 38703-FAC135

Applicant's Attachment NHC-1
Schedule 5
Page 3 of 4

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
Reconciliation January, 2022

Line No.	Description	January Actual	January Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	913,115	967,010	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	14	-	4
5	Gas Generation	273,678	593,865	5
	Purchases through MISO			
6	Wind Purchase Power Agreement Purchases	90,717	76,890	6
7	Non-Wind PPA Market Purchases	141,264	65,912	7
8	Other	280	-	8
9	Purchased I	7,292	5,894	9
	LESS:			
10	Energy Losses and Company Use	66,608	70,664	10
11	Inter-System Sales through MISO	44,636	330,195	11
12	Inter-System Sales other than MISO	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	13
14	Sales (S)	1,315,116	1,308,712	14
	Fuel Cost			
15	Coal and Oil Generation	$ 23,001,892	$ 20,157,249	15
16	Nuclear Generation	-	-	16
17	Hydro Generation	-	-	17
18	Other Generation - Internal Combustion	2,203	-	18
19	Gas Generation	20,227,469	22,604,674	19
20	Financial Hedges Gains/Losses & Transactional Fees	-	-	20
	Purchases through MISO			
21	Wind Purchase Power Agreement Purchases	8,162,108	7,923,164	21
22	Non-Wind PPA Market Purchases	7,659,290	3,075,250	22
23	Other	6,673	-	23
24	MISO Components of Cost of Fuel	1,516,613	1,620,185	24
25	Purchased Power other than MISO	1,086,815	1,004,936	25
	LESS:			
26	Inter-System Sales through MISO	1,875,771	8,657,771	26
27	Inter-System Sales other than MISO	-	-	27
28	Non-Jurisdictional Retail Sales	-	-	28
29	Transmission Losses	212,251	494,131	29
30	Lakefield PPA Adjustment	267,375	642,380	30
31	Purchased Power in Excess	-	-	31
32	Total Fuel Costs (F)	$ 59,307,666	$ 46,591,176	32
33	F / S (Mills/kWh)	45.097	35.601	33
	Weighted Average Deviation	-21.06%		

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
November, December 2021, and January 2022

Line No.	Description	Total Actual	Total Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	1,720,605	2,702,456	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	48	-	4
5	Gas Generation	867,867	1,422,744	5
	Purchases through MISO			
6	Wind Purchase Power Agreement Purchases	225,370	223,046	6
7	Non-Wind PPA Market Purchases	795,842	211,575	7
8	Other	313	-	8
9	Purchased Power other than MISO	21,645	22,471	9
	LESS:			
10	Energy Losses and Company Use	175,803	189,453	10
11	Inter-System Sales through MISO	55,163	884,156	11
12	Inter-System Sales other than MISO	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	13
14	Sales (S)	3,400,724	3,508,683	14
	Fuel Cost			
15	Coal and Oil Generation	$ 42,747,421	$ 55,562,003	15
16	Nuclear Generation	-	-	16
17	Hydro Generation	-	-	17
18	Other Generation - Internal Combustion	6,166	-	18
19	Gas Generation	60,281,747	47,670,829	19
20	Financial Hedges Gains/Losses & Transactional Fees	482,546	-	20
	Purchases through MISO			
21	Wind Purchase Power Agreement Purchases	23,575,450	23,951,971	21
22	Non-Wind PPA Market Purchases	44,665,211	6,835,347	22
23	Other	7,482	-	23
24	MISO Components of Cost of Fuel	11,144,778	4,363,569	24
25	Purchased Power other than MISO	3,424,862	3,744,464	25
	LESS:			
26	Inter-System Sales through MISO	2,207,067	20,851,963	26
27	Inter-System Sales other than MISO	-	-	27
28	Non-Jurisdictional Retail Sales	-	-	28
29	Transmission Losses	253,044	1,201,802	29
30	Lakefield PPA Adjustment	277,558	1,202,086	30
31	Purchased Power in Excess	-	-	31
32	Total Fuel Costs (F)	$ 183,597,994	$ 118,872,332	32
33	F / S (Mills/kWh)	53.988	33.879	33
	Weighted Average Deviation	-37.25%		

Cause No. 38703-FAC135

Applicant's Attachment NHC-1
Schedule 6
Page 1 of 1

AES INDIANA
Determination of MISO Components of Fuel Cost
November, December 2021, and January 2022

Line No.	Energy Market FAC Adjustment Components	Total November (A)	Total December (B)	Total January (C)	Line No.
1	Delta LMP[1]	$ 7,304,202	$ 2,957,873	$ 5,817,848	1
2	FTR (Revenue) / Expenses	660,058	(127,372)	(3,683,354)	2
3	RT Marg. Loss Surplus Credit	(843,785)	(444,694)	(804,405)	3
4	Virtuals Bids and Offers for Load	-	-	-	4
5	DA & RAC Recovery of Unit Commitment Costs	(253,839)	(49,895)	(106,434)	5
5a	RSG 1st Pass Charges	68,995	29,176	95,606	5a
5b	RSG 2nd Pass Distribution Correction	-	-	-	5b
6	Inadvertent Energy	(59,739)	23,638	(3,850)	6
7	Ancillary Services Revenue	(47,938)	(30,384)	(19,250)	7
8	Ancillary Services Costs	120,547	119,276	136,250	8
9	Ancillary Services Incentive to Follow Dispatch[2]	137,229	70,905	80,927	9
10	Ramp Capability[3]	(4,280)	(1,808)	3,275	10
11	Total (Columns A, B, & C to Schedule 5, line 24)	$ 7,081,450	$ 2,546,715	$ 1,516,613	11

Negative amount is a credit to expense (**payment from MISO**)
Positive amount is a debit to expense (**payment to MISO**)

[1]Differential of MCC and MLC between the load zone and generation pricing nodes
[2]Net of Contingency Reserve Deployment Failure Credit
[3]Ramp Capability Payments Net of Uplift

Cause No. 38703-FAC135

AES INDIANA
MISO Charges by Month by Charge Type

Line No.	Charge Type	Nov-21 Invoice Total	Dec-21 Invoice Total	Jan-22 Invoice Total	Line No.
1	Day Ahead Market Administration Amount	$ 148,918	$ 183,018	$ 216,761	1
2	Day Ahead Regulation Amount	(9,648)	(6,778)	(1,283)	2
3	Day Ahead Spinning Reserve Amount	(37,475)	(2,196)	(214)	3
4	Day-Ahead Short-Term Reserve Amount	-	(6,287)	(2,896)	
5	Day Ahead Supplemental Reserve Amount	-	-	-	5
6	Day Ahead Asset Energy Amount	28,292,539	10,302,693	6,734,382	6
7	Day Ahead Financial Bilateral Transaction Congestion Amount	-	-	-	7
8	Day Ahead Financial Bilateral Transaction Loss Amount	-	-	-	8
9	Day Ahead Congestion Rebate on Carve-Out Grandfathered Agrmnts	-	-	-	9
10	Day Ahead Losses Rebate on Carve-Out Grandfathered Agrmnts	-	-	-	10
11	Day Ahead Congestion Rebate on Option B Grandfathered Agrmnts	-	-	-	11
12	Day Ahead Losses Rebate on Option B Grandfathered Agrmnts	-	-	-	12
13	Day Ahead Non-Asset Energy Amount	-	-	-	13
14	Day Ahead Ramp Capability Amount	(11,938)	(5,263)	(2,391)	14
15	Day Ahead Revenue Sufficiency Guarantee Distribution Amount	64,595	30,814	50,760	15
16	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amt	(131,579)	(40,344)	(101,960)	16
17	Day Ahead Schedule 24 Allocation Amount	22,586	25,910	33,581	17
18	Day Ahead Virtual Energy Amount	-	-	-	18
	Day Ahead Subtotal	$ 28,337,998	$ 10,481,567	$ 6,926,740	
19	Financial Transmission Rights Market Administration Amount	$ 5,228	$ 7,453	$ 8,975	19
20	Auction Revenue Rights Transaction Amount	(231,072)	(264,066)	(264,066)	20
21	Financial Transmission Rights Annual Transaction Amount	189,043	229,027	229,027	21
22	Auction Revenue Rights Infeasible Uplift Amount	60,108	23,861	23,861	22
23	Auction Revenue Rights Stage 2 Distribution Amount	(146,019)	(110,708)	(110,708)	23
24	Financial Transmission Rights Full Funding Guarantee Amount	(15,826)	103,407	-	24
25	Financial Transmission Guarantee Uplift Amount	12,866	(128,357)	-	25
26	Financial Transmission Rights Hourly Allocation Amount	806,623	154,565	(3,521,487)	26
27	Financial Transmission Rights Monthly Allocation Amount	(15,665)	(31,694)	(39,981)	27
28	Financial Transmission Rights Monthly Transaction Amount	-	-	-	28
29	Financial Transmission Rights Transaction Amount	-	-	-	29
30	Financial Transmission Rights Yearly Allocation Amount	-	(103,407)	-	30
	Financial Transmission Rights Subtotal	$ 665,286	$ (119,919)	$ (3,674,379)	
31	Real Time Market Administration Amount	$ 18,296	$ 22,305	$ 25,347	31
32	Contingency Reserve Deployment Failure Charge Amount	21,124	-	-	32
33	Excessive Energy Amount	(28,447)	(19,948)	(15,372)	33
34	Real Time Excessive Deficient Energy Deployment Charge Amount	7,979	8,950	7,768	34
35	Net Regulation Adjustment Amount	-	-	-	35
36	Non-Excessive Energy Amount	3,397,244	1,400,811	4,556,831	36
37	Real Time Regulation Amount	(6,115)	10,495	(2,817)	37
38	Regulation Cost Distribution Amount	58,361	46,568	56,440	38
39	Real Time Spinning Reserve Amount	5,303	(12,444)	(593)	39
40	Spinning Reserve Cost Distribution Amount	54,924	39,436	35,674	40
41	Real Time Short-Term Reserve Amount	-	(12,547)	(11,447)	41
42	Real-Time Short-Term Reserve Deployment Failure Charge Amount	-	-	-	42
43	Short-Term Reserve Cost Distribution Amount	-	26,609	35,042	43
44	Real Time Supplemental Reserve Amount	(2)	(627)	-	44
45	Supplemental Reserve Cost Distribution Amount	7,262	6,664	9,093	45
46	Real Time Asset Energy Amount	3,257,478	510,698	(251,609)	46
47	Real Time Demand Response Allocation Uplift Charge	111,934	62,128	73,466	47
48	Real Time Financial Bilateral Transaction Congestion Amount	-	-	-	48
49	Real Time Financial Bilateral Transaction Loss Amount	-	-	-	49
50	Real Time Congestion Rebate on Carve-Out Grandfathered Agrmnts	-	-	-	50
51	Real Time Losses Rebate on Carve-Out Grandfathered Agrmnts	-	-	-	51
52	Real Time Distribution of Losses Amount	(843,785)	(444,694)	(804,405)	52
53	Real Time Miscellaneous Amount	2,857	(395)	9,161	53
54	Real Time MVP Distribution Amount	(3,055)	(6,501)	(6,977)	54
55	Real Time Non-Asset Energy Amount	-	-	-	55
56	Real Time Net Inadvertent Distribution Amount	(59,739)	23,638	(3,850)	56
57	Real Time Price Volatility Make Whole Payment	(132,831)	(133,499)	(319,348)	57
58	Real Time Resource Adequacy Auction Amount	(24,416)	(25,230)	(25,230)	58
59	Real Time Ramp Capability Amount	(3,911)	(4,551)	(2,071)	59
60	Real Time Revenue Neutrality Uplift Amount	1,138,444	209,478	212,313	60
61	Real Time Revenue Sufficiency Guarantee First Pass Dist Amount	67,651	31,393	109,089	61
62	Real Time Revenue Sufficiency Guarantee Make Whole Payment Amt	(187,684)	(46,442)	(73,505)	62
63	Real Time Schedule 24 Allocation Amount	2,780	3,160	3,923	63
64	Real Time Schedule 24 Distribution Amount	(63,425)	(65,202)	(72,769)	64
65	Real Time Schedule 49 Cost Distribution Amount	4,937	4,843	5,366	65
66	Real Time Virtual Energy Amount	-	-	-	66
	Real Time Subtotal	$ 6,803,164	$ 1,635,096	$ 3,549,520	
	Grand Total	$ 35,806,448	$ 11,996,744	$ 6,801,881	

CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the forgoing was served by hand delivery, electronic transmission or United States Mail, first class, postage prepaid on the Office of Utility Consumer Counselor, 115 W. Washington Street, Suite 1500 South, Indianapolis, Indiana 46204, (infomgt@oucc.in.gov) and a copy was served by hand delivery, electronic transmission or United States Mail, first class, postage prepaid, to Gregory T. Guerrettaz, Financial Solutions Group, Inc., 2680 East Main Street, Suite 223, Plainfield, Indiana 46168 (greg@fsgcorp.com).

In addition, a courtesy copy was provided by hand delivery, electronic transmission or United States Mail, first class, postage prepaid, to Anne Becker, Lewis & Kappes, One American Square, Suite 2500, Indianapolis, Indiana 46282, (abecker@lewis-kappes.com), and a courtesy copy to: ATyler@lewis-kappes.com and ETennant@Lewis-kappes.com.

Dated this 17th day of March, 2022.

Jeffrey M. Peabody

Teresa Morton Nyhart (No. 14044-49)
Jeffrey M. Peabody (No. 28000-53)
Barnes & Thornburg LLP
11 South Meridian Street
Indianapolis, Indiana 46204
Nyhart Telephone: (317) 231-7716
Peabody Telephone: (317) 231-6465
Facsimile: (317) 231-7433
Nyhart Email: tnyhart@btlaw.com
Peabody Email: jpeabody@btlaw.com

ATTORNEYS FOR APPLICANT
INDIANAPOLIS POWER & LIGHT COMPANY
D/B/A AES INDIANA

DMS 22231725v1

AES INDIANA
Statement of Jurisdictional Electric Operating Income for the Twelve Months Ended January 31, 2022
(In $000's except where otherwise stated)

Line No.	Description	Per Books For The Twelve Months Ended January 31, 2022: Total Electric For the Twelve Months Ended January 31, 2022	MISO Attachment GG	Applicable to Jurisdictional Retail Customers	Line No.
1	Operating Revenues	$ 1,452,350	$ 2,636	$ 1,449,714	1
2	Operating Expenses:				2
3	Operation and Maintenance Expenses	$ 882,293	$ 969	$ 881,324	3
4	Depreciation and Amortization	257,105	366	256,739	4
5	Taxes Other than Income Taxes:	45,305	74	45,231	5
6	Income Taxes:	39,366	307	39,059	6
7	Total Operating Expenses	$ 1,224,069	$ 1,716	$ 1,222,353	7
8	Operating Income	$ 228,281	$ 920	$ 227,361	8

(d)(2) Test (In $000's)
Summary of Increase in Operating Expenses Applicable to Jurisdictional Retail Customers
For the Twelve Months Ended January 31, 2022

		Per Cause Nos. 45029	Per Books January 31, 2022	Increase (Decrease)	
9	Total Operating Expenses	$ 1,193,106	$ 1,222,353	$ 29,247	9
10	Fuel Costs	436,216	432,388	(3,828)	10
11	Operating Expenses Excluding Fuel Costs	$ 756,890	$ 789,965	$ 33,075	11

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

12	Jurisdictional Retail Electric Operating Income (January 31, 2022)	$ 227,361,000	12
13	Total Authorized Operating Income [1]	226,529,000	13
14	Excess/(Deficiency)	$ 832,000	14

(1) Calculated on Applicant's Exhibit 3.

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

Line No.				Line No.
1	Operating Income per Cause No. 45029		$220,076,000	1
2	Effective February 2021			2
3	Allowed Return on CCT Utility Plant per Cause No. 42170-ECR33 (2)	1,483,145		3
4	Jurisdictional Portion	100.00%		4
5	Jurisdictional Total for Cause No. 42170-ECR33	1,483,145		5
6	Proration for Cause No. 42170-ECR33	28/365		6
7	Total for Cause No. 42170-ECR33		114,000	7
8	Effective for March 2021 - January 2022			8
9	Allowed Return on CCT Utility Plant per Cause No. 42170-ECR34 (2)	1,541,335		9
10	Jurisdictional Portion	100.00%		10
11	Jurisdictional Total for Cause No. 42170-ECR34	1,541,335		11
12	Proration for Cause No. 42170-ECR34	337/365		12
13	Total for Cause No. 42170-ECR34		1,423,000	13
14	Effective for February 2021 - October 2021			14
15	Allowed Return on TDISC-1 Distribution Utility Plant per Cause No. 45264-TDSIC-1 (2)	2,551,960		15
16	Jurisdictional Portion	100.00%		16
17	Jurisdictional Total for Cause No. 45264-TDSIC-1	2,551,960		17
18	Proration for Cause No.45264-TDSIC-1	273/365		18
19	Total for Cause No. 45264-TDSIC-1		1,909,000	19
20	Effective for February 2021 - October 2021			20
21	Allowed Return on TDISC-1 - Transmission Utility Plant per Cause No. 45264-TDSIC-1 (2)	530,592		21
22	Jurisdictional Portion	100.00%		22
23	Jurisdictional Total for Cause No. 45264-TDSIC-1	530,592		23
24	Proration for Cause No.45264-TDSIC-1	273/365		24
25	Total for Cause No. 45264-TDSIC-1		397,000	25
26	Effective for November 2021 - January 2022			26
27	Allowed Return on TDISC-3 Distribution Utility Plant per Cause No. 45264-TDSIC-3 (2)	8,370,218		27
28	Jurisdictional Portion	100.00%		28
29	Jurisdictional Total for Cause No. 45264-TDSIC-3	8,370,218		29
30	Proration for Cause No.45264-TDSIC-3	92/365		30
31	Total for Cause No. 45264-TDSIC-3		2,110,000	31
32	Effective for November 2021 - January 2022			32
33	Allowed Return on TDISC-3 - Transmission Utility Plant per Cause No. 45264-TDSIC-3 (2)	1,982,306		33
34	Jurisdictional Portion	100.00%		34
35	Jurisdictional Total for Cause No. 45264-TDSIC-3	1,982,306		35
36	Proration for Cause No.45264-TDSIC-3	92/365		36
37	Total for Cause No. 45264-TDSIC-3		500,000	37
26	Total Authorized Operating Income		$226,529,000	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
135	1/31/2022	$227,361,000	$226,529,000	$832,000
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
116	4/30/2017	183,962,000	165,030,000	18,932,000
				$275,608,218

AES INDIANA
Operating Income Earnings Test
Calculated Refund
Period Ending January 31, 2022

Line No.	FAC Period	FAC No.	Determined	Authorized	Differential
1	January 31, 2022	135	$227,361,000	$226,529,000	$832,000
2	Accumulated Earnings Bank Differential				$275,608,218
3	Over-Earnings Basis				$832,000
4	Quarterly Convention				25%
5	Quarterly Amount - Basis for Revenue Credits (Show as Negative Value)				($208,000)
6	Revenue Conversion Factor				1.357520
7	Revenue Credit Amount				($282,364)

Revenue Conversion Factor

8	Calculated Rate of Return from page 3 of this exhibit	6.65%
9	Gross Rate for Borrowed Funds (1)	2.20%
10	Gross Rate for Other Funds (Line 8 - Line 9)	4.45%
11	Debt and Equity Revenue Conversion Factors	

	For Debt & Expense		For Equity	
	Statutory Rate	Effective Rate	Statutory Rate	Effective Rate
11a Utility Receipts Tax	1.4600%	1.4548%	1.4000%	1.3950%
11b Public Utility Fee	0.12761%	0.1276%	0.1276%	0.1276%
11c Uncollectibles	0.3562%	0.3562%	0.3562%	0.3562%
11d State Income Tax	4.9000%	0.0750%	4.9000%	4.8763%
11e Federal Income Tax	21.0000%	0.0000%	21.0000%	19.5814%
11f Effective Rate		2.0136%		26.3365%
11g Complement (1-Line 8f)		97.9864%		73.6635%
11h Revenue Conversion Factor for Debt & Expense		1.02055		
11i Revenue Conversion Factor for Equity				1.35752

12	Revenue Conversion Factor for Capital [((Line 9 x Line 11h) + (Line 10 x Line 11i))/Line 8]	1.24604

AES INDIANA
Determination of Fuel Cost Adjustment
Beginning with August 2022 Based on the Estimated
Three Months Average of June, July, and August 2022

Line No.	Description	(A) Estimated Month of: June	(B) Estimated Month of: July	(C) Estimated Month of: August	(D) Total	(E) Estimated Three Month Average	Line No.
	kWh Source (000's)						
1	Coal and Oil Generation	637,289	857,258	836,652	2,331,199	777,066	1
2	Nuclear Generation	-	-	-	-	-	2
3	Hydro Generation	-	-	-	-	-	3
4	Other Generation - Internal Combustion	-	-	-	-	-	4
5	Gas Generation	605,096	719,440	683,319	2,007,855	669,285	5
	Purchases through MISO:						
6	Wind Purchase Power Agreement Purchases	48,142	37,263	40,692	126,097	42,032	6
7	Non-Wind PPA Market Purchases	52,391	14,912	17,294	84,597	28,199	7
8	Other	-	-	-	-	-	8
9	Purchased Power other than MISO	18,112	17,322	16,407	51,841	17,280	9
	LESS:						
10	Energy Losses and Company Use	55,780	63,786	61,069	180,635	60,212	10
11	Inter-System Sales through MISO	149,162	260,380	267,629	677,171	225,724	11
12	Inter-System Sales other than MISO	-	-	-	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	-	-	-	13
14	**Sales (S)**	1,156,088	1,322,029	1,265,666	3,743,783	1,247,926	14
	Fuel Cost ($)						
15	Coal and Oil Generation	16,871,101	20,961,184	19,662,899	57,495,184	19,165,061	15
16	Nuclear Generation	-	-	-	-	-	16
17	Hydro Generation	-	-	-	-	-	17
18	Other Generation - Internal Combustion	-	-	-	-	-	18
19	Gas Generation	21,421,883	27,389,521	25,405,189	74,216,593	24,738,864	19
	Purchases through MISO:						
20	Wind Purchase Power Agreement Purchases	4,940,837	3,831,018	3,499,511	12,271,366	4,090,455	20
21	Non-Wind PPA Market Purchases	2,392,839	626,766	658,357	3,677,962	1,225,987	21
22	Other	-	-	-	-	-	22
23	MISO Components of Cost of Fuel	1,765,347	2,018,739	1,932,675	5,716,761	1,905,587	23
24	Purchased Power other than MISO	3,010,839	2,819,645	2,728,627	8,559,111	2,853,037	24
	Less:						
25	Inter-System Sales through MISO	4,367,277	7,697,815	7,656,369	19,721,461	6,573,820	25
26	Inter-System Sales other than MISO	- -	-	-	-	-	26
27	Non-Jurisdictional Retail Sales	- -	-	-	-	-	27
28	Transmission Losses	487,424	562,813	521,402	1,571,639	523,880	28
29	Lakefield PPA Adjustment	242,955	279,703	230,564	753,222	251,074	29
30	Total Fuel Cost (F)	$ 45,305,190	$ 49,106,542	$ 45,478,923	$ 139,890,655	$ 46,630,217	30
31	**F ÷ S (Line 30 ÷ Line 14) (Mills/kWh)**					37.366	31
32	Reduction from Earnings Test				($282,364)		32
33	Reduction in Fuel Factor (Line 32 divided by estimated Indiana jurisdictional sales of		3,743,783	kWh (000's)	(Mills/kWh)	(0.075)	33
		Months to be Reconciled					
		November	December	January	Total		
34	Fuel Cost Variance	$ 36,943,851	$ 14,618,271	$ 12,764,694	$ 64,326,816		34
	(Mills/kWh)						
35	Variance Charge (Line 32 Total divided by estimated Indiana jurisdictional sales of		3,743,783	kWh (000's)		17.182	35
36	Adjusted Fuel Cost Charge (Line 31 + Line 33)					54.473	36
37	Less: Base Cost of Fuel Included in Rates					32.938	37
38	Fuel Cost Charge					21.535	38
39	Fuel Cost Charge Adjusted for Indiana Utility Receipts Tax (1)					21.857	39

(1) Line 38 Divided By (1-(1.46% URT Rate/(1-0.04900)))

Cause No. 38703-FAC134

Applicant's Attachment NHC-1
Schedule 1R
Page 1 of 1

AES INDIANA
Determination of Fuel Cost Adjustment
Beginning with January 2022 Based on the Estimated
Three Months Average of March, April, and May 2022

Line No.	Description	(A) Estimated Month of: March	(B) April	(C) May	(D) Total	(E) Estimated Three Month Average	Line No.
	kWh Source (000's)						
1	Coal and Oil Generation	960,436	717,336	522,016	2,199,788	733,263	1
2	Nuclear Generation	-	-	-	-	-	2
3	Hydro Generation	-	-	-	-	-	3
4	Other Generation - Internal Combustion	-	-	-	-	-	4
5	Gas Generation	159,355	39,709	128,616	327,680	109,227	5
	Purchases through MISO:						
6	Wind Purchase Power Agreement Purchases	68,912	77,609	52,277	198,798	66,266	6
7	Non-Wind PPA Market Purchases	20,500	163,842	324,885	509,227	169,742	7
8	Other	-	-	-	-	-	8
9	Purchased Power other than MISO	13,006	15,039	16,599	44,644	14,881	9
	LESS:						
10	Energy Losses and Company Use	50,263	45,015	37,985	133,263	44,421	10
11	Inter-System Sales through MISO	130,228	35,550	22,093	187,871	62,624	11
12	Inter-System Sales other than MISO	-	-	-	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	-	-	-	13
14	Sales (S)	1,041,718	932,970	984,315	2,959,003	986,334	14
	Fuel Cost ($)						
15	Coal and Oil Generation	24,025,668	18,072,077	13,573,056	55,670,801	18,556,934	15
16	Nuclear Generation	-	-	-	-	-	16
17	Hydro Generation	-	-	-	-	-	17
18	Other Generation - Internal Combustion	-	-	-	-	-	18
19	Gas Generation	7,809,344	2,875,955	6,180,580	16,865,879	5,621,960	19
	Purchases through MISO:						
20	Wind Purchase Power Agreement Purchases	7,139,181	7,227,936	6,131,197	20,498,314	6,832,771	20
21	Non-Wind PPA Market Purchases	1,405,535	6,752,569	13,014,281	21,172,385	7,057,462	21
22	Other	-	-	-	-	-	22
23	MISO Components of Cost of Fuel	1,615,706	1,447,038	1,526,673	4,589,417	1,529,806	23
24	Purchased Power other than MISO	1,970,588	2,324,347	2,692,015	6,986,950	2,328,983	24
	Less:						
25	Inter-System Sales through MISO	3,521,536	915,377	607,991	5,044,904	1,681,635	25
26	Inter-System Sales other than MISO	-	-	-	-	-	26
27	Non-Jurisdictional Retail Sales	-	-	-	-	-	27
28	Transmission Losses	405,641	345,928	128,430	879,999	293,333	28
29	Lakefield PPA Adjustment	138,590	4,294	163,537	306,421	102,140	29
30	Total Fuel Cost (F)	$ 39,900,255	$ 37,434,323	$ 42,217,844	$ 119,552,422	$ 39,850,808	30
31	F ÷ S (Line 30 ÷ Line 14) (Mills/kWh)					40.403	31
32	Reduction from Earnings Test				($475,344)		32
33	Reduction in Fuel Factor (Line 32 divided by estimated Indiana jurisdictional sales of		2,959,003	kWh (000's)	(Mills/kWh)	(0.161)	33

Line No.	Description	Months to be Reconciled: August	September	October	Total		Line No.
34	Fuel Cost Variance	$ 5,414,616	$ 7,581,706	$ 19,285,369	$ 32,281,690		34
35	Fuel Cost Variance - FAC 133 - 50% Variance				$ 6,841,811		35
36	Subtotal Variances				$ 39,123,501		36
37	Fuel Cost Variances not Included in Interim Rate				$ (39,123,501)		37
38	TOTAL Fuel Cost Variance Included in this Filing					$ -	38

Line No.	Description						Line No.
	(Mills/kWh)						
39	Variance Charge (Line 38 Total divided by estimated Indiana jurisdictional sales of		2,959,003	kWh (000's)		-	39
40	Adjusted Fuel Cost Charge (Line 31 + Line 33 + Line 39)					40.242	40
41	Less: Base Cost of Fuel Included in Rates					32.938	41
42	Fuel Cost Charge					7.304	42
43	Fuel Cost Charge Adjusted for Indiana Utility Receipts Tax (1)					7.418	43

AES INDIANA
Reconciliation of Actual Incremental Cost of Fuel
Incurred to Applicable Incremental Retail Fuel Clause
Revenues for October, 2021

Line No.	Class of Customers	kWh Sales (In 000's) (A)	Base Cost of Fuel Included in Rates 32.938 Mills/kWh (B) (Col A * mills above)	Actual Cost of Fuel Incurred 51.165 Mills/kWh (C) (Col A * mills above)	Actual Incremental Cost of Fuel Incurred (D) (Col C - Col B)	Actual Incremental Cost of Fuel Billed Including Utility Receipts Tx (E)	Actual Incremental Cost of Fuel Billed Excluding Utility Receipts Tx [1] (F)	Fuel Cost [2] Variance From Cause No. 38703-FAC132 (G)	Incremental Fuel Clause Revenues to be Reconciled with Actual Incremental Cost of Fuel Incurred (H) (Col F - Col G)	Fuel Cost Variance (I) (Col D - Col H)	Line No.
1	Total Residential	342,828	$ 11,292,069	$ 17,540,795	$ 6,248,726	$ (12,438)	$ (12,255)				1
2	Total Commercial	133,391	4,393,633	6,824,951	2,431,318	(4,817)	(4,746)				2
3	Total Industrial	516,412	17,009,578	26,422,220	9,412,642	(17,938)	(17,673)				3
4	Total Electric Vehicle Public Charging Stations	3	99	153	54	-	-				4
5	Total Lighting	5,679	187,055	290,566	103,511	(133)	(131)				5
6	Total Other										6
7	Total Retail Sales Subject to FAC	998,313	$ 32,882,434	$ 51,078,685	$ 18,196,251	$ (35,326)	$ (34,805)	$ 1,054,313	$ (1,089,118)	$ 19,285,369	7
8	Total Retail Sales NOT Subject to FAC	-									8
9	Total Non-jurisdictional Retail Sales	-									9
10	Sales	998,313									10
11	Original Variance									$ 16,883,428	11
12	Difference									$ 2,401,941	12

(1) Column E Multiplied By (1-(1.4% URT Rate/(1-.05075)))

(2) Column G includes amortization of the prior period (over)/under collections of fuel costs and the NOI credit. FAC 132 included an NOI credit of -$3,330,787 and a fuel cost variance of $12,987,449 which is being recovered over two FAC periods per the Order for FAC 132.

Cause No. 38703-FAC134

Applicant's Attachment NHC-1
Schedule 5R
Page 3 of 4

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
Reconciliation October, 2021

Line No.	Description	October Actual	October Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	500,538	766,255	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	2	-	4
5	Gas Generation	207,310	377,350	5
	Purchases through MISO			
6	Wind Purchase Power Agreement Purchases	38,539	65,445	6
7	Non-Wind PPA Market Purchases	256,097	59,345	7
8	Other	92	-	8
9	Purchased I	10,410	12,855	9
	LESS:			
10	Energy Losses and Company Use	49,249	53,167	10
11	Inter-System Sales through MISO	25,537	243,428	11
12	Inter-System Sales other than MISO	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	13
14	Sales (S)	938,202	984,655	14
	Fuel Cost			
15	Coal and Oil Generation	$ 10,865,067	$ 15,464,635	15
16	Nuclear Generation	-	-	16
17	Hydro Generation	-	-	17
18	Other Generation - Internal Combustion	203	-	18
19	Gas Generation	13,977,551	8,568,668	19
20	Financial Hedges Gains/Losses & Transactional Fees	(1,601,046)	-	20
	Purchases through MISO			
21	Wind Purchase Power Agreement Purchases	4,953,401	6,807,508	21
22	Non-Wind PPA Market Purchases	15,160,506	1,305,644	22
23	Other	714	-	23
24	MISO Components of Cost of Fuel	3,923,619	1,238,696	24
25	Purchased Power other than MISO	1,703,176	2,165,444	25
	LESS:			
26	Inter-System Sales through MISO	899,652	4,763,076	26
27	Inter-System Sales other than MISO	-	-	27
28	Non-Jurisdictional Retail Sales	-	-	28
29	Transmission Losses	31,103	277,436	29
30	Lakefield PPA Adjustment	49,015	190,877	30
31	Purchased Power in Excess	-	-	31
32	Total Fuel Costs (F)	$ 48,003,421	$ 30,319,206	32
33	F / S (Mills/kWh)	51.165	30.792	33
	Weighted Average Deviation	-39.82%		

Cause No. 38703-FAC134

Applicant's Attachment NHC-1
Schedule 6R
Page 1 of 1

AES INDIANA
Determination of MISO Components of Fuel Cost
August, September, and October 2021

Line No.	Energy Market FAC Adjustment Components	Total August (A)	Total September (B)	Total October (C)	Line No.
1	Delta LMP[1]	$ 2,749,567	$ 2,967,497	$ 3,715,409	1
2	FTR (Revenue) / Expenses	(1,008,355)	(958,666)	196,237	2
3	RT Marg. Loss Surplus Credit	(741,015)	(590,974)	(499,480)	3
4	Virtuals Bids and Offers for Load	-	-	-	4
5	DA & RAC Recovery of Unit Commitment Costs	(140,571)	(54,310)	(149,574)	5
5a	RSG 1st Pass Charges	127,720	96,705	312,040	5a
5b	RSG 2nd Pass Distribution Correction	-	-	-	5b
6	Inadvertent Energy	12,756	(14,017)	(25,086)	6
7	Ancillary Services Revenue	(13,710)	(21,305)	(6,684)	7
8	Ancillary Services Costs	139,299	122,035	154,008	8
9	Ancillary Services Incentive to Follow Dispatch[2]	66,315	91,157	222,675	9
10	Ramp Capability[3]	2,271	(454)	4,074	10
11	Total (Columns A, B, & C to Schedule 5, line 24)	$ 1,194,277	$ 1,637,668	$ 3,923,619	11

Negative amount is a credit to expense (**payment from MISO**)
Positive amount is a debit to expense (**payment to MISO**)

[1]Differential of MCC and MLC between the load zone and generation pricing nodes
[2]Net of Contingency Reserve Deployment Failure Credit
[3]Ramp Capability Payments Net of Uplift