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-FAC136**

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) April 28, 2023 – the date the Company is filing this Verified Application;

(ii) April 28, 2023 – the date the Company is prefiling testimony and exhibits supporting this Verified Application;

(iii) June 2, 2023 – the latest date by which the OUCC and any intervenor shall prefile its testimony and exhibits concerning this Verified Application[1];

(iv) June 9, 2023 – the latest date by which Duke Energy Indiana shall file rebuttal testimony;

(v) On or after June 14, 2023 – the day on which the Company requests that the evidentiary hearing concerning this Verified Application be held; and

(vi) June 30, 2023 – 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 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

[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.

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 February 28, 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, including the update approved by the Commission on

January 11, 2023, in Cause No. 42061-ECR38. 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 February 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 $0.030339 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 February 28, 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 February 28, 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, and subsequent ECR, FMCA, TDSIC, and REP orders, as applicable.

9. The reconciliation of the actual incremental cost of fuel billed retail customers for the three (3) months ended February 28, 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 $0.032016 per kWh; the net fuel charge in Cause No. 38707-FAC135 was $0.036503 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 $0.005061 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 July 2023 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)*	3.2% decrease
Commercial *(based on three different sets of energy and demand billing determinants)*	>2.4% decrease
Industrial *(based on four different sets of energy and demand billing determinants)*	>3.8% 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 December 2022 through February 2023;

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

iii) authorizing and approving the estimated fuel cost adjustment factor of $0.005061 per kWh to become effective upon the later of the date of approval by the Commission or the first billing cycle of July 2023;

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

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[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 March 30, 2023.

[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.

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 July through September 2023 is 33.6439851 mills per kWh. This amount, when multiplied by the equivalent conversion factor per 1000 pounds of steam of .1084, results in a cost factor of $3.6470080 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 $0.7250860 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 December 2022 through February is shown on Attachment B, Schedule 2. The total reconciliation adjustment of $(450,530) 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 July 2023 by Applicant for steam service;

iii) authorizing and approving the reconciliation adjustments to International Paper as shown on Attachment B, Schedule 2 for the December 2022 through February 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 28th day of April, 2023.

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: April 28, 2023

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 28th day of April 2023.

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
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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 July, August, and September 2023

Line No.	Description	Estimated Month of: July 2023 (A)	August 2023 (B)	September 2023 (C)	Total (D)	Estimated Three-Month Average (E)	Source (F)	Line No.
	MWh Source:							
1	Steam Generation	1,407,549	1,332,543	954,577	3,694,669	1,231,556	Sch.2,Ln 7	1
2	Nuclear Generation	-	-	-	-	-	Sch.2,Ln 8	2
3	Hydro and Solar Generation	43,793	43,579	36,224	123,596	41,199	Sch.2,Ln 9	3
	Other Generation --							
4	Internal Combustion	-	-	-	-	-	Sch.2,Ln 10	4
5	Gas Combustion Turbine	599,221	580,294	395,944	1,575,459	525,153	Sch.2,Ln 11	5
6	Integrated Gasification Combined Cycle	395,038	385,909	286,055	1,067,002	355,667	Sch.2,Ln 12	6
7	Purchased Power	559,261	670,286	908,763	2,138,310	712,770	Sch.3,Col.A	7
	Less:							
8	Intersystem Sales	-	-	-	-	-	Sch.4,Col.A	8
9	Energy Losses & Company Use	90,275	91,538	70,699	252,512	84,170		9
10	Sales (S)	2,914,587	2,921,073	2,510,864	8,346,524	2,782,175		10
	Fuel Cost:							
11	Steam Generation	$ 45,147,000	$ 42,640,000	$ 30,855,000	$ 118,642,000	$ 39,547,333	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	17,096,000	16,742,000	10,248,000	44,086,000	14,695,333	Sch.2,Ln 4	15
16	Integrated Gasification Combined Cycle	11,176,000	10,889,000	8,115,000	30,180,000	10,060,000	Sch.2,Ln 5	16
17	Hedging Position 1/	1,016,000	372,000	414,000	1,802,000	600,667		17
18	Purchased Power	25,145,000	26,869,000	29,502,000	81,516,000	27,172,000	Sch 3, Col. C	18
19	Net MISO Energy Market	5,528,000	4,092,000	4,683,000	14,303,000	4,767,667		19
20	Net MISO Ancillary Services Market	-	-	-	-	-		20
	Less:							
21	Intersystem Sales	-	-	-	-	-	Sch.4,Col.C	21
22	Steam Sales	407,000	403,000	413,000	1,223,000	407,667	Sch.5,Ln 4	22
23	Total Fuel Cost (F)	$ 104,701,000	$ 101,201,000	$ 83,404,000	$ 289,306,000	$ 96,435,333		23
24	F / S (Mills Per kWh)					34.662		24
	Months to be Reconciled							
		December 2022	January 2023	February 2023	3 Months Total			
25	Monthly Fuel Cost Reconciliation Variance	$ 12,605,783	$ (14,978,997)	$ (17,746,938)	$ (20,120,152) 2/		Sch.6s	25
26	Net FAC136 Reconciliation Factor -$ 20,120,152 / 7,604,218 MWhrs					(2.646)		26
27	Subtotal					32.016		27
28	Less: Base Cost of Fuel Included in Rates					26.955		28
29	Total Fuel Cost Adjustment Factor (Mills Per kWh)					5.061		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 July, August, and September 2023
Used in Developing the Retail Fuel Cost Factor to be
Effective Upon the Order of the Commission

Line No.	Description	Estimated Month of: July 2023 (A)	August 2023 (B)	September 2023 (C)	Total (D)	Estimated Three-Month Average (E)	Line No.
	Fuel Cost:						
1	Steam Generation	$ 45,147,000	$ 42,640,000	$ 30,855,000	$ 118,642,000	$ 39,547,334	1
2	Nuclear Generation	-	-	-	-	-	2
	Other Generation -						
3	Internal Combustion	-	-	-	-	-	3
4	Gas Combustion Turbine	17,096,000	16,742,000	10,248,000	44,086,000	14,695,333	4
5	Integrated Gasification Combined Cycle	11,176,000	10,889,000	8,115,000	30,180,000	10,060,000	5
6	Total Fuel Cost	$ 73,419,000	$ 70,271,000	$ 49,218,000	$ 192,908,000	$ 64,302,667	6
	Net Generation MWh Output:						
7	Steam Generation	1,407,549	1,332,543	954,577	3,694,669	1,231,556	7
8	Nuclear Generation	-	-	-	-	-	8
9	Hydro and Solar Generation	43,793	43,579	36,224	123,596	41,199	9
	Other Generation -						
10	Internal Combustion	-	-	-	-	-	10
11	Gas Combustion Turbine	599,221	580,294	395,944	1,575,459	525,153	11
12	Integrated Gasification Combined Cycle	395,038	385,909	286,055	1,067,002	355,667	12
13	Total Net Generation	2,445,601	2,342,325	1,672,800	6,460,726	2,153,575	13

DUKE ENERGY INDIANA, LLC

Determination of Estimated
Net Energy Costs of Native Load Purchased Power
for the Months of July, August, and September 2023
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)	
	July 2023							
1	Various Purchases 1/	559,261	$ -	$ 25,145,000	$ -	$ 25,145,000	$ 25,145,000	1
	August 2023							
2	Various Purchases 1/	670,286	-	26,869,000	-	26,869,000	26,869,000	2
	September 2023							
3	Various Purchases 1/	908,763	-	29,502,000	-	29,502,000	29,502,000	3
4	Total Purchased Power	2,138,310	$ -	$ 81,516,000	$ -	$ 81,516,000	$ 81,516,000	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 PPA's 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 July, August, and September 2023
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)	
	July 2023								
1	Power Coordination Agreement Sales	_1/	-	$ -	$ -	$ -	$ -	$ -	1
	August 2023								
2	Power Coordination Agreement Sales	_1/	-	-	-	-	-	-	2
	September 2023								
3	Power Coordination Agreement Sales	_1/	-	-	-	-	-	-	3
4	Total Intersystem Sales		-	$ -	$ -	$ -	$ -	$ -	4

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

DUKE ENERGY INDIANA, LLC

Determination of Estimated Equivalent Fuel Costs
Recovered Through the Sale of Steam
for the Months of July, August, and September 2023
Used in Developing the Retail Fuel Cost Factor to be
Effective Upon the Order of the Commission

Line No.	Description	Estimated Month of: July 2023 (A)	August 2023 (B)	September 2023 (C)	Total (D)	Estimated Three-Month Average (E)	Source	Line No.
1	Total Pounds of Steam Supplied (000's)	111,660	110,465	113,276	335,401	111,800		1
2	Total Equivalent kWh Generated (000's) At Cayuga, Other Generating Stations Of the Company and Through Purchased Power Transactions (Note 1)	12,104	11,974	12,279	36,357	12,119		2
3	Equivalent Cost per 1000 lbs Steam (Note 2)	3.6470080	3.6470080	3.6470080				3
4	Fuel Costs Recovered Through the Sale of Steam (Line 1 * Line 3) (Rounded to 000's)	$ 407,000	$ 403,000	$ 413,000	$ 1,223,000	$ 407,667		4

Note 1: Equivalent MWh = 0.1084 * Line 1

Note 2: Fuel Cost

Description	July 2023 (A)	August 2023 (B)	September 2023 (C)	Total (D)	Three-Month Average (E)	Source
Steam Generation	$ 45,147,000	$ 42,640,000	$ 30,855,000	$ 118,642,000	$ 39,547,333	Sch. 2, Ln 1
Nuclear Generation	-	-	-	-	-	Sch. 2, Ln 2
Other Generation						
Internal Combustion	-	-	-	-	-	Sch. 2, Ln 3
Gas Combustion Turbine	17,096,000	16,742,000	10,248,000	44,086,000	14,695,333	Sch. 2, Ln 4
Integrated Gasification Combined Cycle	11,176,000	10,889,000	8,115,000	30,180,000	10,060,000	Sch. 2, Ln 5
Hedging Position	1,016,000	372,000	414,000	1,802,000	600,667	Sch. 1, Ln 17
Purchased Power	25,145,000	26,869,000	29,502,000	81,516,000	27,172,000	Sch. 1, Ln 18
Net MISO Energy Market	5,528,000	4,092,000	4,683,000	14,303,000	4,767,667	Sch. 1, Ln 19
Net MISO Ancillary Services Market	-	-	-	-	-	Sch. 1, Ln 20
Less:						
Intersystem Sales	-	-	-	-	-	Sch. 4, Col. C
Total Fuel Costs	$ 105,108,000	$ 101,604,000	$ 83,817,000	$ 290,529,000	$ 96,843,000	
MWh						
Sales (S)	2,914,587	2,921,073	2,510,864	8,346,524	2,782,175	Sch. 1, Ln 10
Energy Losses & Company Use	90,275	91,538	70,699	252,512	84,170	Sch. 1, Ln 9
Equivalent kWh - Steam Sale	12,104	11,974	12,279	36,357	12,119	Sch. 5, Ln 2
Total kWh (K)	3,016,966	3,024,585	2,593,842	8,635,393	2,878,464	
F/K (Mills Per kWh)					33.6439851	
Equivalent Cost per 1000 lbs Steam (Mills Per kWh * 0.1084)					$ 3.6470080	

DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Incremental Cost of Fuel
Incurred to Actual Incremental Cost of Fuel Billed
Retail Customers for the December 2022 Billing Cycle

Line No.	Class of Customers	MWh Sold	Base Cost of Fuel Included in Rates 26.955 Mills/kWh	Actual Cost of Fuel Incurred - 58.635 Mills/kWh (See Sch. 7)	Actual Incremental Cost of Fuel Incurred	Actual Incremental Cost of Fuel Billed Excluding Utility Receipts Tax	Fuel Cost Variance from Cause No. 38707- FAC 132 and 133	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	876,255	$ 23,619,454	$ 51,379,212	$ 27,759,758	$ 40,293,136	$ 13,306,303	$ 26,986,833	$ 772,925	1
2	Total Commercial	529,343	14,268,441	31,038,027	16,769,586	24,062,014	8,038,297	16,023,717	745,869	2
3	Total Industrial	732,055	19,732,541	42,924,045	23,191,504	23,214,053	11,116,565	12,097,488	11,094,016	3
4	Total Other	147,253	3,969,205	8,634,179	4,664,974	6,908,100	2,236,099	4,672,001	(7,027)	4
5	Total Retail kWh Sales Subject to Fuel Clause Adjustment	2,284,906	$ 61,589,641	$ 133,975,463	$ 72,385,822	$ 94,477,303	$ 34,697,264	$ 59,780,039	$ 12,605,783	5
6	Retail kWh Sales Not Subject to the Fuel Clause Adjustment	18,102								6
7	kWh Sales for Resale	260,345								7
8	Sales	2,563,353								8

DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Incremental Cost of Fuel
Incurred to Actual Incremental Cost of Fuel Billed
Retail Customers for the January 2023 Billing Cycle

Line No.	Class of Customers	MWh Sold	Base Cost of Fuel Included in Rates 26.955 Mills/kWh	Actual Cost of Fuel Incurred - 41.362 Mills/kWh (See Sch. 7)	Actual Incremental Cost of Fuel Incurred	Actual Incremental Cost of Fuel Billed Excluding Utility Receipts Tax	Fuel Cost Variance from Cause No. 38707- FAC 133 and 134	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	941,346	$ 25,373,981	$ 38,935,953	$ 13,561,972	$ 34,026,781	$ 19,465,047	$ 14,561,734	$ (999,762)	1
2	Total Commercial	509,840	13,742,737	21,088,002	7,345,265	18,624,478	10,542,414	8,082,064	(736,799)	2
3	Total Industrial	655,474	17,668,302	27,111,716	9,443,414	35,878,370	13,553,819	22,324,551	(12,881,137)	3
4	Total Other	141,158	3,804,914	5,838,577	2,033,663	5,313,811	2,918,849	2,394,962	(361,299)	4
5	Total Retail kWh Sales Subject to Fuel Clause Adjustment	2,247,818	$ 60,589,934	$ 92,974,248	$ 32,384,314	$ 93,843,440	$ 46,480,129	$ 47,363,311	$ (14,978,997)	5
6	Retail kWh Sales Not Subject to the Fuel Clause Adjustment	13,967								6
7	kWh Sales for Resale	130,025								7
8	Sales	2,391,810								8

DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Incremental Cost of Fuel
Incurred to Actual Incremental Cost of Fuel Billed
Retail Customers for the February 2023 Billing Cycle

Line No.	Class of Customers	MWh Sold	Base Cost of Fuel Included in Rates 26.955 Mills/kWh	Actual Cost of Fuel Incurred - 34.185 Mills/kWh (See Sch. 7)	Actual Incremental Cost of Fuel Incurred	Actual Incremental Cost of Fuel Billed Excluding Utility Receipts Tax	Fuel Cost Variance from Cause No. 38707- FAC 133 and 134	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	839,633	$ 22,632,308	$ 28,702,854	$ 6,070,546	$ 30,342,341	$ 17,020,825	$ 13,321,516	$ (7,250,970)	1
2	Total Commercial	532,959	14,365,910	18,219,203	3,853,293	19,038,739	10,804,008	8,234,731	(4,381,438)	2
3	Total Industrial	779,803	21,019,590	26,657,566	5,637,976	26,279,726	15,807,967	10,471,759	(4,833,783)	3
4	Total Other	140,458	3,786,045	4,801,557	1,015,512	5,143,588	2,847,329	2,296,259	(1,280,747)	4
5	Total Retail kWh Sales Subject to Fuel Clause Adjustment	2,292,853	$ 61,803,853	$ 78,381,180	$ 16,577,327	$ 80,804,394	$ 46,480,129	$ 34,324,265	(17,746,938)	5
6	Retail kWh Sales Not Subject to the Fuel Clause Adjustment	19,276								6
7	kWh Sales for Resale	166,335								7
8	Sales	2,478,464								8
9	Fuel Cost Variance from the December 2022 Billing Cycle (See Attachment A, Schedule 6, Page 1 of 3, Column H)								12,605,783	9
10	Fuel Cost Variance from the January 2023 Billing Cycle (See Attachment A, Schedule 6, Page 2 of 3, Column H)								(14,978,997)	10
11	Total Fuel Cost Variance for the Three (3) Months Ended February 2023								$ (20,120,152)	11

DUKE ENERGY INDIANA, LLC

Determination of Fuel Cost Per kWh
Based on Actual Fuel Cost for
December 2022

Line No.	Description	Total Actual December 2022 (A)	WVPA 70MW Firm Sale (B)	Wholesale Formula Rate ASM 4/ (C)	Adjusted Actual December 2022 (D)	Line No.
	kWh Sales (000's):					
	Native Load Sales					
	Retail					
1	Residential	876,255			876,255	1
2	Commercial	529,343			529,343	2
3	Industrial	746,210			746,210	3
4	Public Street and Highway Lighting	6,186			6,186	4
5	Other Public Authorities	145,014			145,014	5
6	Billed Retail Sales	2,303,008			2,303,008	6
7	Unbilled Retail Sales	138,603			138,603	7
8	Wholesale Sales	260,345	42,280	218,065	-	8
9	Total Native Load Sales (S)	2,701,956	42,280	218,065	2,441,611	9
	Fuel Cost:					
10	Native Load Fuel Cost, Including Virtual Energy Amounts 1/	$ 153,373,359	$ 2,091,104	$ 12,195,708	$ 139,086,547	10
11	Realized Hedging Activity, Excluding Virtual Energy Amounts 2/	7,951,357	124,422	641,725	7,185,210	11
12	Wind and Solar REC Proceeds 5/	2,739	43	221	2,475	12
13	Prior Period Hedging Adjustment 6/	15,182	238	1,225	13,719	13
14	Prior Period Cost Adjustments 3/	(3,245,779)	44,417	(165,386)	(3,124,810)	14
15	Total Fuel Cost (F)	$ 158,096,858	$ 2,260,224	$ 12,673,493	$ 143,163,141	15
16	Fuel Cost - Mills per kWh (F/S)	58.512	53.458	58.118	58.635	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, and payments to customers for excess distributed generation.

2/ Hedging component subtotals follow: LMP hedging total $2,191,486; Gas hedging total $5,759,871.

3/ Prior Period Adjustment Totals by month: 1)Sep22 S105 ($1,094,521); 2)Oct22 S105 ($425,416); 3)Nov22 S105 ($1,725,842).

Prior Period Adjustment WVPA 70 by month: 1)Sep22 S105 $27,211; 2)Oct22 S105 $5,685; 3)Nov22 S105 $11,521.

Prior Period Adjustment Wholesale Formula Rate by month: 1)Sep22 S105 ($50,572); 2)Oct22 S105 ($8,623); 3)Nov22 S105 ($106,191).

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)Sep22 S105 LMP $5,445; 2)Oct22 S105 LMP $5,580; 3)Nov22 S105 LMP $4,157.

DUKE ENERGY INDIANA, LLC

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

Line No.	Description	Total Actual January 2023 (A)	WVPA 70MW Firm Sale (B)	Wholesale Formula Rate ASM 4/ (C)	Adjusted Actual January 2023 (D)	Line No.
	kWh Sales (000's):					
	Native Load Sales					
	Retail					
1	Residential	941,346			941,346	1
2	Commercial	509,840			509,840	2
3	Industrial	668,131			668,131	3
4	Public Street and Highway Lighting	5,270			5,270	4
5	Other Public Authorities	137,198			137,198	5
6	Billed Retail Sales	2,261,785			2,261,785	6
7	Unbilled Retail Sales	(69,973)			(69,973)	7
8	Wholesale Sales	130,025	23,100	106,925	-	8
9	Total Native Load Sales (S)	2,321,837	23,100	106,925	2,191,812	9
	Fuel Cost:					
10	Native Load Fuel Cost, Including Virtual Energy Amounts 1/	$ 88,510,253	$ 808,317	$ 4,255,090	$ 83,446,846	10
11	Realized Hedging Activity, Excluding Virtual Energy Amounts 2/	7,638,707	75,998	351,777	7,210,932	11
12	Wind and Solar REC Proceeds 5/	-	-	-	-	12
13	Prior Period Cost Adjustments 3/	-	-	-	-	13
14	Total Fuel Cost (F)	$ 96,148,960	$ 884,315	$ 4,606,867	$ 90,657,778	14
15	Fuel Cost - Mills per kWh (F/S)	41.411	38.282	43.085	41.362	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, and payments to customers for excess distributed generation.

2/ Hedging component subtotals follow: LMP hedging total ($11,284); Gas hedging total $7,649,991.

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 type
(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 custom

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
February 2023

Line No.	Description	Total Actual February 2023 (A)	WVPA 70MW Firm Sale (B)	Wholesale Formula Rate ASM 4/ (C)	Adjusted Actual February 2023 (D)	Line No.
	kWh Sales (000's):					
	Native Load Sales					
	Retail					
1	Residential	839,633			839,633	1
2	Commercial	532,959			532,959	2
3	Industrial	795,695			795,695	3
4	Public Street and Highway Lighting	5,154			5,154	4
5	Other Public Authorities	138,688			138,688	5
6	Billed Retail Sales	2,312,129			2,312,129	6
7	Unbilled Retail Sales	(151,504)			(151,504)	7
8	Wholesale Sales	166,335	30,170	136,165	-	8
9	Total Native Load Sales (S)	2,326,960	30,170	136,165	2,160,625	9
	Fuel Cost:					
10	Native Load Fuel Cost, Including Virtual Energy Amounts 1/	$ 70,597,371	$ 932,371	$ 4,250,012	$ 65,414,988	10
11	Realized Hedging Activity, Excluding Virtual Energy Amounts 2/	9,793,987	126,983	573,108	9,093,896	11
12	Wind and Solar PPA REC Proceeds 5/	(698,913)	(9,062)	(40,898)	(648,953)	12
13	Prior Period Cost Adjustments 3/	-	-	-	-	13
14	Total Fuel Cost (F)	$ 79,692,445	$ 1,050,292	$ 4,782,222	$ 73,859,931	14
15	Fuel Cost - Mills per kWh (F/S)	34.247	34.812	35.121	34.185	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, and payments to customers for excess distributed generation.

2/ Hedging component subtotals follow: LMP hedging total $51,867; Gas hedging total $9,742,120.

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 (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 cus

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 December 2022, January and February 2023

Line No.		DEI Generation Fuel for DEI Native Load 1/ MWh	$	$/MWh	MISO Total Net Charges Corresponding to DEI Gen. Allocated to Serve DEI Native Load 2/ MWh	$	$/MWh	DEI Generation Total Expense for DEI Native Load MWh	$	$/MWh	Other MISO Charges and/or Credits Allocated to DEI Native Load 3/ $	Total DEI Native Load Purchases 4/ MWh	$	$/MWh	Total Via Fuel Adjustment Clause 5/ MWh	$	$/MWh	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	
	December 2022																	
1	01 - 03	130,466.303	4,668,574.46	35.78	130,466.303	1,088,784.32	8.35	130,466.303	5,757,358.78	44.13	(2,927,251.63)	123,900.373	8,358,791.07	67.46	254,366.676	11,188,898.22	43.99	1
2	04 - 10	389,934.244	15,716,511.49	40.31	389,934.244	59,787.62	0.15	389,934.244	15,776,299.11	40.46	(171,460.66)	199,966.400	10,824,892.37	54.13	589,900.644	26,429,730.82	44.80	2
3	11 - 17	411,258.983	14,870,516.19	36.16	411,258.983	1,729,246.66	4.20	411,258.983	16,599,762.85	40.36	(1,274,959.19)	202,308.157	11,957,165.67	59.10	613,567.140	27,281,969.33	44.46	3
4	18 - 24	569,198.496	22,828,530.05	40.11	569,198.496	13,377,265.01	23.50	569,198.496	36,205,795.06	63.61	2,569,422.36	136,330.333	13,822,483.23	101.39	705,528.829	52,597,700.65	74.55	4
5	25 - 31	369,728.429	14,882,625.67	40.25	369,728.429	2,808,130.18	7.60	369,728.429	17,690,755.85	47.85	(699,230.53)	195,551.406	19,240,270.15	98.39	565,279.835	36,231,795.47	64.10	5
6	Subtotals	1,870,586.455	72,966,757.86	39.01	1,870,586.455	19,063,213.79	10.19	1,870,586.455	92,029,971.65	49.20	(2,503,479.65)	858,056.669	64,203,602.49	74.82	2,728,643.124	153,730,094.49	56.34	6
7														WVPA-IMPA Adjustment 6/	(315,886.522)	(15,564,881.88)	49.27	7
8														Native Alloc. Of Gas Pipeline Res. Fee 7/		208,839.54		8
9														Other Fuel Cost Adjustments		-		9
10															2,412,756.602	138,374,052.15	57.35	10

Line No.		DEI Generation Fuel for DEI Native Load 1/ MWh	$	$/MWh	MISO Total Net Charges Corresponding to DEI Gen. Allocated to Serve DEI Native Load 2/ MWh	$	$/MWh	DEI Generation Total Expense for DEI Native Load MWh	$	$/MWh	Other MISO Charges and/or Credits Allocated to DEI Native Load 3/ $	Total DEI Native Load Purchases 4/ MWh	$	$/MWh	Total Via Fuel Adjustment Clause 5/ MWh	$	$/MWh	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	
	January 2023																	
11	01 - 07	272,536.969	9,537,063.54	34.99	272,536.969	660,936.49	2.43	272,536.969	10,198,000.03	37.42	(2,117,231.71)	256,939.265	10,117,499.99	39.38	529,476.234	18,198,268.31	34.37	11
12	08 - 14	285,965.410	9,802,039.67	34.28	285,965.410	844,159.73	2.95	285,965.410	10,646,199.40	37.23	(1,259,077.38)	272,903.709	10,736,039.22	39.34	558,869.119	20,123,161.24	36.01	12
13	15 - 21	315,601.790	10,507,066.66	33.29	315,601.790	863,010.30	2.73	315,601.790	11,370,076.96	36.03	(831,863.49)	232,474.669	9,532,110.55	41.00	548,076.459	20,070,324.02	36.62	13
14	22 - 28	391,711.228	12,775,829.55	32.62	391,711.228	1,085,198.54	2.77	391,711.228	13,861,028.09	35.39	(548,702.50)	198,552.346	7,737,981.64	38.97	590,263.574	21,050,307.23	35.66	14
15	29 - 31	198,328.791	6,791,480.21	34.24	198,328.791	249,445.44	1.26	198,328.791	7,040,925.65	35.50	(299,926.60)	64,521.260	2,588,612.25	40.12	262,850.052	9,329,611.30	35.49	15
16	Subtotals	1,464,144.188	49,413,479.63	33.75	1,464,144.188	3,702,750.50	2.53	1,464,144.188	53,116,230.13	36.28	(5,056,801.68)	1,025,391.249	40,712,243.65	39.70	2,489,535.438	88,771,672.10	35.66	16
17														WVPA-IMPA Adjustment 6/	(157,879.989)	(5,448,428.59)	34.51	17
18														Native Alloc. Of Gas Pipeline Res. Fee 7/		(165,223.29)		18
19														Other Fuel Cost Adustments		-		19
20															2,331,655.449	83,158,020.22	35.66	20

Line No.		DEI Generation Fuel for DEI Native Load 1/ MWh	$	$/MWh	MISO Total Net Charges Corresponding to DEI Gen. Allocated to Serve DEI Native Load 2/ MWh	$	$/MWh	DEI Generation Total Expense for DEI Native Load MWh	$	$/MWh	Other MISO Charges and/or Credits Allocated to DEI Native Load 3/ $	Total DEI Native Load Purchases 4/ MWh	$	$/MWh	Total Via Fuel Adjustment Clause 5/ MWh	$	$/MWh	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	
	February 2023																	
21	01 - 04	270,525.711	8,966,153.33	33.14	270,525.711	172,463.61	0.64	270,525.711	9,138,616.94	33.78	(2,099,088.71)	103,622.582	4,145,777.50	40.01	374,148.293	11,185,305.73	29.90	21
22	05 - 11	353,396.642	11,536,916.30	32.65	353,396.642	758,943.93	2.15	353,396.642	12,295,860.23	34.79	(281,836.24)	203,729.481	6,009,367.50	29.50	557,126.123	18,023,391.49	32.35	22
23	12 - 18	326,847.600	10,155,084.26	31.07	326,847.600	1,005,607.82	3.08	326,847.600	11,160,692.08	34.15	(436,655.70)	222,088.270	6,653,534.61	29.96	548,935.870	17,377,570.99	31.66	23
24	19 - 25	314,663.948	10,246,823.67	32.56	314,663.948	512,421.34	1.63	314,663.948	10,759,245.01	34.19	(338,368.15)	213,652.485	6,867,619.13	32.14	528,316.433	17,288,495.99	32.72	24
25	26 - 28	108,176.229	3,662,522.55	33.86	108,176.229	354,978.16	3.28	108,176.229	4,017,500.71	37.14	(254,320.09)	111,275.478	3,427,081.56	30.80	219,451.707	7,190,262.18	32.76	25
26	Subtotals	1,373,610.130	44,567,500.11	32.45	1,373,610.130	2,804,414.86	2.04	1,373,610.130	47,371,914.97	34.49	(3,410,268.89)	854,368.296	27,103,380.30	31.72	2,227,978.426	71,065,026.38	31.90	26
27														WVPA-IMPA Adjustment 6/	(187,993.157)	(5,989,272.50)	31.86	27
28														Native Alloc. Of Gas Pipeline Res. Fee 7/		139,406.99		28
29														Other Fuel Cost Adustments 8/		-		29
30															2,039,985.269	65,215,160.87	31.97	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 ($19,681.04), ($33,911.41) and ($3,252.69) respectively, for Excessive Energy Amounts for the months of December 2022, January 2023, February 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.

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
March 2022 through February 2023

Line No.	Description	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
1	**MWh Sales (S)**	2,279,303	2,413,377	2,243,184	2,744,483	2,765,529	3,010,836	2,643,634	2,143,415	2,206,768	2,701,956	2,321,837	2,326,960	1
	Fuel Cost (F)													
2	Native Load Fuel Cost	$ 100,741,729	$ 118,693,849	$ 135,086,424	$ 154,931,063	$ 158,879,404	$ 185,939,722	$ 146,790,130	$ 102,351,337	$ 84,591,546	$ 153,373,359	$ 88,510,253	$ 70,597,371	2
3	Realized Hedging Activity	192,397	(3,992,487)	(12,636,327)	(16,906,711)	(3,658,687)	(6,250,763)	3,810,710	9,044,074	11,418,081	7,951,357	7,638,707	9,793,987	3
4	Other Adjustments	11,819	(13,581)	309	13,770	-	(349,992)	(227,731)	(152,417)	(555,041)	17,921	-	(698,913)	4
5	Prior Period Cost Adjustments 1/	(1,770,738)	-	-	(2,089,798)	-	-	(5,921,580)	-	-	(3,245,779)	-	-	5
6	Total Fuel Cost (F)	$ 99,175,207	$ 114,687,781	$ 122,450,406	$ 135,948,324	$ 155,220,717	$ 179,338,967	$ 144,451,529	$ 111,242,994	$ 95,454,586	$ 158,096,858	$ 96,148,960	$ 79,692,445	6
7	Fuel Cost Per kWh (Mills) F/S	$ 43.511	$ 47.522	$ 54.588	$ 49.535	$ 56.127	$ 59.565	$ 54.641	$ 51.900	$ 43.255	$ 58.512	$ 41.411	$ 34.247	7
	Fuel Cost Factor Restated Based On Synchronization of Sumatra Adjustments													
8	Remove: Prior Period Sumatra Adjustments Reflected in the Current Month	(1,770,738)	-	-	(2,089,798)	-	-	(5,921,580)	-	-	(3,245,779)	-	-	8
9	Remove: Hedging and Other Fuel Adjustments	204,216	(4,006,068)	(12,636,018)	(16,892,941)	(3,658,687)	(6,600,755)	3,582,979	8,891,657	10,863,040	7,969,278	7,638,707	9,095,074	9
10	Add: Subsequent Sumatra Adjustments that Pertain to the Month Presented	(552,717)	(498,768)	(1,041,905)	(892,744)	(2,624,982)	(2,403,854)	(1,094,521)	(425,416)	(1,725,842)	-	-	-	10
11	Restated Total Fuel Costs	$ 100,189,012	$ 118,195,081	$ 134,044,519	$ 154,038,319	$ 156,254,422	$ 183,535,868	$ 145,695,609	$ 101,925,921	$ 82,865,704	$ 153,373,359	$ 88,510,253	$ 70,597,371	11
12	Fuel Cost Factor	43.956	48.975	59.756	56.127	56.501	60.958	55.112	47.553	37.551	56.764	38.121	30.339	12
13	Percentage Variance from Preliminary Fuel Cost (Ln. 6) to Adjusted Fuel Cost, Excluding Hedging and Other Adjustments (Ln. 11)	1.02 %	3.06 %	9.47 %	13.31 %	0.67 %	2.34 %	0.86 %	(8.38 %)	(13.19 %)	(2.99 %)	(7.94 %)	(11.41 %)	13

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

DUKE ENERGY INDIANA, LLC

Actual Fuel Cost Per kWh
Compared to Estimated Fuel Cost Per kWh
for the Months of December, January and February 2023

Line No.	Description	December 2022 Actual	December 2022 Forecast	January 2023 Actual	January 2023 Forecast	February 2023 Actual	February 2023 Forecast	Total Actual	Total Forecast	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
	MWh Source:									
	Native Load Sales									
	Retail									
1	Residential	876,255	846,714	941,346	998,497	839,633	1,020,320	2,657,234	2,865,531	1
2	Commercial	529,343	526,026	509,840	522,924	532,959	495,785	1,572,142	1,544,735	2
3	Industrial	746,210	821,939	668,131	766,666	795,695	766,391	2,210,036	2,354,996	3
4	Public Street and Highway Lighting	6,186	4,316	5,270	4,286	5,154	4,183	16,610	12,785	4
5	Other Public Authorities	145,014	156,944	137,198	150,216	138,688	150,764	420,900	457,924	5
6	Total Billed Sales	2,303,008	2,355,939	2,261,785	2,442,589	2,312,129	2,437,443	6,876,922	7,235,971	6
7	Unbilled Retail Sales	138,603	(19,942)	(69,973)	6,464	(151,504)	(182,479)	(82,874)	(195,957)	7
8	Wholesale Sales	260,345	347,282	130,025	323,270	166,335	290,642	556,705	961,194	8
9	Total Native Load Sales (S)	2,701,956	2,683,279	2,321,837	2,772,323	2,326,960	2,545,606	7,350,753	8,001,208	9
	Fuel Cost:									
10	Native Load Fuel Cost	$ 153,373,359	$ 144,052,000	$ 88,510,253	$ 111,284,000	$ 70,597,371	$ 108,895,000	312,480,983	364,231,000	10
11	Hedging Activity and Other Adjustments	7,969,278	2,274,780	7,638,707	936,588	9,095,074	2,171,540	24,703,059	5,382,908	11
12	Total Fuel Cost	161,342,637	146,326,780	96,148,960	112,220,588	79,692,445	111,066,540	337,184,042	369,613,908	12
13	Fuel Cost - Mills Per kWh Before Prior Period Adjustment (F/S)	$ 59.713	$ 54.533	$ 41.411	$ 40.479	$ 34.247	$ 43.631	$ 45.871	$ 46.195	13
14	Percentage (%) Actual is Over (Under) Estimate Before Prior Period Adjustments	9.50 %		2.30 %		(21.51 %)		(0.70 %)		14
15	Prior Period Cost Adjustments	(3,245,779)	-	-	-	-	-	(3,245,779)	-	15
16	Total Fuel Cost (F_1)	$ 158,096,858	$ 146,326,780	$ 96,148,960	$ 112,220,588	$ 79,692,445	$ 111,066,540	$ 333,938,263	$ 369,613,908	16
17	Fuel Cost - Mills Per kWh After Prior Period Adjustment (F_1/S)	$ 58.512	$ 54.533	$ 41.411	$ 40.479	$ 34.247	$ 43.631	$ 45.429	$ 46.195	17
18	Percentage (%) Actual is Over (Under) Estimate After Prior Period Adjustments	7.30 %		2.30 %		(21.51 %)		(1.66 %)		18

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	December-22	January-23	February-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	$ (7,288.58)	$ (2,280.47)	$ (2,295.44)	7
8	DA Virtual Energy Amount	DA Virtual	$ -	$ -	$ -	8
9	FTR Hourly Allocation Amount	FTR	$ (3,288,624.75)	$ (736,849.84)	$ (925,498.03)	9
10	FTR Monthly Allocation Amount	MISO FTR MTH ALLOC	$ (60,324.70)	$ (78,279.99)	$ (43,358.90)	10
11	FTR Transaction Amount	MISO FTR Transaction	$ -	$ -	$ -	11
12	FTR Yearly Allocation Amount	MISO FTR YRLY ALLOC	$ (33,910.00)	$ -	$ -	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	$ (2,195,129.11)	$ (794,555.73)	$ (647,533.98)	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	$ 144,449.40	$ (4,574.77)	$ (10,529.75)	20
21	RT Revenue Sufficiency Guarantee Make Whole Payment Amount	MISO RT RSG MKWHL	$ (346,868.87)	$ (159,634.48)	$ (2,625.56)	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	$ 60,324.55	$ 78,618.06	$ 43,359.02	25
26	RNU CRDFC Uplift Component	RNU CRDFC Uplift Component	$ (39,778.39)	$ -	$ (229.42)	26
27	FTR Full Funding Guarantee Amount	MISO FTR Full Fd Guar	$ 33,910.00	$ -	$ -	27
28	FTR Guarantee Uplift Amount	MISO FTR Guar Uplift	$ (37,953.00)	$ -	$ -	28
29	Auction Revenue Rights Stage 2 Distribution Amount	MISO FTR ARR Stage 2	$ (173,658.33)	$ (174,951.49)	$ (175,890.45)	29
30	RT Price Volatility Make Whole Payment	MISO RT VOL MKWHL	$ (560,792.17)	$ (766,477.73)	$ (286,346.53)	30
31	DA Revenue Sufficiency Guarantee Distribution Amount	MISO DA RSG Dist Amt	$ 100,407.59	$ 57,046.70	$ 64,173.80	31
32	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	MISO RT RSG 1st Pass	$ 1,048,912.92	$ 53,138.84	$ 8,698.01	32
33	Net Regulation Adjustment Amount	MISO Net Reg Adj Amt	$ 22,754.23	$ 4,749.51	$ 1,229.19	33
34	Regulation Cost Distribution Amount	MISO Reg Dist	$ 32,240.73	$ 107,667.96	$ 82,198.74	34
35	Spinning Reserve Cost Distribution Amount	MISO Spin Dist	$ 121,241.80	$ 76,734.67	$ 46,882.14	35
36	Supplemental Reserve Cost Distribution Amount	MISO Supp Dist	$ (4,932.94)	$ 10,339.39	$ 8,070.34	36
37	RT Excessive/Deficient Energy Deployment Charge Amount	MISO Reg Penalty	$ 133,460.66	$ 118,658.00	$ 38,810.52	37
38	DA Regulation Amount	DA Regulation	$ (275,333.41)	$ (390,633.05)	$ (135,534.33)	38
39	DA Spinning Reserve Amount	DA Spinning	$ (63,207.78)	$ (118,584.36)	$ (76,435.09)	39
40	RT Regulation Amount	MISO RT Regulation	$ (47,934.59)	$ (29,637.86)	$ (39,962.83)	40
41	RT Spinning Reserve Amount	MISO RT Spinning	$ 51,704.36	$ (13,947.25)	$ 1,857.72	41
42	RT Supplemental Reserve Amount	MISO RT Supplemental	$ (42,195.97)	$ 4.10	$ 47.13	42
43	DA Supplemental Reserve Amount	DA Supplemental	$ (1,232.90)	$ (16.57)	$ (782.79)	43
44	Auction Revenue Rights Infeasible Uplift Amount	MISO infesbl ARR UP	$ 55,551.52	$ 55,962.45	$ 56,262.80	44
45	Contingency Reserve Deployment Failure Charge Amount	Contingency Reserve Deployment Failure Charge Amount	$ -	$ -	$ -	45
46	FTR Monthly Transaction Amount	MISO FTR MTH TX AMT	$ -	$ (38,383.26)	$ -	46
47	FTR Annual Transaction Amount	MISO FTR YRLY TX AMT	$ 7,358,426.92	$ 7,413,222.01	$ 7,453,008.77	47
48	Auction Revenue Rights Transaction Amount	MISO ARR Revenues	$ (8,638,658.73)	$ (8,702,987.15)	$ (8,749,696.21)	48
49	MISO DR Alloc Uplift	MISO DR Alloc Uplift	$ 2,434.24	$ -	$ -	49
50	MISO Misc Round Adj	MISO Misc/Round Adj	$ 4,952,057.07	$ (965,248.97)	$ 1,094.77	50
51	Internal Charge Type Related to MISO RT Regulation	MISO RT MIL MWP	$ (17,836.84)	$ (16,796.67)	$ (8,053.35)	51
52	Internal Charge Type Related to MISO RT Regulation	MISO Reg MIL UNDP	$ 68,366.82	$ 56,542.44	$ 25,572.18	52
53	MISO Disputed Amount	MISO Disputed Amount	$ -	$ -	$ -	53
54	RT Ramp Capability	RT Ramp Capability	$ (1,886.23)	$ (3,280.02)	$ (390.39)	54
55	DA Ramp Capability	DA Ramp Capability	$ (4,731.44)	$ (2,232.88)	$ (1,480.40)	55
56	Madison PJM Charges	Madison PJM Charges	$ (838,065.68)	$ (81,166.83)	$ (27,970.50)	56
57	Battery Charges	Native Battery MISO Charges	$ (10,996.71)	$ (252.12)	$ (103,867.64)	57
58	Short-Term Reserve Cost Distribution Amount	MISO ST Res Dist Amt	$ 17,844.58	$ 6,638.65	$ 2,574.49	58
59	Real-Time Short-Term Reserve Amount	MISO ST Reserve Amt	$ (2,046.08)	$ 123.14	$ (88.82)	59
60	Day-Ahead Short-Term Reserve Amount	DA ST Reserve	$ (14,179.84)	$ (15,476.11)	$ (5,538.10)	60
61	Net Charges/(Credits) to Duke Energy Indiana (Attachment A, Schedule 8, column J, lines 6, 16 and 26)		$ (2,503,479.65)	$ (5,056,801.68)	$ (3,410,268.89)	61

DUKE ENERGY INDIANA, LLC

Determination of International Paper
Fuel Cost Adjustment Factor Based on Estimated Average Fuel Costs
for the Months of July, August, and September 2023

Line No.	Description	Estimated Month of: July 2023 (A)	August 2023 (B)	September 2023 (C)	Total (D)	Estimated Three-Month Average (E)	Source ATTACHMENT A	Line No.
	MWh Source:							
1	Steam Generation	1,407,549	1,332,543	954,577	3,694,669	1,231,556	Sch. 2, Line 7	1
2	Nuclear Generation	-	-	-	-	-	Sch. 2, Line 8	2
3	Hydro and Solar Generation	43,793	43,579	36,224	123,596	41,199	Sch. 2, Line 9	3
	Other Generation --							
4	Internal Combustion	-	-	-	-	-	Sch. 2, Line 10	4
5	Gas Combustion Turbine	599,221	580,294	395,944	1,575,459	525,153	Sch. 2, Line 11	5
6	Integrated Gasification Combined Cycle	395,038	385,909	286,055	1,067,002	355,667	Sch. 2, Line 12	6
7	Purchased Power	559,261	670,286	908,763	2,138,310	712,770	Sch 3, Col. A	7
8	Equivalent kWh - Steam Sale	12,104	11,974	12,279	36,357	12,119	Sch. 5, Line 2	8
	Less:							
9	Intersystem Sales	-	-	-	-	-	Sch. 4, Col. A	9
10	Total kWh (K)	3,016,966	3,024,585	2,593,842	8,635,393	2,878,464		10
	Fuel Cost:							
11	Steam Generation	$ 45,147,000	$ 42,640,000	$ 30,855,000	$ 118,642,000	$ 39,547,333	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	17,096,000	16,742,000	10,248,000	44,086,000	14,695,333	Sch. 2, Line 4	15
16	Integrated Gasification Combined Cycle	11,176,000	10,889,000	8,115,000	30,180,000	10,060,000	Sch. 2, Line 5	16
17	Hedging Position	1,016,000	372,000	414,000	1,802,000	600,667	Sch. 1, Line 17	17
18	Purchased Power	25,145,000	26,869,000	29,502,000	81,516,000	27,172,000	Sch 3, Col. C	18
19	Net MISO Energy Market	5,528,000	4,092,000	4,683,000	14,303,000	4,767,667	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)	$ 105,108,000	$ 101,604,000	$ 83,817,000	$ 290,529,000	$ 96,843,000		22
23	F / K (Mills Per kWh)					33.6439851		23
24	Equivalent Cost Per 1000 lbs Steam (Line 23 * 0.1084)					3.6470080		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					0.7250860		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 December 2022 through February 2023

Line No.	Month	Steam Supplied (lbs.)	Actual Fuel Cost Adjustment Factor 1/	Estimated Fuel Cost Adjustment Factor	Variance	Reconciliation Amount	Line No.
1	December 2022	124,623,269	4.4892873	4.2369937	0.2522936	31,442	1
2	January 2023	124,842,425	1.0855761	2.8818473	(1.7962712)	(224,251)	2
3	February 2023	123,851,976	0.8009710	2.8818473	(2.0808763)	(257,721)	3
4	TOTAL RECONCILIATION					$ (450,530)	4

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

	December 2022	January 2023	February 2023
MWh Sales (K)	2,553,164	2,452,229	2,150,590
Fuel Cost (F)	$ 143,163,141	$ 90,657,778	$ 73,859,931
F/K (Mills Per kWh)	56.0728339	36.9695400	34.3440316
Equivalent Cost per 1000lbs Steam	6.0782952	4.0074981	3.7228930
Less: Base Cost of Fuel Included in Rates	1.5890079	2.9219220	2.9219220
Fuel Cost Charge Factor (Per 1000lbs Steam)	4.4892873	1.0855761	0.8009710