FILED
September 13, 2024
INDIANA UTILITY
REGULATORY COMMISSION

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 DECEMBER 2024 THROUGH FEBRUARY 2025, IN ACCORDANCE WITH THE PROVISIONS OF I.C. 8-1-2-42, CONTINUED USE OF RATEMAKING TREATMENT FOR COSTS OF WIND POWER PURCHASES PURSUANT TO CAUSE NOS. 43485 AND 43740, AND APPROVAL OF A FUEL HEDGING PLAN AND AUTHORITY TO RECOVER COSTS OF THE FUEL HEDGING PLAN PURSUANT TO I.C. 8-1-2-42.	)	**CAUSE NO. 38703 FAC 145**

VERIFIED APPLICATION

TO THE INDIANA UTILITY REGULATORY COMMISSION:

INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA (hereinafter called "Applicant" 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 December 2024 through February 2025 (the “Forecast Period”).

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 Forecast Period. The Company’s filing also reflects a true-up of fuel-related MISO costs and revenues for the period of May 2024 through July 2024 (the “Historical Period”). As discussed further in the Company’s testimony, the Company is including costs pursuant to the Settlement Agreement approved in Cause No. 38703 FAC 133S1. As also discussed further in the Company’s testimony, the Company has included costs for contract for differences (“CFD”) and credits for cash disbursements received from the Hardy Hills solar project. 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 no reduction in the fuel cost factor applied for is necessary because the Applicant did not earn more than the authorized level for the twelve months ending July 31, 2024; 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 Alexander Dickerson, Applicant continues to follow the guidelines and procedures established in Cause No. 43414. The Purchased Power Daily Benchmarks for the Historical Period are set forth in Attachment AD-1.

6. Applying the Purchased Power Daily Benchmarks set forth above to individual power purchase transactions included in this proceeding shows $1,096,458 of purchased power costs in excess of the applicable Purchased Power Daily Benchmarks incurred in the Historical Period, of which $29,741 is not recoverable. Applicant is therefore requesting recovery of $1,066,718 in purchased power costs. A summary of the purchased power volumes, costs, the total of hourly purchased power costs above the applicable Purchased Power Daily Benchmarks for the Historical Period and the reasons for the purchases at-risk after consideration of MISO economic dispatch, is set forth in Attachment AD-2.

7. Consistent with the Commission's Orders in Cause No. 43740, Applicant continues to apply ratemaking treatment to recover the purchased power costs incurred under the Lakefield Wind Park purchase power agreement.

8. As discussed in greater detail in AES Indiana's case-in-chief, AES Indiana is proposing an updated fuel hedging plan to safeguard customers against the price volatility associated with the fuel markets. More specifically, this policy takes a more holistic evaluation of hedging, as compared to the existing policy, focusing on managing power pricing for customers. This includes the incorporation of coal, natural gas, and power to focus on the portfolio of assets for AES Indiana rather than specific units or plants. The updated policy combines the hedges utilized for coal, natural gas, and power to achieve a target hedge percentage of AES Indiana's forecasted retail load. The fuel hedging plan is an appropriate risk management tool that allows AES Indiana to mitigate exposure to coal and natural gas supply risk.

9. AES Indiana seeks approval of the updated fuel hedging plan. Consistent with current practice, the Company seeks approval from the Commission to continue to be able to pass all hedging gains and losses, including any associated transactional costs, through AES Indiana's FAC. Specific transactions shall be subject to review based upon an analysis of the facts and circumstances as they existed at the time the transactions at issue were entered into, and upon a finding that the transactions were reasonable, the transactional costs and associated gains and losses will be recoverable through the FAC.

10. 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.

11. Applicant's average cost of fuel for the Forecast Period, after taking into consideration its estimated and actual fuel costs for the Historical Period, is estimated to be $0.037734 for the proposed factor.

12. As more fully illustrated on Schedule 1, taking into account the projected fuel costs and fuel variance, the resulting fuel factor is $(0.001293). This factor would represent a decrease from the basic rates otherwise anticipated to be applicable during the billing cycles for the months of December 2024 through February 2025.

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

14. 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 (Atty. No. 14044-49)
Jeffrey M. Peabody (Atty. No. 28000-53)
Taft Stettinius & Hollister LLP
One Indiana Square, Suite 3500
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15. Applicant requests that the Commission approve the following 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**
October 18, 2024	OUCC/Intervenors File Case-in-Chief
October 25, 2024	Petitioner's Rebuttal Testimony
Week of November 11, 2024	Hearing
November 27, 2024	Order

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 December 2024 (Regular Billing District 41 and Special Billing District 01), which begins November 27, 2024. 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) approve the proposed Tariff attached hereto as Attachment NHC-1-A;

(iii) approve AES Indiana's updated fuel hedging plan and AES Indiana's ongoing recovery of costs, gains, or losses, including any associated transactional costs, associated with the hedging plans through the fuel adjustment clause in accordance with the review of the reasonableness of the transaction(s) as described in Applicant's testimony; and

(iv) grant to Applicant all other appropriate relief.

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

Chad A. Rogers
Director, Regulatory Affairs

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Attorneys for Indianapolis Power & Light Company
d/b/a AES Indiana

Verification

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

Dated this 13th day of September, 2024.

Natalie Herr Coklow

Natalie Herr Coklow

Attachment NHC-1-A

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:

$$\text{Adjustment Factor} = \frac{F}{S} - \$0.039027$$

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the month of ~~September~~ December 2024 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 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 ~~February~~ May 2024 through ~~April~~ July 2024.

D. The Adjustment Factor to be effective for all bills rendered for electric service beginning with the first billing cycles for ~~September~~ December 2024 (Regular Billing District 41 and Special Billing Route 01) will be $~~(0.007725)~~(0.001293) per KWH.

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:

$$\text{Adjustment Factor} = \frac{F}{S} - \$0.039027$$

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the month of December 2024 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 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 May 2024 through July 2024.

D. The Adjustment Factor to be effective for all bills rendered for electric service beginning with the first billing cycles for December 2024 (Regular Billing District 41 and Special Billing Route 01) will be $(0.001293) per KWH.

AES INDIANA
Determination of Fuel Cost Adjustment
Beginning with December 2024 Based on the Estimated
Three Months Average of December 2024, January and February 2025

Line No.	Description	(A) December	(B) January	(C) February	(D) Total	(E) Estimated Three Month Average	Line No.
		Estimated Month of:					
	kWh Source (000's)						
1	Coal and Oil Generation	669,994	693,631	617,088	1,980,713	660,238	1
2	Nuclear Generation	-	-	-	-	-	2
3	Hydro Generation	-	-	-	-	-	3
4	Other Generation - Internal Combustion	-	-	-	-	-	4
5	Gas Generation	851,006	1,091,617	830,954	2,773,577	924,526	5
6	Wind Generation	29,842	21,616	24,132	75,590	25,197	6
	Purchases through MISO:						
7	Wind Purchase Power Agreement Purchases	51,536	50,067	47,636	149,239	49,746	7
8	Non-Wind PPA Market Purchases	1,466	-	5,768	7,234	2,411	8
9	Other	-	-	-	-	-	9
10	Purchased Power other than MISO	6,354	4,879	7,458	18,691	6,230	10
	LESS:						
11	Energy Losses and Company Use	53,946	59,476	53,241	166,663	55,554	11
12	Inter-System Sales through MISO	393,733	520,656	332,470	1,246,859	415,620	12
13	Inter-System Sales other than MISO	-	-	-	-	-	13
14	Non-Jurisdictional Retail Sales	-	-	-	-	-	14
15	**Sales (S)**	1,162,519	1,281,678	1,147,325	3,591,522	1,197,174	15
	Fuel Cost ($)						
16	Coal and Oil Generation	18,536,115	17,145,461	15,072,572	50,754,148	16,918,049	16
17	Nuclear Generation	-	-	-	-	-	17
18	Hydro Generation	-	-	-	-	-	18
19	Other Generation - Internal Combustion	-	-	-	-	-	19
20	Gas Generation	27,791,554	39,453,603	28,935,113	96,180,270	32,060,090	20
	Purchases through MISO:						
21	Wind Purchase Power Agreement Purchases	5,122,257	4,805,667	4,951,318	14,879,242	4,959,747	21
22	Non-Wind PPA Market Purchases	99,887	-	261,153	361,040	120,347	22
23	Other	-	-	-	-	-	23
24	MISO Components of Cost of Fuel	1,555,449	1,714,884	1,535,119	4,805,452	1,601,817	24
25	Purchased Power other than MISO	1,043,070	776,180	1,182,840	3,002,090	1,000,697	25
	Less:						
26	Inter-System Sales through MISO	10,234,478	15,203,636	9,122,156	34,560,270	11,520,090	26
27	Inter-System Sales other than MISO	-	-	-	-	-	27
28	Non-Jurisdictional Retail Sales	-	-	-	-	-	28
29	Transmission Losses	435,137	538,937	453,307	1,427,381	475,794	29
30	Lakefield PPA Adjustment	-	-	-	-	-	30
31	**Total Fuel Cost (F)**	$ 43,478,717	$ 48,153,222	$ 42,362,652	$ 133,994,591	$ 44,664,863	31
32	**F ÷ S (Line 31 ÷ Line 15) (Mills/kWh)**					37.309	32
		Months to be Reconciled					
		May	June	July	Total		
33	Fuel Cost Variance (includes Joint Venture CfD and Cash Receipts)	$ (1,161,878)	$ 2,663,710	$ (2,538,593)	$ (1,036,761)		33
34	FAC 133 S1 Settlement Costs to Recovered over 24 Months(1)				2,564,810		34
35	Total Fuel Cost Variance and Adjustments Included in this Filing					$ 1,528,049	35
	(Mills/kWh)						
36	Variance Charge (Line 35 Total divided by estimated Indiana jurisdictional sales of		3,591,522 kWh (000's)			0.425	36
37	Adjusted Fuel Cost Charge (Line 32 + Line 36)					37.734	37
38	Less: Base Cost of Fuel Included in Rates					39.027	38
39	Fuel Cost Charge					(1.293)	39

(1) Per the Order in Cause No. 38703 FAC 133 S1, $20,518,476 of previously deferred costs are to be collected over 24 months beginning with the first FAC filing after issuance of a final Order which is FAC 139 with rates begininning in June 2023. In addition, the approved settlement agreement included a one-time credit of $6,800,000 to offset costs in the first FAC filing after the issuance of a final Order.

AES INDIANA
Determination of Net Energy Cost of Purchased Power
For the Estimated Months of December 2024, January and February 2025

Line No	Supplier	kWh Purchased (000's) (A)	Energy * (B)	Line No
	December			
	Purchases through MISO:			
1	Wind Purchase Power Agreement Purchases	51,536	$ 5,122,257	1
2	Non-Wind PPA Market Purchases	1,466	99,887	2
3	Other	-	-	3
4	MISO Components of Cost of Fuel	-	1,555,449	4
5	Purchased Power other than MISO	6,354	1,043,070	5
6	Total	59,356	$ 7,820,663	6
	January			
	Purchases through MISO:			
7	Wind Purchase Power Agreement Purchases	50,067	$ 4,805,667	7
8	Non-Wind PPA Market Purchases	-	-	8
9	Other	-	-	9
10	MISO Components of Cost of Fuel	-	1,714,884	10
11	Purchased Power other than MISO	4,879	776,180	11
12	Total	54,946	$ 7,296,731	12
	February			
	Purchases through MISO:			
13	Wind Purchase Power Agreement Purchases	47,636	$ 4,951,318	13
14	Non-Wind PPA Market Purchases	5,768	261,153	14
15	Other	-	-	15
16	MISO Components of Cost of Fuel	-	1,535,119	16
17	Purchased Power other than MISO	7,458	1,182,840	17
18	Total	60,862	$ 7,930,430	18
19	Total Net Energy Cost of Purchased Power	175,164	$ 23,047,824	19

* Demand Charges have not been estimated.

AES INDIANA
Determination of Fuel Costs Recovered Through
Inter-System and Non-Jurisdictional Retail Sales by Month
For the Estimated Months of December 2024, January and February 2025

Line No.	Purchaser	kWh Sold (000's)	Fuel Cost *	Line No.
		(A)	(B)	
	December			
1	Inter-System Sales through MISO	393,733	$ 10,234,478	1
2	Inter-System Sales other than MISO	-	-	2
3	Non-Jurisdictional Retail Sales	-	-	3
4	Total	393,733	$ 10,234,478	4
	January			
5	Inter-System Sales through MISO	520,656	$ 15,203,636	5
6	Inter-System Sales other than MISO	-	-	6
7	Non-Jurisdictional Retail Sales	-	-	7
8	Total	520,656	$ 15,203,636	8
	February			
9	Inter-System Sales through MISO	332,470	$ 9,122,156	9
10	Inter-System Sales other than MISO	-	-	10
11	Non-Jurisdictional Retail Sales	-	-	11
12	Total	332,470	$ 9,122,156	12
13	Total Inter-System and Non-Jurisdictional Retail Sales	1,246,859	$ 34,560,270	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 May 2024

Billed Rates Approved in Cause No. 45029

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 35.018 Mills/kWh (C) (Col A * mills above)	Actual Incremental Cost of Fuel Incurred (D) (Col C - Col B)	Line No.
1	Total Residential	244,951	$ 8,068,196	$ 8,577,693	$ 509,497	1
2	Total Commercial	97,213	3,202,002	3,404,205	202,203	2
3	Total Industrial	369,590	12,173,555	12,942,303	768,748	3
4	Total Electric Vehicle Public Charging Stations	5	165	175	10	4
5	Total Lighting	5,801	191,073	203,139	12,066	5
6	Total Other					6
7	Total Retail Sales Subject to FAC	717,560	$ 23,634,991	$ 25,127,515	$ 1,492,524	7

Billed Rates Approved in Cause No. 45911

Line No.	Class of Customers	kWh Sales (In 000's) (E)	Base Cost of Fuel Included in Rates 39.027 Mills/kWh (F) (Col A * mills above)	Actual Cost of Fuel Incurred 35.018 Mills/kWh (G) (Col A * mills above)	Actual Incremental Cost of Fuel Incurred (H) (Col C - Col B)	Actual Incremental Cost of Fuel Incurred Total (I)	Actual Incremental Cost of Fuel Billed (J)	Fuel Cost [(1)] Variance From Cause No. 38703-FAC142 (K)	Fuel Clause Revenues to be Reconciled with Actual Incremental Cost of Fuel Incurred (L) (Col E - Col F)	Fuel Cost Variance (M) (Col D - Col G)	Line No.
8	Total Residential	91,647	$ 3,576,707	$ 3,209,296	$ (367,411)	$ 142,086	$ 485,950				8
9	Total Commercial	36,372	1,419,490	1,273,675	(145,815)	56,388	215,799				9
10	Total Industrial	138,279	5,396,615	4,842,254	(554,361)	214,387	797,725				10
11	Total Electric Vehicle Public Charging Stations	2	78	70	(8)	2	22				11
12	Total Lighting	2,170	84,689	75,989	(8,700)	3,366	(123)				12
13	Total Other										13
14	Total Retail Sales Subject to FAC	268,470	$ 10,477,579	$ 9,401,284	$ (1,076,295)	$ 416,229	$ 1,499,373	$ (491,801)	$ 1,991,174	$ (1,574,945)	14
15	Total Retail Sales NOT Subject to FAC	-									15
16	Total Non-jurisdictional Retail Sales	-									16
17	Sales	986,030									17
18	Hardy Hills Contract for Differences (CfD)									710,567	18
19	Hardy Hills Cash Receipts									(297,500)	19
20	Fuel Cost Variance with CfD and Receipts									$ (1,161,878)	20

(1) Column F includes amortization of the prior period (over)/under collections of fuel costs. FAC 142 ($1,475,404), or ($491,801) per month.

Cause No. 38703-FAC145

AES INDIANA
Reconciliation of Actual Incremental Cost of Fuel
Incurred to Applicable Incremental Retail Fuel Clause
Revenues for June 2024

Billed Rates Approved in Cause No. 45029

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 34.187 Mills/kWh (C) (Col A * mills above)	Actual Incremental Cost of Fuel Incurred (D) (Col C - Col B)
1	Total Residential	28,395	$ 935,275	$ 970,742	$ 35,467
2	Total Commercial	10,392	342,292	355,271	12,979
3	Total Industrial	26,087	859,254	891,836	32,582
4	Total Electric Vehicle Public Charging Stations	1	33	34	1
5	Total Lighting	678	22,332	23,179	847
6	Total Other				
7	Total Retail Sales Subject to FAC	65,553	$ 2,159,186	$ 2,241,062	$ 81,876

Billed Rates Approved in Cause No. 45911

Line No.	Class of Customers	kWh Sales (In 000's) (E)	Base Cost of Fuel Included in Rates 39.027 Mills/kWh (F) (Col A * mills above)	Actual Cost of Fuel Incurred 34.187 Mills/kWh (G) (Col A * mills above)	Actual Incremental Cost of Fuel Incurred (H) (Col C - Col B)	Actual Incremental Cost of Fuel Incurred Total (I)	Actual Incremental Cost of Fuel Billed (J)	Fuel Cost (1) Variance From Cause No. 38703-FAC143 (K)
8	Total Residential	349,980	$ 13,658,669	$ 11,964,766	$ (1,693,903)	$ (1,658,436)	$ (1,104,799)	
9	Total Commercial	128,088	4,998,890	4,378,944	(619,946)	(606,967)	(388,998)	

AES INDIANA
Reconciliation of Actual Incremental Cost of Fuel
Incurred to Applicable Incremental Retail Fuel Clause
Revenues for July 2024

Line No.	Class of Customers	kWh Sales (In 000's) (A)	Base Cost of Fuel Included in Rates 39.027 Mills/kWh (B) (Col A * mills above)	Actual Cost of Fuel Incurred 30.728 Mills/kWh (C) (Col A * mills above)	Actual Incremental Cost of Fuel Incurred (D) (Col C - Col B)	Actual Incremental Cost of Fuel Billed (E)	Fuel Cost [1] Variance From Cause No. 38703-FAC143 (F)	Incremental Fuel Clause Revenues to be Reconciled with Actual Incremental Cost of Fuel Incurred (G) (Col E - Col F)	Fuel Cost Variance (H) (Col D - Col G)	Line No.
1	Total Residential	456,551	$ 17,817,817	$ 14,028,899	$ (3,788,918)	$ (1,563,414)				1
2	Total Commercial	155,417	6,065,459	4,775,654	(1,289,805)	(521,652)				2
3	Total Industrial	725,383	28,309,522	22,289,569	(6,019,953)	(2,444,713)				3
4	Total Electric Vehicle Public Charging Stations	7	273	215	(58)	(26)				4
5	Total Lighting	3,814	148,849	117,197	(31,652)	(12,951)				5
6	Total Other									6
7	Total Retail Sales Subject to FAC	1,341,172	$ 52,341,920	$ 41,211,534	$ (11,130,386)	$ (4,542,756)	$ 4,382,663	$ (8,925,419)	$ (2,204,967)	7
8	Total Retail Sales NOT Subject to FAC	-								8
9	Total Non-jurisdictional Retail Sales	-								9
10	Sales	1,341,172								10
11	Hardy Hills Contract for Differences (CfD)								541,374	11
12	Hardy Hills Cash Receipts								(875,000)	12
13	Fuel Cost Variance with CfD and Receipts								$ (2,538,593)	13

(1) Column F includes amortization of the prior period (over)/under collections of fuel costs. FAC 143 $13,147,990, or $4,382,663 per month.

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
Reconciliation May 2024

Line No.	Description	May Actual	May Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	185,148	297,209	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	10	-	4
5	Gas Generation	839,030	867,618	5
6	Wind Generation	17,621	-	6
	Purchases through MISO:			
7	Wind Purchase Power Agreement Purchases	29,602	61,804	7
8	Non-Wind PPA Market Purchases	39,022	34,475	8
9	Other	636	-	9
10	Purchased Power other than MISO	14,909	14,264	10
	LESS:			
11	Energy Losses and Company Use	46,463	46,525	11
12	Inter-System Sales through MISO	82,133	226,260	12
13	Inter-System Sales other than MISO	-	-	13
14	Non-Jurisdictional Retail Sales	-	-	14
15	Sales (S)	997,382	1,002,586	15
	Fuel Cost			
16	Coal and Oil Generation	$ 8,269,265	$ 8,890,221	16
17	Nuclear Generation	-	-	17
18	Hydro Generation	-	-	18
19	Other Generation - Internal Combustion	2,891	-	19
20	Gas Generation	18,977,593	24,077,898	20
21	Financial Hedges Gains/Losses & Transactional Fees	-	-	21
	Purchases through MISO:			
22	Wind Purchase Power Agreement Purchases	4,238,316	4,264,349	22
23	Non-Wind PPA Market Purchases	1,459,216	1,316,274	23
24	Other	32,414	-	24
25	MISO Components of Cost of Fuel	1,578,184	1,352,488	25
26	Purchased Power other than MISO	2,194,791	2,315,420	26
	LESS:			
27	Inter-System Sales through MISO	1,627,487	5,622,033	27
28	Inter-System Sales other than MISO	-	-	28
29	Non-Jurisdictional Retail Sales	-	-	29
30	Transmission Losses	183,415	358,732	30
31	Lakefield PPA Adjustment	11,826	132,999	31
32	Purchased Power in Excess	4,011	-	32
33	Total Fuel Costs (F)	$ 34,925,931	$ 36,102,886	33
34	F / S (Mills/kWh)	35.018	36.010	34
	Weighted Average Deviation	2.83%		

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
Reconciliation June 2024

Line No.	Description	June Actual	June Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	233,298	204,142	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	9	-	4
5	Gas Generation	746,433	956,833	5
6	Wind Generation	22,646	15,364	6
	Purchases through MISO			
7	Wind Purchase Power Agreement Purchases	29,472	32,474	7
8	Non-Wind PPA Market Purchases	143,851	64,849	8
9	Other	448	-	9
10	Purchased Power other than MISO	15,131	17,338	10
	LESS:			
11	Energy Losses and Company Use	51,963	54,507	11
12	Inter-System Sales through MISO	18,431	61,912	12
13	Inter-System Sales other than MISO	-	-	13
14	Non-Jurisdictional Retail Sales	-	-	14
15	Sales (S)	1,120,894	1,174,582	15
	Fuel Cost			
16	Coal and Oil Generation	$ 10,269,808	$ 6,581,755	16
17	Nuclear Generation	-	-	17
18	Hydro Generation	-	-	18
19	Other Generation - Internal Combustion	4,243	-	19
20	Gas Generation	17,650,515	22,996,912	20
21	Financial Hedges Gains/Losses & Transactional Fees	-	-	21
	Purchases through MISO			
22	Wind Purchase Power Agreement Purchases	3,800,898	3,501,450	22
23	Non-Wind PPA Market Purchases	4,374,832	2,518,289	23
24	Other	25,831	-	24
25	MISO Components of Cost of Fuel	129,658	853,922	25
26	Purchased Power other than MISO	2,534,986	2,947,310	26
	LESS:			
27	Inter-System Sales through MISO	381,542	1,349,796	27
28	Inter-System Sales other than MISO	-	-	28
29	Non-Jurisdictional Retail Sales	-	-	29
30	Transmission Losses	77,112	368,759	30
31	Lakefield PPA Adjustment	-	-	31
32	Purchased Power in Excess	12,637	-	32
33	Total Fuel Costs (F)	$ 38,319,480	$ 37,681,083	33
34	F / S (Mills/kWh)	34.187	32.080	34
	Weighted Average Deviation	-6.16%		

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
Reconciliation July 2024

Line No.	Description	July Actual	July Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	176,602	551,236	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	10	-	4
5	Gas Generation	999,222	1,074,187	5
6	Wind Generation	9,891	7,291	
	Purchases through MISO			
7	Wind Purchase Power Agreement Purchases	22,045	26,250	7
8	Non-Wind PPA Market Purchases	70,662	2,243	8
9	Other	755	-	9
10	Purchased Power other than MISO	13,459	17,231	10
	LESS:			
11	Energy Losses and Company Use	55,007	62,588	11
12	Inter-System Sales through MISO	46,506	267,121	12
13	Inter-System Sales other than MISO	-	-	13
14	Non-Jurisdictional Retail Sales	-	-	14
15	Sales (S)	1,191,133	1,348,730	15
	Fuel Cost			
16	Coal and Oil Generation	$ 8,280,905	$ 15,983,683	16
17	Nuclear Generation	-	-	17
18	Hydro Generation	-	-	18
19	Other Generation - Internal Combustion	3,212	-	19
20	Gas Generation	22,601,699	27,605,680	20
21	Financial Hedges Gains/Losses & Transactional Fees	-	-	21
	Purchases through MISO			
22	Wind Purchase Power Agreement Purchases	2,087,914	2,389,210	22
23	Non-Wind PPA Market Purchases	2,139,221	342,849	23
24	Other	80,746	-	24
25	MISO Components of Cost of Fuel	252,649	980,527	25
26	Purchased Power other than MISO	2,267,274	2,847,430	26
	LESS:			
27	Inter-System Sales through MISO	939,228	6,475,852	27
28	Inter-System Sales other than MISO	-	-	28
29	Non-Jurisdictional Retail Sales	-	-	29
30	Transmission Losses	$159,969.00	470,844	30
31	Lakefield PPA Adjustment	-	-	31
32	Purchased Power in Excess	13,093	-	32
33	Total Fuel Costs (F)	$ 36,601,330	$ 43,202,684	33
34	F / S (Mills/kWh)	30.728	32.032	34
	Weighted Average Deviation	4.24%		

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
May, June and July, 2024

Line No.	Description	Total Actual	Total Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	595,048	1,052,587	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	29	-	4
5	Gas Generation	2,584,685	2,898,639	5
6	Wind Generation	50,158	22,656	
	Purchases through MISO			
7	Wind Purchase Power Agreement Purchases	81,119	120,528	7
8	Non-Wind PPA Market Purchases	253,535	101,566	8
9	Other	1,839	-	9
10	Purchased Power other than MISO	43,499	48,834	10
	LESS:			
11	Energy Losses and Company Use	153,433	163,619	11
12	Inter-System Sales through MISO	147,070	555,292	12
13	Inter-System Sales other than MISO	-	-	13
14	Non-Jurisdictional Retail Sales	-	-	14
15	Sales (S)	3,309,409	3,525,898	15
	Fuel Cost			
16	Coal and Oil Generation	$ 26,819,978	$ 31,455,658	16
17	Nuclear Generation	-	-	17
18	Hydro Generation	-	-	18
19	Other Generation - Internal Combustion	10,346	-	19
20	Gas Generation	59,229,807	74,680,490	20
21	Financial Hedges Gains/Losses & Transactional Fees	-	-	21
	Purchases through MISO			
22	Wind Purchase Power Agreement Purchases	10,127,128	10,155,009	22
23	Non-Wind PPA Market Purchases	7,973,269	4,177,413	23
24	Other	138,991	-	24
25	MISO Components of Cost of Fuel	1,960,491	3,186,936	25
26	Purchased Power other than MISO	6,997,051	8,110,160	26
	LESS:			
27	Inter-System Sales through MISO	2,948,257	13,447,681	27
28	Inter-System Sales other than MISO	-	-	28
29	Non-Jurisdictional Retail Sales	-	-	29
30	Transmission Losses	420,496	1,198,334	30
31	Lakefield PPA Adjustment	11,826	132,999	31
32	Purchased Power in Excess	29,741	-	32
33	Total Fuel Costs (F)	$ 109,846,741	$ 116,986,653	33
34	F / S (Mills/kWh)	33.192	33.179	34
	Weighted Average Deviation	-0.04%		

AES INDIANA
Determination of MISO Components of Fuel Cost
May, June and July, 2024

Line No.	**Energy Market FAC Adjustment Components**	Total May **(A)**	Total June **(B)**	Total July **(C)**	Line No.
1	Delta LMP[1]	$ 2,333,432	$ 946,928	$ 801,383	1
2	FTR (Revenue) / Expenses	(723,778)	(526,626)	(324,290)	2
3	RT Marg. Loss Surplus Credit	(102,611)	(332,921)	(303,705)	3
4	Virtuals Bids and Offers for Load	-	-	-	4
5	DA & RAC Recovery of Unit Commitment Costs	(15,514)	(34,812)	(9,092)	5
5a	RSG 1st Pass Charges	8,721	5,598	23,609	5a
5b	RSG 2nd Pass Distribution Correction	-	-	-	5b
6	Inadvertent Energy	9,623	(9,040)	(32,589)	6
7	Ancillary Services Revenue	(50,573)	(44,204)	(164,476)	7
8	Ancillary Services Costs	132,304	122,973	224,120	8
9	Ancillary Services Incentive to Follow Dispatch[2]	3,062	1,872	31,199	9
10	Ramp Capability[3]	(16,482)	(110)	6,490	10
11	MISO Transmission Owner's Payment not on Settlement Statement - credit to FAC.	-	-	-	11
12	Total (Columns A, B, & C to Schedule 5, line 24)	$ 1,578,184	$ 129,658	$ 252,649	12

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

AES INDIANA
MISO Charges by Month by Charge Type

Line No.	Charge Type	May-24 Invoice Total	Jun-24 Invoice Total	Jul-24 Invoice Total	Line No.
1	Day Ahead Market Administration Amount	$ 194,665	$ 184,207	$ 202,498	1
2	Day Ahead Regulation Amount	-	-	-	2
3	Day Ahead Spinning Reserve Amount	(28,240)	(17,084)	(15,741)	3
4	Day-Ahead Short-Term Reserve Amount	-	-	(280)	4
5	Day Ahead Supplemental Reserve Amount	(37,308)	(17,264)	(64,651)	5
6	Day Ahead Asset Energy Amount	654,264	1,980,329	(2,013,469)	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	(34,798)	(17,152)	(12,442)	14
15	Day Ahead Revenue Sufficiency Guarantee Distribution Amount	18,692	17,009	24,793	15
16	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amt	(32,758)	(50,071)	(32,457)	16
17	Day Ahead Schedule 24 Allocation Amount	28,355	30,467	30,489	17
18	Day Ahead Virtual Energy Amount	-	-	-	18
	Day Ahead Subtotal	$ 762,872	$ 2,110,441	$ (1,881,260)	
19	Financial Transmission Rights Market Administration Amount	$ 2,501	$ 3,374	$ 5,507	19
20	Auction Revenue Rights Transaction Amount	(366,347)	(551,526)	(551,526)	20
21	Financial Transmission Rights Annual Transaction Amount	196,655	368,840	368,840	21
22	Auction Revenue Rights Infeasible Uplift Amount	39,453	6,014	6,014	22
23	Auction Revenue Rights Stage 2 Distribution Amount	(245,617)	(233,289)	(233,289)	23
24	Financial Transmission Rights Full Funding Guarantee Amount	(87,219)	(1)	-	24
25	Financial Transmission Guarantee Uplift Amount	75,548	5	-	25
26	Financial Transmission Rights Hourly Allocation Amount	(324,761)	(112,854)	86,413	26
27	Financial Transmission Rights Monthly Allocation Amount	(11,490)	(3,816)	(742)	27
28	Financial Transmission Rights Monthly Transaction Amount	-	-	-	28
29	Financial Transmission Rights Transaction Amount	-	-	-	29
30	Financial Transmission Rights Yearly Allocation Amount	-	-	-	30
	Financial Transmission Rights Subtotal	$ (721,277)	$ (523,253)	$ (318,783)	
31	Real Time Market Administration Amount	$ 24,654	$ 21,598	$ 19,193	31
32	Contingency Reserve Deployment Failure Charge Amount	-	-	-	32
33	Excessive Energy Amount	-	-	-	33
34	Real Time Excessive Deficient Energy Deployment Charge Amount	(7,166)	(5,026)	(7,443)	34
35	Net Regulation Adjustment Amount	2,967	2,018	31,214	35
36	Non-Excessive Energy Amount	95	-	-	36
37	Real Time Regulation Amount	1,033,710	4,219,802	3,401,193	37
38	Regulation Cost Distribution Amount	(7,526)	(1,501)	(2,434)	38
39	Real Time Spinning Reserve Amount	43,466	51,792	60,157	39
40	Spinning Reserve Cost Distribution Amount	5,199	(4,751)	(35,995)	40
41	Real Time Short-Term Reserve Amount	54,614	42,925	45,026	41
42	Real-Time Short-Term Reserve Deployment Failure Charge Amount	-	(145)	(3,572)	42
43	Short-Term Reserve Cost Distribution Amount	5,556	4,207	21,965	43
44	Real Time Supplemental Reserve Amount	17,303	(3,460)	(41,803)	44
45	Supplemental Reserve Cost Distribution Amount	28,668	24,050	96,973	45
46	Real Time Asset Energy Amount	492,267	(1,018,475)	42,530	46
47	Real Time Demand Response Allocation Uplift Charge	-	4	874	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	(102,611)	(332,921)	(303,705)	52
53	Real Time Miscellaneous Amount	4,447	2,003	(2,676)	53
54	Real Time MVP Distribution Amount	(60,954)	(12,397)	(12,287)	54
55	Real Time Non-Asset Energy Amount	-	-	-	55
56	Real Time Net Inadvertent Distribution Amount	9,623	(9,040)	(32,589)	56
57	Real Time Price Volatility Make Whole Payment	(436,460)	(455,369)	(245,552)	57
58	Real Time Resource Adequacy Auction Amount	108,283	25,200	6,689	58
59	Real Time Ramp Capability Amount	(3,985)	(788)	(4,289)	59
60	Real Time Revenue Neutrality Uplift Amount	214,527	362,350	440,994	60
61	Real Time Revenue Sufficiency Guarantee First Pass Dist Amount	10,784	6,436	28,883	61
62	Real Time Revenue Sufficiency Guarantee Make Whole Payment Amt	(1,682)	(1,906)	(2,611)	62
63	Real-Time Storage as Transmission Only Asset Amount	-	-	-	63
64	Real Time Schedule 24 Allocation Amount	3,591	3,573	2,890	64
65	Real Time Schedule 24 Distribution Amount	(63,143)	(63,466)	(61,601)	65
66	Real Time Schedule 49 Cost Distribution Amount	54,838	56,080	57,825	66
67	Real Time Virtual Energy Amount	-	-	-	67
	Real Time Subtotal	$ 1,431,065	$ 2,912,793	$ 3,499,849	
	Grand Total	$ 1,472,660	$ 4,499,981	$ 1,299,806	

CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the forgoing was served by electronic transmission 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 electronic transmission 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 electronic transmission 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 13th day of September, 2024.

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