FILED
April 21, 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 JUNE 2022 THROUGH AUGUST 2022, IN ACCORDANCE WITH THE PROVISIONS OF I.C. 8-1-2-42, AND CONTINUED USE OF RATEMAKING TREATMENT FOR COSTS OF WIND POWER PURCHASES PURSUANT TO CAUSE NOS. 43485 AND 43740, AND AUTHORITY TO RECOVER COSTS OF THE FUEL HEDGING PLAN PURSUANT TO I.C. 8-1-2-42.	**CAUSE NO. 38703 FAC-135**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

PUBLIC'S EXHIBIT NO. 1

PRE-FILED TESTIMONY OF OUCC WITNESS GREGORY T. GUERRETTAZ

April 21, 2022

IURC PUBLIC'S EXHIBIT NO. 1
5-12-22 DATE
REPORTER

Respectfully submitted,

Lorraine Hitz
Lorraine Hitz
Attorney No. 18006-29
Deputy Consumer Counselor

OFFICE OF UTILITY CONSUMER COUNSELOR

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

(AES Indiana)

Review of Fuel Cost Adjustment

Cause No. 38703-FAC 135

Pre-Filed Testimony of Gregory T. Guerrettaz, CPA

1. Q - Please state your name, title, and business address.

   A - My name is Gregory T. Guerrettaz. I am a CPA and a Municipal Advisor. My office is located at 2680 East Main Street, Suite 223, Plainfield, Indiana 46168. My qualifications are attached to this testimony as Appendix A.

2. Q - What is the purpose of your testimony in this Cause?

   A - I will give an opinion concerning the relief requested by Indianapolis Power & Light Company ("IPL", "Applicant" or "AES Indiana") in its Application for Approval of Fuel Cost Charge, filed on March 17, 2022, as discussed in AES Indiana's direct testimony. My testimony will discuss:

   (a) Whether AES Indiana has calculated the fuel cost element of the proposed fuel cost adjustment in conformity with the requirements of Ind. Code § 8-1-2-42, although AES Indiana has chosen to exclude two variance flow-throughs explained herein;

   (b) Whether the fuel costs paid by AES Indiana, when compared to fuel costs recovered by AES Indiana for the quarter ended January 31, 2022, resulted in a variance which was used to calculate the fuel cost adjustment for the quarter ended August 31, 2022, in conformity with the requirements of I.C. § 8-1-2-42;

   (c) Whether the level of net operating income experienced by AES Indiana for the twelve months ended January 31, 2022 was greater than that granted in IPL's rate case proceedings, Cause No. 45029, as well as applicable ECCRA and Transmission, Distribution and Storage System Improvement Charge Property ("TDSIC") Orders; and

(d) Whether the fuel cost adjustment for the quarter ended January 31, 2022 has been properly applied in conformity with the requirements of Cause Nos. 38703-FAC 131.

3. Q - Please explain Schedule A.

A - Schedule A presents the components of AES Indiana's proposed fuel cost adjustment factor, as supplemented, and shows how the components are used in the calculation. The fuel cost element of the proposed fuel cost adjustment contains more than AES Indiana's actual fuel costs. For example, this calculation includes certain costs of AES Indiana's power purchases, MISO charges and credits, and ASM charges.

Schedule A also demonstrates the fuel cost paid by AES Indiana, when compared to the fuel costs recovered from AES Indiana's customers for the quarter ended January 31 2022 and the variance to be recovered. As filed by AES, Schedule A has multiple line items to arrive at the variance factor. The following items have been used to calculate the combined variance:

(1) The first item that is subtracted is the over-earnings. This adjustment is made by taking the current overearnings of $282,364 divided by the projected sales of 3,743,783 KWh's (000's) resulting in a reduction of (.075).

(2) The next adjustment AES is proposing is a combination of several variances: (A) the variance from FAC 135 of $64,326,816; (B) the remaining one-half of the variance from FAC 133 of $6,481,810; (C) the variance of FAC 134 adjusted for a tie-line correction with Duke adding $2,401,941 for a total of $32,281,690; and (D) a reduction of $35,168,380 for the estimated impact of Eagle Valley outage.

These combined variances total $68,281,936, which AES Indiana is requesting be spread over FACs 135 and 136. Therefore, the combined variance to be added to the forecasted cost of 37.366 Mills/KWh is 9.119 or $34,140,968 (one-half of the combined variance) stated above. Once the forecasted cost of 37.366 Mills per KWh is added to the 9.119, and the earnings reduction of (.075), the total requested amount is 46.410 Mills per KWh. Subtracting the base cost of fuel of 32.938 results in a factor of 13.472 Mill per KWh before IURT and 13.673 with IURT.

4. Q - Are two separate factors required for this FAC period?

   A - Yes, the IURT has been eliminated effective July 1, 2022. Therefore, the factor with IURT will be charged up to June 30, 2022 and the factor without IURT will be billed in July and August.

5. Q - Please explain Schedules B and B-1.

   A - Schedule B compares AES Indiana's actual electric net operating income applicable to jurisdictional retail sales for the twelve months ending January 31, 2022 (as adjusted for rounding), to IPL's authorized electric net operating income per the Commission's Order in Cause No. 45029, as adjusted for all applicable Qualified Pollution Control Property ("QPCP") proceedings under Cause Nos. 42170-ECRs, 45264, and TDSIC Orders. Schedule B-1 depicts AES Indiana's cumulative over- or under- earnings for each fuel cost adjustment for the relevant period calculated.

6. Q - Has AES Indiana earned a level of net operating income greater than that authorized by the Commission?

   A - Yes. As shown on Schedule B, AES Indiana had jurisdictional net operating income (for the twelve months ending January 31, 2022) greater than that granted in Cause No. 45029, as adjusted for applicable ECR and TDSIC Causes.

7. Q - Since there are over-earnings in this FAC, does the OUCC need to review the sum of the "earnings bank"?

   A -Yes. AES Indiana is currently over-earning in this FAC, requiring the OUCC to review "Excess (Under) Earnings for the Relevant Period" as shown on Schedule B-1. As can be seen from this schedule, the Sum of Differentials for the relevant period is a positive $275,608,218, which has accumulated through the following FAC proceedings (FAC 116 through FAC 135).

8. Q - Has the fuel cost adjustment for the quarter ending January 31, 2022, been accurately applied in conformity with the requirements of Cause No. 38703-FAC 131?

A - Yes. The fuel cost adjustment approved by the Commission in Cause No. 38703-FAC 131 was the amount applied to AES Indiana's customers for the period approved.

9. Q - Has the FAC factor been adjusted for the over-earnings?

A - Yes, an adjustment has been made on Schedule A.

10. Q - Please explain Schedule C.

A - Schedule C compares AES Indiana's pro forma operating expenses approved by the Commission in Cause No. 45029 with the actual operating expenses incurred by AES Indiana for the twelve months ending January 31, 2022. The purpose of this calculation is to determine whether AES Indiana had actual decreases in other operating expenses which could be used to offset increases in AES Indiana's fuel cost. As can be seen on Schedule C, AES Indiana did not have decreases in other operating costs that could be used to offset fuel cost increases.

11. Q - Please explain Schedules D and E.

A - Schedule D sets forth the total fuel cost, in Mills, for the period January 2018 through January 2022. Schedule E graphically depicts the results of Schedule D for the period January 2018 through January 2022.

12. Q - Does the OUCC have any comments regarding the:

1) purchased power benchmark agreement approved in Cause No. 43414;

2) Ancillary Services Market ("ASM");

3) bill analysis;

4) steam generation cost comparison;

5) actual cost of fuel (Mills/KWh) comparison;

6) coal contract analysis;

7) coal inventory;

8) Lakefield Wind Park ("Lakefield") and Hoosier Wind Power Project LLC ("Hoosier");

9) coal price decrement;

10) unit commitment status;

11) hedging program;

12) the Eagle Valley Outage ("Eagle Valley");

13) Root Cause Analysis ("RCA");

14) sub-docket request; or

15) variance request deferral?

A - OUCC Witness Michael Eckert will provide testimony on these issues.

13. Q - Please explain Schedule F.

A - Schedule F is the comparison of actual fuel cost and estimated fuel cost for this FAC period and includes transmission loss adjustments.

14. Q - Does the OUCC have an opinion regarding the projections used by AES Indiana for fuel costs and sales of power for the quarter ending August 31, 2022, after the review that was just discussed?

A - Yes. The OUCC performed a detailed review of AES Indiana's estimation model. The forecast is affected by the following items:

1) Daily changes of the price of natural gas;

2) Daily changes of power prices for the MISO market;

3) Recent hedges put into place; and

4) AES Indiana's coal inventory issues.

During the audit, AES Indiana provided the OUCC with more current natural gas and power prices, which showed the as-filed projected Fuel ÷ Sales (F÷S) of 37.366 Mills per KWhs is lower than an updated F÷S with current natural gas and power prices. IPL and the OUCC have chosen not to update the filing for these updated rates, as this would result in a further increase to the factor. The F÷S cost in this FAC uses generation from Eagle Valley Generating Station, but the forecasted cost of natural gas used to run the facility is quite high due to market conditions.

15. Q - Please explain Schedule G.

A - Schedule G reflects the proposed and historical fuel cost adjustment factors. The proposed factor was broken out to show the factor being charged for June with IURT and July and August without IURT.

16. Q - Please explain Schedule H.

A - Schedule H is the schedule setting forth the MISO – Cost Flow Through in this FAC.

17. Q - Please explain Schedule I.

A - Schedule I is the schedule setting forth all MISO charge types by month.

18. Q - Did AES Indiana include the fuel cost and fuel revenue associated with sales from its public electric vehicle charging stations in this FAC?

A - Yes. The amounts accounted for as fuel costs are reflected on Attachment NHC-1, Schedule 4.

19. Q - What was AES Indiana's weighted average deviation for the reconciliation period?

A - The weighted average deviation for the reconciliation period is a negative 37.25%. Therefore, AES Indiana underestimated for this period, which is attributable to large price increases in natural gas and power.

20. Q - How will AES Indiana's interim proposed factor affect the average residential customer?

A - An average residential customer using 1,000 KWh per month will experience an increase of $6.25, or 5.08% with the proposed mitigated factor or $14.44, or 11.74% with the unmitigated factor using IURT.

21. Q - Is AES Indiana's coal inventory within its target levels?

A - Yes. IPL expressed concerns during the audit regarding decreases to its coal inventory level and the challenges of coal transportation. AES Indiana indicated they were reviewing all options and will present additional ways to control coal inventory.

22. Q - Should AES Indiana provide an update to the OUCC on coal inventory changes in the next FAC?

A - Yes. The OUCC has requested an update in the next FAC so it can stay informed of AES Indiana's decisions regarding coal inventory levels and coal transportation.

23. Q - Is AES Indiana seeking to recover any purchased power costs incurred in November 2021, December 2021 or January 2022 that are in excess of the Daily Benchmarks?

A - Yes. AES Indiana is seeking to recover $567,887 of the non-outage[1] portion of purchased power costs in excess of the applicable Purchased Power Daily Benchmarks from FACs 133, 134 and 135. Mr. Eckert provides testimony on the recoverable detail.

24. Q - What information does the OUCC continue to review in FAC audits?

A - The FAC is impacted by ever-changing generation costs, the generation mix, MISO market offer components, MISO instructions, purchased power costs in the MISO market and other items.

25. Q - What additional items did the OUCC cover during the audit?

A - The OUCC spent considerable time on the power hedges that were put into place as a result of the extended outage at Eagle Valley. The company experienced a total gain of $6,743,900. This gain was used as a reduction to the actual costs in each month on Schedule 5. Because the variance is only being charged in this FAC, these gains will flow back as the regulatory asset is charged going forward.

26. Q - Did AES Indiana address the further progress they have made regarding fuel hedging policy with the OUCC?

A - Yes, considerable discussion took place surrounding the natural gas hedging policy. AES Indiana walked the OUCC through the structure of the hedges. The process continues despite high natural gas prices in the short run and some reductions in future prices.

27. Q - What other additional items came up during the audit?

[1] Defined by AES Indiana as the dollar amount attributable to other generating stations not related to Eagle Valley outage.

A - Numerous items were covered during the audit. Below are the most important points.

1) Coal price stress test;

2) Lowest point that was acceptable to AES Indiana for coal inventory during the period of November 1, 2021 to December 31, 2021 and what level prompted higher dollar costs;

3) Summer Forecast for 2022 presented by WeatherDesk™;

4) Various disclosures in the 10-K regarding the cash flow issues as noted in AES Indiana's Witness Natalie Coklow's testimony, verified back to page 110 of the 10-K and various notes in AES Indiana's 2021 10-K;

5) The tie line correction of $2,401,901 for October that has been treated as a prior period correction by AES Indiana;

6) AES Indiana treatment and breakout of the new ASM charge types and the effect on the FAC 135;

7) Changes in the heat rates for units in the proposed forecast versus actual heat rates; and

8) Current operating status of Eagle Valley and the likely capacity factor of the station.

It is important to point out that all these items and topics are necessary to reach the OUCC's opinion on the FAC factor being proposed.

28. Q - What does the OUCC recommend?

A - The OUCC recommends:

1) the Commission approve AES Indiana's proposed fuel cost charge of 13.673 (with IURT for June 2022) Mills per KWh on an interim subject to refund basis, dependent on the outcome of the sub-docket in FAC 133 S1;

2) the Commission approve AES Indiana's proposed fuel cost charge of 13.472 (without IURT for July and August 2022) Mills per KWh;

3) AES Indiana continue to use its commitment model and continue to provide the results to the OUCC in each FAC;

4) AES Indiana provide the OUCC with updates on any strategies developed for hedging natural gas and power hedges on a going forward basis; and

5) AES continue to defer as a regulatory asset, without carrying charges, the variances calculated during the reconciliation period of November 2021 through January 2022, as well as the remaining variances, for potential recovery in a future FAC filing or pending the conclusion of the FAC 133 sub-docket.

29. Q - Does this conclude your pre-filed testimony?

A - Yes.

Appendix A - Qualifications of Gregory T. Guerrettaz

1. Q - Please state your name, title, and business address.

   A - My name is Gregory T. Guerrettaz. I am a CPA. My office is located at 2680 East Main Street, Suite 223, in Plainfield, Indiana 46168.

2. Q - By whom are you employed and what is your position?

   A - Gregory T. Guerrettaz, CPA is a wholly owned subsidiary of Financial Solutions Group, Inc. (formed in 1998) which is registered with the Securities and Exchange Commission (SEC), effective January 1, 2011. I am employed as President of Financial Solutions Group, Inc. ("FSG Corp."), a public finance and utility rate consulting firm.

3. Q - Please summarize your educational and professional qualifications.

   A - I received a Bachelor's degree in Accounting from Indiana University. During my employment, I have attended and spoken at numerous seminars on governmental accounting and finance throughout the United States. I continue to maintain all requirements under Continuing Professional Education.

4. Q - How long have you been employed by FSG Corp., and in what capacities?

   A - I founded FSG Corp. in 1998 and am employed as the President of the company. FSG Corp.'s practice is split about 50% utility and 50% finance related. I have been responsible for numerous projects, including utility rate engagements, cost of capital analyses and rate of return, utility financial analyses, utility business valuations, other projects related to a variety of utility issues and preparation of electric trackers for utilities in the State of Indiana.

   I have pre-filed written, and given oral, testimony to the Indiana Utility Regulatory Commission on a variety of issues over the years including, but not limited to, revenue requirement calculations, accounting methodology and related areas, utility historical and pro-forma financial information, cost of capital analysis, rate structure and cost of service issues, issuance of both long and short-term debt, utility operating information, utility trackers and a variety of other utility related issues.

I prepare activity-based budgets and assist communities in the preparation of both short and long-range plans for all types of entities. I have served as Financial Advisor for over two billion dollars of tax-exempt and taxable securities. FSG Corp. is registered with the Security and Exchange Commission (SEC) and the Municipal Security Rulemaking Board (MSRB), and currently I hold a Series 50 license as a Municipal Advisor.

5. Q - Please state your experience prior to joining FSG Corp.

A - I was employed for 8 years with a national accounting firm in Indianapolis. I was a partner in that firm for 4 years and, for 4 years was a partner in a partnership between that firm and Municipal Consultants, Inc. Prior to that, Municipal Consultants, Inc. employed me for 7 years (4 of those as a shareholder) until the partnership and eventual merger with the national accounting firm. While at Municipal Consultants, Inc., I reviewed, prepared and analyzed over 900 FAC filings by various electric utilities. I also testified numerous times, over the seven years, regarding the earnings and return tests. Preceding my time with Municipal Consultants, Inc., I worked for 3 years as a Staff Accountant for the Accounting Department of the Public Service Commission of Indiana, now known as the Indiana Utility Regulatory Commission. In this position, I prepared and presented testimony in major electric and water cases. I have performed utility reviews since 1981. I have also performed a variety of feasibility and cost-of-service studies, for cities and counties throughout Indiana.

I am a Certified Public Accountant, licensed in the State of Indiana, and am a member of the American Institute of Certified Public Accountants and the Indiana CPA Society. I am an Associate Member of the Association of Indiana Counties and the Indiana Association of Cities and Towns. I have served as the Chairman of the Indiana CPA Utilities Committee in the past.

OFFICE OF UTILITY CONSUMER COUNSELOR
REVIEW OF FUEL COST ADJUSTMENT
Indianapolis Power & Light Company
Cause No. 38703-FAC 135

Calculation of Proposed Fuel Cost Adjustment Factor

Requested by AES

	Mills/KWh
Average projected fuel cost for quarter including June, July and August 2022	37.366
Reduction in Fuel Factor from Earnings Test **(1)**	(0.075)
Total Combination Variance **(2)**	9.119
Total Request by AES	46.410
Less: Base cost of fuel	32.938
Proposed FAC without IURT (July and Aug billing cycle)	13.472
Provision for Indiana Utility Receipts Tax	0.201
Proposed FAC with IURT (June billing cycle)	13.673

NOTE:
(1) Over-earnings $282,364 / 3,743,783
(2) See Testimony pages 2 and 3

OFFICE OF UTILITY CONSUMER COUNSELOR
REVIEW OF FUEL COST ADJUSTMENT
Indianapolis Power & Light Company
Cause No. 38703-FAC 135

Comparison of Authorized Return
with Actual Net Operating Income (in $000's)

Actual Twelve Months Ending January 31, 2022		
Jurisdictional Operating Revenue	$	1,449,714
Jurisdictional Operating Expense		1,222,353
Jurisdictional Net Operating Income	$	227,361
Per Cause No. 45029		
Jurisdictional Net Operating Income	$	220,076,000
Adjustments for Cause No. 42170-ECR33 and ECR 34	$	1,537,000
Adjustments for Cause No. 45264 TDISC-1 Combined	$	2,306,000
Adjustments for Cause No. 45264 TDISC-3 Combined	$	2,610,000
Adjusted Jurisdictional Net Operating Income Total	$	226,529,000
Over (Under)	$	832,000
Quarter Amount	$	208,000
Revenue Conversion		1.35752
Reduction Applied	$	282,364

OUCC REVIEW OF FUEL COST ADJUSTMENT

Indianapolis Power & Light Company
Cause No. 38703-FAC 135

Excess (Under) Earnings for Relevant Period

Item No.	FAC No.	Reporting Pd.	Determined Return	Authorized Return	Differential
1	135	1/31/2022	$ 227,361,000	$ 226,529,000	$ 832,000
2	134	10/31/2021	226,080,000	224,682,000	1,398,000
3	133	7/31/2021	219,585,000	223,889,000	(4,304,000)
4	132	04/30/2021	232,893,000	223,097,000	9,796,000
5	131	01/31/2021	227,171,000	222,310,000	4,861,000
6	130	10/31/2020	229,881,000	221,451,000	8,430,000
7	129	07/31/2020	242,467,000	221,368,000	21,099,000
8	128	04/30/2020	236,917,000	221,285,000	15,632,000
9	127	01/31/2020	234,075,000	221,201,000	12,874,000
10	126	10/31/2019	230,875,000	218,710,000	12,165,000
11	125	07/31/2019	229,431,000	206,716,000	22,715,000
12	124	04/30/2019	217,179,000	194,654,170	22,524,830
13	123	01/31/2019	212,078,000	182,107,612	29,970,388
14	122	10/31/2018	201,730,000	172,128,000	29,602,000
15	121	07/31/2018	190,971,000	171,399,000	19,572,000
16	120	04/30/2018	180,892,000	170,247,000	10,645,000
17	119	01/31/2018	177,867,000	169,205,000	8,662,000
18	118	10/31/2017	180,108,000	168,291,000	11,817,000
19	117	07/31/2017	185,397,000	167,012,000	18,385,000
20	116	04/30/2017	183,962,000	165,030,000	18,932,000
			Sum of Differential for Relevant Period		$ 275,608,218

OFFICE OF UTILITY CONSUMER COUNSELOR
REVIEW OF FUEL COST ADJUSTMENT
Indianapolis Power & Light Company
Cause No. 38703-FAC 135

Comparison of Pro-Forma Operating Expense
with Actual Operating Expense
(000's Omitted)

Actual Twelve Months Ending January 31, 2022	
Total Operating Expense	$ 1,222,353
Less: Fuel Costs	432,388
Operating Expense Excluding Fuel Cost	$ 789,965
Per Cause No. 45029	
Total Operating Expense	$ 1,193,106
Less: Fuel Costs	436,216
Operating Expense Excluding Fuel Cost	$ 756,890
Over (Under)	$ 33,075

OFFICE OF UTILITY CONSUMER COUNSELOR
REVIEW OF FUEL COST ADJUSTMENT
Indianapolis Power & Light Company
Cause No. 38703-FAC 135

Actual Cost of Fuel to Generate Electricity and
the Actual Cost of Fuel Included in the Cost of Purchased Power

Line No.	Description	January 2018	February 2018	March 2018	April 2018	May 2018	June 2018	July 2018	August 2018	September 2018	October 2018	November 2018	December 2018
	KWH Source (000's) :												
1.	Coal Generation	990,036	689,328	696,709	787,934	676,527	910,918	905,578	868,108	736,774	618,164	484,297	731,685
2.	Nuclear Generation	-	-	-	-	-	-	-	-	-	-	-	-
3.	Hydro Generation	-	-	-	-	-	-	-	-	-	-	-	-
4.	Other Generation - Internal Combustion	21	9	17	20	12	12	9	5	16	18	12	14
5.	Gas Generation	224,873	48,058	37,554	150,034	594,750	511,818	609,488	311,399	138,680	494,247	431,913	466,575
	Purchases through MISO:												
6.	Wind Purchase Power Agreement Purchases	101,724	75,762	95,866	75,600	50,833	64,029	39,956	42,710	60,959	74,194	81,800	81,368
7.	Non-Wind PPA Market Purchases	156,836	299,066	319,710	80,232	14,581	21,268	25,793	135,474	220,606	21,044	147,140	27,598
8.	Other	-	-	-	-	-	-	-	38	38	24	27	24
9.	Purchased Power other than MISO	4,072	6,233	9,806	11,770	17,203	17,032	17,630	15,091	14,065	13,434	9,730	7,074
	LESS:												
10.	Energy Losses and Company Use	75,537	60,068	61,603	54,260	61,903	66,059	69,340	69,314	60,716	56,261	59,624	64,390
11.	Inter-System Sales through MISO	44,455	1,386	1,468	88,871	183,919	273,074	281,529	55,887	23,084	157,312	28,772	101,395
12.	Inter-System Sales other than MISO	-	-	-	-	-	-	-	-	-	-	-	-
13.	Non-Jurisdictional Retail Sales	-	-	-	-	-	-	-	-	-	-	-	-
14.	Sales (S)	1,357,570	1,057,002	1,096,591	962,459	1,108,084	1,185,944	1,247,585	1,247,624	1,087,338	1,007,552	1,066,523	1,148,553
	Fuel Cost $ (F) :												
15.	Coal Generation	$ 22,191,868	$ 15,270,812	$ 15,385,585	$ 16,852,047	$ 15,283,077	$ 19,771,026	$ 19,756,719	$ 19,331,194	$ 16,111,160	$ 13,225,424	$ 11,162,973	$ 15,643,611
16.	Nuclear Generation	-	-	-	-	-	-	-	-	-	-	-	-
17.	Hydro Generation	-	-	-	-	-	-	-	-	-	-	-	-
18.	Other Generation - Internal Combustion	2,725	1,121	1,968	4,111	1,479	2,105	4,150	2,047	22,385	2,903	1,768	1,881
19.	Gas Generation	14,230,121	2,145,062	1,607,754	5,980,969	14,923,755	13,243,301	14,726,796	9,746,473	6,534,356	13,784,067	14,169,464	13,236,706
	Purchases through MISO:												
20.	Wind Purchase Power Agreement Purchases	7,403,016	5,668,997	6,981,390	5,854,999	3,906,035	4,683,473	3,200,212	3,305,516	4,681,452	5,515,248	6,054,392	6,080,583
21.	Non-Wind PPA Market Purchases	8,353,963	7,963,752	8,865,458	2,216,364	388,387	709,430	729,688	4,558,694	7,676,243	691,243	5,679,801	937,146
22.	Other	38,190	-	-	-	-	-	-	1,126	1,113	724	591	682
23.	MISO Components of Cost of Fuel	3,253,978	966,074	1,377,352	546,152	1,176,271	461,118	967,200	908,262	1,219,441	807,030	1,121,030	1,359,718
24.	Purchased Power other than MISO	658,850	1,006,311	1,665,587	1,969,914	2,924,049	2,869,450	2,982,249	2,540,302	2,312,404	2,021,117	1,401,498	1,003,459
	LESS:												
25.	Inter-System Sales through MISO	1,025,499	23,807	27,090	1,994,324	3,610,379	4,978,387	5,220,277	998,923	422,187	2,858,106	527,637	1,829,782
26.	Inter-System Sales other than MISO	-	-	-	-	-	-	-	-	-	-	-	-
27.	Non-Jurisdictional Retail Sales	-	-	-	-	-	-	-	-	-	-	-	-
28.	Transmission Losses	138,715	5,342	2,455	208,726	381,458	420,573	486,653	212,345	99,684	304,273	85,497	295,626
29.	Lakefield PPA Adjustment	101,493	(3,036)	618	138,037	218,333	364,348	181,589	42,452	35,890	306,648	45,830	227,468
30.	Purchased Power in Excess	7,509	-	1,694	1	-	-	-	-	-	-	-	-
31.	Total Fuel Costs (F)	$ 54,859,495	$ 32,996,016	$ 35,853,237	$ 31,083,468	$ 34,392,883	$ 35,976,595	$ 36,478,495	$ 39,139,894	$ 38,000,793	$ 32,578,729	$ 38,932,553	$ 35,910,910
32.	Fuel Cost per KWH (in Mills) F/S	$ 40.410	$ 31.217	$ 32.695	$ 32.296	$ 31.038	$ 30.336	$ 29.239	$ 31.372	$ 34.948	$ 32.335	$ 36.504	$ 31.266

OFFICE OF UTILITY CONSUMER COUNSELOR
REVIEW OF FUEL COST ADJUSTMENT
Indianapolis Power & Light Company
Cause No. 38703-FAC 135

Actual Cost of Fuel to Generate Electricity and the Actual Cost of Fuel Included in the Cost of Purchased Power

Line No.	Description	January 2019	February 2019	March 2019	April 2019	May 2019	June 2019	July 2019	August 2019	September 2019	October 2019	November 2019	December 2019
	KWH Source (000's) :												
1.	Coal Generation	770,207	686,760	609,764	478,816	458,862	724,120	789,818	757,758	769,213	856,262	928,065	927,979
2.	Nuclear Generation	-	-	-	-	-	-	-	-	-	-	-	-
3.	Hydro Generation	-	-	-	-	-	-	-	-	-	-	-	-
4.	Other Generation - Internal Combustion	20	18	21	23	10	11	22	16	21	8	15	5
5.	Gas Generation	540,187	463,083	500,822	386,005	446,217	520,853	687,668	644,957	580,973	574,081	503,730	543,891
	Purchases through MISO:												
6.	Wind Purchase Power Agreement Purchases	77,865	63,944	84,775	78,799	69,525	51,012	44,188	36,827	62,428	87,732	83,809	84,592
7.	Non-Wind PPA Market Purchases	43,724	24,321	86,364	110,442	87,872	21,733	34,678	5,545	20,264	197	10,246	6,473
8.	Other	8	6	11	22	31	34	30	44	34	26	26	11
9.	Purchased Power other than MISO	7,137	8,356	9,668	14,770	13,659	15,459	19,167	18,310	16,369	14,009	9,054	6,648
	LESS:												
10.	Energy Losses and Company Use	74,812	64,295	64,408	52,410	56,613	60,207	74,746	68,228	63,636	54,511	59,893	65,043
11.	Inter-System Sales through MISO	69,387	80,189	119,240	118,968	43,667	234,050	200,045	211,938	282,634	534,597	439,388	382,950
12.	Inter-System Sales other than MISO	-	-	-	-	-	-	-	-	-	-	-	-
13.	Non-Jurisdictional Retail Sales	-	-	-	-	-	-	-	-	-	-	-	-
14.	Sales (S)	1,294,949	1,102,004	1,107,777	897,499	975,896	1,038,965	1,300,780	1,183,291	1,103,032	943,207	1,035,664	1,121,606
	Fuel Cost $ (F) :												
15.	Coal Generation	$ 16,696,294	$ 14,706,645	$ 13,722,596	$ 10,424,270	$ 10,401,513	$ 15,713,388	$ 16,230,872	$ 15,236,020	$ 15,669,695	$ 17,031,501	$ 19,211,506	$ 17,862,410
16.	Nuclear Generation	-	-	-	-	-	-	-	-	-	-	-	-
17.	Hydro Generation	-	-	-	-	-	-	-	-	-	-	-	-
18.	Other Generation - Internal Combustion	2,992	2,712	3,242	4,947	1,595	1,759	4,203	2,526	3,094	1,154	2,470	780
19.	Gas Generation	14,983,451	10,813,630	12,383,862	8,412,722	9,206,214	10,560,348	13,774,871	12,347,535	11,272,816	9,653,971	10,285,132	10,162,980
20.	Financial Hedges Gains/Losses & Trans. Fees	-	-	-	-	-	-	-	-	-	-	-	-
	Purchases through MISO:												
21.	Wind Purchase Power Agreement Purchases	6,113,708	4,802,582	6,768,046	6,048,356	5,409,411	3,942,332	3,335,474	2,838,063	4,652,850	6,778,041	6,648,508	6,587,935
22.	Non-Wind PPA Market Purchases	2,176,397	632,183	2,965,688	3,002,418	2,159,779	445,025	831,948	99,556	702,619	3,865	243,780	122,784
23.	Other	225	192	314	700	827	924	813	1,169	913	706	687	297
24.	MISO Components of Cost of Fuel	1,344,091	816,947	(206,912)	2,740,064	49,393	655,668	1,109,015	858,330	1,791,027	1,294,798	1,446,196	1,266,124
25.	Purchased Power other than MISO	933,770	1,224,752	1,510,746	2,265,633	2,171,605	2,549,657	3,211,065	2,947,222	2,597,391	2,252,739	1,397,289	873,619
	LESS:												
26.	Inter-System Sales through MISO	1,204,084	1,378,211	2,015,320	1,973,918	683,448	3,831,213	3,377,524	3,469,006	4,441,529	8,021,192	7,494,076	6,151,467
27.	Inter-System Sales other than MISO	-	-	-	-	-	-	-	-	-	-	-	-
28.	Non-Jurisdictional Retail Sales	-	-	-	-	-	-	-	-	-	-	-	-
29.	Transmission Losses	219,757	214,951	222,738	153,443	90,769	273,022	359,847	321,204	371,880	311,351	409,395	327,432
30.	Lakefield PPA Adjustment	136,211	47,132	102,456	166,441	63,516	146,258	192,921	95,630	277,465	520,486	407,456	300,163
31.	Purchased Power in Excess	98,057	-	-	-	-	-	-	-	-	-		
32.	Total Fuel Costs (F)	$ 40,592,819	$ 31,359,349	$ 34,807,068	$ 30,605,308	$ 28,562,604	$ 29,618,608	$ 34,567,969	$ 30,444,581	$ 31,599,531	$ 28,163,746	$ 30,924,641	$ 30,097,867
33.	Fuel Cost per KWH (in Mills) F/S	$ 31.347	$ 28.457	$ 31.421	$ 34.101	$ 29.268	$ 28.508	$ 26.575	$ 25.729	$ 28.648	$ 29.860	$ 29.860	$ 26.835

SCHEDULE D
(Continued)

OFFICE OF UTILITY CONSUMER COUNSELOR
REVIEW OF FUEL COST ADJUSTMENT
Indianapolis Power & Light Company
Cause No. 38703-FAC 135

Actual Cost of Fuel to Generate Electricity and the Actual Cost of Fuel Included in the Cost of Purchased Power

Line No.	Description	January 2020	February 2020	March 2020	April 2020	May 2020	June 2020	July 2020	August 2020	September 2020	October 2020	November 2020	December 2020
	KWH Source (000's) :												
1.	Coal Generation	629,367	797,762	352,582	(6,945)	18,808	476,399	805,452	726,943	547,994	454,911	406,656	933,629
2.	Nuclear Generation	-	-	-	-	-	-	-	-	-	-		
3.	Hydro Generation	-	-	-	-	-	-	-	-	-	-		
4.	Other Generation - Internal Combustion	17	15	17	19	10	14	9	15	20	12	12	27
5.	Gas Generation	600,605	526,779	431,161	500,461	588,385	740,517	849,534	516,354	507,369	591,349	441,249	496,280
	Purchases through MISO:												
6.	Wind Purchase Power Agreement Purchases	72,777	85,331	73,840	75,404	53,913	43,584	37,037	47,741	43,136	41,895	58,893	57,207
7.	Non-Wind PPA Market Purchases	72,562	4,162	256,736	315,833	269,846	45,347	7,222	69,716	45,799	28,264	103,272	7,736
8.	Other	9	8	15	26	40	47	57	48	51	35	21	16
9.	Purchased Power other than MISO	7,980	6,482	11,862	13,970	15,401	19,302	19,411	17,469	15,866	11,562	10,123	8,162
	LESS:												
10.	Energy Losses and Company Use	68,045	64,478	58,114	49,898	52,020	62,342	72,591	67,715	55,881	52,260	53,782	66,319
11.	Inter-System Sales through MISO	153,446	255,982	76,391	41	1,732	188,768	390,262	140,735	144,700	176,874	42,072	295,848
12.	Inter-System Sales other than MISO	-	-	-	-	-	-	-	-	-	-	-	-
13.	Non-Jurisdictional Retail Sales	-	-	-	-	-	-	-	-	-	-	-	-
14.	Sales (S)	1,161,826	1,100,079	991,708	848,829	892,651	1,074,100	1,255,869	1,169,836	959,654	898,894	924,372	1,140,890
	Fuel Cost $ (F) :												
15.	Coal Generation	$ 12,762,365	$ 15,475,847	$ 6,531,454	$ 1,463	$ 707,441	$ 9,495,157	$ 15,965,045	$ 14,925,058	$ 10,750,486	$ 10,938,210	$ 8,492,560	$ 17,990,480
16.	Nuclear Generation	-	-	-	-	-	-	-	-	-	-	-	-
17.	Hydro Generation	-	-	-	-	-	-	-	-	-	-	-	-
18.	Other Generation - Internal Combustion	2,475	11,715	103,829	1,314	1,186	1,727	1,054	1,801	2,338	1,526	1,324	3,391
19.	Gas Generation	10,437,380	10,554,048	7,777,162	7,195,834	8,730,098	11,584,612	14,338,159	10,123,756	7,974,287	10,643,545	8,518,400	10,042,131
20.	Financial Hedges Gains/Losses & Trans. Fees	-	-	-	-	-	-	-	-	-	-	-	-
	Purchases through MISO:												
21.	Wind Purchase Power Agreement Purchases	5,599,074	6,620,038	6,349,109	6,152,717	5,388,452	5,502,919	2,234,272	3,812,773	4,767,733	5,807,100	7,957,840	6,157,677
22.	Non-Wind PPA Market Purchases	1,674,294	90,525	4,840,437	6,000,682	5,084,625	753,861	176,328	1,600,695	792,037	511,042	2,297,255	131,614
23.	Other	242	217	403	695	1,065	1,258	1,433	1,115	1,171	817	479	374
24.	MISO Components of Cost of Fuel	1,228,608	817,713	735,285	812,239	542,060	597,545	922,538	36,436	490,558	673,875	974,731	789,238
25.	Purchased Power other than MISO	1,079,064	835,271	1,718,351	2,119,067	2,391,097	3,051,478	3,020,823	2,640,812	2,600,977	1,910,708	1,431,699	1,066,322
	LESS:												
26.	Inter-System Sales through MISO	2,632,469	4,039,637	1,214,308	994	25,709	2,758,676	5,949,606	2,200,469	2,070,538	3,235,829	642,821	4,798,579
27.	Inter-System Sales other than MISO	-	-	-	-	-	-	-	-	-	-	-	-
28.	Non-Jurisdictional Retail Sales	-	-	-	-	-	-	-	-	-	-	-	-
29.	Transmission Losses	168,228	270,901	67,041	-	6,112	194,868	346,961	213,296	175,576	239,449	80,282	325,137
30.	Lakefield PPA Adjustment	60,051	295,414	93,247	(376)	1,669	102,739	238,979	168,077	56,282	108,245	30,154	117,481
31.	Purchased Power in Excess	-	-	-	-	-	-	-	-	-	-	-	-
32.	Total Fuel Costs (F)	$ 29,922,754	$ 29,799,422	$ 26,681,434	$ 22,283,393	$ 22,812,534	$ 27,932,274	$ 30,124,106	$ 30,560,604	$ 25,077,191	$ 26,903,300	$ 28,921,031	$ 30,940,030
33.	Fuel Cost per KWH (in Mills) F/S	$ 25.755	$ 27.088	$ 26.905	$ 26.252	$ 25.556	$ 26.005	$ 23.987	$ 26.124	$ 26.131	$ 29.929	$ 31.287	$ 27.119

SCHEDULE D
(Continued)

OFFICE OF UTILITY CONSUMER COUNSELOR
REVIEW OF FUEL COST ADJUSTMENT
Indianapolis Power & Light Company
Cause No. 38703-FAC 135

Actual Cost of Fuel to Generate Electricity and the Actual Cost of Fuel Included in the Cost of Purchased Power

Line No.	Description	January 2021	February 2021	March 2021	April 2021	May 2021	June 2021	July 2021	August 2021	September 2021	October 2021	November 2021	December 2021
	KWH Source (000's) :												
1.	Coal Generation	955,235	831,066	780,187	711,009	624,722	698,779	788,815	912,737	704,109	500,538	184,482	623,008
2.	Nuclear Generation	-	-	-	-	-	-	-	-	-	-	-	-
3.	Hydro Generation	-	-	-	-	-	-	-	-	-	-	-	-
4.	Other Generation - Internal Combustion	16	17	15	10	14	12	12	9	9	2	19	15
5.	Gas Generation	498,866	423,048	466,231	194,733	70,111	172,257	191,859	271,949	108,110	207,310	382,977	211,212
	Purchases through MISO:					-	-	-					
6.	Wind Purchase Power Agreement Purchases	48,251	42,148	34,729	44,667	36,481	35,842	27,171	30,060	44,287	38,539	59,790	74,863
7.	Non-Wind PPA Market Purchases	1,533	45,941	8,101	118,780	230,274	256,927	244,777	126,699	215,195	289,542	427,674	226,904
8.	Other	10	13	23	35	33	37	128	124	51	92	19	14
9.	Purchased Power other than MISO	6,219	6,829	13,358	16,094	15,681	16,709	14,658	15,776	15,190	10,410	7,585	6,768
	LESS:					-	-	-					
10.	Energy Losses and Company Use	62,973	61,560	51,593	46,520	48,566	57,892	61,860	65,214	53,790	51,304	52,802	56,393
11.	Inter-System Sales through MISO	253,049	117,416	275,234	156,900	2,710	12,844	17,611	39,146	6,714	16,288	-	10,527
12.	Inter-System Sales other than MISO	-	-	-	-	-	-	-	-	-	-	-	-
13.	Non-Jurisdictional Retail Sales	-	-	-	-	-	-	-	-	-	-	-	-
14.	Sales (S)	1,194,108	1,170,086	975,817	881,908	926,040	1,109,827	1,187,949	1,252,994	1,026,447	978,841	1,009,744	1,075,864
	Fuel Cost $ (F) :												
15.	Coal Generation	$ 18,215,836	$ 16,261,039	$ 15,170,668	$ 14,088,080	$ 12,947,434	$ 14,566,015	$ 16,170,366	$ 18,506,946	$ 14,707,630	$ 10,865,067	$ 4,974,914	$ 14,770,615
16.	Nuclear Generation	-	-	-	-	-	-	-	-	-	-	-	-
17.	Hydro Generation	-	-	-	-	-	-	-	-	-	-	-	-
18.	Other Generation - Internal Combustion	2,079	1,996	1,250	2,274	1,850	1,565	1,932	1,103	1,931	203	2,954	1,009
19.	Gas Generation	10,576,392	23,585,279	10,256,313	5,642,310	3,812,298	8,382,253	9,964,055	14,459,213	8,234,683	13,977,551	24,572,739	15,481,539
20.	Financial Hedges Gains/Losses & Trans. Fees	-	-	-	-	-	(758,807)	(832,167)	(2,080,504)	(1,953,922)	(1,601,046)	-	482,546
	Purchases through MISO:					-	-	-					
21.	Wind Purchase Power Agreement Purchases	5,647,543	4,595,633	6,072,044	5,851,366	4,406,203	3,369,274	2,478,097	3,111,966	4,894,700	4,953,401	7,929,986	7,483,356
22.	Non-Wind PPA Market Purchases	52,443	2,469,000	136,619	2,982,658	6,861,548	8,564,046	8,991,144	5,095,128	9,512,983	17,335,847	27,481,782	9,524,139
23.	Other	230	296	539	803	796	910	3,135	3,032	1,247	714	472	337
24.	MISO Components of Cost of Fuel	1,070,150	2,259,360	609,901	472,209	887,341	947,011	1,316,000	1,194,277	1,637,668	1,181,362	7,081,450	2,546,715
25.	Purchased Power other than MISO	812,041	968,863	2,153,696	2,539,973	2,474,999	2,744,086	2,487,989	2,541,299	2,463,525	1,703,176	1,225,785	1,112,262
	LESS:					-	-	-					
26.	Inter-System Sales through MISO	4,072,886	3,422,725	4,608,943	2,697,427	46,933	292,850	395,817	1,055,312	141,081	621,586	-	331,296
27.	Inter-System Sales other than MISO	-	-	-	-	-	-	-	-	-	-	-	-
28.	Non-Jurisdictional Retail Sales	-	-	-	-	-	-	-	-	-	-	-	-
29.	Transmission Losses	408,345	306,663	256,504	161,095	9,799	60,408	87,000	227,063	32,517	25,713	-	40,793
30.	Lakefield PPA Adjustment	100,644	51,489	84,538	111,306	6,116	13,128	35,132	58,681	19,532	42,006	69	10,114
31.	Purchased Power in Excess	-	-	-	-	-	-	-	-	-	-	-	-
32.	Total Fuel Costs (F)	$ 31,794,839	$ 46,360,589	$ 29,451,045	$ 28,609,845	$ 31,329,621	$ 37,449,967	$ 40,062,602	$ 41,491,404	$ 39,307,315	$ 47,726,970	$ 73,270,013	$ 51,020,315
33.	Fuel Cost per KWH (in Mills) F/S	$ 26.626	$ 39.622	$ 30.181	$ 32.441	$ 33.832	$ 33.744	$ 33.724	$ 33.114	$ 38.295	$ 48.759	$ 72.563	$ 47.423

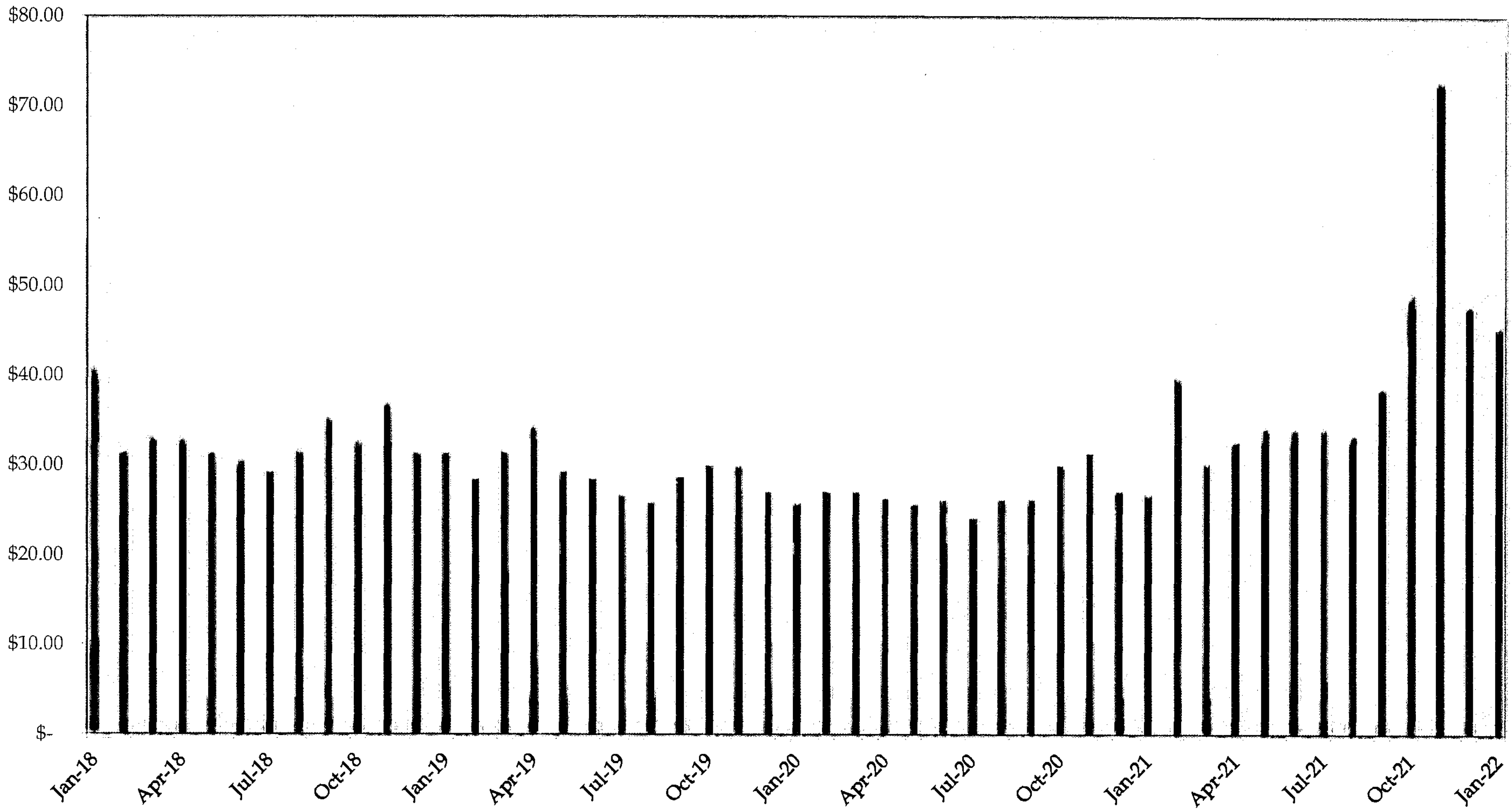
OFFICE OF UTILITY CONSUMER COUNSELOR
REVIEW OF FUEL COST ADJUSTMENT
Indianapolis Power & Light Company
Cause No. 38703-FAC 135

Actual Cost of Fuel to Generate Electricity and the Actual Cost of Fuel Included in the Cost of Purchased Power

Line No.	Description	January 2022
	KWH Source (000's) :	
1.	Coal Generation	913,115
2.	Nuclear Generation	-
3.	Hydro Generation	-
4.	Other Generation - Internal Combustion	14
5.	Gas Generation	273,678
	Purchases through MISO:	
6.	Wind Purchase Power Agreement Purchases	90,717
7.	Non-Wind PPA Market Purchases	141,264
8.	Other	280
9.	Purchased Power other than MISO	7,292
	LESS:	
10.	Energy Losses and Company Use	66,608
11.	Inter-System Sales through MISO	44,636
12.	Inter-System Sales other than MISO	-
13.	Non-Jurisdictional Retail Sales	-
14.	Sales (S)	1,315,116
	Fuel Cost $ (F) :	
15.	Coal Generation	$ 23,001,892
16.	Nuclear Generation	-
17.	Hydro Generation	-
18.	Other Generation - Internal Combustion	2,203
19.	Gas Generation	20,227,469
20.	Financial Hedges Gains/Losses & Trans. Fees	-
	Purchases through MISO:	
21.	Wind Purchase Power Agreement Purchases	8,162,108
22.	Non-Wind PPA Market Purchases	7,659,290
23.	Other	6,673
24.	MISO Components of Cost of Fuel	1,516,613
25.	Purchased Power other than MISO	1,086,815
	LESS:	
26.	Inter-System Sales through MISO	1,875,771
27.	Inter-System Sales other than MISO	-
28.	Non-Jurisdictional Retail Sales	-
29.	Transmission Losses	212,251
30.	Lakefield PPA Adjustment	267,375
31.	Purchased Power in Excess	-
32.	Total Fuel Costs (F)	$ 59,307,666
33.	Fuel Cost per KWH (in Mills) F/S	$ 45.097

OFFICE OF UTILITY CONSUMER COUNSELOR
REVIEW OF FUEL COST ADJUSTMENT
Indianapolis Power & Light Company
Cause No. 38703-FAC 135

Actual Fuel Cost (in mills) for January 2018 through January 2022



SCHEDULE E

OFFICE OF UTILITY CONSUMER COUNSELOR
REVIEW OF FUEL COST ADJUSTMENT
Indianapolis Power & Light Company
Cause No. 38703-FAC 135

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

Month	Actual Sales	Actual Fuel Cost	Average Actual Fuel Cost	Forecast Sales	Forecast Fuel Cost	Average Forecast Fuel Cost	Weighted Average Error
November 2021	1,009,744	$ 73,270,013	$ 72.563	991,037	$ 31,827,841	$ 32.116	(53.988)
							33.879
December 2021	1,075,864	51,020,315	47.423	1,208,934	40,453,315	33.462	
January 2022	1,315,116	59,307,666	45.097	1,308,712	46,591,176	35.601	(20.109)
Total	3,400,724	$ 183,597,994	$ 53.988	3,508,683	$ 118,872,332	$ 33.879	-37.25%

(1) Includes transmission loss adjustments of:

November 2021	$ -
December 2021	40,793
January 2022	212,251
Total	$ 253,044

OFFICE OF UTILITY CONSUMER COUNSELOR
REVIEW OF FUEL COST ADJUSTMENT
Indianapolis Power & Light Company
Cause No. 38703-FAC 135

Tracker History

Cause No.		Requested & Approved Fuel Cost Adjustment Factor Adjusted for Indiana Utility Receipts Tax	
38703-FAC135		13.472	Without IURT
38703-FAC135		13.673	With IURT
38703-FAC134		7.418	
38703-FAC133		5.350	
38703-FAC132		2.147	IPL
38703-FAC132		(0.036)	OUCC
38703-FAC131		(6.178)	
38703-FAC130		(3.725)	
38703-FAC129		(8.576)	
38703-FAC128		(7.414)	
38703-FAC127		(8.665)	
38703-FAC126		(4.648)	
Revised 38703-FAC125		(5.374)	
38703-FAC125		(5.370)	
38703-FAC124		(3.484)	
38703-FAC123	**(2)**	(2.890)	
38703-FAC122		1.165	IPL
38703-FAC122		0.000	OUCC
38703-FAC121		(1.582)	
38703-FAC120		(0.464)	
38703-FAC119		1.347	
38703-FAC118		2.504	
38703-FAC117		1.006	
38703-FAC116		3.945	
38703-FAC115		0.480	
38703-FAC114		3.707	
38703-FAC113	**(1)**	2.534	

(1) New base of 31.520 mills/kWh and a significant increase due to the variance

(2) Effective 12/05/18, a new base rate of 32.938 (established by Cause No. 45029) replaced the old rate of 31.520 (established by Cause No. 44576).

OFFICE OF UTILITY CONSUMER COUNSELOR
REVIEW OF FUEL COST ADJUSTMENT
Indianapolis Power & Light Company
Cause No. 38703-FAC 135

MISO - COST FLOW THROUGH IN THIS FAC

November 2021, December 2021 and January 2022

In Purchased Power

Month	Purchases through MISO Wind Purchase	Purchases through MISO Non-Wind	MISO Components Cost of Fuel	MISO Sales
November 2021	$ 7,929,986	$ 27,481,782	$ 7,081,450	$ -
December 2021	7,483,356	9,524,139	2,546,715	331,296
January 2022	8,162,108	7,659,290	1,516,613	1,875,771
Total	$ 23,575,450	$ 44,665,211	$11,144,778	$ 2,207,067

OFFICE OF UTILITY CONSUMER COUNSELOR
REVIEW OF FUEL COST ADJUSTMENT
Indianapolis Power & Light Company
Cause No. 38703-FAC 135

MISO CHARGE TYPES BY MONTH

	Charge Type	November 2021 Invoice Total	December 2021 Invoice Total	January 2022 Invoice Total
1	Day Ahead Market Administration Amount	$ 148,918	$ 183,018	$ 216,761
2	Day Ahead Regulation Amount	(9,648)	(6,778)	(1,283)
3	Day Ahead Spinning Reserve Amount	(37,475)	(2,196)	(214)
4	Day-Ahead Short-Term Reserve Amount	-	(6,287)	(2,896)
5	Day Ahead Supplemental Reserve Amount	-	-	-
6	Day Ahead Asset Energy Amount	28,292,539	10,302,693	6,734,382
7	Day Ahead Financial Bilateral Transaction Congestion Amount	-	-	-
8	Day Ahead Financial Bilateral Transaction Loss Amount	-	-	-
9	Day Ahead Congestion Rebate on Carve-Out Grandfathered Agrmnts	-	-	-
10	Day Ahead Losses Rebate on Carve-Out Grandfathered Agrmnts	-	-	-
11	Day Ahead Congestion Rebate on Option B Grandfathered Agrmnts	-	-	-
12	Day Ahead Losses Rebate on Option B Grandfathered Agrmnts	-	-	-
13	Day Ahead Non-Asset Energy Amount	-	-	-
14	Day Ahead Ramp Capability Amount	(11,938)	(5,263)	(2,391)
15	Day Ahead Revenue Sufficiency Guarantee Distribution Amount	64,595	30,814	50,760
16	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amt.	(131,579)	(40,344)	(101,960)
17	Day Ahead Schedule 24 Allocation Amount	22,586	25,910	33,581
18	Day Ahead Virtual Energy Amount	-	-	-
	Day Ahead Subtotal	$ 28,337,998	$ 10,481,567	$ 6,926,740
19	Financial Transmission Rights Market Administration Amount	$ 5,228	$ 7,453	$ 8,975
20	Auction Revenue Rights Transaction Amount	(231,072)	(264,066)	(264,066)
21	Financial Transmission Rights Annual Transaction Amount	189,043	229,027	229,027
22	Auction Revenue Rights Infeasible Uplift Amount	60,108	23,861	23,861
23	Auction Revenue Rights Stage 2 Distribution Amount	(146,019)	(110,708)	(110,708)
24	Financial Transmission Rights Full Funding Guarantee Amount	(15,826)	103,407	-
25	Financial Transmission Guarantee Uplift amount	12,866	(128,357)	-
26	Financial Transmission Rights Hourly Allocation Amount	806,623	154,565	(3,521,487)
27	Financial Transmission Rights Monthly Allocation Amount	(15,665)	(31,694)	(39,981)
28	Financial Transmission Rights Monthly Transaction Amount	-	-	-
29	Financial Transmission Rights Transaction Amount	-	-	-
30	Financial Transmission Rights Yearly Allocation Amount	-	(103,407)	-
	Financial Transmission Rights Subtotal	$ 665,286	$ (119,919)	$ (3,674,379)
31	Real Time Market Administration Amount	$ 18,296	$ 22,305	$ 25,347
32	Contingency Reserve Deployment Failure Charge Amount	21,124	-	-
33	Excessive Energy Amount	(28,447)	(19,948)	(15,372)
34	Real Time Excessive Deficient Energy Deployment Charge Amount	7,979	8,950	7,768
35	Net Regulation Adjustment Amount	-	-	-
36	Non-Excessive Energy Amount	3,397,244	1,400,811	4,556,831
37	Real Time Regulation Amount	(6,115)	10,495	(2,817)
38	Regulation Cost Distribution Amount	58,361	46,568	56,440
39	Real Time Spinning Reserve Amount	5,303	(12,444)	(593)
40	Spinning Reserve Cost Distribution Amount	54,924	39,436	35,674
41	Real Time Short-Term Reserve Amount	-	(12,547)	(11,447)
42	Real Time Short-Term Reserve Cost Distribution Amount	-	26,609	35,042
43	Real Time Supplemental Reserve Amount	(2)	(627)	-
44	Supplemental Reserve Cost Distribution Amount	7,262	6,664	9,093
45	Real Time Asset Energy Amount	3,257,478	510,698	(251,609)
46	Real Time Demand Response Allocation Uplift Charge	111,934	62,128	73,466
47	Real Time Financial Bilateral Transaction Congestion Amount	-	-	-
48	Real Time Financial Bilateral Transaction Loss Amount	-	-	-
49	Real Time Congestion Rebate on Carve-Out Grandfathered Agrmnts	-	-	-
50	Real Time Losses Rebate on Carve-Out Grandfathered Agrmnts	-	-	-
51	Real Time Distribution of Losses Amount	(843,785)	(444,694)	(804,405)
52	Real Time Miscellaneous Amount	2,857	(395)	9,161
53	Real Time MVP Distribution Amount	(3,055)	(6,501)	(6,977)
54	Real Time Non-Asset Energy Amount	-	-	-
55	Real Time Net Inadvertent Distribution Amount	(59,739)	23,638	(3,850)
56	Real Time Price Volatility Make Whole Payment	(132,831)	(133,499)	(319,348)
57	Real Time Resource Adequacy Auction Amount	(24,416)	(25,230)	(25,230)
58	Real Time Ramp Capabilty Amount	(3,911)	(4,551)	(2,071)
59	Real Time Revenue Neutrality Uplift Amount	1,138,444	209,478	212,313
60	Real Time Revenue Sufficiency Guarantee First Pass Dist Amount	67,651	31,393	109,089
61	Real Time Revenue Sufficiency Guarantee Make Whole Payment Amt.	(187,684)	(46,442)	(73,505)
62	Real Time Schedule 24 Allocation Amount	2,780	3,160	3,923
63	Real Time Schedule 24 Distribution Amount	(63,425)	(65,202)	(72,769)
64	Real Time Schedule 49 Cost Distribution Amount	4,937	4,843	5,366
65	Real Time Uninstructed Deviation Amount	-	-	-
66	Real Time Virtual Energy Amount	-	-	-
	Real Time Subtotal	$ 6,803,164	$ 1,635,096	$ 3,549,520
	Grand Total	$ 35,806,448	$ 11,996,744	$ 6,801,881

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

By:
Indiana Office of
Utility Consumer Counselor

April 21, 2022
Date

CERTIFICATE OF SERVICE

This is to certify that a copy of the foregoing ***Indiana Office of Utility Consumer Counselor Public's Exhibit No. 1, Pre-filed Testimony of OUCC Witness Gregory T. Guerrettaz*** has been served upon the following parties of record in the captioned proceeding by electronic service on April 21, 2022.

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