FILED
September 16, 2022
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 2022 THROUGH FEBRUARY 2023, IN ACCORDANCE WITH THE PROVISIONS OF I.C. 8-1-2-42, AND CONTINUED USE OF RATEMAKING TREATMENT FOR COSTS OF WIND POWER PURCHASES PURSUANT TO CAUSE NOS. 43485 AND 43740, AND CONTINUED RECOVERY OF THE COSTS OF THE FUEL HEDGING PLAN PURSUANT TO I.C. 8-1-2-42.	)	**CAUSE NO. 38703 FAC 137**

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-l-2-42 for the purpose of securing approval of a new fuel cost factor for electric service for the billing months of December 2022 through February 2023.

3. AES Indiana is requesting recovery of projected fuel-related costs attributable to Applicant accepting transmission service from the Midcontinent Independent System Operator, Inc. ("MISO") for the period of December 2022 through February 2023. The Company's filing also reflects a true-up of fuel-related MISO costs and revenues for the period of May 2022 through July 2022. As discussed further in the Company's testimony, the Company is including fifty-percent of the variance of the non-outage related costs from the FAC 136 historical period as approved in FAC 136. 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, 2022; and (iv) the estimate of Applicant's prospective average fuel costs for the FAC period are reasonable after taking into consideration the reconciliation of Applicant's actual fuel cost recoveries for the reconciliation period.

5. In Cause No. 43414, Applicant and Indiana Office of Utility Consumer Counselor ("OUCC") agreed upon a "Benchmark" triggering mechanism for the judgment of the reasonableness of purchased power costs. Each day, a Benchmark is established based upon a generic Gas Turbine ("GT") with a generic GT heat rate of 12,500 btu/kWh, using the day ahead natural gas prices for the NYMEX Henry Hub, plus $0.60/mmbtu gas transport charge for a generic

gas-fired GT. The Benchmark methodology was approved in Cause No. 43414 on April 23, 2008 ("Purchased Power Daily Benchmark(s)"). As explained by Applicant's witness David Jackson, Applicant continues to follow the guidelines and procedures established in Cause No. 43414. The Purchased Power Daily Benchmarks for May 2022 through July 2022 are set forth in Attachment DJ-1.

6. Applying the Purchased Power Daily Benchmarks set forth above to individual power purchase transactions included in this proceeding shows $2,542,396 of purchased power costs in excess of the applicable Purchased Power Daily Benchmarks incurred in May 2022 through July 2022. A summary of the purchased power volumes, costs, the total of hourly purchased power costs above the applicable Purchased Power Daily Benchmarks for May 2022 through July 2022 and the reasons for the purchases at-risk after consideration of MISO economic dispatch, is set forth in Attachment DJ-2.

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

8. The books and records of Applicant supporting the data and calculations set forth herein are available for inspection and review by the OUCC and this Commission. Applicant is contemporaneously prefiling with the Commission its direct testimony, attachments, and workpapers in support of this Application.

9. Applicant's average cost of fuel for the months of December 2022 through February 2023, after taking into consideration its estimated and actual fuel costs for the months of May 2022 through July 2022, is estimated to be $0.070262 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 would be $0.037324. This factor would represent an increase from the basic rates otherwise anticipated to be applicable during the billing cycles for the months of December 2022 through February 2023.

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

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**
October 21, 2022	OUCC/Intervenors File Case-in-Chief
November 1, 2022	Petitioner's Rebuttal Testimony
Week of November 7 or 14, 2022	Hearing
November 30	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 December 2022 (Regular Billing District 41 and Special Billing District 01), which begins November 30, 2022. Such fuel

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

WHEREFORE, Applicant respectfully requests that the Commission:

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

(ii) grant to Applicant deferral accounting authority as requested in Paragraph 11;

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

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

(v) grant to Applicant all other appropriate relief.

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

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

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

ATTORNEYS FOR APPLICANT

Verification

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

Dated this 16th day of September, 2022.

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:

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

where:

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

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

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

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

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

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

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

STANDARD CONTRACT RIDER NO. 6 (Continued)

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

C. The Adjustment Factor may be further modified to reflect the difference between incremental fuel cost billed and the incremental fuel cost actually experienced during the months of ~~February~~ May 2022 through ~~April~~ July 2022.

D. The Adjustment Factor to be effective for all bills rendered for electric service beginning with the first billing cycles for ~~September~~ December 2022 (Regular Billing District 41 and Special Billing Route 01) will be $~~0.029255~~0.037324 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:

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

where:

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

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

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

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

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

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

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

STANDARD CONTRACT RIDER NO. 6 (Continued)

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

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

D. The Adjustment Factor to be effective for all bills rendered for electric service beginning with the first billing cycles for December 2022 (Regular Billing District 41 and Special Billing Route 01) will be \$0.037324 per KWH.

AES INDIANA
Determination of Fuel Cost Adjustment
Beginning with February 2023 Based on the Estimated
Three Months Average of December 2022, January, and February 2023

Line No.	Description	(A) Estimated Month of: December	(B) January	(C) February	(D) Total	(E) Estimated Three Month Average	Line No.
	kWh Source (000's)						
1	Coal and Oil Generation	967,794	950,033	858,094	2,775,921	925,307	1
2	Nuclear Generation	-	-	-	-	-	2
3	Hydro Generation	-	-	-	-	-	3
4	Other Generation - Internal Combustion	-	-	-	-	-	4
5	Gas Generation	956,341	1,116,722	961,538	3,034,601	1,011,534	5
	Purchases through MISO:						
6	Wind Purchase Power Agreement Purchases	71,111	80,811	68,240	220,162	73,387	6
7	Non-Wind PPA Market Purchases	-	-	-	-	-	7
8	Other	-	-	-	-	-	8
9	Purchased Power other than MISO	5,813	6,599	7,521	19,933	6,644	9
	LESS:						
10	Energy Losses and Company Use	58,059	62,723	55,724	176,506	58,835	10
11	Inter-System Sales through MISO	739,695	791,480	684,716	2,215,891	738,630	11
12	Inter-System Sales other than MISO	-	-	-	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	-	-	-	13
14	**Sales (S)**	1,203,305	1,299,962	1,154,953	3,658,220	1,219,407	14
	Fuel Cost ($)						
15	Coal and Oil Generation	22,015,779	23,109,726	22,443,729	67,569,234	22,523,078	15
16	Nuclear Generation	-	-	-	-	-	16
17	Hydro Generation	-	-	-	-	-	17
18	Other Generation - Internal Combustion	-	-	-	-	-	18
19	Gas Generation	69,995,007	89,625,494	74,267,226	233,887,727	77,962,576	19
	Purchases through MISO:						
20	Wind Purchase Power Agreement Purchases	8,296,890	8,114,034	7,123,675	23,534,599	7,844,866	20
21	Non-Wind PPA Market Purchases	-	-	-	-	-	21
22	Other	-	-	-	-	-	22
23	MISO Components of Cost of Fuel	2,866,275	3,096,510	2,751,099	8,713,884	2,904,628	23
24	Purchased Power other than MISO	875,857	1,004,936	1,383,675	3,264,468	1,088,156	24
	Less:						
25	Inter-System Sales through MISO	34,655,626	42,581,609	35,810,316	113,047,551	37,682,517	25
26	Inter-System Sales other than MISO	- -	-	-	-	-	26
27	Non-Jurisdictional Retail Sales	- -	-	-	-	-	27
28	Transmission Losses	811,820	1,007,107	869,810	2,688,737	896,246	28
29	Lakefield PPA Adjustment	1,711,281	2,119,235	1,646,719	5,477,235	1,825,745	29
30	**Total Fuel Cost (F)**	$ 66,871,081	$ 79,242,749	$ 69,642,559	$ 215,756,389	$ 71,918,796	30
31	**F ÷ S (Line 30 ÷ Line 14) (Mills/kWh)**					58.979	31
32	Reduction from Earnings Test				$0		32
33	Reduction in Fuel Factor (Line 32 divided by estimated Indiana jurisdictional sales of		3,658,220	kWh (000's)	**(Mills/kWh)**	-	33

Line No.	Description	Months to be Reconciled: May	June	July	Total	50%	Line No.
34	Fuel Cost Variance	$ 22,258,483	$ 26,100,791	$ 16,136,362	$ 64,495,636	$ 32,247,818	34
35	50% Fuel Cost Variance as Calculated in FAC 136					9,027,280	35
36	Total Fuel Cost Variance Included in this Filing					$ 41,275,098	36
	(Mills/kWh)						
37	Variance Charge (Line 36 Total divided by estimated Indiana jurisdictional sales of		3,658,220	kWh (000's)		11.283	37
38	Adjusted Fuel Cost Charge (Line 31 + Line 33 + Line 37)					70.262	38
39	Less: Base Cost of Fuel Included in Rates					32.938	39
40	Fuel Cost Charge					37.324	40

AES INDIANA
Determination of Net Energy Cost of Purchased Power
For the Estimated Months of December 2022, January, and February 2023

Line No	Supplier	kWh Purchased (000's) (A)	Energy * (B)	Line No
	December			
	Purchases through MISO:			
1	Wind Purchase Power Agreement Purchases	71,111	$ 8,296,890	1
2	Non-Wind PPA Market Purchases	-	-	2
3	Other	-	-	3
4	MISO Components of Cost of Fuel	-	2,866,275	4
5	Purchased Power other than MISO	5,813	875,857	5
6	Total	76,924	$ 12,039,022	6
	January			
	Purchases through MISO:			
7	Wind Purchase Power Agreement Purchases	80,811	$ 8,114,034	7
8	Non-Wind PPA Market Purchases	-	-	8
9	Other	-	-	9
10	MISO Components of Cost of Fuel	-	3,096,510	10
11	Purchased Power other than MISO	6,599	1,004,936	11
12	Total	87,410	$ 12,215,480	12
	February			
	Purchases through MISO:			
13	Wind Purchase Power Agreement Purchases	68,240	$ 7,123,675	13
14	Non-Wind PPA Market Purchases	-	-	14
15	Other	-	-	15
16	MISO Components of Cost of Fuel	-	2,751,099	16
17	Purchased Power other than MISO	7,521	1,383,675	17
18	Total	75,761	$ 11,258,449	18
19	Total Net Energy Cost of Purchased Power	240,095	$ 35,512,951	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 2022, January, and February 2023

Line No.	Purchaser	kWh Sold (000's)	Fuel Cost *	Line No.
		(A)	(B)	
	December			
1	Inter-System Sales through MISO	739,695	$ 34,655,626	1
2	Inter-System Sales other than MISO	-	-	2
3	Non-Jurisdictional Retail Sales	-	-	3
4	Total	739,695	$ 34,655,626	4
	January			
5	Inter-System Sales through MISO	791,480	$ 42,581,609	5
6	Inter-System Sales other than MISO	-	-	6
7	Non-Jurisdictional Retail Sales	-	-	7
8	Total	791,480	$ 42,581,609	8
	February			
9	Inter-System Sales through MISO	684,716	$ 35,810,316	9
10	Inter-System Sales other than MISO	-	-	10
11	Non-Jurisdictional Retail Sales	-	-	11
12	Total	684,716	$ 35,810,316	12
13	Total Inter-System and Non-Jurisdictional Retail Sales	2,215,891	$ 113,047,551	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, 2022

Line No.	Class of Customers	kWh Sales (In 000's)	Base Cost of Fuel Included in Rates 32.938 Mills/kWh	Actual Cost of Fuel Incurred 64.502 Mills/kWh	Actual Incremental Cost of Fuel Incurred	Actual Incremental Cost of Fuel Billed Including Utility Receipts Tx	Actual Incremental Cost of Fuel Billed Excluding Utility Receipts Tx [1]	Fuel Cost [2] Variance From Cause No. 38703-FAC134	Incremental Fuel Clause Revenues to be Reconciled with Actual Incremental Cost of Fuel Incurred	Fuel Cost Variance	Line No.
		(A)	(B) (Col A * mills above)	(C) (Col A * mills above)	(D) (Col C - Col B)	(E)	(F)	(G)	(H) (Col F - Col G)	(I) (Col D - Col H)	
1	Total Residential	311,654	$ 10,265,259	$ 20,102,306	$ 9,837,047	$ 2,312,976	$ 2,277,465				1
2	Total Commercial	123,780	4,077,066	7,984,058	3,906,992	915,520	901,465				2
3	Total Industrial	479,797	15,803,554	30,947,866	15,144,312	3,435,024	3,382,289				3
4	Total Electric Vehicle Public Charging Stations	2	66	129	63	16	16				4
5	Total Lighting	3,860	127,141	248,978	121,837	32,585	32,085				5
6	Total Other										6
7	Total Retail Sales Subject to FAC	919,093	$ 30,273,086	$ 59,283,337	$ 29,010,251	$ 6,696,121	$ 6,593,320	$ (158,448)	$ 6,751,768	$ 22,258,483	7
8	Total Retail Sales NOT Subject to FAC	-									8
9	Total Non-jurisdictional Retail Sales	-									9
10	Sales	919,093									10

(1) Column E Multiplied By (1-(1.46% URT Rate/(1-.049000)))

(2) Column G includes amortization of the prior period (over)/under collections of fuel costs and the NOI credit. FAC 134 included an NOI credit of -$475,344 and a fuel cost variance of $0.

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

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 59.533 Mills/kWh (C) (Col A * mills above)	Actual Incremental Cost of Fuel Incurred (D) (Col C - Col B)	Actual Incremental Cost of Fuel Billed Including Utility Receipts Tx (E)	Actual Incremental Cost of Fuel Billed Excluding Utility Receipts Tx [1] (F)	Fuel Cost [2] Variance From Cause No. 38703-FAC132/FAC135 (G)	Incremental Fuel Clause Revenues to be Reconciled with Actual Incremental Cost of Fuel Incurred (H) (Col F - Col G)	Fuel Cost Variance (I) (Col D - Col H)	Line No.
1	Total Residential	410,112	$ 13,508,270	$ 24,415,198	$ 10,906,928	$ 5,604,747	$ 5,518,702				1
2	Total Commercial	149,003	4,907,861	8,870,596	3,962,735	2,035,302	2,004,056				2
3	Total Industrial	575,037	18,940,569	34,233,678	15,293,109	7,986,743	7,864,128				3
4	Total Electric Vehicle Public Charging Stations	3	99	179	80	42	41				4
5	Total Lighting	3,480	114,624	207,175	92,551	54,726	53,886				5
6	Total Other										6
7	Total Retail Sales Subject to FAC	1,137,635	$ 37,471,423	$ 67,726,826	$ 30,255,403	$ 15,681,560	$ 15,440,813	$ 11,286,201	$ 4,154,612	$ 26,100,791	7
8	Total Retail Sales NOT Subject to FAC	$ -									8
9	Total Non-jurisdictional Retail Sales	-									9
10	Sales	1,137,635									10

(1) Column E Multiplied By (1-(1.46% URT Rate/(1-.049000)))

(2) Column G includes amortization of the prior period (over)/under collections of fuel costs and the NOI credit. FAC 135 included an NOI credit of -$282,364 and a fuel cost variance of $34,140,968.

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

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 50.360 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-FAC132/FAC135 (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	499,522	$ 16,453,256	$ 25,155,928	$ 8,702,672	$ 6,728,665				1
2	Total Commercial	163,719	5,392,576	8,244,889	2,852,313	2,210,063				2
3	Total Industrial	570,372	18,786,913	28,723,934	9,937,021	7,709,742				3
4	Total Electric Vehicle Public Charging Stations	3	99	151	52	45				4
5	Total Lighting	3,695	121,706	186,080	64,374	57,756				5
6	Total Other									6
7	Total Retail Sales Subject to FAC	1,237,311	$ 40,754,550	$ 62,310,982	$ 21,556,432	$ 16,706,271	$ 11,286,201	$ 5,420,070	$ 16,136,362	7
8	Total Retail Sales NOT Subject to FAC	-								8
9	Total Non-jurisdictional Retail Sales	-								9
10	Sales	1,237,311								10

(1) Column G includes amortization of the prior period (over)/under collections of fuel costs and the NOI credit. FAC 135 included an NOI credit of -$282,364 and a fuel cost variance of $34,140,968.

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

Line No.	Description	May Actual	May Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	265,468	522,016	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	13	-	4
5	Gas Generation	501,819	128,616	5
	Purchases through MISO:			
6	Wind Purchase Power Agreement Purchases	50,976	52,277	6
7	Non-Wind PPA Market Purchases	200,402	324,885	7
8	Other	336	-	8
9	Purchased Power other than MISO	13,903	16,599	9
	LESS:			
10	Energy Losses and Company Use	48,773	37,985	10
11	Inter-System Sales through MISO	20,040	22,093	11
12	Inter-System Sales other than MISO	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	13
14	Sales (S)	964,104	984,315	14
	Fuel Cost			
15	Coal and Oil Generation	$ 7,918,875	$ 13,573,056	15
16	Nuclear Generation	-	-	16
17	Hydro Generation	-	-	17
18	Other Generation - Internal Combustion	2,123	-	18
19	Gas Generation	28,488,382	6,180,580	19
20	Financial Hedges Gains/Losses & Transactional Fees	(1,292,165)	-	20
	Purchases through MISO:			
21	Wind Purchase Power Agreement Purchases	6,342,074	6,131,197	21
22	Non-Wind PPA Market Purchases	15,972,723	13,014,281	22
23	Other	9,738	-	23
24	MISO Components of Cost of Fuel	3,389,240	1,526,673	24
25	Purchased Power other than MISO	2,327,291	2,692,015	25
	LESS:			
26	Inter-System Sales through MISO	717,530	607,991	26
27	Inter-System Sales other than MISO	-	-	27
28	Non-Jurisdictional Retail Sales	-	-	28
29	Transmission Losses	119,777	128,430	29
30	Lakefield PPA Adjustment	123,771	163,537	30
31	Purchased Power in Excess	10,635	-	31
32	Total Fuel Costs (F)	$ 62,186,568	$ 42,217,844	32
33	F / S (Mills/kWh)	64.502	42.891	33
	Weighted Average Deviation	-33.50%		

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

Line No.	Description	June Actual	June Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	483,778	637,289	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	14	-	4
5	Gas Generation	542,023	605,096	5
	Purchases through MISO			
6	Wind Purchase Power Agreement Purchases	39,328	48,142	6
7	Non-Wind PPA Market Purchases	117,536	52,391	7
8	Other	413	-	8
9	Purchased Power other than MISO	16,210	18,112	9
	LESS:			
10	Energy Losses and Company Use	55,967	55,780	10
11	Inter-System Sales through MISO	32,938	149,162	11
12	Inter-System Sales other than MISO	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	13
14	Sales (S)	1,110,397	1,156,088	14
	Fuel Cost			
15	Coal and Oil Generation	$ 13,794,488	$ 16,871,101	15
16	Nuclear Generation	-	-	16
17	Hydro Generation	-	-	17
18	Other Generation - Internal Combustion	892	-	18
19	Gas Generation	31,782,189	21,421,883	19
20	Financial Hedges Gains/Losses & Transactional Fees	-	-	20
	Purchases through MISO			
21	Wind Purchase Power Agreement Purchases	4,832,186	4,940,837	21
22	Non-Wind PPA Market Purchases	11,100,334	2,392,839	22
23	Other	11,924	-	23
24	MISO Components of Cost of Fuel	3,744,474	1,765,347	24
25	Purchased Power other than MISO	2,704,119	3,010,839	25
	LESS:			
26	Inter-System Sales through MISO	1,331,664	4,367,277	26
27	Inter-System Sales other than MISO	-	-	27
28	Non-Jurisdictional Retail Sales	-	-	28
29	Transmission Losses	270,409	487,424	29
30	Lakefield PPA Adjustment	263,268	242,955	30
31	Purchased Power in Excess	-	-	31
32	Total Fuel Costs (F)	$ 66,105,265	$ 45,305,190	32
33	F / S (Mills/kWh)	59.533	39.188	33
	Weighted Average Deviation	-34.17%		

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

Line No.	Description	July Actual	July Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	723,699	857,258	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	-	-	4
5	Gas Generation	627,869	719,440	5
	Purchases through MISO			
6	Wind Purchase Power Agreement Purchases	40,139	37,263	6
7	Non-Wind PPA Market Purchases	44,768	14,912	7
8	Other	384	-	8
9	Purchased Power other than MISO	15,226	17,322	9
	LESS:			
10	Energy Losses and Company Use	61,696	63,786	10
11	Inter-System Sales through MISO	163,245	260,380	11
12	Inter-System Sales other than MISO	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	13
14	Sales (S)	1,227,144	1,322,029	14
	Fuel Cost			
15	Coal and Oil Generation	$ 19,241,352	$ 20,961,184	15
16	Nuclear Generation	-	-	16
17	Hydro Generation	-	-	17
18	Other Generation - Internal Combustion	264	-	18
19	Gas Generation	37,166,790	27,389,521	19
20	Financial Hedges Gains/Losses & Transactional Fees	-	-	20
	Purchases through MISO			
21	Wind Purchase Power Agreement Purchases	3,556,705	3,831,018	21
22	Non-Wind PPA Market Purchases	3,514,639	626,766	22
23	Other	11,060	-	23
24	MISO Components of Cost of Fuel	3,336,424	2,018,739	24
25	Purchased Power other than MISO	2,490,818	2,819,645	25
	LESS:			
26	Inter-System Sales through MISO	6,067,135	7,697,815	26
27	Inter-System Sales other than MISO	-	-	27
28	Non-Jurisdictional Retail Sales	-	-	28
29	Transmission Losses	607,118	562,813	29
30	Lakefield PPA Adjustment	844,400	279,703	30
31	Purchased Power in Excess	-	-	31
32	Total Fuel Costs (F)	$ 61,799,399	$ 49,106,542	32
33	F / S (Mills/kWh)	50.360	37.145	33
	Weighted Average Deviation	-26.24%		

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel
May, June, and July 2022

Line No.	Description	Total Actual	Total Forecast	Line No.
	kWh Source (000's)			
1	Coal and Oil Generation	1,472,945	2,016,563	1
2	Nuclear Generation	-	-	2
3	Hydro Generation	-	-	3
4	Other Generation - Internal Combustion	27	-	4
5	Gas Generation	1,671,711	1,453,152	5
	Purchases through MISO			
6	Wind Purchase Power Agreement Purchases	130,443	137,682	6
7	Non-Wind PPA Market Purchases	362,706	392,188	7
8	Other	1,133	-	8
9	Purchased Power other than MISO	45,339	52,033	9
	LESS:			
10	Energy Losses and Company Use	166,436	157,551	10
11	Inter-System Sales through MISO	216,223	431,635	11
12	Inter-System Sales other than MISO	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	13
14	Sales (S)	3,301,645	3,462,432	14
	Fuel Cost			
15	Coal and Oil Generation	$ 40,954,715	$ 51,405,341	15
16	Nuclear Generation	-	-	16
17	Hydro Generation	-	-	17
18	Other Generation - Internal Combustion	3,279	-	18
19	Gas Generation	97,437,361	54,991,984	19
20	Financial Hedges Gains/Losses & Transactional Fees	(1,292,165)	-	20
	Purchases through MISO			
21	Wind Purchase Power Agreement Purchases	14,730,965	14,903,052	21
22	Non-Wind PPA Market Purchases	30,587,696	16,033,886	22
23	Other	32,722	-	23
24	MISO Components of Cost of Fuel	10,470,138	5,310,759	24
25	Purchased Power other than MISO	7,522,228	8,522,499	25
	LESS:			
26	Inter-System Sales through MISO	8,116,329	12,673,083	26
27	Inter-System Sales other than MISO	-	-	27
28	Non-Jurisdictional Retail Sales	-	-	28
29	Transmission Losses	997,304	1,178,667	29
30	Lakefield PPA Adjustment	1,231,439	686,195	30
31	Purchased Power in Excess	10,635	-	31
32	Total Fuel Costs (F)	$ 190,091,232	$ 136,629,576	32
33	F / S (Mills/kWh)	57.575	39.461	33
	Weighted Average Deviation	-31.46%		

AES INDIANA
Determination of MISO Components of Fuel Cost
May, June, and July 2022

Line No.	**Energy Market FAC Adjustment Components**	**Total May (A)**	**Total June (B)**	**Total July (C)**	Line No.
1	Delta LMP[1]	$ 3,841,351	$ 5,560,229	$ 5,232,680	1
2	FTR (Revenue) / Expenses	155,043	(1,228,944)	(1,002,401)	2
3	RT Marg. Loss Surplus Credit	(683,134)	(1,198,800)	(1,228,239)	3
4	Virtuals Bids and Offers for Load	-	-	-	4
5	DA & RAC Recovery of Unit Commitment Costs	(50,435)	39,465	(23,832)	5
5a	RSG 1st Pass Charges	188,864	288,402	145,666	5a
5b	RSG 2nd Pass Distribution Correction	-	-	-	5b
6	Inadvertent Energy	(2,332)	24,181	66,512	6
7	Ancillary Services Revenue	(15,965)	(12,862)	(46,856)	7
8	Ancillary Services Costs	176,181	166,399	141,566	8
9	Ancillary Services Incentive to Follow Dispatch[2]	103,543	97,845	55,882	9
10	Ramp Capability[3]	3,114	8,559	(4,554)	10
11	MISO Transmission Owner's Payment not on Settlement Statement - credit to FAC.	(326,990)	-	-	11
12	Total (Columns A, B, & C to Schedule 5, line 24)	$ 3,389,240	$ 3,744,474	$ 3,336,424	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-22 Invoice Total	Jun-22 Invoice Total	Jul-22 Invoice Total	Line No.
1	Day Ahead Market Administration Amount	$ 150,288	$ 163,047	$ 225,182	1
2	Day Ahead Regulation Amount	-	(97)	-	2
3	Day Ahead Spinning Reserve Amount	(15,321)	(1,230)	(549)	3
4	Day-Ahead Short-Term Reserve Amount	(9,260)	(398)	(1,108)	4
4	Day Ahead Supplemental Reserve Amount	(177)	-	-	4
5	Day Ahead Asset Energy Amount	18,087,167	16,774,030	(7,897,620)	5
6	Day Ahead Financial Bilateral Transaction Congestion Amount	-	-	-	6
7	Day Ahead Financial Bilateral Transaction Loss Amount	-	-	-	7
8	Day Ahead Congestion Rebate on Carve-Out Grandfathered Agrmnts	-	-	-	8
9	Day Ahead Losses Rebate on Carve-Out Grandfathered Agrmnts	-	-	-	9
10	Day Ahead Congestion Rebate on Option B Grandfathered Agrmnts	-	-	-	10
11	Day Ahead Losses Rebate on Option B Grandfathered Agrmnts	-	-	-	11
12	Day Ahead Non-Asset Energy Amount	-	-	-	12
13	Day Ahead Ramp Capability Amount	(3,952)	(1,070)	(3,130)	13
14	Day Ahead Revenue Sufficiency Guarantee Distribution Amount	63,565	71,209	61,932	14
15	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amt	(27,828)	(1,575)	(45,131)	15
16	Day Ahead Schedule 24 Allocation Amount	23,818	25,341	30,386	16
17	Day Ahead Virtual Energy Amount	-	-	-	17
	Day Ahead Subtotal	$ 18,268,300	$ 17,029,257	$ (7,630,038)	
18	Financial Transmission Rights Market Administration Amount	$ 6,206	$ 6,648	$ 8,165	18
19	Auction Revenue Rights Transaction Amount	(318,472)	(1,229,841)	(1,229,841)	19
20	Financial Transmission Rights Annual Transaction Amount	258,827	811,369	811,369	20
21	Auction Revenue Rights Infeasible Uplift Amount	53,655	30,866	30,866	21
22	Auction Revenue Rights Stage 2 Distribution Amount	(91,778)	(167,227)	(167,227)	22
23	Financial Transmission Rights Full Funding Guarantee Amount	-	-	-	23
24	Financial Transmission Guarantee Uplift Amount	-	-	-	24
25	Financial Transmission Rights Hourly Allocation Amount	301,253	(671,377)	(446,926)	25
26	Financial Transmission Rights Monthly Allocation Amount	(48,442)	(2,734)	(642)	26
27	Financial Transmission Rights Monthly Transaction Amount	-	-	-	27
28	Financial Transmission Rights Transaction Amount	-	-	-	28
29	Financial Transmission Rights Yearly Allocation Amount	-	-	-	29
	Financial Transmission Rights Subtotal	$ 161,249	$ (1,222,296)	$ (994,236)	
30	Real Time Market Administration Amount	$ 14,926	$ 17,505	$ 23,377	30
31	Contingency Reserve Deployment Failure Charge Amount	-	-	-	31
32	Excessive Energy Amount	(29,416)	(10,730)	(33,225)	32
33	Real Time Excessive Deficient Energy Deployment Charge Amount	8,876	4,055	9,570	33
34	Net Regulation Adjustment Amount	-	-	-	34
35	Non-Excessive Energy Amount	319,024	(69,994)	1,132,097	35
36	Real Time Regulation Amount	(211)	(2,247)	(4,851)	36
37	Regulation Cost Distribution Amount	76,988	60,053	56,715	37
38	Real Time Spinning Reserve Amount	9,002	(8,159)	(36,518)	38
39	Spinning Reserve Cost Distribution Amount	74,270	63,032	25,052	39
40	Real Time Short-Term Reserve Amount	26	(712)	(2,821)	40
41	Real-Time Short-Term Reserve Deployment Failure Charge Amount	-	-	-	41
42	Short-Term Reserve Cost Distribution Amount	18,933	26,897	19,153	42
43	Real Time Supplemental Reserve Amount	(25)	(18)	(1,009)	43
44	Supplemental Reserve Cost Distribution Amount	5,990	16,417	40,646	44
45	Real Time Asset Energy Amount	50,288	(2,991,320)	(715,506)	45
46	Real Time Demand Response Allocation Uplift Charge	94,669	95,385	56,996	46
47	Real Time Financial Bilateral Transaction Congestion Amount	-	-	-	47
48	Real Time Financial Bilateral Transaction Loss Amount	-	-	-	48
49	Real Time Congestion Rebate on Carve-Out Grandfathered Agrmnts	-	-	-	49
50	Real Time Losses Rebate on Carve-Out Grandfathered Agrmnts	-	-	-	50
51	Real Time Distribution of Losses Amount	(683,134)	(1,198,800)	(1,228,239)	51
52	Real Time Miscellaneous Amount	-	576	(2,534)	52
53	Real Time MVP Distribution Amount	(9,184)	(13,782)	(13,865)	53
54	Real Time Non-Asset Energy Amount	-	-	-	54
55	Real Time Net Inadvertent Distribution Amount	(2,332)	24,181	66,512	55
56	Real Time Price Volatility Make Whole Payment	(53,891)	(110,508)	(329,353)	56
57	Real Time Resource Adequacy Auction Amount	(25,230)	(1,630,009)	(1,684,342)	57
58	Real Time Ramp Capability Amount	(1,898)	(5,511)	(16,880)	58
59	Real Time Revenue Neutrality Uplift Amount	596,379	461,301	64,211	59
60	Real Time Revenue Sufficiency Guarantee First Pass Dist Amount	217,097	333,964	174,239	60
61	Real Time Revenue Sufficiency Guarantee Make Whole Payment Amt	(93,458)	(30,654)	(58,679)	61
62	Real Time Schedule 24 Allocation Amount	2,365	2,720	3,154	62
63	Real Time Schedule 24 Distribution Amount	(68,407)	(56,595)	(60,886)	63
64	Real Time Schedule 49 Cost Distribution Amount	38,510	35,251	40,495	64
65	Real Time Virtual Energy Amount	-	-	-	65
	Real Time Subtotal	$ 560,157	$ (4,987,702)	$ (2,476,491)	
	Grand Total	$ 18,989,706	$ 10,819,259	$ (11,100,765)	

CERTIFICATE OF SERVICE

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

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

Dated this 16th day of September, 2022.

Jeffrey M. Peabody

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

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

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

DMS 22935992v1