FILED
December 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 MARCH 2025 THROUGH MAY 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 146**

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 March 2025 through May 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 August 2024 through October 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 October 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 $757,747 of purchased power costs in excess of the applicable Purchased Power Daily Benchmarks incurred in the Historical Period, of which $57,555 is not recoverable. Applicant is therefore requesting recovery of $700,193 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 $0.033692 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 $(0.005335). This factor would represent a decrease from the basic rates otherwise anticipated to be applicable during the billing cycles for the months of March 2025 through May 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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One Indiana Square, Suite 3500
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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**
January 17, 2025	OUCC/Intervenors File Case-in-Chief
January 27, 2025	Petitioner's Rebuttal Testimony
Week of February 10, 2025	Hearing
February 26, 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 March 2025 (Regular Billing District 41 and Special Billing District 01), which begins February 28, 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 <u>Attachment NHC-1-A</u>;

(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 13th day of December, 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 ~~December~~ March 2025~~4~~ 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~~ August 2024 through ~~July~~ October 2024.

D. The Adjustment Factor to be effective for all bills rendered for electric service beginning with the first billing cycles for ~~December~~ March ~~2024~~ 2025 (Regular Billing District 41 and Special Billing Route 01) will be $~~(0.001293)~~(0.005335) 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 March 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 August 2024 through October 2024.

D. The Adjustment Factor to be effective for all bills rendered for electric service beginning with the first billing cycles for March 2025 (Regular Billing District 41 and Special Billing Route 01) will be $(0.005335) per KWH.

AES INDIANA
Determination of Fuel Cost Adjustment
Beginning with March 2025 Based on the Estimated
Three Months Average of March, April and May 2025

Line No.	Description	(A)	(B)	(C)	(D)	(E)	Line No.
		Estimated Month of:				Estimated Three Month Average	
	kWh Source (000's)	March	April	May	Total		
1	Coal and Oil Generation	356,504	439,735	550,871	1,347,110	449,037	1
2	Nuclear Generation	-	-	-	-	-	2
3	Hydro Generation	-	-	-	-	-	3
4	Other Generation - Internal Combustion	-	-	-	-	-	4
5	Gas Generation	741,760	810,169	740,629	2,292,558	764,186	5
6	Wind Generation	25,858	19,203	20,661	65,722	21,907	6
	Purchases through MISO:						
7	Wind Purchase Power Agreement Purchases	45,756	40,683	37,311	123,750	41,250	7
8	Non-Wind PPA Market Purchases	9,794	13,039	14,476	37,309	12,436	8
9	Other	-	-	-	-	-	9
10	Purchased Power other than MISO	80,689	21,994	40,295	142,978	47,659	10
	LESS:						
11	Energy Losses and Company Use	49,395	42,490	47,703	139,588	46,529	11
12	Inter-System Sales through MISO	146,528	386,708	328,563	861,799	287,266	12
13	Inter-System Sales other than MISO	-	-	-	-	-	13
14	Non-Jurisdictional Retail Sales	-	-	-	-	-	14
15	**Sales (S)**	1,064,438	915,625	1,027,977	3,008,040	1,002,680	15
	Fuel Cost ($)						
16	Coal and Oil Generation	9,422,368	11,245,075	14,211,697	34,879,140	11,626,380	16
17	Nuclear Generation	-	-	-	-	-	17
18	Hydro Generation	-	-	-	-	-	18
19	Other Generation - Internal Combustion	-	-	-	-	-	19
20	Gas Generation	19,169,575	22,025,635	21,441,537	62,636,747	20,878,916	20
	Purchases through MISO:						
21	Wind Purchase Power Agreement Purchases	5,369,169	5,375,407	4,369,040	15,113,616	5,037,872	21
22	Non-Wind PPA Market Purchases	1,542,010	2,083,290	2,341,760	5,967,060	1,989,020	22
23	Other	-	-	-	-	-	23
24	MISO Components of Cost of Fuel	1,366,738	1,175,664	1,319,921	3,862,323	1,287,441	24
25	Purchased Power other than MISO	2,847,187	678,589	1,233,336	4,759,112	1,586,371	25
	Less:						
26	Inter-System Sales through MISO	3,370,267	9,289,168	8,109,761	20,769,196	6,923,065	26
27	Inter-System Sales other than MISO	-	-	-	-	-	27
28	Non-Jurisdictional Retail Sales	-	-	-	-	-	28
29	Transmission Losses	352,555	316,719	365,372	1,034,646	344,882	29
30	Lakefield PPA Adjustment	-	-	-	-	-	30
31	**Total Fuel Cost (F)**	$ 35,994,225	$ 32,977,773	$ 36,442,158	$ 105,414,156	$ 35,138,053	31
32	**F ÷ S (Line 31 ÷ Line 15) (Mills/kWh)**					35.044	32

Line No.	Description	Months to be Reconciled					Line No.
		August	September	October	Total		
33	Fuel Cost Variance (includes Joint Venture CfD and Cash Receipts)	$ (902,406)	$ (2,644,039)	$ (3,084,458)	$ (6,630,903)		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					$ (4,066,093)	35
	(Mills/kWh)						
36	Variance Charge (Line 35 Total divided by estimated Indiana jurisdictional sales of		3,008,040 kWh (000's)			(1.352)	36
37	Adjusted Fuel Cost Charge (Line 32 + Line 36)					33.692	37
38	Less: Base Cost of Fuel Included in Rates					39.027	38
39	Fuel Cost Charge					(5.335)	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 March, April and May 2025

Line No	Supplier	kWh Purchased (000's) (A)	Energy * (B)	Line No
	March			
	Purchases through MISO:			
1	Wind Purchase Power Agreement Purchases	45,756	$ 5,369,169	1
2	Non-Wind PPA Market Purchases	9,794	1,542,010	2
3	Other	-	-	3
4	MISO Components of Cost of Fuel	-	1,366,738	4
5	Purchased Power other than MISO	80,689	2,847,187	5
6	Total	136,239	$ 11,125,104	6
	April			
	Purchases through MISO:			
7	Wind Purchase Power Agreement Purchases	40,683	$ 5,375,407	7
8	Non-Wind PPA Market Purchases	13,039	2,083,290	8
9	Other	-	-	9
10	MISO Components of Cost of Fuel	-	1,175,664	10
11	Purchased Power other than MISO	21,994	678,589	11
12	Total	75,716	$ 9,312,950	12
	May			
	Purchases through MISO:			
13	Wind Purchase Power Agreement Purchases	37,311	$ 4,369,040	13
14	Non-Wind PPA Market Purchases	14,476	2,341,760	14
15	Other	-	-	15
16	MISO Components of Cost of Fuel	-	1,319,921	16
17	Purchased Power other than MISO	40,295	1,233,336	17
18	Total	92,082	$ 9,264,057	18
19	Total Net Energy Cost of Purchased Power	304,037	$ 29,702,111	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 March, April and May 2025

Line No.	Purchaser	kWh Sold (000's)	Fuel Cost *	Line No.
		(A)	(B)	
	March			
1	Inter-System Sales through MISO	146,528	$ 3,370,267	1
2	Inter-System Sales other than MISO	-	-	2
3	Non-Jurisdictional Retail Sales	-	-	3
4	Total	146,528	$ 3,370,267	4
	April			
5	Inter-System Sales through MISO	386,708	$ 9,289,168	5
6	Inter-System Sales other than MISO	-	-	6
7	Non-Jurisdictional Retail Sales	-	-	7
8	Total	386,708	$ 9,289,168	8
	May			
9	Inter-System Sales through MISO	328,563	$ 8,109,761	9
10	Inter-System Sales other than MISO	-	-	10
11	Non-Jurisdictional Retail Sales	-	-	11
12	Total	328,563	$ 8,109,761	12
13	Total Inter-System and Non-Jurisdictional Retail Sales	861,799	$ 20,769,196	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 August 2024

Line No.	Class of Customers	kWh Sales (In 000's)	Base Cost of Fuel Included in Rates 39.027 Mills/kWh	Actual Cost of Fuel Incurred 32.154 Mills/kWh	Actual Incremental Cost of Fuel Incurred	Actual Incremental Cost of Fuel Billed	Fuel Cost [1] Variance From Cause No. 38703-FAC143	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) (Col E - Col F)	(H) (Col D - Col G)	
1	Total Residential	471,921	$ 18,417,661	$ 15,174,147	$ (3,243,514)	$ (1,616,377)				1
2	Total Commercial	161,350	6,297,006	5,188,048	(1,108,958)	(549,554)				2
3	Total Industrial	577,595	22,541,800	18,571,990	(3,969,810)	(1,927,738)				3
4	Total Electric Vehicle Public Charging Stations	6	234	193	(41)	(20)				4
5	Total Lighting	5,689	222,025	182,924	(39,101)	(19,567)				5
6	Total Other									6
7	Total Retail Sales Subject to FAC	1,216,561	$ 47,478,726	$ 39,117,302	$ (8,361,424)	$ (4,113,256)	$ 4,382,663	$ (8,495,919)	$ 134,495	7
8	Total Retail Sales NOT Subject to FAC	-								8
9	Total Non-jurisdictional Retail Sales	-								9
10	Sales	1,216,561								10
11	Hardy Hills Contract for Differences (CfD)								713,099	11
12	Hardy Hills Cash Receipts								(1,750,000)	12
13	Fuel Cost Variance with CfD and Receipts								$ (902,406)	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
Reconciliation of Actual Incremental Cost of Fuel
Incurred to Applicable Incremental Retail Fuel Clause
Revenues for September 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 33.725 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-FAC144 (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	448,935	$ 17,520,586	$ 15,140,332	$ (2,380,254)	$ (3,455,519)				1
2	Total Commercial	157,647	6,152,489	5,316,645	(835,844)	(1,221,887)				2
3	Total Industrial	575,885	22,475,064	19,421,722	(3,053,342)	(4,258,872)				3
4	Total Electric Vehicle Public Charging Stations	7	273	236	(37)	(52)				4
5	Total Lighting	4,905	191,427	165,421	(26,006)	(37,932)				5
6	Total Other									6
7	Total Retail Sales Subject to FAC	1,187,379	$ 46,339,839	$ 40,044,356	$ (6,295,483)	$ (8,974,262)	$ (4,354,632)	$ (4,619,630)	$ (1,675,853)	7
8	Total Retail Sales NOT Subject to FAC	-								8
9	Total Non-jurisdictional Retail Sales	-								9
10	Sales	1,187,379								10
11	Hardy Hills Contract for Differences (CfD)								571,814	11
12	Hardy Hills Cash Receipts								(1,540,000)	12
13	Fuel Cost Variance with CfD and Receipts								$ (2,644,039)	13

(1) Column F includes amortization of the prior period (over)/under collections of fuel costs. FAC 144 ($13,063,897), or ($4,354,632) per month.

AES INDIANA
Reconciliation of Actual Incremental Cost of Fuel
Incurred to Applicable Incremental Retail Fuel Clause
Revenues for October 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 32.582 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-FAC144 (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	330,615	$ 12,902,912	$ 10,772,098	$ (2,130,814)	$ (2,544,996)				1
2	Total Commercial	129,301	5,046,230	4,212,885	(833,345)	(1,008,570)				2
3	Total Industrial	496,497	19,376,788	16,176,865	(3,199,923)	(3,792,770)				3
4	Total Electric Vehicle Public Charging Stations	3	117	98	(19)	(24)				4
5	Total Lighting	7,101	277,131	231,365	(45,766)	(55,128)				5
6	Total Other									6
7	Total Retail Sales Subject to FAC	963,517	$ 37,603,178	$ 31,393,311	$ (6,209,867)	$ (7,401,488)	$ (4,354,632)	$ (3,046,856)	$ (3,163,011)	7
8	Total Retail Sales NOT Subject to FAC	-								8
9	Total Non-jurisdictional Retail Sales	-								9
10	Sales	963,517								10
11	Hardy Hills Contract for Differences (CfD)								878,553	11
12	Hardy Hills Cash Receipts								(800,000)	12
13	Fuel Cost Variance with CfD and Receipts								$ (3,084,458)	13

(1) Column F includes amortization of the prior period (over)/under collections of fuel costs. FAC 144 ($13,063,897), or ($4,354,632) per month.

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

Line No.	Description	August Actual	August Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	333,848	532,440	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	14	-	4
5	Gas Generation	902,049	1,046,734	5
6	Wind Generation	10,452	10,613	6
	Purchases through MISO:			
7	Wind Purchase Power Agreement Purchases	25,304	28,564	7
8	Non-Wind PPA Market Purchases	54,852	490	8
9	Other	233	-	9
10	Purchased Power other than MISO	13,834	17,113	10
	LESS:			
11	Energy Losses and Company Use	55,945	59,755	11
12	Inter-System Sales through MISO	75,347	288,516	12
13	Inter-System Sales other than MISO	-	-	13
14	Non-Jurisdictional Retail Sales	-	-	14
15	Sales (S)	1,209,294	1,287,682	15
	Fuel Cost			
16	Coal and Oil Generation	$ 13,135,286	$ 15,366,310	16
17	Nuclear Generation	-	-	17
18	Hydro Generation	-	-	18
19	Other Generation - Internal Combustion	3,522	-	19
20	Gas Generation	20,476,015	27,275,346	20
21	Financial Hedges Gains/Losses & Transactional Fees	-	-	21
	Purchases through MISO:			
22	Wind Purchase Power Agreement Purchases	2,330,449	2,637,106	22
23	Non-Wind PPA Market Purchases	1,947,541	82,146	23
24	Other	(37,787)	-	24
25	MISO Components of Cost of Fuel	434,976	936,146	25
26	Purchased Power other than MISO	2,321,972	2,808,650	26
	LESS:			
27	Inter-System Sales through MISO	1,447,318	7,032,474	27
28	Inter-System Sales other than MISO	-	-	28
29	Non-Jurisdictional Retail Sales	-	-	29
30	Transmission Losses	225,005	451,969	30
31	Lakefield PPA Adjustment	-	-	31
32	Purchased Power in Excess	56,241	-	32
33	Total Fuel Costs (F)	$ 38,883,410	$ 41,621,260	33
34	F / S (Mills/kWh)	32.154	32.323	34
	Weighted Average Deviation	0.53%		

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

Line No.	Description	September Actual	September Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	225,411	461,369	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	9	-	4
5	Gas Generation	766,751	965,358	5
6	Wind Generation	6,934	13,586	6
	Purchases through MISO			
7	Wind Purchase Power Agreement Purchases	24,241	36,558	7
8	Non-Wind PPA Market Purchases	66,943	9,689	8
9	Other	820	-	9
10	Purchased Power other than MISO	18,226	14,967	10
	LESS:			
11	Energy Losses and Company Use	47,008	48,705	11
12	Inter-System Sales through MISO	51,952	403,258	12
13	Inter-System Sales other than MISO	-	-	13
14	Non-Jurisdictional Retail Sales	-	-	14
15	Sales (S)	1,010,375	1,049,564	15
	Fuel Cost			
16	Coal and Oil Generation	$ 8,958,842	$ 14,864,233	16
17	Nuclear Generation	-	-	17
18	Hydro Generation	-	-	18
19	Other Generation - Internal Combustion	2,465	-	19
20	Gas Generation	17,876,300	24,727,631	20
21	Financial Hedges Gains/Losses & Transactional Fees	-	-	21
	Purchases through MISO			
22	Wind Purchase Power Agreement Purchases	3,479,104	3,766,949	22
23	Non-Wind PPA Market Purchases	2,003,084	239,382	23
24	Other	30,710	-	24
25	MISO Components of Cost of Fuel	246,629	1,324,550	25
26	Purchased Power other than MISO	2,606,166	2,443,570	26
	LESS:			
27	Inter-System Sales through MISO	993,729	9,446,799	27
28	Inter-System Sales other than MISO	-	-	28
29	Non-Jurisdictional Retail Sales	-	-	29
30	Transmission Losses	133,395	354,057	30
31	Lakefield PPA Adjustment	-	-	31
32	Purchased Power in Excess	1,314	-	32
33	Total Fuel Costs (F)	$ 34,074,862	$ 37,565,460	33
34	F / S (Mills/kWh)	33.725	35.791	34
	Weighted Average Deviation	6.13%		

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

Line No.	Description	October Actual	October Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	103,804	292,619	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	1	-	4
5	Gas Generation	839,513	1,078,175	5
6	Wind Generation	19,246	19,738	
	Purchases through MISO			
7	Wind Purchase Power Agreement Purchases	28,452	40,718	7
8	Non-Wind PPA Market Purchases	50,533	43	8
9	Other	29	-	9
10	Purchased Power other than MISO	11,220	12,353	10
	LESS:			
11	Energy Losses and Company Use	42,007	44,271	11
12	Inter-System Sales through MISO	109,564	445,367	12
13	Inter-System Sales other than MISO	-	-	13
14	Non-Jurisdictional Retail Sales	-	-	14
15	Sales (S)	901,227	954,009	15
	Fuel Cost			
16	Coal and Oil Generation	$ 5,130,359	$ 9,351,792	16
17	Nuclear Generation	-	-	17
18	Hydro Generation	-	-	18
19	Other Generation - Internal Combustion	2,564	-	19
20	Gas Generation	18,444,010	26,133,964	20
21	Financial Hedges Gains/Losses & Transactional Fees	-	-	21
	Purchases through MISO			
22	Wind Purchase Power Agreement Purchases	5,138,526	4,773,885	22
23	Non-Wind PPA Market Purchases	1,122,078	4,497	23
24	Other	15,017	-	24
25	MISO Components of Cost of Fuel	(233,635)	1,203,959	25
26	Purchased Power other than MISO	1,972,664	2,001,050	26
	LESS:			
27	Inter-System Sales through MISO	2,051,453	9,999,694	27
28	Inter-System Sales other than MISO	-	-	28
29	Non-Jurisdictional Retail Sales	-	-	29
30	Transmission Losses	$176,728.00	308,449	30
31	Lakefield PPA Adjustment	-	-	31
32	Purchased Power in Excess	-	-	32
33	Total Fuel Costs (F)	$ 29,363,402	$ 33,161,003	33
34	F / S (Mills/kWh)	32.582	34.760	34
	Weighted Average Deviation	6.68%		

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
August, September and October, 2024

Line No.	Description	Total Actual	Total Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	663,063	1,286,429	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	24	-	4
5	Gas Generation	2,508,313	3,090,267	5
6	Wind Generation	36,632	43,937	
	Purchases through MISO			
7	Wind Purchase Power Agreement Purchases	77,997	105,840	7
8	Non-Wind PPA Market Purchases	172,328	10,222	8
9	Other	1,082	-	9
10	Purchased Power other than MISO	43,280	44,433	10
	LESS:			
11	Energy Losses and Company Use	144,960	152,731	11
12	Inter-System Sales through MISO	236,863	1,137,141	12
13	Inter-System Sales other than MISO	-	-	13
14	Non-Jurisdictional Retail Sales	-	-	14
15	Sales (S)	3,120,896	3,291,255	15
	Fuel Cost			
16	Coal and Oil Generation	$ 27,224,487	$ 39,582,335	16
17	Nuclear Generation	-	-	17
18	Hydro Generation	-	-	18
19	Other Generation - Internal Combustion	8,551	-	19
20	Gas Generation	56,796,325	78,136,941	20
21	Financial Hedges Gains/Losses & Transactional Fees	-	-	21
	Purchases through MISO			
22	Wind Purchase Power Agreement Purchases	10,948,079	11,177,940	22
23	Non-Wind PPA Market Purchases	5,072,703	326,025	23
24	Other	7,940	-	24
25	MISO Components of Cost of Fuel	447,970	3,464,655	25
26	Purchased Power other than MISO	6,900,802	7,253,270	26
	LESS:			
27	Inter-System Sales through MISO	4,492,500	26,478,966	27
28	Inter-System Sales other than MISO	-	-	28
29	Non-Jurisdictional Retail Sales	-	-	29
30	Transmission Losses	535,128	1,114,476	30
31	Lakefield PPA Adjustment	-	-	31
32	Purchased Power in Excess	57,555	-	32
33	Total Fuel Costs (F)	$ 102,321,674	$ 112,347,724	33
34	F / S (Mills/kWh)	32.786	34.135	34
	Weighted Average Deviation	4.11%		

Cause No. 38703-FAC146

AES INDIANA
Determination of MISO Components of Fuel Cost
August, September and October, 2024

Line No.	**Energy Market FAC Adjustment Components**	Total August **(A)**	Total September **(B)**	Total October **(C)**	Line No.
1	Delta LMP[1]	$ 1,494,091	$ 955,868	$ 213,649	1
2	FTR (Revenue) / Expenses	(836,115)	(591,108)	(388,020)	2
3	RT Marg. Loss Surplus Credit	(341,975)	(154,482)	(160,876)	3
4	Virtuals Bids and Offers for Load	-	-	-	4
5	DA & RAC Recovery of Unit Commitment Costs	20,280	(28,128)	8,358	5
5a	RSG 1st Pass Charges	14,229	6,157	4,032	5a
5b	RSG 2nd Pass Distribution Correction	-	-	-	5b
6	Inadvertent Energy	(22,771)	(12,215)	(30,410)	6
7	Ancillary Services Revenue	(103,472)	(59,424)	(48,087)	7
8	Ancillary Services Costs	200,859	138,313	162,436	8
9	Ancillary Services Incentive to Follow Dispatch[2]	13,317	(4,085)	6,842	9
10	Ramp Capability[3]	(3,467)	(4,267)	(1,559)	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)	$ 434,976	$ 246,629	$ (233,635)	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	Aug-24 Invoice Total	Sep-24 Invoice Total	Oct-24 Invoice Total	Line No.
1	Day Ahead Market Administration Amount	$ 212,069	$ 200,357	$ 192,568	1
2	Day Ahead Regulation Amount	(87)	(720)	(1,928)	2
3	Day Ahead Spinning Reserve Amount	(27,994)	(15,804)	(26,748)	3
4	Day-Ahead Short-Term Reserve Amount	(17)	-	(16)	4
5	Day Ahead Supplemental Reserve Amount	(40,955)	(13,580)	(8,860)	5
6	Day Ahead Asset Energy Amount	(1,230,954)	(2,011,651)	(5,094,337)	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	(18,489)	(22,852)	(14,110)	14
15	Day Ahead Revenue Sufficiency Guarantee Distribution Amount	25,485	20,488	17,705	15
16	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amt	(4,897)	(44,299)	(10,088)	16
17	Day Ahead Schedule 24 Allocation Amount	32,343	31,751	28,938	17
18	Day Ahead Virtual Energy Amount	-	-	-	18
	Day Ahead Subtotal	$ (1,053,496)	$ (1,856,310)	$ (4,916,876)	
19	Financial Transmission Rights Market Administration Amount	$ 4,422	$ 4,498	$ 3,822	19
20	Auction Revenue Rights Transaction Amount	(551,526)	(644,147)	(644,147)	20
21	Financial Transmission Rights Annual Transaction Amount	368,840	413,282	413,282	21
22	Auction Revenue Rights Infeasible Uplift Amount	6,014	77,909	77,909	22
23	Auction Revenue Rights Stage 2 Distribution Amount	(233,289)	(219,924)	(219,924)	23
24	Financial Transmission Rights Full Funding Guarantee Amount	-	(92)	-	24
25	Financial Transmission Guarantee Uplift Amount	-	141	-	25
26	Financial Transmission Rights Hourly Allocation Amount	(423,317)	(213,725)	(10,902)	26
27	Financial Transmission Rights Monthly Allocation Amount	(2,838)	(4,552)	(4,238)	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	$ (831,694)	$ (586,610)	$ (384,198)	
31	Real Time Market Administration Amount	$ 23,070	$ 18,764	$ 21,972	31
32	Contingency Reserve Deployment Failure Charge Amount	-	-	-	32
33	Excessive Energy Amount	-	-	-	33
34	Real Time Excessive Deficient Energy Deployment Charge Amount	29	(4,190)	5,248	34
35	Net Regulation Adjustment Amount	12,044	2,580	5,879	35
36	Non-Excessive Energy Amount	-	-	-	36
37	Real Time Regulation Amount	2,932,057	3,416,845	3,359,867	37
38	Regulation Cost Distribution Amount	(391)	(3,397)	(8,741)	38
39	Real Time Spinning Reserve Amount	61,772	62,479	78,003	39
40	Spinning Reserve Cost Distribution Amount	9,168	(2,142)	1,483	40
41	Real Time Short-Term Reserve Amount	38,729	42,058	55,887	41
42	Real-Time Short-Term Reserve Deployment Failure Charge Amount	(88)	(16)	136	42
43	Short-Term Reserve Cost Distribution Amount	11,362	7,509	7,218	43
44	Real Time Supplemental Reserve Amount	(43,109)	(23,765)	(3,412)	44
45	Supplemental Reserve Cost Distribution Amount	88,995	26,267	21,329	45
46	Real Time Asset Energy Amount	(218,414)	269,426	54,471	46
47	Real Time Demand Response Allocation Uplift Charge	1,280	725	891	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	(341,975)	(154,482)	(160,876)	52
53	Real Time Miscellaneous Amount	(15,548)	(6,134)	(24,522)	53
54	Real Time MVP Distribution Amount	(12,665)	(6,345)	(5,941)	54
55	Real Time Non-Asset Energy Amount	-	-	-	55
56	Real Time Net Inadvertent Distribution Amount	(22,771)	(12,215)	(30,410)	56
57	Real Time Price Volatility Make Whole Payment	(336,383)	(425,255)	(411,143)	57
58	Real Time Resource Adequacy Auction Amount	26,040	(97,245)	(107,939)	58
59	Real Time Ramp Capability Amount	(637)	(7,496)	(8,283)	59
60	Real Time Revenue Neutrality Uplift Amount	310,779	408,756	497,994	60
61	Real Time Revenue Sufficiency Guarantee First Pass Dist Amount	18,693	9,598	4,608	61
62	Real Time Revenue Sufficiency Guarantee Make Whole Payment Amt	(653)	(5,104)	(1,155)	62
63	Real-Time Storage as Transmission Only Asset Amount	-	-	-	63
64	Real Time Schedule 24 Allocation Amount	3,525	2,977	3,305	64
65	Real Time Schedule 24 Distribution Amount	(61,141)	(61,650)	(60,225)	65
66	Real Time Schedule 49 Cost Distribution Amount	49,790	54,342	56,712	66
67	Real Time Virtual Energy Amount	-	-	-	67
	Real Time Subtotal	$ 2,533,558	$ 3,512,890	$ 3,352,356	
	Grand Total	$ 648,368	$ 1,069,970	$ (1,948,718)	

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 December, 2024.

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