STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA FOR APPROVAL OF A FUEL COST FACTOR FOR ELECTRIC SERVICE DURING THE BILLING MONTHS OF SEPTEMBER 2025 THROUGH NOVEMBER 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 NO. 43740, AND CONTINUED RECOVERY OF THE COSTS OF THE FUEL HEDGING PLAN PURSUANT TO I.C. 8-1-2-42.	)	**CAUSE NO. 38703 FAC 148**

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 September 2025 through November 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 February 2025 through April 2025 (the "Historical Period"). As 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 joint venture renewable projects. 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 sum of Applicant's differentials for the relevant period is less than zero; 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 $239,894 of purchased power costs in excess of the applicable Purchased Power Daily Benchmarks incurred in the Historical Period, of which $8,172 is not recoverable. Applicant is therefore requesting recovery of $231,721 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 Order 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. 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. 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 $0.042929 for the proposed factor.

10. As more fully illustrated on Schedule 1, taking into account the projected fuel costs and fuel variance, the resulting fuel factor is $0.003902. This factor would represent an increase from the basic rates otherwise anticipated to be applicable during the billing cycles for the months of September 2025 through November 2025.

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

12. 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)
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13. 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
July 21, 2025	OUCC/Intervenors File Case-in-Chief
July 31, 2025	Petitioner's Rebuttal Testimony
Week of August 11, 2025	Hearing
August 27, 2025	Order

14. 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 September 2025 (Regular Billing District 41 and Special Billing District 01), which begins August 29, 2025. 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 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 16th day of June, 2025.

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 ~~June~~ September 2025 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 ~~November 2024 through January 2025~~February 2025 through April 2025.

D. The Adjustment Factor to be effective for all bills rendered for electric service beginning with the first billing cycles for ~~June~~ September 2025 (Regular Billing District 41 and Special Billing Route 01) will be $~~0.001223~~0.003902 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:

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where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the month of September 2025 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 2025 through April 2025.

D. The Adjustment Factor to be effective for all bills rendered for electric service beginning with the first billing cycles for September 2025 (Regular Billing District 41 and Special Billing Route 01) will be $0.003902 per KWH.

AES INDIANA
Determination of Fuel Cost Adjustment
Beginning with September 2025 Based on the Estimated
Three Months Average of September, October and November 2025

Line No.	Description	(A) Estimated Month of: September	(B) Estimated Month of: October	(C) Estimated Month of: November	(D) Total	(E) Estimated Three Month Average	Line No.
	kWh Source (000's)						
1	Coal and Oil Generation	548,612	611,974	616,154	1,776,740	592,247	1
2	Nuclear Generation	-	-	-	-	-	2
3	Hydro Generation	-	-	-	-	-	3
4	Other Generation - Internal Combustion	-	-	-	-	-	4
5	Gas Generation	716,373	760,201	578,849	2,055,423	685,141	5
6	Wind Generation	14,006	20,552	24,912	59,470	19,823	6
	Purchases through MISO:						
7	Wind Purchase Power Agreement Purchases	37,359	41,563	46,740	125,663	41,888	7
8	Non-Wind PPA Market Purchases	76,309	6,126	37,586	120,020	40,007	8
9	Other	-	-	-	-	-	9
10	Purchased Power other than MISO	14,894	12,384	12,056	39,334	13,111	10
	LESS:						
11	Energy Losses and Company Use	45,494	40,561	44,508	130,562	43,521	11
12	Inter-System Sales through MISO	286,941	453,688	219,971	960,600	320,200	12
13	Inter-System Sales other than MISO	-	-	-	-	-	13
14	Non-Jurisdictional Retail Sales	-	-	-	-	-	14
15	**Sales (S)**	1,075,118	958,551	1,051,819	3,085,488	1,028,496	15
	Fuel Cost ($)						
16	Coal and Oil Generation	14,063,591	15,401,587	15,388,361	44,853,539	14,951,180	16
17	Nuclear Generation	-	-	-	-	-	17
18	Hydro Generation	-	-	-	-	-	18
19	Other Generation - Internal Combustion	-	-	-	-	-	19
20	Gas Generation	25,009,236	26,310,183	22,495,330	73,814,749	24,604,916	20
	Purchases through MISO:						
21	Wind Purchase Power Agreement Purchases	3,945,769	4,994,757	5,513,702	14,454,229	4,818,076	21
22	Non-Wind PPA Market Purchases	2,085,060	185,987	1,234,783	3,505,831	1,168,610	22
23	Other	-	-	-	-	-	23
24	MISO Components of Cost of Fuel	1,270,790	1,133,007	1,243,250	3,647,047	1,215,682	24
25	Purchased Power other than MISO	2,422,710	2,001,450	1,924,930	6,349,090	2,116,363	25
	Less:						
26	Inter-System Sales through MISO	7,840,522	12,082,340	5,969,474	25,892,336	8,630,779	26
27	Inter-System Sales other than MISO	-	-	-	-	-	27
28	Non-Jurisdictional Retail Sales	-	-	-	-	-	28
29	Transmission Losses	423,029	367,597	411,031	1,201,657	400,552	29
30	Lakefield PPA Adjustment	-	-	-	-	-	30
31	**Total Fuel Cost (F)**	$ 40,533,606	$ 37,577,035	$ 41,419,851	$ 119,530,492	$ 39,843,496	31
32	**F ÷ S (Line 31 ÷ Line 15) (Mills/kWh)**					38.740	32

Line No.	Description	Months to be Reconciled: February	Months to be Reconciled: March	Months to be Reconciled: April	Total		Line No.
33	Fuel Cost Variance (includes Joint Venture CfD and Cash Receipts)	$ 5,376,583	$ 4,298,094	$ 3,249,792	$ 12,924,469		33
34	Total Fuel Cost Variance and Adjustments Included in this Filing					$ 12,924,469	34
	(Mills/kWh)						
35	Variance Charge (Line 34 Total divided by estimated Indiana jurisdictional sales of		3,085,488 kWh (000's)			4.189	35
36	Adjusted Fuel Cost Charge (Line 32 + Line 35)					42.929	36
37	Less: Base Cost of Fuel Included in Rates					39.027	37
38	Fuel Cost Charge					3.902	38

AES INDIANA
Determination of Net Energy Cost of Purchased Power
For the Estimated Months of September, October and November 2025

Line No	Supplier	kWh Purchased (000's) (A)	Energy * (B)	Line No
	September			
	Purchases through MISO:			
1	Wind Purchase Power Agreement Purchases	37,359	$ 3,945,769	1
2	Non-Wind PPA Market Purchases	76,309	2,085,060	2
3	Other	-	-	3
4	MISO Components of Cost of Fuel	-	1,270,790	4
5	Purchased Power other than MISO	14,894	2,422,710	5
6	Total	128,562	$ 9,724,329	6
	October			
	Purchases through MISO:			
7	Wind Purchase Power Agreement Purchases	41,563	$ 4,994,757	7
8	Non-Wind PPA Market Purchases	6,126	185,987	8
9	Other	-	-	9
10	MISO Components of Cost of Fuel	-	1,133,007	10
11	Purchased Power other than MISO	12,384	2,001,450	11
12	Total	60,073	$ 8,315,202	12
	November			
	Purchases through MISO:			
13	Wind Purchase Power Agreement Purchases	46,740	$ 5,513,702	13
14	Non-Wind PPA Market Purchases	37,586	1,234,783	14
15	Other	-	-	15
16	MISO Components of Cost of Fuel	-	1,243,250	16
17	Purchased Power other than MISO	12,056	1,924,930	17
18	Total	96,382	$ 9,916,665	18
19	Total Net Energy Cost of Purchased Power	285,017	$ 27,956,196	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 September, October and November 2025

Line No.	Purchaser	kWh Sold (000's)	Fuel Cost *	Line No.
		(A)	(B)	
	September			
1	Inter-System Sales through MISO	286,941	$ 7,840,522	1
2	Inter-System Sales other than MISO	-	-	2
3	Non-Jurisdictional Retail Sales	-	-	3
4	Total	286,941	$ 7,840,522	4
	October			
5	Inter-System Sales through MISO	453,688	$ 12,082,340	5
6	Inter-System Sales other than MISO	-	-	6
7	Non-Jurisdictional Retail Sales	-	-	7
8	Total	453,688	$ 12,082,340	8
	November			
9	Inter-System Sales through MISO	219,971	$ 5,969,474	9
10	Inter-System Sales other than MISO	-	-	10
11	Non-Jurisdictional Retail Sales	-	-	11
12	Total	219,971	$ 5,969,474	12
13	Total Inter-System and Non-Jurisdictional Retail Sales	960,600	$ 25,892,336	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 February 2025

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 41.294 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-FAC145 (F)	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	590,493	$ 23,045,170	$ 24,383,815	$ 1,338,645	$ (763,375)				1
2	Total Commercial	181,864	7,097,606	7,509,892	412,286	(237,043)				2
3	Total Industrial	502,665	19,617,507	20,757,049	1,139,542	(650,580)				3
4	Total Electric Vehicle Public Charging Stations	6	234	248	14	(7)				4
5	Total Lighting	3,362	131,209	138,830	7,621	(4,383)				5
6	Total Other									6
7	Total Retail Sales Subject to FAC	1,278,390	$ 49,891,726	$ 52,789,834	$ 2,898,108	$ (1,655,388)	$ 509,350	$ (2,164,738)	$ 5,062,846	7
8	Total Retail Sales NOT Subject to FAC	-								8
9	Total Non-jurisdictional Retail Sales	-								9
10	Sales	1,278,390								10
11	Hardy Hills Contract for Differences (CfD)								453,737	11
12	Hardy Hills Cash Receipts								(140,000)	12
13	Fuel Cost Variance with CfD and Receipts								$ 5,376,583	13

(1) Column F includes amortization of the prior period (over)/under collections of fuel costs. FAC 145 $1,528,049, or $509,350 per month.

AES INDIANA
Reconciliation of Actual Incremental Cost of Fuel
Incurred to Applicable Incremental Retail Fuel Clause
Revenues for March 2025

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 36.476 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-FAC146 (F)	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	437,587	$ 17,077,706	$ 15,961,423	$ (1,116,283)	$ (2,323,221)				1
2	Total Commercial	147,765	5,766,825	5,389,876	(376,949)	(778,761)				2
3	Total Industrial	436,303	17,027,597	15,914,588	(1,113,009)	(2,143,164)				3
4	Total Electric Vehicle Public Charging Stations	4	156	146	(10)	(22)				4
5	Total Lighting	10,303	402,095	375,812	(26,283)	(41,472)				5
6	Total Other									6
7	Total Retail Sales Subject to FAC	1,031,962	$ 40,274,379	$ 37,641,845	$ (2,632,534)	$ (5,286,640)	$ (1,355,364)	$ (3,931,276)	$ 1,298,742	7
8	Total Retail Sales NOT Subject to FAC	-								8
9	Total Non-jurisdictional Retail Sales	-								9
10	Sales	1,031,962								10
11	Hardy Hills Contract for Differences (CfD)								816,342	11
12	Hardy Hills Cash Receipts								(350,000)	12
13	Pike BESS Contract for Differences (CfD)								2,815,584	13
14	Pike BESS Cash Receipts								(282,574)	14
15	Fuel Cost Variance with CfD and Receipts								$ 4,298,094	15

(1) Column F includes amortization of the prior period (over)/under collections of fuel costs. FAC 146 ($4,066,093), or ($1,355,364) per month.

AES INDIANA
Reconciliation of Actual Incremental Cost of Fuel
Incurred to Applicable Incremental Retail Fuel Clause
Revenues for April 2025

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 35.693 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-FAC146 (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	356,419	$ 13,909,964	$ 12,721,663	$ (1,188,301)	$ (1,899,203)				1
2	Total Commercial	130,798	5,104,654	4,668,573	(436,081)	(702,304)				2
3	Total Industrial	483,627	18,874,511	17,262,099	(1,612,412)	(2,577,833)				3
4	Total Electric Vehicle Public Charging Stations	5	195	178	(17)	(28)				4
5	Total Lighting	5,105	199,233	182,213	(17,020)	(27,256)				5
6	Total Other									6
7	Total Retail Sales Subject to FAC	975,954	$ 38,088,557	$ 34,834,726	$ (3,253,831)	$ (5,206,624)	$ (1,355,364)	$ (3,851,260)	$ 597,429	7
8	Total Retail Sales NOT Subject to FAC	-								8
9	Total Non-jurisdictional Retail Sales	-								9
10	Sales	975,954								10
11	Hardy Hills Contract for Differences (CfD)								896,245	11
12	Hardy Hills Cash Receipts								(945,000)	12
13	Pike BESS Contract for Differences (CfD)								2,712,056	13
14	Pike BESS Cash Receipts								(10,938)	14
15	Fuel Cost Variance with CFD and Distributions								$ 3,249,792	15

(1) Column F includes amortization of the prior period (over)/under collections of fuel costs. FAC 146 ($4,066,093), or ($1,355,364) per month.

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
Reconciliation February 2025

Line No.	Description	February Actual	February Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	428,563	617,088	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	10	-	4
5	Gas Generation	642,548	830,954	5
6	Wind Generation	17,722	24,132	6
	Purchases through MISO:			
7	Wind Purchase Power Agreement Purchases	41,323	47,636	7
8	Non-Wind PPA Market Purchases	106,548	5,768	8
9	Other	1,044	-	9
10	Purchased Power other than MISO	7,581	7,458	10
	LESS:			
11	Energy Losses and Company Use	55,280	53,242	11
12	Inter-System Sales through MISO	71,086	332,470	12
13	Inter-System Sales other than MISO	-	-	13
14	Non-Jurisdictional Retail Sales	-	-	14
15	Sales (S)	1,118,973	1,147,323	15
	Fuel Cost			
16	Coal and Oil Generation	$ 12,122,070	$ 15,072,572	16
17	Nuclear Generation	-	-	17
18	Hydro Generation	-	-	18
19	Other Generation - Internal Combustion	2,634	-	19
20	Gas Generation	26,613,412	28,935,113	20
21	Financial Hedges Gains/Losses & Transactional Fees	-	-	21
	Purchases through MISO:			
22	Wind Purchase Power Agreement Purchases	4,653,541	4,951,318	22
23	Non-Wind PPA Market Purchases	3,481,980	261,153	23
24	Other	37,361	-	24
25	MISO Components of Cost of Fuel	828,660	1,535,119	25
26	Purchased Power other than MISO	1,238,768	1,182,840	26
	LESS:			
27	Inter-System Sales through MISO	2,506,958	9,122,156	27
28	Inter-System Sales other than MISO	-	-	28
29	Non-Jurisdictional Retail Sales	-	-	29
30	Transmission Losses	259,471	453,307	30
31	Lakefield PPA Adjustment	-	-	31
32	Purchased Power in Excess	4,850	-	32
33	Total Fuel Costs (F)	$ 46,207,147	$ 42,362,652	33
34	F / S (Mills/kWh)	41.294	36.923	34
	Weighted Average Deviation	-10.59%		

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
Reconciliation March 2025

Line No.	Description	March Actual	March Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	432,582	356,504	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	10	-	4
5	Gas Generation	595,450	741,760	5
6	Wind Generation	27,493	25,858	6
	Purchases through MISO			
7	Wind Purchase Power Agreement Purchases	36,845	45,756	7
8	Non-Wind PPA Market Purchases	72,645	9,794	8
9	Other	661	-	9
10	Purchased Power other than MISO	10,461	80,689	10
	LESS:			
11	Energy Losses and Company Use	49,300	49,395	11
12	Inter-System Sales through MISO	119,733	146,528	12
13	Inter-System Sales other than MISO	-	-	13
14	Non-Jurisdictional Retail Sales	-	-	14
15	Sales (S)	1,007,114	1,064,438	15
	Fuel Cost			
16	Coal and Oil Generation	$ 11,602,475	$ 9,422,368	16
17	Nuclear Generation	-	-	17
18	Hydro Generation	-	-	18
19	Other Generation - Internal Combustion	4,983	-	19
20	Gas Generation	16,930,060	19,169,575	20
21	Financial Hedges Gains/Losses & Transactional Fees	-	-	21
	Purchases through MISO			
22	Wind Purchase Power Agreement Purchases	6,133,293	5,369,169	22
23	Non-Wind PPA Market Purchases	2,239,246	1,542,010	23
24	Other	24,233	-	24
25	MISO Components of Cost of Fuel	1,281,361	1,366,738	25
26	Purchased Power other than MISO	1,713,820	2,847,187	26
	LESS:			
27	Inter-System Sales through MISO	2,942,469	3,370,267	27
28	Inter-System Sales other than MISO	-	-	28
29	Non-Jurisdictional Retail Sales	-	-	29
30	Transmission Losses	249,923	352,555	30
31	Lakefield PPA Adjustment	-	-	31
32	Purchased Power in Excess	1,284	-	32
33	Total Fuel Costs (F)	$ 36,735,795	$ 35,994,225	33
34	F / S (Mills/kWh)	36.476	33.815	34
	Weighted Average Deviation	-7.30%		

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
Reconciliation April 2025

Line No.	Description	April Actual	April Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	401,048	439,735	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	-	-	4
5	Gas Generation	654,954	810,169	5
6	Wind Generation	25,554	19,203	
	Purchases through MISO			
7	Wind Purchase Power Agreement Purchases	27,177	40,683	7
8	Non-Wind PPA Market Purchases	56,942	13,039	8
9	Other	798	-	9
10	Purchased Power other than MISO	11,484	21,994	10
	LESS:			
11	Energy Losses and Company Use	45,107	42,490	11
12	Inter-System Sales through MISO	214,248	386,708	12
13	Inter-System Sales other than MISO	-	-	13
14	Non-Jurisdictional Retail Sales	-	-	14
15	Sales (S)	918,602	915,625	15
	Fuel Cost			
16	Coal and Oil Generation	$ 11,150,958	$ 11,245,075	16
17	Nuclear Generation	-	-	17
18	Hydro Generation	-	-	18
19	Other Generation - Internal Combustion	3,202	-	19
20	Gas Generation	17,888,490	22,025,635	20
21	Financial Hedges Gains/Losses & Transactional Fees	-	-	21
	Purchases through MISO			
22	Wind Purchase Power Agreement Purchases	5,414,490	5,375,407	22
23	Non-Wind PPA Market Purchases	1,599,808	2,083,290	23
24	Other	29,249	-	24
25	MISO Components of Cost of Fuel	(87,178)	1,175,664	25
26	Purchased Power other than MISO	1,922,763	678,589	26
	LESS:			
27	Inter-System Sales through MISO	4,919,144	9,289,168	27
28	Inter-System Sales other than MISO	-	-	28
29	Non-Jurisdictional Retail Sales	-	-	29
30	Transmission Losses	$212,642	316,719	30
31	Lakefield PPA Adjustment	-	-	31
32	Purchased Power in Excess	2,038	-	32
33	Total Fuel Costs (F)	$ 32,787,958	$ 32,977,773	33
34	F / S (Mills/kWh)	35.693	36.017	34
	Weighted Average Deviation	0.91%		

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
February, March and April, 2025

Line No.	Description	Total Actual	Total Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	1,262,193	1,413,327	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	20	-	4
5	Gas Generation	1,892,952	2,382,883	5
6	Wind Generation	70,769	69,193	
	Purchases through MISO			
7	Wind Purchase Power Agreement Purchases	105,345	134,075	7
8	Non-Wind PPA Market Purchases	236,135	28,601	8
9	Other	2,503	-	9
10	Purchased Power other than MISO	29,526	110,141	10
	LESS:			
11	Energy Losses and Company Use	149,687	145,127	11
12	Inter-System Sales through MISO	405,067	865,706	12
13	Inter-System Sales other than MISO	-	-	13
14	Non-Jurisdictional Retail Sales	-	-	14
15	Sales (S)	3,044,689	3,127,386	15
	Fuel Cost			
16	Coal and Oil Generation	$ 34,875,503	$ 35,740,015	16
17	Nuclear Generation	-	-	17
18	Hydro Generation	-	-	18
19	Other Generation - Internal Combustion	10,819	-	19
20	Gas Generation	61,431,962	70,130,323	20
21	Financial Hedges Gains/Losses & Transactional Fees	-	-	21
	Purchases through MISO			
22	Wind Purchase Power Agreement Purchases	16,201,324	15,695,894	22
23	Non-Wind PPA Market Purchases	7,321,034	3,886,453	23
24	Other	90,843	-	24
25	MISO Components of Cost of Fuel	2,022,843	4,077,521	25
26	Purchased Power other than MISO	4,875,351	4,708,616	26
	LESS:			
27	Inter-System Sales through MISO	10,368,571	21,781,591	27
28	Inter-System Sales other than MISO	-	-	28
29	Non-Jurisdictional Retail Sales	-	-	29
30	Transmission Losses	722,036	1,122,581	30
31	Lakefield PPA Adjustment	-	-	31
32	Purchased Power in Excess	8,172	-	32
33	Total Fuel Costs (F)	$ 115,730,900	$ 111,334,650	33
34	F / S (Mills/kWh)	38.011	35.600	34
	Weighted Average Deviation	-6.34%		

AES INDIANA
Determination of MISO Components of Fuel Cost
February, March and April, 2025

Line No.	**Energy Market FAC Adjustment Components**	Total February **(A)**	Total March **(B)**	Total April **(C)**	Line No.
1	Delta LMP[1]	$ 1,520,341	$ 1,638,940	$ 1,407,084	1
2	FTR (Revenue) / Expenses	$ (605,597)	$ (686,832)	$ (1,494,321)	2
3	RT Marg. Loss Surplus Credit	$ (298,090)	$ (27,268)	$ (163,815)	3
4	Virtuals Bids and Offers for Load	$ -	$ -	$ -	4
5	DA & RAC Recovery of Unit Commitment Costs	$ 12,167	$ (541)	$ (1,081)	5
5a	RSG 1st Pass Charges	$ 20,906	$ 16,462	$ 13,093	5a
5b	RSG 2nd Pass Distribution Correction	$ -	$ -	$ -	5b
6	Inadvertent Energy	$ 58,714	$ 179,910	$ (232)	6
7	Ancillary Services Revenue	$ (144,689)	$ (24,767)	$ (34,802)	7
8	Ancillary Services Costs	$ 261,871	$ 173,625	$ 195,918	8
9	Ancillary Services Incentive to Follow Dispatch[2]	$ 17,357	$ 7,103	$ 6,730	9
10	Ramp Capability[3]	$ (14,320)	$ 4,729	$ (15,752)	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 25)	$ 828,660	$ 1,281,361	$ (87,178)	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		Feb-25 Invoice Total		Mar-25 Invoice Total		Apr-25 Invoice Total	Line No.
1	Day Ahead Market Administration Amount	$	284,605	$	214,146	$	241,868	1
2	Day Ahead Regulation Amount	$	-		-		-	2
3	Day Ahead Spinning Reserve Amount	$	(2,774)		(3,275)		(18,076)	3
4	Day-Ahead Short-Term Reserve Amount	$	-		-		-	4
5	Day Ahead Supplemental Reserve Amount	$	(82,908)		(5,027)		(16,493)	5
6	Day Ahead Asset Energy Amount	$	(3,943,818)		(4,179,787)		(9,482,548)	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	$	(36,769)		(21,669)		(39,923)	14
15	Day Ahead Revenue Sufficiency Guarantee Distribution Amount	$	37,674		31,567		25,415	15
16	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amt	$	(23,033)		(33,223)		(29,908)	16
17	Day Ahead Schedule 24 Allocation Amount	$	34,491		31,415		32,762	17
18	Day Ahead Virtual Energy Amount	$	-		-		-	18
	Day Ahead Subtotal	$	(3,732,532)	$	(3,965,853)	$	(9,286,903)	
19	Financial Transmission Rights Market Administration Amount	$	4,314		5,298		2,213	19
20	Auction Revenue Rights Transaction Amount	$	(697,894)		(228,858)		(228,858)	20
21	Financial Transmission Rights Annual Transaction Amount	$	464,257		199,181		199,180	21
22	Auction Revenue Rights Infeasible Uplift Amount	$	44,890		55,874		56,560	22
23	Auction Revenue Rights Stage 2 Distribution Amount	$	(224,405)		(166,864)		(165,988)	23
24	Financial Transmission Rights Full Funding Guarantee Amount	$	-		-		-	24
25	Financial Transmission Guarantee Uplift Amount	$	-		-		-	25
26	Financial Transmission Rights Hourly Allocation Amount	$	(191,068)		(536,668)		(1,314,073)	26
27	Financial Transmission Rights Monthly Allocation Amount	$	(1,377)		(9,497)		(41,142)	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	$	(601,283)	$	(681,534)	$	(1,492,108)	
31	Real Time Market Administration Amount		37,010		25,505		31,727	31
32	Contingency Reserve Deployment Failure Charge Amount		-		-		-	32
33	Excessive Energy Amount		-		-		-	33
34	Real Time Excessive Deficient Energy Deployment Charge Amount		(39,470)		(14,362)		(8,160)	34
35	Net Regulation Adjustment Amount		17,140		7,188		7,523	35
36	Non-Excessive Energy Amount		-		-		-	36
37	Real Time Regulation Amount		4,283,598		2,385,612		4,248,515	37
38	Regulation Cost Distribution Amount		-		-		-	38
39	Real Time Spinning Reserve Amount		80,336		77,650		83,173	39
40	Spinning Reserve Cost Distribution Amount		(14,355)		(6,054)		2,252	40
41	Real Time Short-Term Reserve Amount		58,115		57,319		57,154	41
42	Real-Time Short-Term Reserve Deployment Failure Charge Amount		(1,219)		-		-	42
43	Short-Term Reserve Cost Distribution Amount		10,365		6,625		10,640	43
44	Real Time Supplemental Reserve Amount		(43,432)		(10,411)		(2,485)	44
45	Supplemental Reserve Cost Distribution Amount		113,057		32,029		44,951	45
46	Real Time Asset Energy Amount		442,832		877,579		377,906	46
47	Real Time Demand Response Allocation Uplift Charge		284		3		178	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		(298,090)		(27,268)		(163,815)	52
53	Real Time Miscellaneous Amount		(49,253)		(1,112)		259	53
54	Real Time MVP Distribution Amount		(45,470)		(78,118)		(29,191)	54
55	Real Time Non-Asset Energy Amount		-		-		-	55
56	Real Time Net Inadvertent Distribution Amount		58,714		179,910		(232)	56
57	Real Time Price Volatility Make Whole Payment		(339,039)		(338,677)		(425,104)	57
58	Real Time Resource Adequacy Auction Amount		37,115		(259,137)		(245,124)	58
59	Real Time Ramp Capability Amount		(8,628)		(9,224)		(10,038)	59
60	Real Time Revenue Neutrality Uplift Amount		123,885		196,834		358,877	60
61	Real Time Revenue Sufficiency Guarantee First Pass Dist Amount		29,112		18,480		16,046	61
62	Real Time Revenue Sufficiency Guarantee Make Whole Payment Amt		(3,005)		(5,420)		(2,746)	62
63	Real-Time Storage as Transmission Only Asset Amount		-		-		-	63
64	Real Time Schedule 24 Allocation Amount		4,485		3,742		4,297	64
65	Real Time Schedule 24 Distribution Amount		(62,040)		(61,350)		(62,302)	65
66	Real Time Schedule 49 Cost Distribution Amount		92,497		40,104		42,440	66
67	Real Time Virtual Energy Amount		-		-		-	67
	Real Time Subtotal	$	4,484,544	$	3,097,447	$	4,336,741	
	Grand Total	$	150,729	$	(1,549,940)	$	(6,442,270)	

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing was served this 16th day of June, 2025, by email transmission, hand delivery or United States Mail, first class, postage prepaid to:

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