OFFICIAL EXHIBITS

FILED
July 28, 2022
INDIANA UTILITY
REGULATORY COMMISSION

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-FAC133**

IURC
PETITIONER'S
EXHIBIT NO. 11
9-19-22 AT
DATE REPORTER

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.[1] 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.

[1] International Paper acquired Temple-Inland's corrugated packaging business on February 13, 2012.

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

(i) July 28, 2022 – the date the Company is filing this Verified Application;

(ii) July 28, 2022 – the date the Company is prefiling testimony and exhibits supporting this Verified Application;

(iii) September 1, 2022 – the latest date by which the OUCC and any intervenor shall prefile its testimony and exhibits concerning this Verified Application[2];

(iv) September 9, 2022 – the latest date by which Duke Energy Indiana shall file rebuttal testimony

(v) On or after September 14, 2022 – the day on which the Company requests that the evidentiary hearing concerning this Verified Application be held; and

(vi) September 30, 2022 – 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 additional showing pursuant to a public hearing held subject to the notice provisions required by IC 8-1-1-8.

[2] 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.

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 this and future 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, will be 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. As such, the authorized net operating income for the twelve-month ended May 2022 period reflected in this filing will be based on the Commission's Orders in Cause No. 45253 Step 1 (for the months of March 2021 through July 2021) and Cause No. 45253 Step 2 (for the months of August 2021 through February 2022). 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 ("CWIP Order"), which approved construction work in progress ("CWIP") ratemaking treatment for certain qualified pollution control property and the Commission's Orders in subsequent CWIP related proceedings, including the update approved by the Commission on January 12, 2022, in Cause No. 42061-ECR36. 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, including subsequent update proceedings, 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 ("TDSIC") projects; 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 May 2022, 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 $0.060221 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 costs and credits in its fuel cost in this proceeding in accordance with the MISO Order, 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 May 31, 2022, 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 May 31, 2022, to the phased-in jurisdictional return and expenses authorized by the Commission in its Orders in Cause No. 45253 Step 1 and Step 2, and subsequent CWIP, 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 May 31, 2022, resulted in a positive variance factor (*i.e.,* actual net jurisdictional fuel costs per kilowatt-hour incurred were more than fuel costs billed customers, resulting in a net under-collection of fuel costs). The Company experienced a sizeable under-collection for the current reconciliation period. To reduce the FAC impact to customers, the Petitioner is proposing that the collection of the under-billings be spread over a period of six months instead of the typical three-month recovery period.

10. Applicant's net fuel charge in this proceeding is $0.072903 per kWh; the net fuel charge in Cause No. 38707-FAC132 was $0.061198 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 $0.045948 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 October 2022 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[3] [4]
Residential *(based on typical customer at 1,000 kWh)*	7.2% increase
Commercial *(based on three different sets of energy and demand billing determinants)*	<8.8% increase
Industrial *(based on four different sets of energy and demand billing determinants)*	<10.7% increase

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 March through May 2022;

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 $0.045948 per kWh to become effective upon the later of the date of approval by the Commission or the first billing cycle of October 2022;

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.

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[3] 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 July 1, 2022.

[4] 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.

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. 44087.

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

5. Applicant's estimated fuel cost for October through December 2022 is 53.7454020 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 $5.8260016 per thousand pounds of steam. This cost factor, less the base cost of fuel of $1.5890079 per 1000 pounds of steam will result in a fuel cost adjustment factor of $4.2369937 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 March through May 2022 is shown on Attachment B, Schedule 2. The total reconciliation adjustment of $559,793 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 October 2022 by Applicant for steam service;

iii) authorizing and approving the reconciliation adjustments to International Paper as shown on Attachment B, Schedule 2 for the March through May 2022 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 July 2022.

DUKE ENERGY INDIANA, LLC

By: ______________________________

Suzanne E. Sieferman, Director Rates and Regulatory Planning

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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: Suzanne E. Sieferman
Suzanne E. Sieferman

Dated: 7/28/2022

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
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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 July 2022.

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)
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ATTACHMENT A
SCHEDULE 1

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 October, November, and December 2022

Line No.	Description	Estimated Month of: October 2022 (A)	November 2022 (B)	December 2022 (C)	Total (D)	Estimated Three-Month Average (E)	Source (F)	Line No.
	MWh Source:							
1	Steam Generation	922,088	1,014,787	1,240,097	3,176,972	1,058,991	Sch.2,Ln 7	1
2	Nuclear Generation	-	-	-	-	-	Sch.2,Ln 8	2
3	Hydro and Solar Generation	42,609	40,643	41,627	124,879	41,626	Sch.2,Ln 9	3
	Other Generation --							
4	Internal Combustion	-	-	-	-	-	Sch.2,Ln 10	4
5	Gas Combustion Turbine	331,979	313,847	420,992	1,066,818	355,606	Sch.2,Ln 11	5
6	Integrated Gasification Combined Cycle	381,378	410,040	438,620	1,230,038	410,013	Sch.2,Ln 12	6
7	Purchased Power	820,110	770,366	680,468	2,270,944	756,981	Sch.3,Col.A	7
	Less:							
8	Intersystem Sales	-	-	-	-	-	Sch.4,Col.A	8
9	Energy Losses & Company Use	122,688	124,842	138,525	386,055	128,685		9
10	Sales (S)	2,375,476	2,424,841	2,683,279	7,483,596	2,494,532		10
	Fuel Cost:							
11	Steam Generation	$ 26,844,000	$ 29,230,000	$ 35,139,000	$ 91,213,000	$ 30,404,333	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	30,140,000	28,295,000	33,589,000	92,024,000	30,674,667	Sch.2,Ln 4	15
16	Integrated Gasification Combined Cycle	15,544,000	16,561,000	17,367,000	49,472,000	16,490,667	Sch.2,Ln 5	16
17	Hedging Position 1/	(375,720)	790,313	2,274,780	2,689,373	896,458		17
18	Purchased Power	66,576,000	65,906,000	61,541,000	194,023,000	64,674,333	Sch 3, Col. C	18
19	Net MISO Energy Market	(1,054,000)	(367,000)	(2,766,000)	(4,187,000)	(1,395,667)		19
20	Net MISO Ancillary Services Market	-	-	-	-	-		20
	Less:							
21	Intersystem Sales	-	-	-	-	-	Sch.4,Col.C	21
22	Steam Sales	718,000	740,000	818,000	2,276,000	758,667	Sch 5,Ln 4	22
23	Total Fuel Cost (F)	$ 136,956,280	$ 139,675,313	$ 146,326,780	$ 422,958,373	$ 140,986,124		23
24	F / S (Mills Per kWh)					56.518		24
	Months to be Reconciled	March 2022	April 2022	May 2022	3 Months Total			
25	Monthly Fuel Cost Reconciliation Variance	$ 28,389,450	$ 29,485,058	$ 45,054,154	$ 102,928,662 2/		Sch.6s	25
26	Reconciliation Factor Reflecting Appplicant's Proposal to Spread Recovery over 2 Quarters (6 months) $ 51,464,331 / 6,352,934 MWhrs					8.101		26
27	Remaining FAC132 Reconciliation Amount to be Included in Current Proceeding $ 52,627,460 / 6,352,934 MWhrs					8.284		27
28	Subtotal					72.903		28
29	Less: Base Cost of Fuel Included in Rates					26.955		29
30	Total Fuel Cost Adjustment Factor (Mills Per kWh)					45.948		30

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.

ATTACHMENT A
SCHEDULE 2

DUKE ENERGY INDIANA, LLC

**Determination of the
Estimated Cost of Fuel Consumed (Account 151)
and Net Generation (MWh Output)
for the Months of October, November, and December 2022
Used in Developing the Retail Fuel Cost Factor to be
Effective Upon the Order of the Commission**

Line No.	Description	Estimated Month of: October 2022	November 2022	December 2022	Total	Estimated Three-Month Average	Line No.
		(A)	(B)	(C)	(D)	(E)	
	Fuel Cost:						
1	Steam Generation	$ 26,844,000	$ 29,230,000	$ 35,139,000	$ 91,213,000	$ 30,404,333	1
2	Nuclear Generation	-	-	-	-	-	2
	Other Generation -						
3	Internal Combustion	-	-	-	-	-	3
4	Gas Combustion Turbine	30,140,000	28,295,000	33,589,000	92,024,000	30,674,667	4
5	Integrated Gasification Combined Cycle	15,544,000	16,561,000	17,367,000	49,472,000	16,490,667	5
6	Total Fuel Cost	$ 72,528,000	$ 74,086,000	$ 86,095,000	$ 232,709,000	$ 77,569,667	6
	Net Generation MWh Output:						
7	Steam Generation	922,088	1,014,787	1,240,097	3,176,972	1,058,991	7
8	Nuclear Generation	-	-	-	-	-	8
9	Hydro and Solar Generation	42,609	40,643	41,627	124,879	41,626	9
	Other Generation -						
10	Internal Combustion	-	-	-	-	-	10
11	Gas Combustion Turbine	331,979	313,847	420,992	1,066,818	355,606	11
12	Integrated Gasification Combined Cycle	381,378	410,040	438,620	1,230,038	410,013	12
13	Total Net Generation	1,678,054	1,779,317	2,141,336	5,598,707	1,866,236	13

ATTACHMENT A
SCHEDULE 3

DUKE ENERGY INDIANA, LLC

Determination of Estimated
Net Energy Costs of Native Load Purchased Power
for the Months of October, November, and December 2022
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)	
	October 2022							
1	Various Purchases 1/	820,110	$ -	$ 66,576,000	$ -	$ 66,576,000	$ 66,576,000	1
	November 2022							
2	Various Purchases 1/	770,366	-	65,906,000	-	65,906,000	65,906,000	2
	December 2022							
3	Various Purchases 1/	680,468	-	61,541,000	-	61,541,000	61,541,000	3
4	Total Purchased Power	2,270,944	$ -	$ 194,023,000	$ -	$ 194,023,000	$ 194,023,000	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.

DUKE ENERGY INDIANA, LLC

Determination of Estimated Fuel Costs (Account 151)
Recovered Through Intersystem Sales
for the Months of October, November, and December 2022
Used in Developing the Retail Fuel Cost Factor to be
Effective Upon the Order of the Commission

Line No.	Type of Transaction		MWh Sold (A)	Demand Charge (B)	Energy Charge: Fuel Cost (Accounts 151) (C)	Energy Charge: Other Costs (D)	Energy Charge: Total Energy Charge (E)	Total Charges (F)	Line No.
	October 2022								
1	Power Coordination Agreement Sales	_1/	-	$ -	$ -	$ -	$ -	$ -	1
	November 2022								
2	Power Coordination Agreement Sales	_1/	-	-	-	-	-	-	2
	December 2022								
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 October, November, and December 2022
Used in Developing the Retail Fuel Cost Factor to be
Effective Upon the Order of the Commission**

Line No.	Description	Estimated Month of: October 2022 (A)	November 2022 (B)	December 2022 (C)	Total (D)	Estimated Three-Month Average (E)	Source	Line No.
1	Total Pounds of Steam Supplied (000's)	123,315	127,088	140,414	390,817	130,272		1
2	Total Equivalent kWh Generated (000's) At Cayuga, Other Generating Stations Of the Company and Through Purchased Power Transactions (Note 1)	13,367	13,776	15,221	42,364	14,121		2
3	Equivalent Cost per 1000 lbs Steam (Note 2)	5.8260016	5.8260016	5.8260016				3
4	Fuel Costs Recovered Through the Sale of Steam (Line 1 * Line 3) (Rounded to 000's)	$ 718,000	$ 740,000	$ 818,000	$ 2,276,000	$ 758,667		4

Note 1: Equivalent MWh = 0.1084 * Line 1

Note 2: Fuel Cost

	October 2022 (A)	November 2022 (B)	December 2022 (C)	Total (D)	Average (E)	Source
Steam Generation	$ 26,844,000	$ 29,230,000	$ 35,139,000	$ 91,213,000	$ 30,404,333	Sch. 2, Ln 1
Nuclear Generation	-	-	-	-	-	Sch. 2, Ln 2
Other Generation						
Internal Combustion	-	-	-	-	-	Sch. 2, Ln 3
Gas Combustion Turbine	30,140,000	28,295,000	33,589,000	92,024,000	30,674,667	Sch. 2, Ln 4
Integrated Gasification Combined Cycle	15,544,000	16,561,000	17,367,000	49,472,000	16,490,667	Sch. 2, Ln 5
Hedging Position	(375,720)	790,313	2,274,780	2,689,373	896,458	Sch. 1, Ln 17
Purchased Power	66,576,000	65,906,000	61,541,000	194,023,000	64,674,333	Sch. 1, Ln 18
Net MISO Energy Market	(1,054,000)	(367,000)	(2,766,000)	(4,187,000)	(1,395,667)	Sch. 1, Ln 19
Net MISO Ancillary Services Market	-	-	-	-	-	Sch. 1, Ln 20
Less:						
Intersystem Sales	-	-	-	-	-	Sch. 4, Col. C
Total Fuel Costs	$ 137,674,280	$ 140,415,313	$ 147,144,780	$ 425,234,373	$ 141,744,791	
MWh						
Sales (S)	2,375,476	2,424,841	2,683,279	7,483,596	2,494,532	Sch. 1, Ln 10
Energy Losses & Company Use	122,688	124,842	138,525	386,055	128,685	Sch. 1, Ln 9
Equivalent kWh - Steam Sale	13,367	13,776	15,221	42,364	14,121	Sch. 5, Ln 2
Total kWh (K)	2,511,531	2,563,459	2,837,025	7,912,015	2,637,338	
F/K (Mills Per kWh)					53.7454020	
Equivalent Cost per 1000 lbs Steam (Mills Per kWh * 0.1084)					$ 5.8260016	

DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Incremental Cost of Fuel Incurred to Actual Incremental Cost of Fuel Billed Retail Customers for the March 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 - 43.884 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 130	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 Retail kWh Sales Subject to Fuel Clause Adjustment	2,002,909	$ 53,988,412	$ 87,895,659	$ 33,907,247	$ 16,167,388	$ 10,649,591	$ 5,517,797	$ 28,389,450	1
2	Retail kWh Sales Not Subject to the Fuel Clause Adjustment	15,789								2
3	kWh Sales for Resale	284,511								3
4	Sales	2,303,209								4

DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Incremental Cost of Fuel Incurred to Actual Incremental Cost of Fuel Billed
Retail Customers for the April 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 - 47.202 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 131	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 Retail kWh Sales Subject to Fuel Clause Adjustment	1,878,959	$ 50,647,340	$ 88,690,623	$ 38,043,283	$ 21,736,548	$ 13,322,253	$ 8,558,225	$ 29,485,058	1
2	Retail kWh Sales Not Subject to the Fuel Clause Adjustment	15,180								2
3	kWh Sales for Resale	293,306								3
4	Sales	2,187,445								4

DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Incremental Cost of Fuel Incurred to Actual Incremental Cost of Fuel Billed Retail Customers for the May 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 - 55.545 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 131	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 Retail kWh Sales Subject to Fuel Clause Adjustment	1,872,641	$ 50,477,038	$ 104,015,844	$ 53,538,806	$ 21,156,456	$ 13,322,253	$ 8,484,652	45,054,154	1
2	Retail kWh Sales Not Subject to the Fuel Clause Adjustment	14,599								2
3	kWh Sales for Resale	299,468								3
4	Sales	2,186,708								4
5	Fuel Cost Variance from the March 2022 Billing Cycle (See Attachment A, Schedule 6, Page 1 of 3, Column H)								28,389,450	5
6	Fuel Cost Variance from the April 2022 Billing Cycle (See Attachment A, Schedule 6, Page 2 of 3, Column H)								29,485,058	6
7	Total Fuel Cost Variance for the Three (3) Months Ended May 2022								$ 102,928,662	7

DUKE ENERGY INDIANA, LLC

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

Line No.	Description	Total Actual March 2022 (A)	WVPA 70MW Firm Sale (B)	Wholesale Formula Rate ASM 4/ (C)	Adjusted Actual March 2022 (D)	Line No.
	kWh Sales (000's):					
	Native Load Sales					
1	Billed Retail Sales	2,018,698			2,018,698	1
2	Unbilled Retail Sales	(23,906)			(23,906)	2
3	Wholesale Sales	284,511	40,950	243,561	-	3
4	Total Native Load Sales (S)	2,279,303	40,950	243,561	1,994,792	4
	Fuel Cost:					
5	Native Load Fuel Cost, Including Virtual Energy Amounts 1/	$ 100,741,729	$ 1,682,616	$ 9,993,638	$ 89,065,475	5
6	Realized Hedging Activity, Excluding Virtual Energy Amounts 2/	192,397	3,457	20,559	168,381	6
7	Wind and Solar REC Proceeds 5/	-	-	-	-	7
8	Prior Period Hedging Adjustment 6/	11,819	212	1,263	10,344	8
9	Prior Period Cost Adjustments 3/	(1,770,738)	42,509	(108,116)	(1,705,131)	9
10	Total Fuel Cost (F)	$ 99,175,207	$ 1,728,794	$ 9,907,344	$ 87,539,069	10
11	Fuel Cost - Mills per kWh (F/S)	43.511	42.217	40.677	43.884	11

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 (line 5) 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 and gas costs and steam revenues for the Purdue CHP plant.

2/ Hedging component subtotals follow: LMP hedging total ($294,580); Gas hedging total $486,977.

3/ Prior Period Adjustment Totals by month: 1)Dec21 S105 ($312,175); 2)Jan22 S105 ($685,384); 3)Feb22 S105 ($773,179).

Prior Period Adjustment WVPA 70 by month: 1)Dec21 S105 $7,759; 2)Jan22 S105 $12,349; 3)Feb22 S105 $22,401.

Prior Period Adjustment Wholesale Formula Rate by month: 1)Dec21 S105 ($5,317); 2)Jan22 S105 ($81,126); 3)Feb22 S105 ($21,673).

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)Dec21 S105 LMP $2,155; 2)Jan22 S105 LMP $6,606; 3)Feb22 S105 LMP $3,058.

DUKE ENERGY INDIANA, LLC

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

Line No.	Description	Total Actual April 2022 (A)	WVPA 70MW Firm Sale (B)	Wholesale Formula Rate ASM 4/ (C)	Adjusted Actual April 2022 (D)	Line No.
	kWh Sales (000's):					
	Native Load Sales					
1	Billed Retail Sales	1,894,139			1,894,139	1
2	Unbilled Retail Sales	225,932			225,932	2
3	Wholesale Sales	293,306	45,920	247,386	-	3
4	Total Native Load Sales (S)	2,413,377	45,920	247,386	2,120,071	4
	Fuel Cost:					
5	Native Load Fuel Cost, Including Virtual Energy Amounts 1/	$ 118,693,849	$ 2,367,003	$ 12,735,466	$ 103,591,380	5
6	Realized Hedging Activity, Excluding Virtual Energy Amounts 2/	(3,992,487)	(75,966)	(409,254)	(3,507,267)	6
7	Wind and Solar REC Proceeds 5/	(13,581)	(258)	(1,392)	(11,931)	7
8	Prior Period Cost Adjustments 3/	-	-	-	-	8
9	Total Fuel Cost (F)	$ 114,687,781	$ 2,290,779	$ 12,324,820	$ 100,072,182	9
10	Fuel Cost - Mills per kWh (F/S)	47.522	49.886	49.820	47.202	10

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 (line 5) 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 and gas costs and steam revenues for the Purdue CHP plant.

2/ Hedging component subtotals follow: LMP hedging total ($2,428,064); Gas hedging total ($1,564,423).

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 custon

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
May 2022

Line No.	Description	Total Actual May 2022 (A)	WVPA 70MW Firm Sale (B)	Wholesale Formula Rate ASM 4/ (C)	Adjusted Actual May 2022 (D)	Line No.
	kWh Sales (000's):					
	Native Load Sales					
1	Billed Retail Sales	1,887,240			1,887,240	1
2	Unbilled Retail Sales	56,476			56,476	2
3	Wholesale Sales	299,468	46,200	253,268	-	3
4	Total Native Load Sales (S)	2,243,184	46,200	253,268	1,943,716	4
	Fuel Cost:					
5	Native Load Fuel Cost, Including Virtual Energy Amounts 1/	$ 135,086,424	$ 2,448,407	$ 13,724,722	$ 118,913,295	5
6	Realized Hedging Activity, Excluding Virtual Energy Amounts 2/	(12,636,327)	(260,254)	(1,426,712)	(10,949,361)	6
7	Wind and Solar PPA REC Proceeds 5/	309	6	35	268	7
8	Prior Period Cost Adjustments 3/	-	-	-	-	8
9	Total Fuel Cost (F)	$ 122,450,406	$ 2,188,159	$ 12,298,045	$ 107,964,202	9
10	Fuel Cost - Mills per kWh (F/S)	54.588	47.363	48.557	55.545	10

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 (line 5) 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 and gas costs and steam revenues for the Purdue CHP plant.

2/ Hedging component subtotals follow: LMP hedging total ($9,608,794); Gas hedging total ($3,027,533).

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 ty (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 custo

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 March, April and May 2022

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)	
	March 2022																	
1	01 - 05	210,075.247	6,815,875.52	32.44	210,075.247	1,431,879.33	6.82	210,075.247	8,247,754.85	39.26	(3,207,681.47)	189,329.829	9,172,556.27	48.45	399,405.076	14,212,629.65	35.58	1
2	06 - 12	306,988.810	9,814,157.45	31.97	306,988.810	1,284,540.87	4.18	306,988.810	11,098,698.32	36.15	(1,017,379.91)	283,761.801	15,227,373.03	53.66	590,750.611	25,308,691.44	42.84	2
3	13 - 19	288,846.603	9,195,331.50	31.83	288,846.603	3,387,204.79	11.73	288,846.603	12,582,536.29	43.56	(2,793,277.25)	237,377.006	12,944,713.75	54.53	526,223.609	22,733,972.79	43.20	3
4	20 - 26	282,884.349	9,240,936.59	32.67	282,884.349	3,029,827.59	10.71	282,884.349	12,270,764.18	43.38	(3,944,574.84)	254,244.492	13,372,920.29	52.60	537,128.841	21,699,109.63	40.40	4
5	27 - 31	234,420.841	7,612,962.33	32.48	234,420.841	1,015,666.03	4.33	234,420.841	8,628,628.36	36.81	(1,560,147.89)	181,807.912	11,033,138.69	60.69	416,228.753	18,101,619.16	43.49	5
6	Subtotals	1,323,215.850	42,679,263.39	32.25	1,323,215.850	10,149,118.61	7.67	1,323,215.850	52,828,382.00	39.92	(12,523,061.36)	1,146,521.040	61,750,702.02	53.86	2,469,736.890	102,056,022.66	41.32	6
7														WVPA-IMPA Adjustment 6/	(327,727.767)	(13,597,753.88)	41.49	7
8														Native Alloc. Of Gas Pipeline Res. Fee 7/		230,104.42		8
9														Other Fuel Cost Adjustments		-		9
10															2,142,009.123	88,688,373.20	41.40	10

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)	
	April 2022																	
11	01 - 02	84,237.268	3,109,738.16	36.92	84,237.268	520,011.03	6.17	84,237.268	3,629,749.19	43.09	(1,422,503.70)	77,315.786	4,807,282.99	62.18	161,553.054	7,014,528.48	43.42	11
12	03 - 09	294,339.242	10,334,581.29	35.11	294,339.242	1,929,583.50	6.56	294,339.242	12,264,164.79	41.67	(2,185,223.64)	234,074.341	15,940,655.03	68.10	528,413.583	26,019,596.18	49.24	12
13	10 - 16	221,117.017	7,615,364.98	34.44	221,117.017	1,488,510.38	6.73	221,117.017	9,103,875.36	41.17	(1,702,026.07)	290,290.122	19,821,833.08	68.28	511,407.139	27,223,682.37	53.23	13
14	17 - 23	301,218.241	10,122,293.64	33.60	301,218.241	1,010,380.40	3.35	301,218.241	11,132,674.04	36.96	(1,978,831.45)	253,069.346	20,507,630.66	81.04	554,287.587	29,661,473.25	53.51	14
15	24 - 30	255,634.713	8,374,454.67	32.76	255,634.713	1,429,986.50	5.59	255,634.713	9,804,441.17	38.35	(1,711,433.22)	289,362.085	21,040,999.67	72.72	544,996.798	29,134,007.62	53.46	15
16	Subtotals	1,156,546.481	39,556,432.74	34.20	1,156,546.481	6,378,471.81	5.52	1,156,546.481	45,934,904.55	39.72	(9,000,018.08)	1,144,111.680	82,118,401.42	71.77	2,300,658.161	119,053,287.89	51.75	16
17														WVPA-IMPA Adjustment 6/	(334,231.841)	(16,336,710.04)	48.88	17
18														Native Alloc. Of Gas Pipeline Res. Fee 7/		358,015.58	-	18
19														Other Fuel Cost Adustments		-		19
20															1,966,426.320	103,074,593.43	52.42	20

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)	
	May 2022																	
21	01 - 07	305,217.460	10,974,455.84	35.96	305,217.460	1,381,205.08	4.53	305,217.460	12,355,660.92	40.48	(1,776,231.42)	229,275.433	17,524,700.20	76.44	534,492.893	28,104,129.70	52.58	21
22	08 - 14	383,415.365	15,803,941.48	41.22	383,415.365	2,227,609.99	5.81	383,415.365	18,031,551.47	47.03	(2,582,644.15)	202,894.905	18,815,030.42	92.73	586,310.270	34,263,937.74	58.44	22
23	15 - 21	445,613.022	16,871,877.12	37.86	445,613.022	3,584,646.79	8.04	445,613.022	20,456,523.91	45.91	(2,936,627.56)	139,264.905	13,702,366.13	98.39	584,877.927	31,222,262.48	53.38	23
24	22 - 28	359,319.660	13,037,316.56	36.28	359,319.660	2,699,707.99	7.51	359,319.660	15,737,024.55	43.80	(1,784,017.32)	182,963.034	14,960,558.94	81.77	542,282.694	28,913,566.17	53.32	24
25	29 - 31	197,600.921	7,733,658.66	39.14	197,600.921	2,075,125.36	10.50	197,600.921	9,808,784.02	49.64	(3,100,595.99)	60,883.367	5,897,931.14	96.87	258,484.288	12,606,119.17	48.77	25
26	Subtotals	1,691,166.428	64,421,249.66	38.09	1,691,166.428	11,968,295.21	7.08	1,691,166.428	76,389,544.87	45.17	(12,180,116.44)	815,281.644	70,900,586.83	86.96	2,506,448.072	135,110,015.26	53.90	26
27														WVPA-IMPA Adjustment 6/	(354,295.645)	(17,487,817.36)	49.36	27
28														Native Alloc. Of Gas Pipeline Res. Fee 7/		310,194.51	-	28
29															2,152,152.427	117,932,392.41	54.80	29

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 ($960.58), ($4,782.16) and ($19,077.15) respectively, for Excessive Energy Amounts for the months of March 2022, April 2022, May 2022.

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
June 2021 through May 2022

Line No.	Description	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
1	**MWh Sales (S)**	2,496,431	2,710,024	2,859,672	2,507,059	2,311,535	2,425,460	2,394,471	2,726,838	2,525,816	2,279,303	2,413,377	2,243,184	1
	Fuel Cost (F)													
2	Native Load Fuel Cost	$ 73,577,586	$ 83,359,246	$ 97,936,721	$ 90,345,511	$ 100,744,893	$ 122,167,433	$ 94,800,355	$ 118,299,776	$ 91,823,499	$ 100,741,729	$ 118,693,849	$ 135,086,424	2
3	Realized Hedging Activity	(926,874)	(940,583)	(1,216,073)	(1,692,759)	(6,425,721)	(7,433,658)	24,481,610	6,765,024	4,461,654	192,397	(3,992,487)	(12,636,327)	3
4	Other Adjustments	(380,406)	(249,773)	(572,050)	(47,377)	1,000	(352,500)	(357,235)	-	(765,521)	11,819	(13,581)	309	4
5	Prior Period Cost Adjustments 1/	(729,959)	-	-	53,758	-	-	3,176,810	-	-	(1,770,738)	-	-	5
6	Total Fuel Cost (F)	$ 71,540,347	$ 82,168,890	$ 96,148,598	$ 88,659,133	$ 94,320,172	$ 114,381,275	$ 122,101,540	$ 125,064,800	$ 95,519,632	$ 99,175,207	$ 114,687,781	$ 122,450,406	6
7	Fuel Cost Per kWh (Mills) F/S	$ 28.657	$ 30.320	$ 33.622	$ 35.364	$ 40.804	$ 47.159	$ 50.993	$ 45.864	$ 37.817	$ 43.511	$ 47.522	$ 54.588	7
	Fuel Cost Factor Restated Based On **<u>Synchronization of Sumatra Adjustments</u>**													
8	Remove: Prior Period Sumatra Adjustments Reflected in the Current Month	(729,959)	-	-	53,758	-	-	3,176,810	-	-	(1,770,738)	-	-	8
9	Remove: Hedging and Other Fuel Adjustments	(1,307,280)	(1,190,356)	(1,788,123)	(1,740,136)	(6,424,721)	(7,786,158)	24,124,375	6,765,024	3,696,133	204,216	(4,006,068)	(12,636,018)	9
10	Add: Subsequent Sumatra Adjustments that Pertain to the Month Presented	(407,014)	(728,625)	(107,235)	(962,802)	436,505	3,506,864	(312,175)	(685,384)	(773,179)	-	-	-	10
11	Restated Total Fuel Costs	$ 73,170,572	$ 82,630,621	$ 97,829,486	$ 89,382,709	$ 101,181,398	$ 125,674,297	$ 94,488,180	$ 117,614,392	$ 91,050,320	$ 100,741,729	$ 118,693,849	$ 135,086,424	11
12	Fuel Cost Factor	29.310	30.491	34.210	35.652	43.772	51.815	39.461	43.132	36.048	44.198	49.182	60.221	12
13	Percentage Variance from Preliminary Fuel Cost (Ln. 6) to Adjusted Fuel Cost, Excluding Hedging and Other Adjustments (Ln. 11)	2.28 %	0.56 %	1.75 %	0.82 %	7.27 %	9.87 %	(22.62 %)	(5.96 %)	(4.68 %)	1.58 %	3.49 %	10.32 %	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 March, April and May 2022

Line No.	Description	March 2022 Actual	March 2022 Forecast	April 2022 Actual	April 2022 Forecast	May 2022 Actual	May 2022 Forecast	Total Actual	Total Forecast	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
	MWh Source:									
	Native Load Sales									
1	Billed Retail Sales	2,018,698	2,218,885	1,894,139	2,032,293	1,887,240	1,960,280	5,800,077	6,211,458	1
2	Unbilled Retail Sales	(23,906)	16,078	225,932	(4,890)	56,476	195,582	258,502	206,770	2
3	Wholesale Sales	284,511	212,972	293,306	161,270	299,468	171,854	877,285	546,096	3
4	Total Native Load Sales (S)	2,279,303	2,447,935	2,413,377	2,188,673	2,243,184	2,327,716	6,935,864	6,964,324	4
	Fuel Cost:									
5	Native Load Fuel Cost	$ 100,741,729	$ 75,108,000	$ 118,693,849	$ 73,492,000	$ 135,086,424	$ 73,433,000	354,522,002	222,033,000	5
6	Hedging Activity and Other Adjustments	204,216	(296,825)	(4,006,068)	257,220	(12,636,018)	(690,688)	(16,437,870)	(730,293)	6
7	Total Fuel Cost	100,945,945	74,811,175	114,687,781	73,749,220	122,450,406	72,742,312	338,084,132	221,302,707	7
8	Fuel Cost - Mills Per kWh Before Prior Period Adjustment (F/S)	$ 44.288	$ 30.561	$ 47.522	$ 33.696	$ 54.588	$ 31.251	$ 48.744	$ 31.777	8
9	Percentage (%) Actual is Over (Under) Estimate Before Prior Period Adjustments	44.92 %		41.03 %		74.68 %		53.39 %		9
10	Prior Period Cost Adjustments	(1,770,738)	-	-	-	-	-	(1,770,738)	-	10
11	Total Fuel Cost (F_1)	$ 99,175,207	$ 74,811,175	$ 114,687,781	$ 73,749,220	$ 122,450,406	$ 72,742,312	$ 336,313,394	$ 221,302,707	11
12	Fuel Cost - Mills Per kWh After Prior Period Adjustment (F1/S)	$ 43.511	$ 30.561	$ 47.522	$ 33.696	$ 54.588	$ 31.251	$ 48.489	$ 31.777	12
13	Percentage (%) Actual is Over (Under) Estimate After Prior Period Adjustments	42.37 %		41.03 %		74.68 %		52.59 %		13

ATTACHMENT A
SCHEDULE 11

DUKE ENERGY INDIANA, LLC

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

Line No.	MISO Charge Description	cXL - MISO Charge Descripton	March-22	April-22	May-22	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	$ (179,350.99)	$ (190,970.76)	$ (279,440.61)	7
8	DA Virtual Energy Amount	DA Virtual	$ -	$ -	$ -	8
9	FTR Hourly Allocation Amount	FTR	$ (9,703,935.98)	$ (3,956,390.18)	$ (7,019,889.86)	9
10	FTR Monthly Allocation Amount	MISO FTR MTH ALLOC	$ (152,483.97)	$ (55,096.30)	$ (326,532.83)	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	$ (1,570,697.70)	$ (1,989,412.83)	$ (1,477,472.11)	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	$ 15,932.68	$ 15,179.76	$ 48,513.90	20
21	RT Revenue Sufficiency Guarantee Make Whole Payment Amount	MISO RT RSG MKWHL	$ (66,607.05)	$ (642,600.39)	$ (1,623,776.94)	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	$ 135,974.99	$ 55,096.11	$ 326,532.76	25
26	RNU CRDFC Uplift Component	RNU CRDFC Uplift Component	$ (3,477.65)	$ -	$ -	26
27	FTR Full Funding Guarantee Amount	MISO FTR Full Fd Guar	$ -	$ -	$ -	27
28	FTR Guarantee Uplift Amount	MISO FTR Guar Uplift	$ -	$ -	$ -	28
29	Auction Revenue Rights Stage 2 Distribution Amount	MISO FTR ARR Stage 2	$ (66,295.77)	$ (66,277.31)	$ (66,267.60)	29
30	RT Price Volatility Make Whole Payment	MISO RT VOL MKWHL	$ (272,714.44)	$ (1,296,759.55)	$ (1,464,709.67)	30
31	DA Revenue Sufficiency Guarantee Distribution Amount	MISO DA RSG Dist Amt	$ 69,984.27	$ 68,942.92	$ 141,231.04	31
32	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	MISO RT RSG 1st Pass	$ 81,572.64	$ 66,895.98	$ 306,891.20	32
33	Net Regulation Adjustment Amount	MISO Net Reg Adj Amt	$ 1,572.65	$ (2,283.37)	$ (1,439.00)	33
34	Regulation Cost Distribution Amount	MISO Reg Dist	$ 100,317.07	$ 148,340.55	$ 169,257.92	34
35	Spinning Reserve Cost Distribution Amount	MISO Spin Dist	$ 103,187.40	$ 152,760.90	$ 162,429.31	35
36	Supplemental Reserve Cost Distribution Amount	MISO Supp Dist	$ 7,542.19	$ 13,945.77	$ 12,873.02	36
37	RT Excessive/Deficient Energy Deployment Charge Amount	RT Excessive/Deficient Energy Deployment Charge Amount	$ 95,992.46	$ 146,641.36	$ 201,778.41	37
38	DA Regulation Amount	DA Regulation	$ (217,264.84)	$ (371,276.06)	$ (528,907.63)	38
39	DA Spinning Reserve Amount	DA Spinning	$ (93,550.28)	$ (145,549.22)	$ (233,995.00)	39
40	RT Regulation Amount	RT Regulation	$ (27,028.58)	$ (13,240.16)	$ (103,042.54)	40
41	RT Spinning Reserve Amount	RT Spinning	$ (873.72)	$ (17,677.90)	$ (47,307.65)	41
42	RT Supplemental Reserve Amount	RT Supplemental	$ (7.81)	$ (84.73)	$ (8,066.35)	42
43	DA Supplemental Reserve Amount	DA Supplemental	$ -	$ (60.00)	$ (107.97)	43
44	Auction Revenue Rights Infeasible Uplift Amount	MISO infesbl ARR UP	$ 96,001.68	$ 95,974.95	$ 95,960.88	44
45	Contingency Reserve Deployment Failure Charge Amount	Contingency Reserve Deployment Failure Charge Amount	$ -	$ -	$ -	45
46	FTR Monthly Transaction Amount	FTR Monthly Transaction Amount	$ 16,191.67	$ (91,989.21)	$ 227,715.02	46
47	FTR Annual Transaction Amount	FTR Annual Transaction Amount	$ 1,637,320.34	$ 1,636,864.50	$ 1,636,624.55	47
48	Auction Revenue Rights Transaction Amount	MISO ARR Revenues	$ (2,575,374.78)	$ (2,574,657.86)	$ (2,574,280.36)	48
49	MISO DR Alloc Uplift	MISO DR Alloc Uplift	$ 111,297.88	$ 184,491.01	$ 262,630.57	49
50	MISO Misc	MISO Misc/Round Adj	$ 30,292.60	$ (74,318.73)	$ (131,265.82)	50
51	Internal Charge Type Related to MISO RT Regulation	MISO RT MIL MWP	$ (9,590.17)	$ (18,282.64)	$ (33,921.14)	51
52	Internal Charge Type Related to MISO RT Regulation	MISO Reg MIL UNDP	$ 40,769.50	$ 53,305.47	$ 80,930.44	52
53	MISO Disputed Amount	MISO Disputed Amount	$ -	$ -	$ -	53
54	RT Ramp Capability	RT Ramp Capability	$ (770.55)	$ (1,970.50)	$ (5,367.25)	54
55	DA Ramp Capability	DA Ramp Capability	$ (12,920.09)	$ (11,466.85)	$ (12,091.07)	55
56	Madison PJM Charges	Madison PJM Charges	$ (118,547.89)	$ (127,326.89)	$ 124,222.07	56
57	Battery Charges	Native Battery MISO Charges	$ (31,763.05)	$ (42,375.66)	$ (57,002.66)	57
58	Short-Term Reserve Cost Distribution Amount	MISO ST Res Dist Amt	$ 36,634.38	$ 97,629.65	$ 41,087.95	58
59	Real-Time Short-Term Reserve Amount	MISO ST Reserve Amt	$ (390.45)	$ (7,487.29)	$ (1,746.91)	59
60	Day-Ahead Short-Term Reserve Amount	DA ST Reserve	$ -	$ (38,532.62)	$ (22,164.51)	60
61	Net Charges/(Credits) to Duke Energy Indiana (Attachment A, Schedule 8, column J, lines 6, 16 and 26)		$ (12,523,061.36)	$ (9,000,018.08)	$ (12,180,116.44)	61

ATTACHMENT B
SCHEDULE 1

DUKE ENERGY INDIANA, LLC

Determination of International Paper (formerly referred to as Temple-Inland, Inc.)
Fuel Cost Adjustment Factor Based on Estimated Average Fuel Costs
for the Months of October, November, and December 2022

Line No.	Description	Estimated Month of: October 2022 (A)	November 2022 (B)	December 2022 (C)	Total (D)	Estimated Three-Month Average (E)	Source ATTACHMENT A	Line No.
	MWh Source:							
1	Steam Generation	922,088	1,014,787	1,240,097	3,176,972	1,058,991	Sch. 2, Line 7	1
2	Nuclear Generation	-	-	-	-	-	Sch. 2, Line 8	2
3	Hydro and Solar Generation	42,609	40,643	41,627	124,879	41,626	Sch. 2, Line 9	3
	Other Generation --							
4	Internal Combustion	-	-	-	-	-	Sch. 2, Line 10	4
5	Gas Combustion Turbine	331,979	313,847	420,992	1,066,818	355,606	Sch. 2, Line 11	5
6	Integrated Gasification Combined Cycle	381,378	410,040	438,620	1,230,038	410,013	Sch. 2, Line 12	6
7	Purchased Power	820,110	770,366	680,468	2,270,944	756,981	Total, Sch 3, Col. A	7
8	Equivalent kWh - Steam Sale	13,367	13,776	15,221	42,364	14,121	Sch. 5, Line 2	8
	Less:							
9	Intersystem Sales	-	-	-	-	-	Sch. 4, Col. A	9
10	Total kWh (K)	2,511,531	2,563,459	2,837,025	7,912,015	2,637,338		10
	Fuel Cost:							
11	Steam Generation	$ 26,844,000	$ 29,230,000	$ 35,139,000	$ 91,213,000	$ 30,404,333	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	30,140,000	28,295,000	33,589,000	92,024,000	30,674,667	Sch. 2, Line 4	15
16	Integrated Gasification Combined Cycle	15,544,000	16,561,000	17,367,000	49,472,000	16,490,667	Sch. 2, Line 5	16
17	Hedging Position	(375,720)	790,313	2,274,780	2,689,373	896,458	Sch. 1, Line 17	17
18	Purchased Power	66,576,000	65,906,000	61,541,000	194,023,000	64,674,333	Total, Sch 3, Col. C	18
19	Net MISO Energy Market	(1,054,000)	(367,000)	(2,766,000)	(4,187,000)	(1,395,667)	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)	$ 137,674,280	$ 140,415,313	$ 147,144,780	$ 425,234,373	$ 141,744,791		22
23	F / K (Mills Per kWh)					53.7454020		23
24	Equivalent Cost Per 1000 lbs Steam (Line 23 * 0.1084)					5.8260016		24
25	Less: Base Cost of Fuel Included in Rates Per 1000 lbs Steam					1.5890079		25
26	Fuel Cost Adjustment Factor Per 1000 lbs Steam					4.2369937		26

DUKE ENERGY INDIANA, LLC

Reconciliation of Actual Fuel Cost Incurred to Fuel Cost Billed
to International Paper (formerly Temple-Inland, Inc.)
For the Months of March through May 2022

Line No.	Month	Steam Supplied (lbs.)	Actual Fuel Cost Adjustment Factor 1/	Estimated Fuel Cost Adjustment Factor	Variance	Reconciliation Amount	Line No.
1	March 2022	101,332,350	2.6729953	1.5559361	1.1170592	113,194	1
2	April 2022	122,216,126	3.6639800	1.7173391	1.9466409	237,911	2
3	May 2022	110,264,061	3.6099627	1.7173391	1.8926236	208,688	3
4	TOTAL RECONCILIATION					$ 559,793	4

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

	March 2022	April 2022	May 2022
MWh Sales (K)	2,226,473	2,065,077	2,251,084
Fuel Cost (F)	$ 87,539,069	$ 100,072,182	$ 107,964,202
F/K (Mills Per kWh)	39.3173730	48.4592980	47.9609833
Equivalent Cost per 1000lbs Steam	4.2620032	5.2529879	5.1989706
Less: Base Cost of Fuel Included in Rates	1.5890079	1.5890079	1.5890079
Fuel Cost Charge Factor (Per 1000lbs Steam)	2.6729953	3.6639800	3.6099627