**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 2023 THROUGH MAY 2023, IN ACCORDANCE WITH THE PROVISIONS OF I.C. 8-1-242, 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-138** |

**INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR**

**PUBLIC'S EXHIBIT NO. 1**

**PRE-FILED TESTIMONY OF OUCC WITNESS GREGORY T. GUERRETTAZ**

**January 23, 2023**

Lorraine Hitz

Lorraine Hitz
Attorney No. 18006-29
Deputy Consumer Counselor

**OFFICE OF UTILITY CONSUMER COUNSELOR**
**Pre-Filed Testimony of Gregory T. Guerrettaz, CPA**
**Review of Fuel Cost Adjustment**
**CAUSE NO. 38703 FAC-138**
**<u>INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA</u>**

**Q: Please state your name 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.

**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 December 16, 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;

B. Whether the fuel costs paid by AES Indiana, when compared to fuel costs recovered by AES Indiana for the quarter ended October 31, 2022, resulted in a variance which was used to calculate the fuel cost adjustment for the quarter ended May 31, 2023, 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 October 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 October 31, 2022 has been properly applied in conformity with the requirements of Cause No. 38703-FAC 135.

**Q: To the extent you do not address a specific item in your testimony, should it be construed to mean you agree with Petitioners' proposals?**

A: No. My silence on any topics, issues, or items Petitioner proposes does not indicate my approval of these topics, issues or items. Rather, the scope of my testimony is limited to the specific topics discussed herein.

**Q: Please explain Schedule A.**

**A:** Schedule A presents the components that comprise AES Indiana's proposed fuel cost adjustment factor 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 AES Indiana's power purchases, MISO charges and credits, and ASM charges.

Schedule A also demonstrates that the fuel cost paid by AES Indiana, when compared to the fuel costs recovered from AES Indiana's customers for the quarter ended October 31, 2022, resulted in a variance that was used to calculate the fuel cost adjustment for the quarter ending May 31, 2023. As filed by AES, Schedule A has multiple line items to arrive at the variance factor. The following components have been used to calculate the combined variance as shown on this schedule:

A) the current variance from FAC 138 of $12,014,144; and

B) the remaining one-half of the variance from FAC 137 of $32,247,818.

These combined variances total $44,261,962, which AES Indiana is requesting be spread over the three months in FAC 138. Once the forecasted cost of 47.985 Mills per KWh is added to the 15.041, the total requested amount is 63.026 Mills per KWh. Subtracting the base cost of fuel of 32.938 results in a factor of 30.088 Mills/KWh.

**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 May 31, 2023, after the review that was just discussed?**

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

1) Daily changes in the price of natural gas;
2) Daily changes of power prices for the MISO market;
3) Recent hedges put into place;
4) AES Indiana's coal inventory; and
5) Recent gas transportation contracts.

Based on the OUCC's analysis, the OUCC is recommending the F÷S be reduced to 43.844 Mills/KWh as detailed in this report on Schedule A, which is 4.141 less than Petitioner's F÷S of 47.985.

**Q: What components did the OUCC use for the recommended factor?**

**A:** First, the OUCC worked with AES to update the commodity prices for power and natural gas prices. Once the prices were updated by AES, the OUCC then conducted an extensive review of all new gas agreements affecting the forecasted period. Once that review was finalized, the OUCC and AES agreed that recent confidential fixed agreements entered into by AES should be updated also.

**Q: Did the fixed agreements impact the F÷S?**

**A:** Yes. The new agreements increased the monthly cost which increased the F÷S.

**Q: Did the OUCC recompute AES Indiana’s FAC factor to reflect the OUCC’s F÷S?**

**A:** Yes. The OUCC recomputed the FAC factor using the F÷S of 43.844 Mills/KWh which resulted in the OUCC’s recommended factor of 25.947 as shown on Schedule A.

**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 October 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.

**Q: Has AES Indiana earned a level of net operating income greater than that authorized by the Commission?**

**A:** No. As shown on Schedule B, AES Indiana had jurisdictional net operating income for the twelve months ending October 31, 2022 that was less than that granted in Cause No. 45029, as adjusted for applicable ECR and TDSIC Causes. The “Excess (Under) Earnings for the Relevant Period” as shown on Schedule B-1 shows the Sum of Differentials for the relevant period as a positive $178,686,218, which has accumulated through the following FAC proceedings (FAC 119 through FAC 138).

**Q: Why did the earnings change so dramatically for AES in this quarter?**

**A:** AES booked a journal entry in September 2022 for the settlement in FAC 133 S1 between the OUCC, AES Indiana, AES Industrial Group, and Citizens Action Coalition, which the Commission approved on January 18, 2023. The OUCC has accepted the journal entry because the settlement agreement was entered into during the twelve month earnings test period ending October 31, 2022. OUCC Witness Michael Eckert will provide more information on this matter.

**Q: Has the fuel cost adjustment for the quarter ending October 31, 2022, been accurately applied in conformity with the requirements of Cause No. 38703-FAC 135?**

**A:** Yes. The fuel cost adjustment approved by the Commission in Cause No. 38703-FAC 135 was the amount applied to AES Indiana's customers for the period approved.

**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 October 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.

**Q: Please explain Schedules D and E.**

**A:** Schedule D sets forth the total fuel cost, in Mills, for the period January 2019 through October 2022. Schedule E graphically depicts the results of Schedule D for the period January 2019 through October 2022.

**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 inventory;
7) Lakefield Wind Park ("Lakefield") and Hoosier Wind Power Project LLC ("Hoosier");
8) coal price decrement;
9) unit commitment status;
10) hedging program; and
11) Eagle Valley Outage ("Eagle Valley")?

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

**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.

**Q: Please explain Schedule G.**

**A:** Schedule G reflects the proposed and historical fuel cost adjustment factors.

**Q: Please explain Schedule H.**

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

**Q: Please explain Schedule I.**

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

**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.

**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 10.04%. AES Indiana underestimated for this period, which was attributable to large price increases in natural gas and power for the month of August 2022, where the deviation was negative 28.68%.

**Q: How will AES Indiana's proposed factor affect the average residential customer?**

**A:** An average residential customer using 1,000 KWh per month will experience a decrease of $2.44, or 1.65% with the proposed mitigated factor. The OUCC's proposed factor will decrease the customer bill by $6.58. or 4.44%.

**Q: Is AES Indiana's coal inventory within its target levels?**

**A:** Yes. AES Indiana is currently above its target levels.

**Q: Should AES Indiana provide an update to the OUCC on coal inventory changes in the next FAC?**

**A:** Yes. The OUCC has an on-going request for AES Indiana's coal inventory levels and coal transportation issues.

**Q: Is AES Indiana seeking to recover any purchased power costs incurred in August, September or October 2022 that are in excess of the Daily Benchmarks?**

**A:** Yes. AES Indiana is seeking to recover $212,166 of purchased power costs in excess of the applicable Purchased Power Daily Benchmarks in FAC 138. Mr. Eckert provides testimony on this recoverable amount.

**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.

**Q: Did AES Indiana discuss and address its fuel hedging policy with the OUCC?**

**A:** Yes. AES Indiana discussed its natural gas hedging policy and walked the OUCC through the structure of its hedges. The process appears to be coming together to provide a hedge against higher prices in the next two years.

**Q: What other additional items came up during the audit?**

**A:** Numerous items were discussed during the audit and the most important items are listed below:

1) Coal and transportation contracts have been firmed up for the next year. Higher prices have resulted from the process.

2) The Eagle Valley generating station operating status, and its likely winter capacity factor;

3) Schedule GG, as filed by AES Indiana, showing the impact on taxes for the allocation

between jurisdictional and non-jurisdictional income; and

4) The material changes in the commodity prices for the forecasted period.

It is important to point out that reviewing all these issues is necessary to reach the OUCC's opinion on the FAC factor being proposed.

**Q: What does the OUCC recommend?**

**A:** The OUCC recommends:

1) The Commission approve the OUCC's proposed fuel cost charge of 25.947 Mills per KWh;

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

3) AES Indiana update the OUCC on any strategies developed for hedging natural gas and power hedges on a going forward basis.

**Q: Does this conclude your pre-filed testimony?**

**A:** Yes.

**Appendix A - Qualifications of Gregory T. Guerrettaz**

**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.

**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.

**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.

**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 and 54 license as a Municipal Advisor and Chief Compliance Officer.

**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 138

**Calculation of Proposed Fuel Cost Adjustment Factor**

**Requested by AES**

| | Total Variance | | Mills/KWh |
|---|---|---|---|
| Average projected fuel cost for quarter including March 2023, April 2023 and May 2023 **(F÷S)** | | | 47.985 |
| Current Period Variance | $ 12,014,144 | | 4.082 |
| 50% Remaining Fuel Cost Variance Per FAC 137 | | $ 32,247,818 | 10.958 |
| Total Request by AES | | | 63.026 |
| Less: Base cost of fuel | | | 32.938 |
| Proposed FAC AES | | | 30.088 |

**Recomended By OUCC**

| | Total Variance | | Mills/KWh |
|---|---|---|---|
| Average projected fuel cost for quarter including March 2023, April 2023 and May 2023 **(F÷S)** | | | 43.844 |
| Current Period Variance | $ 12,014,144 | | 4.082 |
| 50% Remaining Fuel Cost Variance Per FAC 137 | | $ 32,247,818 | 10.958 |
| Total Request by AES | | | 58.885 |
| Less: Base cost of fuel | | | 32.938 |
| Proposed FAC AES | | | 25.947 |

**OFFICE OF UTILITY CONSUMER COUNSELOR**
**REVIEW OF FUEL COST ADJUSTMENT**
Indianapolis Power & Light Company
Cause No. 38703-FAC 138

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

| | | |
|---|---|---|
| **Actual Twelve Months Ending October 31, 2022** | | |
| Jurisdictional Operating Revenue | $ | 1,689,658 |
| Jurisdictional Operating Expense | | 1,486,392 |
| Jurisdictional Net Operating Income | $ | 203,266 |
| **Per Cause No. 45029** | | |
| Jurisdictional Net Operating Income | $ | 220,076 |
| Adjustments for Cause No. 42170-ECR34 and ECR 35 | $ | 1,486 |
| Adjustments for Cause No. 45264 TDISC-1 Combined | $ | - |
| Adjustments for Cause No. 45264 TDISC-3 Combined | $ | 10,352 |
| **Adjusted Jurisdictional Net Operating Income Total** | $ | 231,914 |
| **Over (Under)** | $ | (28,648) |

# OUCC REVIEW OF FUEL COST ADJUSTMENT

Indianapolis Power & Light Company
Cause No. 38703-FAC 138

## Excess (Under) Earnings for Relevant Period

| Item No. | FAC No. | Reporting Pd. | Determined Return | Authorized Return | Differential |
|---|---|---|---|---|---|
| 1 | 138 | 10/31/2022 | $ 203,266,000 | $ 231,914,000 | $ (28,648,000) |
| 2 | 137 | 7/31/2022 | 215,542,000 | 230,102,000 | (14,560,000) |
| 3 | 136 | 4/30/2022 | 223,712,000 | 228,291,000 | (4,579,000) |
| 4 | 135 | 1/31/2022 | 227,360,000 | 226,529,000 | 831,000 |
| 5 | 134 | 10/31/2021 | 226,080,000 | 224,682,000 | 1,398,000 |
| 6 | 133 | 7/31/2021 | 219,585,000 | 223,889,000 | (4,304,000) |
| 7 | 132 | 04/30/2021 | 232,893,000 | 223,097,000 | 9,796,000 |
| 8 | 131 | 01/31/2021 | 227,171,000 | 222,310,000 | 4,861,000 |
| 9 | 130 | 10/31/2020 | 229,881,000 | 221,451,000 | 8,430,000 |
| 10 | 129 | 07/31/2020 | 242,467,000 | 221,368,000 | 21,099,000 |
| 11 | 128 | 04/30/2020 | 236,917,000 | 221,285,000 | 15,632,000 |
| 12 | 127 | 01/31/2020 | 234,075,000 | 221,201,000 | 12,874,000 |
| 13 | 126 | 10/31/2019 | 230,875,000 | 218,710,000 | 12,165,000 |
| 14 | 125 | 07/31/2019 | 229,431,000 | 206,716,000 | 22,715,000 |
| 15 | 124 | 04/30/2019 | 217,179,000 | 194,654,170 | 22,524,830 |
| 16 | 123 | 01/31/2019 | 212,078,000 | 182,107,612 | 29,970,388 |
| 17 | 122 | 10/31/2018 | 201,730,000 | 172,128,000 | 29,602,000 |
| 18 | 121 | 07/31/2018 | 190,971,000 | 171,399,000 | 19,572,000 |
| 19 | 120 | 04/30/2018 | 180,892,000 | 170,247,000 | 10,645,000 |
| 20 | 119 | 01/31/2018 | 177,867,000 | 169,205,000 | 8,662,000 |
| | | | | Sum of Differential for Relevant Period | $ 178,686,218 |

**OFFICE OF UTILITY CONSUMER COUNSELOR**
**REVIEW OF FUEL COST ADJUSTMENT**
Indianapolis Power & Light Company
Cause No. 38703-FAC 138

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

| | |
|---|---|
| Actual Twelve Months Ending October 31, 2022 | |
| Total Operating Expense | $ 1,486,392 |
| Less: Fuel Costs | 676,328 |
| Operating Expense Excluding Fuel Cost | $ 810,064 |
| Per Cause No. 45029 | |
| Total Operating Expense | $ 1,186,288 |
| Less: Fuel Costs | 436,216 |
| Operating Expense Excluding Fuel Cost | $ 750,072 |
| Over (Under) | $ 59,992 |

**OFFICE OF UTILITY CONSUMER COUNSELOR**
**REVIEW OF FUEL COST ADJUSTMENT**
Indianapolis Power & Light Company
Cause No. 38703-FAC 138

## 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 |

**OFFICE OF UTILITY CONSUMER COUNSELOR**
**REVIEW OF FUEL COST ADJUSTMENT**
Indianapolis Power & Light Company
Cause No. 38703-FAC 138

## 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 138

**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 |

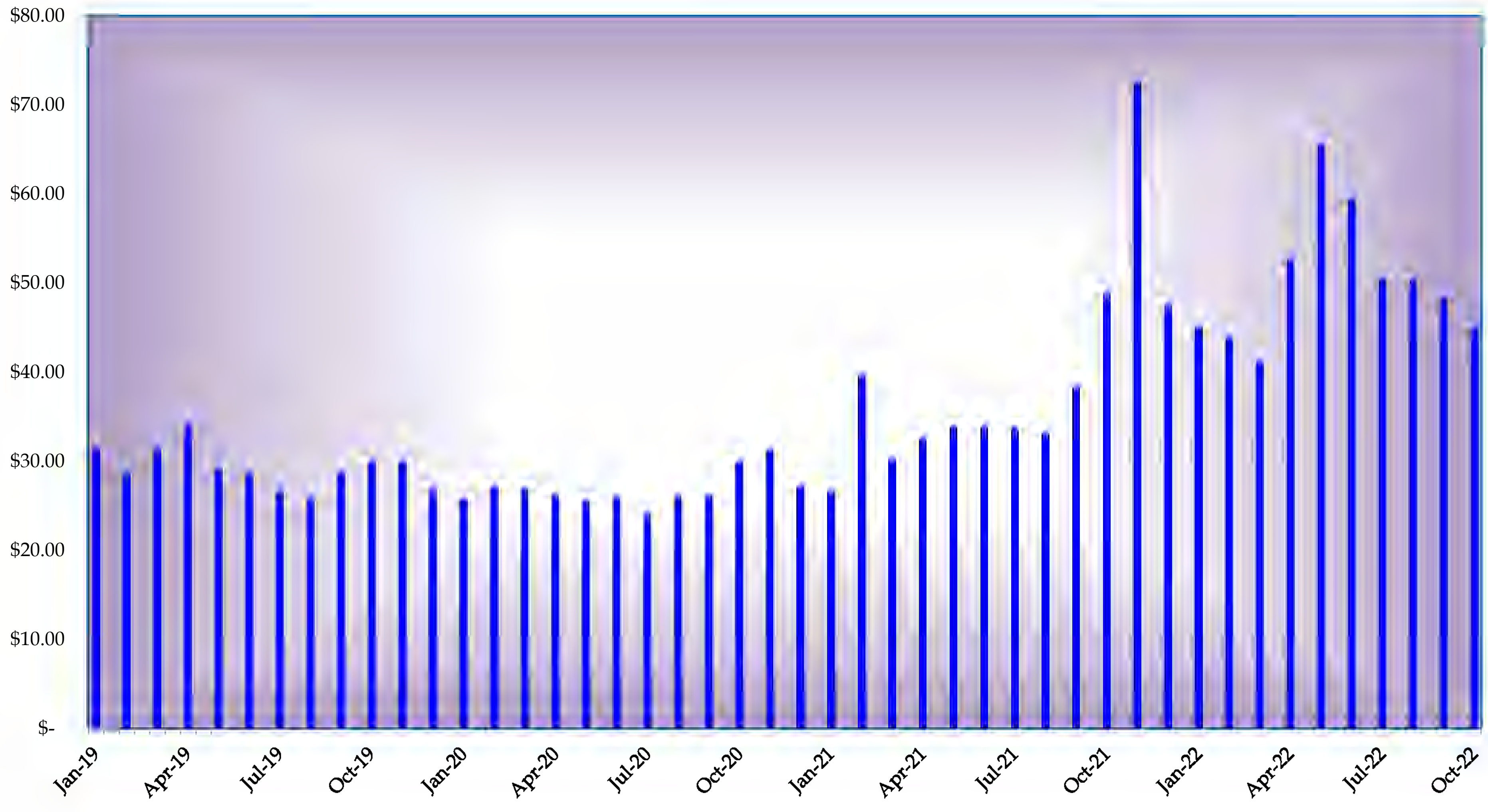
## OFFICE OF UTILITY CONSUMER COUNSELOR
## REVIEW OF FUEL COST ADJUSTMENT
Indianapolis Power & Light Company
Cause No. 38703-FAC 138

### 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 | February 2022 | March 2022 | April 2022 | May 2022 | June 2022 | July 2022 | August 2022 | September 2022 | October 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **KWH Source (000's) :** | | | | | | | | | | |
| 1. | Coal Generation | 913,115 | 752,607 | 730,680 | 613,375 | 265,468 | 483,778 | 723,699 | 839,897 | 632,407 | 576,299 |
| 2. | Nuclear Generation | - | - | - | - | - | - | - | - | - | - |
| 3. | Hydro Generation | - | - | - | - | - | - | - | - | - | - |
| 4. | Other Generation - Internal Combustion | 14 | 13 | 13 | 13 | 13 | 14 | - | 9 | 16 | 17 |
| 5. | Gas Generation | 273,678 | 184,977 | 325,985 | 508,885 | 501,819 | 542,023 | 627,869 | 640,237 | 562,029 | 563,713 |
| | Purchases through MISO: | | | | | | | | | | |
| 6. | Wind Purchase Power Agreement Purchases | 90,717 | 69,836 | 57,680 | 49,368 | 50,976 | 39,328 | 40,139 | 40,767 | 46,747 | 49,010 |
| 7. | Non-Wind PPA Market Purchases | 141,264 | 179,039 | 111,706 | 14,044 | 200,402 | 117,536 | 44,768 | 2,195 | 7,617 | 9,216 |
| 8. | Other | 280 | 244 | 335 | 349 | 336 | 413 | 384 | 430 | 439 | 418 |
| 9. | Purchased Power other than MISO | 7,292 | 8,141 | 11,533 | 11,513 | 13,903 | 16,210 | 15,226 | 12,294 | 10,846 | 12,183 |
| | LESS: | | | | | | | | | | |
| 10. | Energy Losses and Company Use | 66,608 | 56,881 | 52,505 | 45,506 | 48,773 | 55,967 | 61,696 | 59,058 | 49,512 | 43,491 |
| 11. | Inter-System Sales through MISO | 44,636 | 20,731 | 152,216 | 260,498 | 20,040 | 32,938 | 163,245 | 302,477 | 238,381 | 309,480 |
| 12. | Inter-System Sales other than MISO | - | - | - | - | - | - | - | - | - | - |
| 13. | Non-Jurisdictional Retail Sales | - | - | - | - | - | - | - | - | - | - |
| 14. | Sales (S) | 1,315,116 | 1,117,245 | 1,033,211 | 891,543 | 964,104 | 1,110,397 | 1,227,144 | 1,174,294 | 972,208 | 857,885 |
| | **Fuel Cost $ (F) :** | | | | | | | | | | |
| 15. | Coal Generation | $ 23,001,892 | $ 19,537,889 | $ 19,250,722 | $ 17,230,274 | $ 7,918,875 | $ 13,794,488 | $ 19,241,352 | $ 21,011,451 | $ 15,316,693 | $ 14,380,565 |
| 16. | Nuclear Generation | - | - | - | - | - | - | - | - | - | - |
| 17. | Hydro Generation | - | - | - | - | - | - | - | - | - | - |
| 18. | Other Generation - Internal Combustion | 2,203 | 2,481 | 1,584 | 1,471 | 2,123 | 892 | 264 | 3,872 | 1,911 | 10,006 |
| 19. | Gas Generation | 20,227,469 | 15,018,577 | 14,155,764 | 24,540,323 | 28,488,382 | 31,782,189 | 37,166,790 | 41,937,420 | 32,341,187 | 24,857,468 |
| 20. | Financial Hedges Gains/Losses & Trans. Fees | - | - | - | - | (1,292,165) | - | - | - | - | - |
| | Purchases through MISO: | | | | | | | | | | |
| 21. | Wind Purchase Power Agreement Purchases | 8,162,108 | 7,768,052 | 7,126,150 | 8,667,133 | 6,342,074 | 4,832,186 | 3,556,705 | 3,466,155 | 4,405,270 | 6,185,359 |
| 22. | Non-Wind PPA Market Purchases | 7,659,290 | 8,842,750 | 5,832,964 | 876,479 | 15,972,723 | 11,100,334 | 3,514,639 | 172,074 | 496,003 | 650,199 |
| 23. | Other | 6,673 | 5,829 | 7,996 | 9,489 | 9,738 | 11,924 | 11,060 | 12,396 | 12,978 | 12,576 |
| 24. | MISO Components of Cost of Fuel | 1,516,613 | (2,646,879) | (1,016,874) | 2,826,986 | 3,389,240 | 3,744,474 | 3,336,424 | 5,047,681 | 2,866,243 | 849,749 |
| 25. | Purchased Power other than MISO | 1,086,815 | 1,287,151 | 1,903,496 | 1,913,006 | 2,327,291 | 2,704,119 | 2,490,818 | 2,041,453 | 1,790,045 | 1,921,463 |
| | LESS: | | | | | | | | | | |
| 26. | Inter-System Sales through MISO | 1,875,771 | 555,647 | 4,208,626 | 8,067,309 | 717,530 | 1,331,664 | 6,067,135 | 12,467,545 | 8,812,489 | 9,396,080 |
| 27. | Inter-System Sales other than MISO | - | - | - | - | - | - | - | - | - | - |
| 28. | Non-Jurisdictional Retail Sales | - | - | - | - | - | - | - | - | - | - |
| 29. | Transmission Losses | 212,251 | 95,211 | 296,210 | 485,892 | 119,777 | 270,409 | 607,118 | 839,966 | 472,234 | 346,454 |
| 30. | Lakefield PPA Adjustment | 267,375 | 81,563 | 232,292 | 523,976 | 123,771 | 263,268 | 844,400 | 1,220,596 | 891,976 | 576,065 |
| 31. | Purchased Power in Excess | - | - | - | - | 10,635 | - | - | - | - | - |
| 32. | Total Fuel Costs (F) | $ 59,307,666 | $ 49,083,429 | $ 42,524,674 | $ 46,987,984 | $ 62,186,568 | $ 66,105,265 | $ 61,799,399 | $ 59,164,395 | $ 47,053,631 | $ 38,548,786 |
| 33. | Fuel Cost per KWH (in Mills) F/S | $ 45.097 | $ 43.933 | $ 41.158 | $ 52.704 | $ 64.502 | $ 59.533 | $ 50.360 | $ 50.383 | $ 48.399 | $ 44.935 |

**OFFICE OF UTILITY CONSUMER COUNSELOR**
**REVIEW OF FUEL COST ADJUSTMENT**
Indianapolis Power & Light Company
**Cause No. 38703-FAC 138**

**Actual Fuel Cost (in mills) for January 2019 through October 2022**






SCHEDULE E

**OFFICE OF UTILITY CONSUMER COUNSELOR**
**REVIEW OF FUEL COST ADJUSTMENT**
Indianapolis Power & Light Company
Cause No. 38703-FAC 138

**Comparison of Actual Fuel Cost and Estimated Fuel Cost for**
**August, September, October 2022**

| Month | Actual Sales | Actual Fuel Cost | Average Actual Fuel Cost | Forecast Sales | Forecast Fuel Cost | Average Forecast Fuel Cost | Weighted Average Error |
|---|---|---|---|---|---|---|---|
| August 2022 | 1,174,294 | $ 59,164,395 | $ 50.383 | 1,265,666 | $ 45,478,923 | $ 35.933 | (48.185) |
| | | | | | | | 43.347 |
| September 2022 | 972,208 | 47,053,631 | 48.399 | 1,037,934 | 50,394,479 | 48.553 | |
| October 2022 | 857,885 | 38,548,786 | 44.935 | 979,612 | 46,443,253 | 47.410 | (4.838) |
| Total | 3,004,387 | $ 144,766,812 | $ 48.185 | 3,283,212 | $ 142,316,655 | $ 43.347 | -10.04% |

SCHEDULE F

**OFFICE OF UTILITY CONSUMER COUNSELOR**
**REVIEW OF FUEL COST ADJUSTMENT**
Indianapolis Power & Light Company
Cause No. 38703-FAC 138

**Tracker History**

| Cause No. | | Requested & Approved Fuel Cost Adjustment Factor | |
|---|---|---|---|
| 38703-FAC138 | | 30.088 | AES |
| 38703-FAC138 | | 25.947 | OUCC |
| 38703-FAC137 | | 37.324 | AES |
| 38703-FAC137 | | 32.529 | OUCC |
| 38703-FAC136 | | 23.579 | OUCC |
| 38703-FAC136 | | 37.858 | AES |
| 38703-FAC135 | | 13.472 | Without IURT |
| 38703-FAC135 | | 13.673 | With IURT |
| 38703-FAC134 | | 7.418 | |
| 38703-FAC133 | | 5.350 | |
| 38703-FAC132 | | 2.147 | AES |
| 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 | | 0.285 | 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 138

**MISO - COST FLOW THROUGH IN THIS FAC**
**August, September, October 2022**

**In Purchased Power**

| Month | Purchases through MISO Wind Purchase | Purchases through MISO Non-Wind | MISO Components Cost of Fuel | MISO Sales |
|---|---|---|---|---|
| August 2022 | $ 3,466,155 | $ 172,074 | $ 5,047,681 | $ 12,467,545 |
| September 2022 | 4,405,270 | 496,003 | 2,866,243 | 8,812,489 |
| October 2022 | 6,185,359 | 650,199 | 849,749 | 9,396,080 |
| Total | $ 14,056,784 | $ 1,318,276 | $ 8,763,673 | $ 30,676,114 |

# OFFICE OF UTILITY CONSUMER COUNSELOR
# REVIEW OF FUEL COST ADJUSTMENT
Indianapolis Power & Light Company
Cause No. 38703-FAC 138

## MISO CHARGE TYPES BY MONTH

| | Charge Type | August 2022 Invoice Total | September 2022 Invoice Total | October 2022 Invoice Total |
|---|---|---|---|---|
| 1 | Day Ahead Market Administration Amount | $ 216,760 | $ 202,207 | $ 160,334 |
| 2 | Day Ahead Regulation Amount | - | (49) | - |
| 3 | Day Ahead Spinning Reserve Amount | (8) | - | (4,710) |
| 4 | Day-Ahead Short-Term Reserve Amount | (2,437) | (1,357) | (2,649) |
| 5 | Day Ahead Supplemental Reserve Amount | (1) | - | - |
| 6 | Day Ahead Asset Energy Amount | (26,225,043) | (12,836,703) | (13,446,487) |
| 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 | (11,757) | (795) | (11,499) |
| 15 | Day Ahead Revenue Sufficiency Guarantee Distribution Amount | 69,886 | 42,785 | 27,551 |
| 16 | Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amt. | (247,749) | (53,471) | (38,137) |
| 17 | Day Ahead Schedule 24 Allocation Amount | 32,818 | 32,025 | 28,508 |
| 18 | Day Ahead Virtual Energy Amount | - | - | - |
| | Day Ahead Subtotal | $ (26,167,531) | $ (12,615,358) | $ (13,287,089) |
| 19 | Financial Transmission Rights Market Administration Amount | $ 6,666 | $ 5,948 | $ 4,780 |
| 20 | Auction Revenue Rights Transaction Amount | (1,229,841) | (2,005,082) | (2,005,082) |
| 21 | Financial Transmission Rights Annual Transaction Amount | 811,369 | 1,168,783 | 1,168,783 |
| 22 | Auction Revenue Rights Infeasible Uplift Amount | 30,865 | 82,541 | 82,542 |
| 23 | Auction Revenue Rights Stage 2 Distribution Amount | (167,227) | (107,136) | (107,136) |
| 24 | Financial Transmission Rights Full Funding Guarantee Amount | - | - | - |
| 25 | Financial Transmission Guarantee Uplift amount | - | - | - |
| 26 | Financial Transmission Rights Hourly Allocation Amount | (1,285,145) | 58,334 | (909,469) |
| 27 | Financial Transmission Rights Monthly Allocation Amount | (49,344) | (481) | (54,566) |
| 28 | Financial Transmission Rights Monthly Transaction Amount | - | - | - |
| 29 | Financial Transmission Rights Transaction Amount | - | - | - |
| 30 | Financial Transmission Rights Yearly Allocation Amount | - | - | - |
| | Financial Transmission Rights Subtotal | $ (1,882,657) | $ (797,093) | $ (1,820,148) |
| 31 | Real Time Market Administration Amount | $ 18,487 | $ 25,040 | $ 16,619 |
| 32 | Contingency Reserve Deployment Failure Charge Amount | - | - | - |
| 33 | Excessive Energy Amount | (51,023) | (60,341) | (10,988) |
| 34 | Real Time Excessive Deficient Energy Deployment Charge Amount | 7,271 | 4,321 | 5,146 |
| 35 | Net Regulation Adjustment Amount | - | - | - |
| 36 | Non-Excessive Energy Amount | 5,663,360 | (957,877) | 1,358,099 |
| 37 | Real Time Regulation Amount | (3,067) | (1,492) | (1,561) |
| 38 | Regulation Cost Distribution Amount | 54,209 | 50,268 | 49,749 |
| 39 | Real Time Spinning Reserve Amount | (1,664) | (367) | (1,235) |
| 40 | Spinning Reserve Cost Distribution Amount | 33,630 | 37,757 | 57,473 |
| 41 | Real Time Short-Term Reserve Amount | (1,222) | (2,924) | (446) |
| 42 | Real-Time Short-Term Reserve Deployment Failure Charge Amount | - | - | - |
| 43 | Short-Term Reserve Cost Distribution Amount | 10,185 | 12,014 | 7,686 |
| 44 | Real Time Supplemental Reserve Amount | (4) | - | - |
| 45 | Supplemental Reserve Cost Distribution Amount | 14,442 | 6,820 | 6,365 |
| 46 | Real Time Asset Energy Amount | (2,148,114) | (745,418) | (1,130,070) |
| 47 | Real Time Demand Response Allocation Uplift Charge | 13,947 | 12,348 | 7,946 |
| 48 | Real Time Financial Bilateral Transaction Congestion Amount | - | - | - |
| 49 | Real Time Financial Bilateral Transaction Loss Amount | - | - | - |
| 50 | Real Time Congestion Rebate on Carve-Out Grandfathered Agrmnts | - | - | - |
| 51 | Real Time Losses Rebate on Carve-Out Grandfathered Agrmnts | - | - | - |
| 52 | Real Time Distribution of Losses Amount | (1,166,864) | (693,565) | (316,503) |
| 53 | Real Time Miscellaneous Amount | 7,434 | 552,656 | (21,022) |
| 54 | Real Time MVP Distribution Amount | (13,646) | (11,587) | (10,851) |
| 55 | Real Time Non-Asset Energy Amount | - | - | - |
| 56 | Real Time Net Inadvertent Distribution Amount | 17,446 | (18,339) | (24,521) |
| 57 | Real Time Price Volatility Make Whole Payment | (364,239) | (207,527) | (196,711) |
| 58 | Real Time Resource Adequacy Auction Amount | (1,684,342) | (1,630,009) | (1,684,342) |
| 59 | Real Time Ramp Capabilty Amount | (6,540) | (3,799) | (2,002) |
| 60 | Real Time Revenue Neutrality Uplift Amount | 175,881 | 162,710 | 152,925 |
| 61 | Real Time Revenue Sufficiency Guarantee First Pass Dist Amount | 297,507 | 103,419 | 75,357 |
| 62 | Real Time Revenue Sufficiency Guarantee Make Whole Payment Amt. | (174,635) | (11,258) | (19,046) |
| 63 | Real Time Schedule 24 Allocation Amount | 2,810 | 3,947 | 2,958 |
| 64 | Real Time Schedule 24 Distribution Amount | (57,758) | (61,339) | (56,440) |
| 65 | Real Time Schedule 49 Cost Distribution Amount | 56,476 | 42,133 | 45,043 |
| 66 | Real Time Virtual Energy Amount | - | - | - |
| | Real Time Subtotal | $ 699,967 | $ (3,392,409) | $ (1,690,372) |
| | Grand Total | $ (27,350,221) | $ (16,804,860) | $ (16,797,609) |

**AFFIRMATION**

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

Gregory T. Guerrettaz

By:
Indiana Office of
Utility Consumer Counselor

January 23, 2023
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 OUCC Witness Gregory T. Guerrettaz*** has been served upon the following counsel of record in the captioned proceeding by electronic service on January 23, 2023.

Teresa Morton Nyhart
Jeffrey M. Peabody
**BARNES & THORNBURG LLP**
tnyhart@btlaw.com
jpeabody@btlaw.com

Lorraine Hitz

Lorraine Hitz
Deputy Consumer Counselor

**INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR**
115 West Washington Street
Suite 1500 South
Indianapolis, IN 46204
**infomgt@oucc.in.gov**
317/232-2775 - Lorraine's No.
317/232-2494 – Phone
317/232-5923 – Facsimile