OFFICIAL EXHIBITS

FILED
January 31, 2024
INDIANA UTILITY
REGULATORY COMMISSION

IURC PETITIONER'S EXHIBIT NO. 9
3-19-24 AT
DATE REPORTER

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF DUKE ENERGY INDIANA, LLC FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR ELECTRIC SERVICE AND FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR HIGH PRESSURE STEAM SERVICE, IN ACCORDANCE WITH INDIANA CODE §8-1-2-42, INDIANA CODE §8-1-2-42.3, AND VARIOUS ORDERS OF THE INDIANA UTILITY REGULATORY COMMISSION	)))))))))	**CAUSE NO. 38707-FAC139**

VERIFIED APPLICATION AND AFFIDAVIT FOR APPROVAL OF A CHANGE(S) IN FUEL COST ADJUSTMENT (ELECTRIC SERVICE) AND FUEL COST ADJUSTMENT (STEAM SERVICE)

TO THE INDIANA UTILITY REGULATORY COMMISSION:

Duke Energy Indiana, LLC (hereinafter referred to as "Applicant" or "Duke Energy Indiana" or "Company") respectfully represents and shows unto this Commission:

1. Applicant is a public electric generating utility corporation organized and existing under the laws of the State of Indiana and has its principal office at 1000 East Main Street, Plainfield, Indiana. It is engaged in rendering electric utility service in the State of Indiana, and owns, operates, manages and controls, among other things, plants and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such electric service to the public. It also renders steam service to one customer; namely, International Paper. Applicant is subject to the jurisdiction of this Commission in the manner and to the extent provided by the Public Service Commission Act and other laws of the State of Indiana.

2. The names and addresses of the Applicant's attorneys in this matter are Andrew J. Wells and Liane K. Steffes, 1000 East Main Street, Plainfield, Indiana 46168, who are duly authorized to accept service of papers in this Cause on behalf of Applicant.

3. The following are the applicable procedural dates for this proceeding, as agreed to by the OUCC and approved in Cause No. 45253:

(i) January 31, 2024 – the date the Company is filing this Verified Application;

(ii) January 31, 2024 – the date the Company is prefiling testimony and exhibits supporting this Verified Application;

(iii) March 6, 2024 – the latest date by which the OUCC and any intervenor shall prefile its testimony and exhibits concerning this Verified Application[1];

(iv) March 12, 2024 – the latest date by which Duke Energy Indiana shall file rebuttal testimony;

(v) On or after March 18, 2024 – the day on which the Company requests that the evidentiary hearing concerning this Verified Application be held; and

(vi) March 29, 2024 – the end target date by which the Company requests the issuance of the Commission's Order concerning this Verified Application.

I. ELECTRIC SERVICE

1. This Application is filed pursuant to the provisions of the Public Service Commission Act (IC 8-1-2-42 (b), (d), (e), (f) and IC 8-1-2-42.3) and pursuant to Orders of the Commission, including the Orders in Cause Nos. 33735-S1, 33735-S2, 37712, 41363, 38707-FAC70, the June 1, 2005 Order in Cause No. 42685 ("MISO Order"), and the Commission's June 30, 2009

[1] The Commission Order in Cause No. 38707 FAC76, dated June 25, 2008, approved an Agreement on Synchronization of FAC and RTO Proceedings in which Duke Energy Indiana agreed to extend the time the Indiana Office of Utility Consumer Counselor ("OUCC") has to file its audit report and/or other testimony from the statutory 20 days to 35 days from the date Duke Energy Indiana files its testimony. The Agreement also provided that absent unusual circumstances, and assuming the Company prefiled testimony for both its FAC and RTO cases within 3 business days of each other, the OUCC agreed not to seek extensions of time to submit its audit reports/testimony for each case beyond the 35 days. With the RTO schedule moving from quarterly to annual filings, as approved in Cause No. 42736 RTO 54, this portion of the Agreement is no longer applicable. However, the Agreement provides that the Company and OUCC will cooperate such that the FAC order can be issued prior to the billing month to which the new cost factor is intended to apply.

Phase II Order in Cause No. 43426 concerning cost recovery related to the Midcontinent Independent System Operator, Inc.'s ("MISO") ancillary services market ("Phase II ASM Order") for the purpose of securing authorization for a change in the fuel cost adjustment applicable to Applicant's electric rate schedules. Applicant will file with the Commission the required additional showing pursuant to a public hearing held subject to the notice provisions required by IC 8-1-1-8.

2. This Application reflects changes in operations that began on April 1, 2005, resulting from MISO's implementation of energy markets under MISO's Open Access Transmission and Energy Markets Tariff (now known as MISO's Open Access Transmission and Energy and Operating Reserves Tariff and hereinafter "MISO's Tariff"). Such operational changes include purchases and sales of power and dispatch decisions reflecting MISO's day-ahead and real-time energy markets. This Application also reflects changes in operations that began on January 6, 2009, resulting from MISO's implementation of the ancillary service markets ("ASM") under MISO's Tariff. Such operational changes include purchases and sales of ancillary services and dispatch decisions reflecting MISO's day-ahead and real-time ancillary service markets. The recovery of jurisdictional costs requested in this proceeding and the proposed change in Applicant's fuel cost adjustment factor reflect charges and credits incurred by Applicant on behalf of its jurisdictional customers resulting from Applicant's participation in such markets, consistent with the Commission's prior orders regarding participation in and cost recovery of costs incurred due to participation in these markets.

3. This Application is also filed pursuant to the Commission's Order in Cause No. 45253, dated June 29, 2020 (request to change base rates). The Commission's Order in Cause No. 45253 resulted in changes that affect the Company's data filed in the fuel cost adjustment proceedings.

For purposes of computing the authorized net operating income for Indiana Code 8-1-2-42(d)(3), the changes in authorized jurisdictional operating revenues and expenses, as well as the jurisdictional allocation percentages, were phased-in over the same period of time as the Company's net operating income for the applicable twelve-month period affected by this Order. The authorized net operating income for the twelve-month ended November 30, 2023 period reflected in this filing is based on the Commission's Order in Cause No. 45253 and the associated Step 2 compliance filing. The Commission's Order in Cause No. 45253 also approved Applicant's proposed base cost of fuel to generate electricity and the cost of fuel included in the cost of net purchased electricity of $0.026955 per kWh. This Application is also filed pursuant to the Commission's July 3, 2002 Order in consolidated Cause Nos. 42061 and 41744-S1 ("ECR Order"), which approved construction work in progress ratemaking treatment for certain qualified pollution control property and clean energy projects, and the Commission's Orders in subsequent ECR proceedings. The value of the Company's plant is also subject to update as a result of (1) the Commission's June 25, 2014 Order in Cause No. 44367, which authorized Duke Energy Indiana to adjust the Company's authorized net operating income to reflect any approved earnings associated with federally mandated compliance projects ("FMCA") included in that proceeding and subsequent update proceedings; (2) the Commission's June 29, 2016 Order in Cause No. 44720, which authorized the Company to adjust its authorized net operating income to reflect approved earnings associated with its investments in transmission, distribution and storage system improvement ("TDSIC") projects included in that proceeding and subsequent update proceedings; and (3) the Commission's July 6, 2016 Order in Cause No. 44734, which authorized adjustment to the Company's authorized net operating income to reflect approved earnings associated with company-owned renewable energy projects ("REP") included in that proceeding and subsequent update proceedings. As stated above, the Commission's Order in Cause No. 45253 approved Applicant's proposed base cost of fuel of $0.026955 per kWh. Applicant's cost of fuel to generate electricity and the cost of fuel included in the net cost of purchased electricity for the month of November 2023, based on the latest data known to Applicant at the time of filing after excluding prior period costs, hedging, and miscellaneous fuel adjustments, if applicable, was $0.029444 per kWh as shown on Attachment A, Schedule 9, line 12, column L, attached hereto.

4. Duke Energy Indiana has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. Applicant will file testimony showing these facts prior to the date of hearing herein.

5. Applicant's testimony will include an explanation of certain financial transactions (*i.e.*, hedging arrangements) that were entered into by the Company on behalf of retail customers. Applicant will show that it entered into such hedging arrangements in order to mitigate the Company's exposure to price volatility in the bulk power market. Applicant requests that it be allowed to recover the net realized gains or losses associated with its hedging activities incurred on behalf of its native load customers.

6. Applicant's fuel cost adjustment factor takes into account charges and revenues incurred and received by the Applicant resulting from Applicant's participation in the energy and ancillary services markets of MISO's Tariff, as authorized by the Commission in Cause No. 42685 and other Commission orders. In addition, the Commission's Order in Cause No. 45253 approved the inclusion of fuel-related PJM charges and credits associated with operations of the Company's Madison Generating Station in the Applicant's fuel cost adjustment factor subsequent to the effective date of the Order. Pursuant to the Commission's Phase II ASM Order, Applicant is

authorized to recover certain new or modified MISO charges and credits resulting from its participation in ASM as a cost of fuel in its FAC proceedings and recover and account for Day Ahead RSG Distribution Amounts and Real Time RSG First Pass Distribution Amounts in FAC proceedings. Applicant has included MISO and PJM costs and credits in its fuel cost in this proceeding in accordance with the MISO Order, the base rate case order in Cause No. 45253, the Phase II ASM Order and other applicable Orders. Applicant will also provide testimony reporting the monthly average ASM cost distribution amounts paid for Regulation, Spinning, and Supplemental Reserves.

7. Actual increases in Applicant's fuel costs for the 12 months ended November 30, 2023, have not been offset by actual decreases in other operating expenses. Applicant will file testimony and exhibits showing these facts prior to the date of hearing herein.

8. Applicant will file testimony and attachments that will compare actual jurisdictional earnings and expenses for the twelve (12) months ended November 30, 2023, to the phased-in jurisdictional return and expenses authorized by the Commission's Order in Cause No. 45253 and the associated Step 2 compliance filing, subsequent ECR, FMCA, TDSIC, and REP orders as applicable, and the Commission's Order on Remand in Cause No. 45253.

9. The reconciliation of the actual incremental cost of fuel billed retail customers for the period of September through November 2023, resulted in a negative variance factor (*i.e.,* actual net jurisdictional fuel costs per kilowatt-hour incurred were less than fuel costs billed customers, resulting in a net over-collection of fuel costs).

10. Applicant's net fuel charge in this proceeding is $0.029149 per kWh; the net fuel charge in Cause No. 38707-FAC138 was $0.033590 per kWh. The net fuel charge in this proceeding less the base cost of fuel of $0.026955 will result in a fuel cost adjustment factor of $0.002194 per

kWh applicable to bills rendered by Applicant commencing with the first billing cycle upon the later of the date of approval by the Commission or the first April 2024 billing cycle (See Attachment A, Schedule 1).

Approval of the Company's proposed factor will result in the following estimated bill impacts by customer class:

Customer Class	Estimated Bill Impact[2] [3]
Residential *(based on typical customer at 1,000 kWh)*	3.3% decrease
Commercial *(based on three different sets of energy and demand billing determinants)*	>2.5% decrease
Industrial *(based on four different sets of energy and demand billing determinants)*	>4.0% decrease

11. The books and records of Applicant supporting data filed in this proceeding are kept in accordance with the Uniform System of Accounts for Electric Utilities prescribed by this Commission and are available for inspection and review by the OUCC and this Commission.

WHEREFORE, Applicant respectfully prays that the Indiana Utility Regulatory Commission hold a hearing pursuant to IC 8-1-2-42(a) and (d) and enter an order in this Cause:

i) authorizing and approving the reconciliation of incremental fuel costs billed to incremental fuel costs actually incurred during the months of September through November 2023;

ii) authorizing and approving the recovery of net realized gains and losses attributable to certain hedging activities;

[2] Estimated bill impact reflects comparison of change between proposed fuel cost rider factor and current factor as compared to total bill (base bill and all other riders) as of January 1, 2024.

[3] Bill impacts will vary based on customer usage specifics within each class. For the residential class, usage has been assumed at 1,000 kWh. For the commercial and industrial classes, the percentage reflects the highest estimated bill impact based on bill calculations at representative data points for each group as follows: commercial usage at (a) 3 KW/375kWh, (b) 40 KW/10,000 kWh, and (c) 500 KW/150,000 kWh and industrial usage at (a) 75 KW/15,000 kWh, (b) 75KW/50,000 kWh, (c) 50,000 KW/15,000,000 kWh, and (d) 50,000 KW/25,000,000 kWh.

iii) authorizing and approving the estimated fuel cost adjustment factor of $0.002194 per kWh to become effective upon the later of the date of approval by the Commission or the first billing cycle of April 2024;

iv) accepting for filing Applicant's tariff modifications reflecting the estimated fuel cost adjustment factor;

v) issuing such order within twenty (20) days from the date the Commission receives the OUCC audit report; and

vi) making such other and further orders in the proceeding, as the Commission may deem appropriate.

II. STEAM SERVICE

1. This Application is filed pursuant to the Order of the Commission in Cause No. 44087 and pursuant to the provisions of the Public Service Commission Act (IC 8-1-2-42) for the purpose of securing authorization for changes in Applicant's fuel cost adjustment applicable to its rendering of steam service to International Paper.

2. Applicant hereby incorporates by this reference all applicable paragraphs of Part I of this Application.

3. Applicant's proposed factors have been calculated in accordance with the fuel cost adjustment formula contained in the Commission's Order in Cause No. 45740.

4. The calculation showing the proposed fuel cost adjustment is shown on Attachment B, Schedule 1.

5. Applicant's estimated fuel cost for April through June 2024 is 30.3921624 mills per kWh. This amount, when multiplied by the equivalent conversion factor per 1000 pounds of steam of 0.1084, results in a cost factor of $3.2945104 per thousand pounds of steam. This cost factor,

less the base cost of fuel of $2.921922 per 1000 pounds of steam will result in a fuel cost adjustment factor of $0.3725884 per 1000 pounds of steam.

A reconciliation of the actual fuel cost adjustment incurred to the estimated fuel cost adjustment billed for the months of September through November 2023 is shown on Attachment B, Schedule 2. The total reconciliation adjustment of $(108,263) will be applied to International Paper's monthly bill for high-pressure steam service in three monthly installments, upon approval of such amount by the Commission.

6. The books and records of Applicant supporting such data and calculation are available for inspection and review by the OUCC and this Commission.

WHEREFORE, Applicant respectfully prays that the Indiana Utility Regulatory Commission hold a hearing and enter an order in this Cause:

i) authorizing and approving the changes in its existing fuel cost adjustment charge based upon the costs of fuel shown on said Attachment B, Schedule 1 applicable to Applicant's Commission approved contract for rendering steam service to International Paper;

ii) authorizing such changes to become effective upon the later of the date of approval by the Commission or the bill rendered to International Paper in April 2024 by Applicant for steam service;

iii) authorizing and approving the reconciliation adjustments to International Paper as shown on Attachment B, Schedule 2 for the September through November 2023 timeframe;

iv) issuing such order within twenty (20) days from the date the Commission receives the OUCC audit report; and

v) making such other and further orders in the proceeding, as the Commission may deem appropriate and proper.

[SIGNATURE PAGE TO FOLLOW]

Dated this 31st day of January, 2024.

DUKE ENERGY INDIANA, LLC

By:

Christa L. Graft, Manager Rates and Regulatory Strategy

Andrew J. Wells, Associate General Counsel

VERIFICATION

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

Signed: Christa L. Graft
Christa L. Graft

Dated: January 31, 2024

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing Verified Application and Affidavit delivered electronically to the following:

Lorraine Hitz
Michael Eckert
Office of Utility Consumer Counselor
115 W. Washington Street, Suite 1500 South
Indianapolis, Indiana 46204
LHitz@oucc.in.gov
meckert@oucc.in.gov
infomgt@oucc.in.gov

In addition, copies have been distributed electronically, for informational purposes, to the following:

Financial Solutions Group, Inc.
2680 East Main Street
Suite 223
Plainfield, Indiana 46168
Attn: Gregory T. Guerrettaz
greg@fsgcorp.com
kristen@fsgcorp.com
fsg@fsgcorp.com

Dated this 31st day of January 2024.

Andrew J. Wells, Atty. No. 29545-49
Liane K. Steffes, Atty. No. 31522-41
Duke Energy Business Services LLC
1000 East Main Street
Plainfield, Indiana 46168
(317) 838-2461 (office)
(317) 991-1273 (facsimile)
andrew.wells@duke-energy.com
liane.steffes@duke-energy.com

DUKE ENERGY INDIANA, LLC

Determination of Retail Fuel Cost Adjustment Factor to be
Effective Upon the Order of the Commission
Based on Estimated Average Fuel Costs
for the Months of April, May, and June 2024

Line No.	Description	Estimated Month of: April 2024 (A)	May 2024 (B)	June 2024 (C)	Total (D)	Estimated Three-Month Average (E)	Source (F)	Line No.
	MWh Source:							
1	Steam Generation	1,445,075	1,108,540	1,146,483	3,700,098	1,233,366	Sch.2,Ln 7	1
2	Nuclear Generation	-	-	-	-	-	Sch.2,Ln 8	2
3	Hydro and Solar Generation	41,795	43,479	42,355	127,629	42,543	Sch.2,Ln 9	3
	Other Generation --							
4	Internal Combustion	-	-	-	-	-	Sch.2,Ln 10	4
5	Gas Combustion Turbine	561,221	672,272	651,240	1,884,733	628,244	Sch.2,Ln 11	5
6	Integrated Gasification Combined Cycle	12,717	387,766	353,442	753,925	251,308	Sch.2,Ln 12	6
7	Purchased Power	248,787	190,023	482,996	921,806	307,269	Sch.3,Col.A	7
	Less:							
8	Intersystem Sales	-	-	-	-	-	Sch.4,Col.A	8
9	Energy Losses & Company Use	118,450	122,862	138,910	380,222	126,741		9
10	Sales (S)	2,191,145	2,279,218	2,537,606	7,007,969	2,335,989		10
	Fuel Cost:							
11	Steam Generation	$ 43,082,000	$ 33,059,000	$ 34,099,000	$ 110,240,000	$ 36,746,667	Sch.2,Ln 1	11
12	Nuclear Generation	-	-	-	-	-	Sch.2,Ln 2	12
13	Hydro and Solar Generation	-	-	-	-	-		13
	Other Generation --							
14	Internal Combustion	-	-	-	-	-	Sch.2,Ln 3	14
15	Gas Combustion Turbine	15,590,000	17,655,000	18,753,000	51,998,000	17,332,667	Sch.2,Ln 4	15
16	Integrated Gasification Combined Cycle	766,000	10,326,000	9,951,000	21,043,000	7,014,333	Sch.2,Ln 5	16
17	Hedging Position 1/	948,000	1,171,000	1,338,000	3,457,000	1,152,333		17
18	Purchased Power	9,140,000	6,848,000	16,867,000	32,855,000	10,951,667	Sch 3, Col. C	18
19	Net MISO Energy Market	2,324,000	1,455,000	2,294,000	6,073,000	2,024,333		19
20	Net MISO Ancillary Services Market	-	-	-	-	-		20
	Less:							
21	Intersystem Sales	-	-	-	-	-	Sch.4,Col.C	21
22	Steam Sales	385,000	386,000	352,000	1,123,000	374,333	Sch.5,Ln 4	22
23	Total Fuel Cost (F)	$ 71,465,000	$ 70,128,000	$ 82,950,000	$ 224,543,000	$ 74,847,667		23
24	F / S (Mills Per kWh)					32.041		24
	Months to be Reconciled							
		September 2023	October 2023	November 2023	3 Months Total			
25	Monthly Fuel Cost Reconciliation Variance	$ (16,806,092)	$ 1,058,680	$ (2,199,132)	$ (17,946,544) 2/		Sch.6s	25
26	Net FAC139 Reconciliation Factor -$ 17,946,544 / 6,205,655 MWhrs					(2.892)		26
27	Subtotal					29.149		27
28	Less: Base Cost of Fuel Included in Rates					26.955		28
29	Total Fuel Cost Adjustment Factor (Mills Per kWh)					2.194		29

1/ These hedging amounts are based on a "marked" current value of the underlying hedging contracts, and therefore their value could fluctuate until settlement when the ultimate gain or loss on the contracts is known.

2/ See Attachment A, Schedule 6, Page 3 of 3.

DUKE ENERGY INDIANA, LLC

Determination of the
Estimated Cost of Fuel Consumed (Account 151)
and Net Generation (MWh Output)
for the Months of April, May, and June 2024
Used in Developing the Retail Fuel Cost Factor to be
Effective Upon the Order of the Commission

Line No.	Description	Estimated Month of: April 2024	May 2024	June 2024	Total	Estimated Three-Month Average	Line No.
		(A)	(B)	(C)	(D)	(E)	
	Fuel Cost:						
1	Steam Generation	$ 43,082,000	$ 33,059,000	$ 34,099,000	$ 110,240,000	$ 36,746,667	1
2	Nuclear Generation	-	-	-	-	-	2
	Other Generation -						
3	Internal Combustion	-	-	-	-	-	3
4	Gas Combustion Turbine	15,590,000	17,655,000	18,753,000	51,998,000	17,332,667	4
5	Integrated Gasification Combined Cycle	766,000	10,326,000	9,951,000	21,043,000	7,014,333	5
6	Total Fuel Cost	$ 59,438,000	$ 61,040,000	$ 62,803,000	$ 183,281,000	$ 61,093,667	6
	Net Generation MWh Output:						
7	Steam Generation	1,445,075	1,108,540	1,146,483	3,700,098	1,233,366	7
8	Nuclear Generation	-	-	-	-	-	8
9	Hydro and Solar Generation	41,795	43,479	42,355	127,629	42,543	9
	Other Generation -						
10	Internal Combustion	-	-	-	-	-	10
11	Gas Combustion Turbine	561,221	672,272	651,240	1,884,733	628,244	11
12	Integrated Gasification Combined Cycle	12,717	387,766	353,442	753,925	251,308	12
13	Total Net Generation	2,060,808	2,212,057	2,193,520	6,466,385	2,155,461	13

DUKE ENERGY INDIANA, LLC

Determination of Estimated
Net Energy Costs of Native Load Purchased Power
for the Months of April, May, and June 2024
Used in Developing the Retail Fuel Cost Factor to be
Effective Upon the Order of the Commission

Line No.	Type of Power	MWh Purchased	Demand	Energy Charges: Fuel	Energy Charges: Other	Energy Charges: Total Energy	Total	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	
	April 2024							
1	Various Purchases 1/	248,787	$ -	$ 9,140,000	$ -	$ 9,140,000	$ 9,140,000	1
	May 2024							
2	Various Purchases 1/	190,023	-	6,848,000	-	6,848,000	6,848,000	2
	June 2024							
3	Various Purchases 1/	482,996	-	16,867,000	-	16,867,000	16,867,000	3
4	Total Purchased Power	921,806	$ -	$ 32,855,000	$ -	$ 32,855,000	$ 32,855,000	4

1/ Includes budget amounts related to purchases from Benton County Wind Farm, LLC from PPA approved by the Commission Order in Cause No. 43097, dated December 6, 2006; solar PPAs approved in Cause No. 44578, dated August 19, 2015; and Staunton Solar PPA approved in Cause No. 44953, dated November 21, 2017.

ATTACHMENT A
SCHEDULE 4

DUKE ENERGY INDIANA, LLC

Determination of Estimated Fuel Costs (Account 151)
Recovered Through Intersystem Sales
for the Months of April, May, and June 2024
Used in Developing the Retail Fuel Cost Factor to be
Effective Upon the Order of the Commission

Line No.	Type of Transaction		MWh Sold	Demand Charge	Energy Charge: Fuel Cost (Accounts 151)	Energy Charge: Other Costs	Energy Charge: Total Energy Charge	Total Charges	Line No.
			(A)	(B)	(C)	(D)	(E)	(F)	
	April 2024								
1	Power Coordination Agreement Sales	_1/	-	$ -	$ -	$ -	$ -	$ -	1
	May 2024								
2	Power Coordination Agreement Sales	_1/	-	-	-	-	-	-	2
	June 2024								
3	Power Coordination Agreement Sales	_1/	-	-	-	-	-	-	3
4	Total Intersystem Sales		-	$ -	$ -	$ -	$ -	$ -	4

_1/ Power Coordination Agreements terminated on December 31, 2014.

ATTACHMENT A
SCHEDULE 5

DUKE ENERGY INDIANA, LLC

Determination of Estimated Equivalent Fuel Costs
Recovered Through the Sale of Steam
for the Months of April, May, and June 2024
Used in Developing the Retail Fuel Cost Factor to be
Effective Upon the Order of the Commission

Line No.	Description	Estimated Month of: April 2024 (A)	May 2024 (B)	June 2024 (C)	Total (D)	Estimated Three-Month Average (E)	Source	Line No.
1	Total Pounds of Steam Supplied (000s)	116,930	117,078	106,845	340,853	113,618		1
2	Total Equivalent MWh Generated At Cayuga, Other Generating Stations Of the Company and Through Purchased Power Transactions (Note 1)	12,675	12,691	11,582	36,948	12,316		2
3	Equivalent Cost per 1000 lbs Steam (Note 2)	$ 3.2945104	$ 3.2945104	$ 3.2945104				3
4	Fuel Costs Recovered Through the Sale of Steam (Line 1 * Line 3) (Rounded to 000s)	$ 385,000	$ 386,000	$ 352,000	$ 1,123,000	$ 374,333		4

Note 1: Equivalent MWh = 0.1084 * Line 1

Note 2: Fuel Cost

Description	April 2024	May 2024	June 2024	Total	Three-Month Average	Source
Steam Generation	$ 43,082,000	$ 33,059,000	$ 34,099,000	$ 110,240,000	$ 36,746,667	Sch. 1, Ln 11
Nuclear Generation	-	-	-	-	-	Sch. 1, Ln 12
Other Generation						
Internal Combustion	-	-	-	-	-	Sch. 1, Ln 14
Gas Combustion Turbine	15,590,000	17,655,000	18,753,000	51,998,000	17,332,667	Sch. 1, Ln 15
Integrated Gasification Combined Cycle	766,000	10,326,000	9,951,000	21,043,000	7,014,333	Sch. 1, Ln 16
Hedging Position	948,000	1,171,000	1,338,000	3,457,000	1,152,333	Sch. 1, Ln 17
Purchased Power	9,140,000	6,848,000	16,867,000	32,855,000	10,951,667	Sch. 1, Ln 18
Net MISO Energy Market	2,324,000	1,455,000	2,294,000	6,073,000	2,024,333	Sch. 1, Ln 19
Net MISO Ancillary Services Market	-	-	-	-	-	Sch. 1, Ln 20
Less:						
Intersystem Sales	-	-	-	-	-	Sch. 1, Ln 21
Total Fuel Costs	$ 71,850,000	$ 70,514,000	$ 83,302,000	$ 225,666,000	$ 75,222,000	
MWh						
Sales (S)	2,191,145	2,279,218	2,537,606	7,007,969	2,335,989	Sch. 1, Ln 10
Energy Losses & Company Use	118,450	122,862	138,910	380,222	126,741	Sch. 1, Ln 9
Equivalent MWh - Steam Sale	12,675	12,691	11,582	36,948	12,316	Sch. 5, Ln 2
Total MWh (K)	2,322,270	2,414,771	2,688,098	7,425,139	2,475,046	
F/K (Mills Per MWh)					30.3921624	
Equivalent Cost per 1000 lbs Steam (Mills Per MWh * 0.1084)					$ 3.2945104	

DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Incremental Cost of Fuel Incurred to Actual Incremental Cost of Fuel Billed
Retail Customers for September 2023

Line No.	Class of Customers	MWh Sold	Base Cost of Fuel Included in Rates 26.955 Mills/kWh	Actual Cost of Fuel Incurred 1/	Actual Incremental Cost of Fuel Incurred	Actual Incremental Cost of Fuel Billed Excluding Utility Receipts Tax	Fuel Cost Variance from Cause No. 38707-FAC 136	Incremental Fuel Clause Revenues to be Reconciled with Actual Incremental Cost of Fuel Incurred	Fuel Cost Variance (Over) or Under Billing	Line No.
		(A)	(B)	(C)	(D) (Col.C) - (Col.B)	(E)	(F)	(G) (Col. E) - (Col. F)	(H) (Col. D) - (Col. G)	
1	Total Residential	792,567	$ 21,363,643	$ 22,006,296	$ 642,653	$ 4,007,874	$ (2,237,893)	$ 6,245,767	$ (5,603,114)	1
2	Total Commercial	603,113	16,256,911	16,745,945	489,034	2,976,760	(1,702,950)	4,679,710	(4,190,676)	2
3	Total Industrial	807,387	21,763,117	22,417,785	654,668	4,134,460	(2,279,738)	6,414,198	(5,759,530)	3
4	Total Other	172,169	4,640,815	4,780,419	139,604	906,239	(486,137)	1,392,376	(1,252,772)	4
5	Total Retail kWh Sales Subject to Fuel Adjustment Clause	2,375,236	$ 64,024,486	$ 65,950,445	$ 1,925,959	$ 12,025,333	$ (6,706,718)	$ 18,732,051	$ (16,806,092)	5
6	Retail kWh Sales Not Subject to the Fuel Adjustment Clause	24,761								6
7	kWh Sales for Resale	231,764								7
8	Sales	2,631,761								8

1/ Equal to total fuel cost (Schedule 7, column D), minus retail kwh not subject to fuel adjustment clause (Schedule 6, line 6, column A) x fuel cost - mills per kWh (F/S, Schedule 7, column D).

DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Incremental Cost of Fuel Incurred to Actual Incremental Cost of Fuel Billed
Retail Customers for October 2023

Line No.	Class of Customers	MWh Sold	Base Cost of Fuel Included in Rates 26.955 Mills/kWh	Actual Cost of Fuel Incurred 1/	Actual Incremental Cost of Fuel Incurred	Actual Incremental Cost of Fuel Billed Excluding Utility Receipts Tax	Fuel Cost Variance from Cause No. 38707-FAC 137	Incremental Fuel Clause Revenues to be Reconciled with Actual Incremental Cost of Fuel Incurred	Fuel Cost Variance (Over) or Under Billing	Line No.
		(A)	(B)	(C)	(D) (Col.C) - (Col.B)	(E)	(F)	(G) (Col. E) - (Col. F)	(H) (Col. D) - (Col. G)	
1	Total Residential	594,204	$ 16,016,769	$ 20,705,981	$ 4,689,212	$ 4,255,095	$ (153,493)	$ 4,408,588	$ 280,624	1
2	Total Commercial	517,281	13,943,309	18,025,477	4,082,168	3,567,666	(133,622)	3,701,288	380,880	2
3	Total Industrial	568,883	15,334,241	19,823,631	4,489,390	4,022,868	(146,952)	4,169,820	319,570	3
4	Total Other	151,493	4,083,494	5,279,014	1,195,520	1,078,781	(39,133)	1,117,914	77,606	4
5	Total Retail kWh Sales Subject to Fuel Adjustment Clause	1,831,861	$ 49,377,813	$ 63,834,103	$ 14,456,290	$ 12,924,410	$ (473,200)	$ 13,397,610	$ 1,058,680	5
6	Retail kWh Sales Not Subject to the Fuel Adjustment Clause	25,161								6
7	kWh Sales for Resale	222,500								7
8	Sales	2,079,522								8

1/ Equal to total fuel cost (Schedule 7, column D), minus retail kwh not subject to fuel adjustment clause (Schedule 6, line 6, column A) x fuel cost - mills per kWh (F/S, Schedule 7, column D).

DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Incremental Cost of Fuel Incurred to Actual Incremental Cost of Fuel Billed
Retail Customers for November 2023

Line No.	Class of Customers	MWh Sold	Base Cost of Fuel Included in Rates 26.955 Mills/kWh	Actual Cost of Fuel Incurred 1/	Actual Incremental Cost of Fuel Incurred	Actual Incremental Cost of Fuel Billed Excluding Utility Receipts Tax	Fuel Cost Variance from Cause No. 38707-FAC 137	Incremental Fuel Clause Revenues to be Reconciled with Actual Incremental Cost of Fuel Incurred	Fuel Cost Variance (Over) or Under Billing	Line No.
		(A)	(B)	(C)	(D) (Col.C) - (Col.B)	(E)	(F)	(G) (Col. E) - (Col. F)	(H) (Col. D) - (Col. G)	
1	Total Residential	535,243	$ 14,427,475	$ 17,794,469	$ 3,366,994	$ 3,815,383	$ (135,380)	$ 3,950,763	$ (583,769)	1
2	Total Commercial	450,155	12,133,928	14,965,669	2,831,741	3,196,484	(113,859)	3,310,343	(478,602)	2
3	Total Industrial	764,008	20,593,836	25,399,897	4,806,061	5,494,291	(193,243)	5,687,534	(881,473)	3
4	Total Other	121,448	3,273,631	4,037,610	763,979	988,549	(30,718)	1,019,267	(255,288)	4
5	Total Retail kWh Sales Subject to Fuel Adjustment Clause	1,870,854	$ 50,428,870	$ 62,197,645	$ 11,768,775	$ 13,494,707	$ (473,200)	$ 13,967,907	(2,199,132)	5
6	Retail kWh Sales Not Subject to the Fuel Adjustment Clause	26,761								6
7	kWh Sales for Resale	160,801								7
8	Sales	2,058,416								8
9	Fuel Cost Variance for September 2023 (See Attachment A, Schedule 6, Page 1 of 3, Column H)								(16,806,092)	9
10	Fuel Cost Variance for October 2023 (See Attachment A, Schedule 6, Page 2 of 3, Column H)								1,058,680	10
11	Total Fuel Cost Variance for the Three (3) Months Ended November 2023								$ (17,946,544)	11

1/ Equal to total fuel cost (Schedule 7, column D), minus retail kwh not subject to fuel adjustment clause (Schedule 6, line 6, column A) x fuel cost - mills per kWh (F/S, Schedule 7, column D).

DUKE ENERGY INDIANA, LLC

Determination of Fuel Cost Per kWh
Based on Actual Fuel Cost for
September 2023

Line No.	Description	Total Actual September 2023 (A)	WVPA 70MW Firm Sale (B)	Wholesale Formula Rate ASM 4/ (C)	Adjusted Actual September 2023 (D)	Line No.
	kWh Sales (000's):					
	Native Load Sales					
	Retail					
1	Residential	792,567			792,567	1
2	Commercial	603,113			603,113	2
3	Industrial	823,480			823,480	3
4	Public Street and Highway Lighting	4,948			4,948	4
5	Other Public Authorities	175,889			175,889	5
6	Billed Retail Sales	2,399,997			2,399,997	6
7	Unbilled Retail Sales	(181,708)			(181,708)	7
8	Wholesale Sales	231,764	36,260	195,504	-	8
9	Total Native Load Sales (S)	2,450,053	36,260	195,504	2,218,289	9
	Fuel Cost:					
10	Native Load Fuel Cost, Including Virtual Energy Amounts 1/	$ 74,924,698	$ 1,120,171	$ 5,849,551	$ 67,954,976	10
11	Realized Hedging Activity, Excluding Virtual Energy Amounts 2/	384,926	5,697	30,715	348,514	11
12	Wind and Solar REC Proceeds 5/	(66,918)	(990)	(5,340)	(60,588)	12
13	Prior Period Hedging Adjustment 6/	-	-	-	-	13
14	Prior Period Cost Adjustments 3/	(2,191,744)	(54,107)	(589,644)	(1,547,993)	14
15	Total Fuel Cost (F)	$ 73,050,962	$ 1,070,771	$ 5,285,282	$ 66,694,909	15
16	Fuel Cost - Mills per kWh (F/S)	29.816	29.530	27.034	30.066	16

1/ In accordance with the Commission's June 1, 2005 Order in Cause No. 42685 and pertinent subsequent Commission directives, the Company's total native load fuel cost includes applicable MISO costs which were incurred to serve Duke Energy Indiana's native load customers' energy requirements. This line also includes energy costs for third-party solar PPAs, gas costs and steam revenues for the Purdue CHP plant, payments to customers for excess distributed generation, and costs associated with the Speedway PPA.

2/ Hedging component subtotals follow: LMP hedging total $30,903; Gas hedging total $354,023.

3/ Prior Period Adjustment Totals by month: 1)Jun23 S105 ($159,115); 2)Jul23 S105 ($1,016,834); 3)Aug23 S105 ($1,015,795).

Prior Period Adjustment WVPA 70 by month: 1)Jun23 S105 ($17,486); 2)Jul23 S105 ($1,765); 3)Aug23 S105 ($34,856).

Prior Period Adjustment Wholesale Formula Rate by month: 1)Jun23 S105 ($170,008); 2)Jul23 S105 ($136,910); 3)Aug23 S105 ($282,726).

4/ Adjustment to native load fuel cost to reflect that certain of the Company's wholesale formula rates customers are billed directly by MISO for the three ASM cost distribution charge types (i.e. regulation, spinning and supplemental) related to their load. Therefore, the full amount of these charge types is directly attributable to the Company's remaining native load customers.

5/ Net proceeds received during the month from the sale of renewable energy credits (RECs) associated with Company's wind and solar PPAs.

6/ Prior Period Hedging Adjustment Totals by Month: 1)Jun23 S105 LMP $0; 2)Jul23 S105 LMP ($56), Gas $56; 3)Aug23 S105 LMP $0.

DUKE ENERGY INDIANA, LLC

Determination of Fuel Cost Per kWh
Based on Actual Fuel Cost for
October 2023

Line No.	Description		Total Actual October 2023 (A)		WVPA 70MW Firm Sale (B)		Wholesale Formula Rate ASM 4/ (C)		Adjusted Actual October 2023 (D)	Line No.
	kWh Sales (000's):									
	Native Load Sales									
	Retail									
1	Residential			594,204					594,204	1
2	Commercial			517,281					517,281	2
3	Industrial			584,882					584,882	3
4	Public Street and Highway Lighting			5,282					5,282	4
5	Other Public Authorities			155,373					155,373	5
6	Billed Retail Sales			1,857,022					1,857,022	6
7	Unbilled Retail Sales			58,695					58,695	7
8	Wholesale Sales			222,500		32,970		189,530	-	8
9	Total Native Load Sales (S)			2,138,217		32,970		189,530	1,915,717	9
	Fuel Cost:									
10	Native Load Fuel Cost, Including Virtual Energy Amounts 1/	$	71,380,713	$	1,019,166	$	5,748,085	$	64,613,462	10
11	Realized Hedging Activity, Excluding Virtual Energy Amounts 2/		78,355		1,208		6,945		70,202	11
12	Wind and Solar REC Proceeds 5/		-		-		-		-	12
13	Prior Period Cost Adjustments 3/		-		-		-		-	13
14	Total Fuel Cost (F)	$	71,459,068	$	1,020,374	$	5,755,030	$	64,683,664	14
15	Fuel Cost - Mills per kWh (F/S)		33.420		30.949		30.365		33.765	15

1/ In accordance with the Commission's June 1, 2005 Order in Cause No. 42685 and pertinent subsequent Commission directives, the Company's total native load fuel cost includes applicable MISO costs which were incurred to serve Duke Energy Indiana's native load customers' energy requirements. This line also includes energy costs for third-party solar PPAs, gas costs and steam revenues for the Purdue CHP plant, payments to customers for excess distributed generation, and costs associated with the Speedway PPA

2/ Hedging component subtotals follow: LMP hedging total ($13,155); Gas hedging total $91,510.

3/ Prior Period Adjustment Totals by month: None.
Prior Period Adjustment WVPA 70 by month: None.
Prior Period Adjustment Wholesale Formula Rate by month: None.

4/ Adjustment to native load fuel cost to reflect that certain of the Company's wholesale formula rates customers are billed directly by MISO for the three ASM cost distribution charge types (i.e. regulation, spinning and supplemental) related to their load. Therefore, the full amount of these charge types is directly attributable to the Company's remaining native load customei

5/ Net proceeds received during the month from the sale of renewable energy credits (RECs) associated with Company's wind and solar PPAs.

DUKE ENERGY INDIANA, LLC

Determination of Fuel Cost Per kWh
Based on Actual Fuel Cost for
November 2023

Line No.	Description	Total Actual November 2023	WVPA 70MW Firm Sale	Wholesale Formula Rate ASM 4/	Adjusted Actual November 2023	Line No.
		(A)	(B)	(C)	(D)	
	kWh Sales (000's):					
	Native Load Sales					
	Retail					
1	Residential	535,243			535,243	1
2	Commercial	450,155			450,155	2
3	Industrial	781,115			781,115	3
4	Public Street and Highway Lighting	5,140			5,140	4
5	Other Public Authorities	125,962			125,962	5
6	Billed Retail Sales	1,897,615			1,897,615	6
7	Unbilled Retail Sales	216,340			216,340	7
8	Wholesale Sales	160,801	20,510	140,291	-	8
9	Total Native Load Sales (S)	2,274,756	20,510	140,291	2,113,955	9
	Fuel Cost:					
10	Native Load Fuel Cost, Including Virtual Energy Amounts 1/	$ 66,978,521	$ 609,745	$ 4,111,773	$ 62,257,003	10
11	Realized Hedging Activity, Excluding Virtual Energy Amounts 2/	825,442	7,442	50,907	767,093	11
12	Wind and Solar PPA REC Proceeds 5/	(31,177)	(281)	(1,923)	(28,973)	12
13	Prior Period Cost Adjustments 3/	-	-	-	-	13
14	Total Fuel Cost (F)	$ 67,772,786	$ 616,906	$ 4,160,757	$ 62,995,123	14
15	Fuel Cost - Mills per kWh (F/S)	29.793	30.078	29.658	29.800	15

1/ In accordance with the Commission's June 1, 2005 Order in Cause No. 42685 and pertinent subsequent Commission directives, the Company's total native load fuel cost includes applicable MISO costs which were incurred to serve Duke Energy Indiana's native load customers' energy requirements. This line also includes energy costs for third-party solar PPAs, gas costs and steam revenues for the Purdue CHP plant, payments to customers for excess distributed generation, and costs associated with the Speedway P

2/ Hedging component subtotals follow: LMP hedging total $28,335; Gas hedging total $797,107.

3/ Prior Period Adjustment Totals by month: None.
Prior Period Adjustment WVPA 70 by month: None.
Prior Period Adjustment Wholesale Formula Rate by month: None.

4/ Adjustment to native load fuel cost to reflect that certain of the Company's wholesale formula rates customers are billed directly by MISO for the three ASM cost distribution charge typ (i.e. regulation, spinning and supplemental) related to their load. Therefore, the full amount of these charge types is directly attributable to the Company's remaining native load custoı

5/ Net proceeds received during the month from the sale of renewable energy credits (RECs) associated with Company's wind and solar PPAs.

DUKE ENERGY INDIANA, LLC

ATTACHMENT A
SCHEDULE 8

Summary of Fuel Costs Incurred to Meet Native Load
Requirements by Week to Be Recovered Via the Fuel Adjustment Clause
for the Months of September, October and November 2023

Line No.		DEI Generation Fuel for DEI Native Load 1/			MISO Total Net Charges Corresponding to DEI Gen. Allocated to Serve DEI Native Load 2/			DEI Generation Total Expense for DEI Native Load			Other MISO Charges and/or Credits Allocated to DEI Native Load 3/	Total DEI Native Load Purchases 4/			Total Via Fuel Adjustment Clause 5/			Line No.
		MWh	$	$/MWh	MWh	$	$/MWh	MWh	$	$/MWh	$	MWh	$	$/MWh	MWh	$	$/MWh	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	
	September 2023																	
1	01 - 02	97,425.611	3,166,761.91	32.50	97,425.611	266,169.84	2.73	97,425.611	3,432,931.75	35.24	(2,434,545.28)	68,837.706	2,041,056.21	29.65	166,263.317	3,039,442.68	18.28	1
2	03 - 09	461,922.830	15,081,614.52	32.65	461,922.830	65,036.84	0.14	461,922.830	15,146,651.36	32.79	(958,865.27)	146,558.336	6,052,852.18	41.30	608,481.166	20,240,638.27	33.26	2
3	10 - 16	320,615.239	10,300,952.43	32.13	320,615.239	805,934.39	2.51	320,615.239	11,106,886.82	34.64	(472,451.50)	202,711.333	6,352,619.05	31.34	523,326.572	16,987,054.37	32.46	3
4	17 - 23	272,758.405	8,988,137.14	32.95	272,758.405	684,388.69	2.51	272,758.405	9,672,525.83	35.46	(1,147,857.53)	256,589.084	9,055,153.43	35.29	529,347.489	17,579,821.73	33.21	4
5	24 - 30	287,951.448	9,627,043.56	33.43	287,951.448	(11,656.71)	(0.04)	287,951.448	9,615,386.85	33.39	(653,973.71)	247,675.866	9,048,509.66	36.53	535,627.314	18,009,922.80	33.62	5
6	Subtotals	1,440,673.533	47,164,509.56	32.74	1,440,673.533	1,809,873.05	1.26	1,440,673.533	48,974,382.61	33.99	(5,667,693.29)	922,372.325	32,550,190.53	35.29	2,363,045.858	75,856,879.85	32.10	6
7														WVPA-IMPA Adjustment 6/	(275,639.510)	(8,504,309.70)	30.85	7
8														Native Alloc. Of Gas Pipeline Res. Fee 7/		299,245.13		8
9														Other Fuel Cost Adjustments		-		9
10															2,087,406.348	67,651,815.28	32.41	10

		DEI Generation Fuel for DEI Native Load 1/			MISO Total Net Charges Corresponding to DEI Gen. Allocated to Serve DEI Native Load 2/			DEI Generation Total Expense for DEI Native Load			Other MISO Charges and/or Credits Allocated to DEI Native Load 3/	Total DEI Native Load Purchases 4/			Total Via Fuel Adjustment Clause 5/			
		MWh	$	$/MWh	MWh	$	$/MWh	MWh	$	$/MWh	$	MWh	$	$/MWh	MWh	$	$/MWh	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	
	October 2023																	
11	01 - 07	399,000.464	13,274,230.84	33.27	399,000.464	759,879.83	1.90	399,000.464	14,034,110.67	35.17	(4,108,858.04)	136,132.166	5,994,582.72	44.04	535,132.630	15,919,835.35	29.75	11
12	08 - 14	362,919.981	11,769,378.86	32.43	362,919.981	327,470.89	0.90	362,919.981	12,096,849.75	33.33	(755,797.48)	125,293.610	4,437,885.44	35.42	488,213.591	15,778,937.71	32.32	12
13	15 - 21	402,392.461	13,010,250.94	32.33	402,392.461	1,112,673.16	2.77	402,392.461	14,122,924.10	35.10	(1,362,616.45)	91,367.196	3,250,083.80	35.57	493,759.657	16,010,391.45	32.43	13
14	22 - 28	398,915.744	12,827,188.67	32.16	398,915.744	1,017,029.62	2.55	398,915.744	13,844,218.29	34.70	(967,829.12)	107,088.096	3,838,286.65	35.84	506,003.840	16,714,675.82	33.03	14
15	29 - 31	189,689.286	6,020,599.51	31.74	189,689.286	590,248.45	3.11	189,689.286	6,610,847.96	34.85	(982,812.38)	47,756.441	2,105,160.46	44.08	237,445.727	7,733,196.04	32.57	15
16	Subtotals	1,752,917.936	56,901,648.82	32.46	1,752,917.936	3,807,301.95	2.17	1,752,917.936	60,708,950.77	34.63	(8,177,913.47)	507,637.509	19,625,999.07	38.66	2,260,555.445	72,157,036.37	31.92	16
17														WVPA-IMPA Adjustment 6/	(280,185.000)	(8,097,714.22)	28.90	17
18														Native Alloc. Of Gas Pipeline Res. Fee 7/		301,287.53		18
19														Other Fuel Cost Adustments		-		19
20															1,980,370.445	64,360,609.68	32.50	20

		DEI Generation Fuel for DEI Native Load 1/			MISO Total Net Charges Corresponding to DEI Gen. Allocated to Serve DEI Native Load 2/			DEI Generation Total Expense for DEI Native Load			Other MISO Charges and/or Credits Allocated to DEI Native Load 3/	Total DEI Native Load Purchases 4/			Total Via Fuel Adjustment Clause 5/			
		MWh	$	$/MWh	MWh	$	$/MWh	MWh	$	$/MWh	$	MWh	$	$/MWh	MWh	$	$/MWh	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	
	November 2023																	
21	01 - 04	244,571.801	7,643,130.39	31.25	244,571.801	680,262.50	2.78	244,571.801	8,323,392.89	34.03	(2,763,343.51)	57,484.578	2,487,219.34	43.27	302,056.379	8,047,268.72	26.64	21
22	05 - 11	343,579.649	10,733,049.26	31.24	343,579.649	291,081.61	0.85	343,579.649	11,024,130.87	32.09	(551,010.53)	147,444.269	5,244,913.43	35.57	491,023.918	15,718,033.77	32.01	22
23	12 - 18	348,294.972	10,523,617.02	30.21	348,294.972	681,069.53	1.96	348,294.972	11,204,686.55	32.17	(756,414.72)	146,304.218	5,121,072.81	35.00	494,599.190	15,569,344.64	31.48	23
24	19 - 25	316,010.571	9,329,218.72	29.52	316,010.571	538,738.49	1.70	316,010.571	9,867,957.21	31.23	(274,867.03)	173,448.009	5,553,545.02	32.02	489,458.580	15,146,635.20	30.95	24
25	26 - 30	208,304.785	6,100,412.82	29.29	208,304.785	596,352.55	2.86	208,304.785	6,696,765.37	32.15	(661,622.73)	206,780.943	8,035,199.84	38.86	415,085.728	14,070,342.48	33.90	25
26	Subtotals	1,460,761.778	44,329,428.21	30.35	1,460,761.778	2,787,504.68	1.91	1,460,761.778	47,116,932.89	32.26	(5,007,258.52)	731,462.017	26,441,950.44	36.15	2,192,223.795	68,551,624.81	31.27	26
27														WVPA-IMPA Adjustment 6/	(178,762.013)	(5,254,430.78)	29.39	27
28														Native Alloc. Of Gas Pipeline Res. Fee 7/		(1,305,317.24)		28
29														Other Fuel Cost Adustments 8/		-		29
30															2,013,461.782	61,991,876.79	30.79	30

Notes:

The net fuel costs are based on results of the Sumatra computer modeling process using the most current MISO statements available. They will be adjusted in future periods, as needed, based on revised MISO statements and new Sumatra modeling results ("Sumatra adjustments").

1/ Includes the Markland run-of-river hydroelectric generation and Crane solar generation.

2/ Includes the MISO Congestion and Loss components of LMP for generation and purchases allocated to serve native load and offsets to revenue for generating unit off-line auxiliary power (i.e., generation revenues from MISO less corresponding load expense to MISO).
Includes ($4,338.11), ($13,273.49) and ($5,553.49) respectively, for Excessive Energy Amounts for the months of September 2023, October 2023, November 2023.

3/ Includes multiple MISO related charges and credits. See Attachment A, Schedule 11 for additional detail.

4/ Includes net purchased power for DEI native load in excess of DEI generation allocated by Sumatra to serve native load (e.g. Benton County Wind PPA, MISO purchased power, and Bilateral purchased power). In accordance with the Commission's July 29, 2020 Order in Cause No. 45253, the purchased power benchmark process was eliminated for periods after the date of the rate order.

5/ Does not include Sumatra adjustments of prior period costs recognized in the current period or third party transmission activity.

6/ Manual exclusion of fuel cost associated with WVPA and IMPA's joint ownership of Gibson unit 5, necessary because Sumatra models and allocates cost to 100% of Gibson 5.

7/ DEI native load allocation of gas pipeline reservation fees. The fees are allocated based on the percentage of generation from pipeline reservation cost assessed units assigned to native load versus total generation output of these units.

ATTACHMENT A
SCHEDULE 9

DUKE ENERGY INDIANA, LLC

Actual Native Load Cost of Fuel to Generate Electricity and the
Actual Native Load Cost of Fuel Included in the Cost of Purchased Power
December 2022 through November 2023

Line No.	Description	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
1	**MWh Sales (S)**	2,701,956	2,321,837	2,326,960	2,351,797	2,138,922	1,972,822	2,314,637	2,834,919	2,451,238	2,450,053	2,138,217	2,274,756	1
	Fuel Cost (F)													
2	Native Load Fuel Cost	$ 153,373,359	$ 88,510,253	$ 70,597,371	$ 76,978,531	$ 53,168,915	$ 69,180,591	$ 73,330,344	$ 91,833,366	$ 92,778,231	$ 74,924,698	$ 71,380,713	$ 66,978,521	2
3	Realized Hedging Activity	7,951,357	7,638,707	9,793,987	7,507,920	10,246,173	6,460,402	5,243,640	1,211,194	375,518	384,926	78,355	825,442	3
4	Other Adjustments	17,921	-	(698,913)	(711,852)	(1,164,080)	(466,000)	(2,074,750)	7,161	(344,640)	(66,918)	-	(31,177)	4
5	Prior Period Cost Adjustments 1/	(3,245,779)	-	-	(1,734,738)	-	-	(3,093,700)	-	-	(2,191,744)	-	-	5
6	Total Fuel Cost (F)	$ 158,096,858	$ 96,148,960	$ 79,692,445	$ 82,039,861	$ 62,251,008	$ 75,174,993	$ 73,405,534	$ 93,051,721	$ 92,809,109	$ 73,050,962	$ 71,459,068	$ 67,772,786	6
7	Fuel Cost Per kWh (Mills) F/S	$ 58.512	$ 41.411	$ 34.247	$ 34.884	$ 29.104	$ 38.105	$ 31.714	$ 32.823	$ 37.862	$ 29.816	$ 33.420	$ 29.793	7
	Fuel Cost Factor Restated Based On **Synchronization of Sumatra Adjustments**													
8	Remove: Prior Period Sumatra Adjustments Reflected in the Current Month	(3,245,779)	-	-	(1,734,738)	-	-	(3,093,700)	-	-	(2,191,744)	-	-	8
9	Remove: Hedging and Other Fuel Adjustments	7,969,278	7,638,707	9,095,074	6,796,068	9,082,093	5,994,402	3,168,890	1,218,355	30,878	318,008	78,355	794,265	9
10	Add: Subsequent Sumatra Adjustments that Pertain to the Month Presented	(1,351,394)	(68,823)	(314,521)	(1,235,700)	(1,292,185)	(565,815)	(159,115)	(1,016,834)	(1,015,795)	-	-	-	10
11	Restated Total Fuel Costs	$ 152,021,965	$ 88,441,430	$ 70,282,850	$ 75,742,831	$ 51,876,730	$ 68,614,776	$ 73,171,229	$ 90,816,532	$ 91,762,436	$ 74,924,698	$ 71,380,713	$ 66,978,521	11
12	Fuel Cost Factor	56.264	38.091	30.204	32.206	24.254	34.780	31.612	32.035	37.435	30.581	33.383	29.444	12
13	Percentage Variance from Preliminary Fuel Cost (Ln. 6) to Adjusted Fuel Cost, Excluding Hedging and Other Adjustments (Ln. 11)	(3.84 %)	(8.02 %)	(11.81 %)	(7.68 %)	(16.67 %)	(8.73 %)	(0.32 %)	(2.40 %)	(1.13 %)	2.56 %	(0.11 %)	(1.17 %)	13

1/ Prior period adjustments reflect the allocation of operating company fuel expense and purchased power costs for certain prior months based on the results of the Sumatra model.

ATTACHMENT A
SCHEDULE 10

DUKE ENERGY INDIANA, LLC

Actual Fuel Cost Per kWh
Compared to Estimated Fuel Cost Per kWh
for the Months of September, October and November 2023

Line No.	Description	September 2023 Actual	September 2023 Forecast	October 2023 Actual	October 2023 Forecast	November 2023 Actual	November 2023 Forecast	Total Actual	Total Forecast	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
	MWh Source:									
	Native Load Sales									
	Retail									
1	Residential	792,567	807,421	594,204	529,350	535,243	523,686	1,922,014	1,860,457	1
2	Commercial	603,113	595,452	517,281	466,646	450,155	419,023	1,570,549	1,481,121	2
3	Industrial	823,480	868,637	584,882	840,108	781,115	827,804	2,189,477	2,536,549	3
4	Public Street and Highway Lighting	4,948	4,090	5,282	4,100	5,140	4,140	15,370	12,330	4
5	Other Public Authorities	175,889	180,736	155,373	147,797	125,962	141,859	457,224	470,392	5
6	Total Billed Sales	2,399,997	2,456,336	1,857,022	1,988,001	1,897,615	1,916,512	6,154,634	6,360,849	6
7	Unbilled Retail Sales	(181,708)	(196,506)	58,695	98,104	216,340	197,926	93,327	99,524	7
8	Wholesale Sales	231,764	251,034	222,500	209,039	160,801	229,306	615,065	689,379	8
9	Total Native Load Sales (S)	2,450,053	2,510,864	2,138,217	2,295,144	2,274,756	2,343,744	6,863,026	7,149,752	9
	Fuel Cost:									
10	Native Load Fuel Cost	$ 74,924,698	$ 82,990,000	$ 71,380,713	$ 76,536,000	$ 66,978,521	$ 80,007,000	213,283,932	239,533,000	10
11	Hedging Activity and Other Adjustments	318,008	414,000	78,355	(9,000)	794,265	(91,000)	1,190,628	314,000	11
12	Total Fuel Cost	75,242,706	83,404,000	71,459,068	76,527,000	67,772,786	79,916,000	214,474,560	239,847,000	12
13	Fuel Cost - Mills Per kWh Before Prior Period Adjustment (F/S)	$ 30.711	$ 33.217	$ 33.420	$ 33.343	$ 29.793	$ 34.098	$ 31.251	$ 33.546	13
14	Percentage (%) Actual is Over (Under) Estimate Before Prior Period Adjustments	(7.54 %)		0.23 %		(12.63 %)		(6.84 %)		14
15	Prior Period Cost Adjustments	(2,191,744)	-	-	-	-	-	(2,191,744)	-	15
16	Total Fuel Cost (F1)	$ 73,050,962	$ 83,404,000	$ 71,459,068	$ 76,527,000	$ 67,772,786	$ 79,916,000	$ 212,282,816	$ 239,847,000	16
17	Fuel Cost - Mills Per kWh After Prior Period Adjustment (F1/S)	$ 29.816	$ 33.217	$ 33.420	$ 33.343	$ 29.793	$ 34.098	$ 30.931	$ 33.546	17
18	Percentage (%) Actual is Over (Under) Estimate After Prior Period Adjustments	(10.24 %)		0.23 %		(12.63 %)		(7.80 %)		18

ATTACHMENT A
SCHEDULE 11

DUKE ENERGY INDIANA, LLC

Other MISO/PJM Charges/(Credits) Allocated to Native Load Customers

Line No.	MISO/PJM Charge Description	cXL - MISO/PJM Charge Descripton	September-23	October-23	November-23	Line No.
1	DA Congestion Rebate on Carve-Out Grandfathered Agrmnts	DA Cong Rebate CO	$ -	$ -	$ -	1
2	DA Congestion Rebate on Option B Grandfathered Agrmnts	DA Cong Rebate Opt B	$ -	$ -	$ -	2
3	DA Financial Bilateral Transaction Congestion Amount	DA Fin Bilateral Con	$ -	$ -	$ -	3
4	DA Financial Bilateral Transaction Loss Amount	DA Fin Bilateral Los	$ -	$ -	$ -	4
5	DA Losses Rebate on Carve-Out Grandfathered Agrmnts	DA Loss Rebate CO	$ -	$ -	$ -	5
6	DA Losses Rebate on Option B Grandfathered Agrmnts	DA Loss Rebate Opt B	$ -	$ -	$ -	6
7	DA Revenue Sufficiency Guarantee Make Whole Payment Amount	MISO DA RSG MKWHL	$ (19,295.98)	$ (5,860.59)	$ (16,645.03)	7
8	DA Virtual Energy Amount	DA Virtual	$ -	$ -	$ -	8
9	FTR Hourly Allocation Amount	FTR	$ (1,605,997.41)	$ (2,229,299.14)	$ (1,300,961.39)	9
10	FTR Monthly Allocation Amount	MISO FTR MTH ALLOC	$ (41,538.37)	$ (39,966.38)	$ (27,845.02)	10
11	FTR Transaction Amount	MISO FTR Transaction	$ -	$ -	$ -	11
12	FTR Yearly Allocation Amount	MISO FTR YRLY ALLOC	$ -	$ -	$ -	12
13	RT Congestion Rebate on Carve-Out Grandfathered Agrmnts	RT Cong Rebate CO	$ -	$ -	$ -	13
14	RT Congestion Rebate on Option B Grandfathered Agrmnts	RT Cong Rebate Opt B	$ -	$ -	$ -	14
15	RT Distribution of Losses Amount	MISO RT LOSSES	$ (706,397.37)	$ (517,664.64)	$ (605,885.46)	15
16	RT Financial Bilateral Transaction Congestion Amount	RT Fin Bilateral Con	$ -	$ -	$ -	16
17	RT Financial Bilateral Transaction Loss Amount	RT Fin Bilateral Los	$ -	$ -	$ -	17
18	RT Losses Rebate on Carve-Out Grandfathered Agrmnts	RT Loss Rebate CO	$ -	$ -	$ -	18
19	RT Loss Rebate on Option B Grandfathered Agrmnts	RT Loss Rebate Opt B	$ -	$ -	$ -	19
20	RT Net Inadvertent Distribution Amount	MISO RT NAD	$ (4,645.22)	$ (38,591.30)	$ (21,112.80)	20
21	RT Revenue Sufficiency Guarantee Make Whole Payment Amount	MISO RT RSG MKWHL	$ (62,206.00)	$ (50,436.44)	$ (31,915.82)	21
22	Contingency Reserve Deployment Failure Charge Uplift Amount	RT Contingency Reserve Deployment Failure Charge Uplift Amount	$ -	$ -	$ -	22
23	RT Virtual Energy Amount	RT Virtual	$ -	$ -	$ -	23
24	GFA (part of DA and RT Asset Energy)	GFA (part of DA and RT Asset Energy)	$ -	$ -	$ -	24
25	FTR Shortfall	MISO FTR Shortfall	$ 126,990.33	$ 115,786.82	$ 182,803.30	25
26	RNU CRDFC Uplift Component	RNU CRDFC Uplift Component	$ -	$ -	$ -	26
27	FTR Full Funding Guarantee Amount	MISO FTR Full Fd Guar	$ (85,451.91)	$ (75,819.99)	$ (148,385.44)	27
28	FTR Guarantee Uplift Amount	MISO FTR Guar Uplift	$ 67,026.86	$ 85,344.92	$ 144,533.37	28
29	Auction Revenue Rights Stage 2 Distribution Amount	MISO FTR ARR Stage 2	$ (95,878.56)	$ (94,897.57)	$ (95,321.78)	29
30	RT Price Volatility Make Whole Payment	MISO RT VOL MKWHL	$ (654,921.08)	$ (2,549,767.03)	$ (827,098.52)	30
31	DA Revenue Sufficiency Guarantee Distribution Amount	MISO DA RSG Dist Amt	$ 44,942.65	$ 37,813.19	$ 40,430.38	31
32	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	MISO RT RSG 1st Pass	$ 23,299.40	$ 31,511.68	$ 12,921.07	32
33	Net Regulation Adjustment Amount	MISO Net Reg Adj Amt	$ (3,414.60)	$ 7,202.72	$ (10,381.24)	33
34	Regulation Cost Distribution Amount	MISO Reg Dist	$ 74,098.43	$ 84,768.72	$ 87,820.59	34
35	Spinning Reserve Cost Distribution Amount	MISO Spin Dist	$ 67,499.25	$ 96,692.27	$ 84,235.20	35
36	Supplemental Reserve Cost Distribution Amount	MISO Supp Dist	$ 13,587.82	$ 16,640.71	$ 6,044.09	36
37	RT Excessive/Deficient Energy Deployment Charge Amount	MISO Reg Penalty	$ 46,460.70	$ 123,815.24	$ 48,256.50	37
38	DA Regulation Amount	DA Regulation	$ (316,998.11)	$ (447,014.56)	$ (220,648.99)	38
39	DA Spinning Reserve Amount	DA Spinning	$ (92,675.56)	$ (191,256.40)	$ (123,547.74)	39
40	RT Regulation Amount	MISO RT Regulation	$ (57,264.87)	$ (25,661.65)	$ (7,124.73)	40
41	RT Spinning Reserve Amount	MISO RT Spinning	$ (3,695.06)	$ (41,126.44)	$ (15,148.18)	41
42	RT Supplemental Reserve Amount	MISO RT Supplemental	$ (80.40)	$ (313.24)	$ -	42
43	DA Supplemental Reserve Amount	DA Supplemental	$ (3.71)	$ -	$ -	43
44	Auction Revenue Rights Infeasible Uplift Amount	MISO infesbl ARR UP	$ 21,011.34	$ 20,796.36	$ 20,889.33	44
45	Contingency Reserve Deployment Failure Charge Amount	MISO Res Dep Penalty	$ -	$ -	$ -	45
46	FTR Monthly Transaction Amount	MISO FTR MTH TX AMT	$ (69,012.33)	$ (18,583.82)	$ 234,331.37	46
47	FTR Annual Transaction Amount	MISO FTR YRLY TX AMT	$ 3,688,705.02	$ 3,650,963.80	$ 3,667,284.30	47
48	Auction Revenue Rights Transaction Amount	MISO ARR Revenues	$ (5,928,062.60)	$ (5,867,409.36)	$ (5,893,637.68)	48
49	MISO DR Alloc Uplift	MISO DR Alloc Uplift	$ -	$ -	$ -	49
50	MISO Misc Round Adj	MISO Misc/Round Adj	$ 35,257.17	$ (14,519.32)	$ (3,124.56)	50
51	Internal Charge Type Related to MISO RT Regulation	MISO RT MIL MWP	$ (20,777.04)	$ (26,968.90)	$ (9,856.99)	51
52	Internal Charge Type Related to MISO RT Regulation	MISO Reg MIL UNDP	$ 53,034.24	$ 76,298.68	$ 28,277.68	52
53	MISO Disputed Amount	MISO Disputed Amount	$ -	$ -	$ -	53
54	RT Ramp Capability	MISO RT Ramp Cpblty	$ (7,560.68)	$ (17,624.00)	$ (3,028.65)	54
55	DA Ramp Capability	DA Ramp Capability	$ (11,033.80)	$ (43,640.17)	$ (26,852.97)	55
56	Madison PJM Charges	Madison PJM Charges	$ (147,641.57)	$ (176,550.97)	$ (144,325.91)	56
57	Battery Charges	Native Battery MISO Charges	$ (111.96)	$ 368.23	$ 153.25	57
58	Short-Term Reserve Cost Distribution Amount	MISO ST Res Dist Amt	$ 21,481.45	$ 48,936.26	$ 25,739.88	58
59	Real-Time Short-Term Reserve Amount	MISO ST Reserve Amt	$ (676.12)	$ (29,779.58)	$ (24,344.46)	59
60	Day-Ahead Short-Term Reserve Amount	DA ST Reserve	$ (15,747.64)	$ (72,101.58)	$ (33,785.47)	60
61	MISO Excess Congestion	MISO Excess Congestion	$ -	$ -	$ -	61
62	Net Charges/(Credits) to Duke Energy Indiana (Attachment A, Schedule 8, column J, lines 6, 16 and 26)		$ (5,667,693.29)	$ (8,177,913.47)	$ (5,007,258.52)	62

DUKE ENERGY INDIANA, LLC

Determination of International Paper
Fuel Cost Adjustment Factor Based on Estimated Average Fuel Costs
for the Months of April, May, and June 2024

Line No.	Description	Estimated Month of: April 2024 (A)	May 2024 (B)	June 2024 (C)	Total (D)	Estimated Three-Month Average (E)	Source ATTACHMENT A	Line No.
	MWh Source:							
1	Steam Generation	1,445,075	1,108,540	1,146,483	3,700,098	1,233,366	Sch. 2, Line 7	1
2	Nuclear Generation	-	-	-	-	-	Sch. 2, Line 8	2
3	Hydro and Solar Generation	41,795	43,479	42,355	127,629	42,543	Sch. 2, Line 9	3
	Other Generation --							
4	Internal Combustion	-	-	-	-	-	Sch. 2, Line 10	4
5	Gas Combustion Turbine	561,221	672,272	651,240	1,884,733	628,244	Sch. 2, Line 11	5
6	Integrated Gasification Combined Cycle	12,717	387,766	353,442	753,925	251,308	Sch. 2, Line 12	6
7	Purchased Power	248,787	190,023	482,996	921,806	307,269	Sch 3, Col. A	7
8	Equivalent kWh - Steam Sale	12,675	12,691	11,582	36,948	12,316	Sch. 5, Line 2	8
	Less:							
9	Intersystem Sales	-	-	-	-	-	Sch. 4, Col. A	9
10	Total MWh (K)	2,322,270	2,414,771	2,688,098	7,425,139	2,475,046		10
	Fuel Cost:							
11	Steam Generation	$ 43,082,000	$ 33,059,000	$ 34,099,000	$ 110,240,000	$ 36,746,667	Sch. 2, Line 1	11
12	Nuclear Generation	-	-	-	-	-	Sch. 2, Line 2	12
13	Hydro and Solar Generation	-	-	-	-	-		13
	Other Generation --							
14	Internal Combustion	-	-	-	-	-	Sch. 2, Line 3	14
15	Gas Combustion Turbine	15,590,000	17,655,000	18,753,000	51,998,000	17,332,667	Sch. 2, Line 4	15
16	Integrated Gasification Combined Cycle	766,000	10,326,000	9,951,000	21,043,000	7,014,333	Sch. 2, Line 5	16
17	Hedging Position	948,000	1,171,000	1,338,000	3,457,000	1,152,333	Sch. 1, Line 17	17
18	Purchased Power	9,140,000	6,848,000	16,867,000	32,855,000	10,951,667	Sch 3, Col. C	18
19	Net MISO Energy Market	2,324,000	1,455,000	2,294,000	6,073,000	2,024,333	Sch. 1, Line 19	19
20	Net MISO Ancillary Services Market	-	-	-	-	-	Sch. 1, Line 20	20
	Less:							
21	Intersystem Sales	-	-	-	-	-	Sch. 4, Col. C	21
22	Total Fuel Cost (F)	$ 71,850,000	$ 70,514,000	$ 83,302,000	$ 225,666,000	$ 75,222,000		22
23	F / K (Mills Per MWh)					30.3921624		23
24	Equivalent Cost Per 1000 lbs Steam (Line 23 * 0.1084)					3.2945104		24
25	Less: Base Cost of Fuel Included in Rates Per 1000 lbs Steam					2.9219220		25
26	Fuel Cost Adjustment Factor Per 1000 lbs Steam					0.3725884		26

ATTACHMENT B
SCHEDULE 2

DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Fuel Cost Incurred to Fuel Cost Billed to International Paper
For the Months of September 2023 through November 2023

Line No.	Month	Steam Supplied (lbs.)	Actual Fuel Cost Adjustment Factor 1/	Estimated Fuel Cost Adjustment Factor	Variance		Reconciliation Amount	Line No.
1	September 2023	61,784,977	0.1936014	0.7250860	(0.5314846)	$	(32,838)	1
2	October 2023	101,784,497	0.2235921	0.6118706	(0.3882785)		(39,521)	2
3	November 2023	93,515,933	0.2279363	0.6118706	(0.3839343)		(35,904)	3
4	TOTAL RECONCILIATION					$	(108,263)	4

1/ Detailed below are determinants of the actual cost figures represented above.

	September 2023	October 2023	November 2023
MWh Sales (K)	2,323,165	2,236,536	2,174,336
Fuel Cost (F)	$ 66,770,063	$ 64,899,036	$ 63,181,276
F/K (Mills Per kWh)	28.7409904	29.0176577	29.0577335
Equivalent Cost per 1000lbs Steam	3.1155234	3.1455141	3.1498583
Less: Base Cost of Fuel Included in Rates	2.9219220	2.9219220	2.9219220
Fuel Cost Charge Factor (Per 1000lbs Steam)	0.1936014	0.2235921	0.2279363