TESTIMONY OF ART J. BUESCHER III
LEAD RATES AND REGULATORY STRATEGY ANALYST
DUKE ENERGY INDIANA, LLC
CAUSE NO. 42736 RTO-59
BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Art J. Buescher III and my business address is 1000 East Main Street, Plainfield, Indiana 46168.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Indiana, LLC ("Duke Energy Indiana," "Petitioner" or "Company") as Lead Rates and Regulatory Strategy Analyst in Duke Energy Indiana's Rate Department.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN THE INDIANA RATE DEPARTMENT?

A. As Lead Rates and Regulatory Strategy Analyst, I am responsible for the preparation of financial and accounting data used in Duke Energy's rate filings, including rate matters involving Duke Energy Indiana.

Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I graduated from of the University of Indianapolis in May of 1988 with a Bachelor of Science Degree in Accounting. I was employed by the Company in June 1988. During my employment with the Company, I have held various financial and accounting positions supporting the Company and its affiliates.

Prior to my move to the Rates and Regulatory Planning department in 2007, I held various financial and accounting positions in Cost Accounting, Internal Auditing, Energy Trading Accounting, and as Supervisor, Fuels and Joint Ownership Accounting.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony in this proceeding supports the Company's request for approval of the proposed Rider No. 68 adjustment factors for the Company's Standard Contract Rider No. 68 ("Rider No. 68" or "RTO"), which includes a new projection as well as a reconciliation for prior historical periods.

Q. WHAT MONTHS OF HISTORICAL COSTS AND TRANSMISSION REVENUES ARE COVERED BY THE COMPANY'S PETITION IN THIS PROCEEDING?

A. The applicable non-fuel costs and transmission revenues for the reconciliation period of July 2022 through June 2023 are included in this proceeding.

Q. WHAT MONTHS OF PROJECTED COSTS AND TRANSMISSION REVENUES ARE COVERED BY THE COMPANY'S PETITION IN THIS PROCEEDING?

A. The forecasted amounts for applicable costs and transmission revenues are included for the months of January 2024 through December 2024.

II. BACKGROUND

Q. PLEASE BRIEFLY EXPLAIN YOUR UNDERSTANDING OF THE COMPANY'S RETAIL BASE RATE ORDERS RELEVANT TO THE COMPANY'S RIDER NO. 68.

A. In its May 18, 2004 Order in Cause No. 42359, the Commission first approved Rider No. 68 to track recovery from (or credit to) the Company's retail electric customers certain Company charges, credits and transmission revenues related to MISO. In the June 29, 2020 Order in Cause No. 45253, the Company's most recent retail base rate case, the Commission approved Rider No. 68 to continue and to include, on a prospective basis, non-fuel charges and credits assessed from PJM Interconnection, LLC ("PJM"), as it relates to the Company's Madison Generating Station as further described in the prefiled testimony of Mr. James (Brad) Daniel in this proceeding.

Q. ARE THERE OTHER KEY COMMISSION ORDERS THAT PROVIDE IMPORTANT BACKGROUND ON THE DEVELOPMENT OF THE COMPANY'S RIDER NO. 68?

A. Yes. There are a few Commission Orders that have had a significant impact on the development of this rider. In the Commission's June 1, 2005 Order in Cause No. 42685 ("June 1, 2005 Order") the Commission addressed MISO's implementation of the Energy Markets. Specifically with respect to the Company, the June 1, 2005 Order determined that certain Duke Energy Indiana's Energy Markets charges (and credits) were fuel-related and should therefore be reflected in the Company's subsequent Fuel Cost Adjustment Standard Contract Rider No. 60 proceedings. The Order also found that Rider No. 68 should continue to provide for the Company's non-fuel related MISO cost recovery under Energy Markets operations.

The Commission later approved, in its December 19, 2007 Order in Cause No. 42736 RTO-12, the recovery of Schedule 26 ("Network Upgrade Charge from Transmission Expansion Plan") costs assessed the Company by MISO as part of the Regional Expansion and Criteria and Benefits ("RECB") process through Rider No. 68, whether those costs are associated with transmission projects of other transmission owners or whether those costs are associated with the Company's RECB projects. Furthermore in the June 25, 2008 Order in Cause No. 42736 RTO-14, the Commission approved the Company's proposal for recovery of RECB Schedule 26 charges on Company-owned, MISO approved RECB transmission projects. Later in my testimony I provide further discussion on the regulatory treatment of the Company's RECB projects and Attachment 1-G (AJB) provides information on these Company-owned, MISO approved RECB projects, including estimates of Schedule 26 costs.

In the Commission's September 24, 2008 Order in Cause No. 42736 RTO-15 and the Commission's June 30, 2009 Order in Cause No. 42736 RTO-18, the Commission approved the Company's recovery of charges and credits associated with its participation in the MISO Ancillary Services Market ("ASM"). Specifically, the Company began including the following ASM charge types in its

Rider No. 68 filings: (a) the Real Time Revenue Neutrality Uplift Amount exclusive of the credits associated with the Contingency Reserve Deployment Failure Uplift Amount; (b) the Day Ahead Market Administration Amount; and (c) the Real Time Market Administration Amount. In its June 27, 2012 Order in Cause No. 42736 RTO-30, the Commission approved the recovery of Schedule 26-A ("Multi-Value Project Usage Rate" or "MVP") costs allocated to the Company by MISO for projects of other transmission owners through Rider No. 68, whether those costs are associated with transmission projects of other transmission owners. Later in my testimony, I provide further discussion on the regulatory treatment of the Company's MVP projects. Attachment 1-H (AJB) provides information on these Company-owned, MISO approved MVP projects, including estimates of Schedule 26-A costs.

In the Commission's September 24, 2014 Order in Cause No. 42736 RTO-39, the Commission determined that the Real-Time MVP Distribution charge type assessed by MISO was properly includable in Rider No. 68. In the February 24, 2021 Order in Cause No. 42736 RTO-56, the Commission approved the recovery of Schedule 26-C (Cost Recovery For MISO Transmission Owner TEMPS), Schedule 26-D (Cost Recovery For PJM Transmission Owner TEMPS) and Schedule 49 (Cost Allocation For Available System Capacity Usage) costs allocated to the Company through Rider No. 68. In its December 7, 2022 Order in Cause No. 42736 RTO-58, the Commission authorized the Company to recover

MISO Schedule 26-E (Cost Recovery for MISO Transmission Owner IMEPS) under the MISO Tariff in its Rider No. 68 proceedings.

Q. ARE THERE COMPANY-OWNED RECB PROJECTS IN THIS FILING FOR WHICH THE COMPANY IS SEEKING RECOVERY?

A. Yes, the Company has three (3) RECB projects in service as follows: (a) the first phase of a baseline reliability transmission line project spanning approximately four (4) miles and referred to by MISO as Project Number 852 completed in 2009 and the final phase spanning seventeen (17) miles completed in 2013; (b) the Edwardsport 345 kV substation and line project referred to by MISO as Project Number 1263 completed in 2010; and (c) the Dresser substation and transformer project referred to by MISO as Project Number 2050 completed in 2011. In June of 2023, the Company submitted to MISO its revised annual revenue requirement for these projects for changes in the approved return on equity ("ROE"), which totaled $2,739,705, and the Company, as a transmission owner, began receiving updated revenues July 1, 2023. These RECB projects are listed on Attachment 1-G (AJB). The Company, as a transmission customer, also pays MISO its share of the corresponding Schedule 26 costs.

Q. ARE THERE COMPANY-OWNED MVP PROJECTS IN THIS FILING FOR WHICH THE COMPANY IS SEEKING RECOVERY?

A. Yes, the Company has two (2) MISO MVP projects. These two (2) projects consist of three (3) facilities which are comprised of eight (8) separate detail projects. The first detail project went in service May 2018, three (3) went in service June 2018, one (1) went in service June 2019, and one (1) went in service September 2019. The remaining two (2) detail projects were in service by December 2020. The three (3) facilities are as follows:

- MTEP Project ID 2237 is the Sugar Creek to Kansas 345 kV line project known as MISO Facility ID 8313, which consists of four (4) detail projects of which two (2) were in service at the end of 2019 and the final two (2) detail projects were in service by December 2020;
- MTEP Project ID 2202 is the Reconductor Wabash to Wabash Container Section project known as Facility ID 7286, which consists of two (2) detail projects of which both were in service as of June 2018.
- MTEP Project ID 2202 is the Kokomo Delco to Greentown 138 kV Uprate project known as MISO Facility 7287, which consists of two (2) detail projects with the first in service May 2018 and the second in service June 2018.

In June of 2023, the Company submitted to MISO its revised annual revenue requirement for these projects for changes in the approved ROE, which totaled $1,660,279, and the Company, as a transmission owner, began receiving revenues July 1, 2023. These MVP projects are listed on Attachment 1-H (AJB).

Q. HAS THE COMPANY EXCLUDED THE REVENUE RELATED TO THESE RECB AND MVP PROJECTS FROM THIS FILING?

A. Yes, the Company has retained this revenue, as previously ordered by the Commission, and Rider No. 68 costs were not offset by the revenue from these projects.

Q. HAS THE COMPANY EXCLUDED THE REVENUES AND EXPENSES RELATED TO THESE PROJECTS FROM THE FAC EARNINGS TEST?

A. Yes, the Company has excluded the applicable revenues and expenses related to its own RECB and MVP Projects from the FAC Earnings Test. See the direct testimony of Company witness Christa L. Graft in Cause No. 38707 FAC-137, which discusses the adjustments to the Company's Earnings Test to exclude revenues and expenses associated with its own RECB and MVP projects.

III. <u>OVERVIEW OF RIDER NO. 68</u>

Q. PLEASE BRIEFLY DESCRIBE THE NON-FUEL CHARGES AND CREDITS AND TRANSMISSION REVENUES COVERED BY RIDER NO. 68.

A. Under Rider No. 68, the Company will track for recovery from (or credit to) the Company's retail electric customers the following:

- MISO management costs billed to the Company by MISO under Schedules 10 (ISO Cost Recovery Adder) and 10-FERC (FERC Annual Charges Recovery);

- MISO management costs billed to the Company by MISO under Schedule 16 (Financial Transmission Rights Administrative Service Cost Recovery Adder);
- MISO management costs billed to the Company by MISO under Schedule 17 (Energy and Operating Reserve Markets Market Support Administrative Service Cost Recovery Adder);
- Costs billed to the Company by MISO under the MISO Tariff for standard market design which is allocable to the Company's retail electric customers (including charges under Schedule 26, Schedule 26-A, Schedule 26-C, Schedule 26-D, Schedule 26-E, Schedule 49, Real-Time Revenue Neutrality Uplift, Real Time Miscellaneous Amount and Real-Time MVP Distribution Amount);
- Other government mandated transmission costs the Company is required to pay on behalf of its retail electric customers;
- Certain MISO transmission revenues assigned to the Company, collected by MISO under the MISO Tariff, which are allocable to the Company's retail electric customers; and
- Costs billed to the Company by PJM under the PJM Tariff for non-fuel charges or credits applicable to the Company's Ohio-based Madison Generating Station designated as an Indiana resource in MISO (including PJM Scheduling, System Control and Dispatch Service, Reactive Supply and Voltage Control, and Black Start Service).

Q. HAVE ANY NEW NON-FUEL MISO CHARGES OR CREDITS BEEN INCLUDED IN EITHER THE FORECASTED OR RECONCILIATION PERIOD?

A. No.

Q. HAS THE COMPANY ADDRESSED THE NOVEMBER 21, 2019 FERC ORDER ("OPINION NO. 569") IN DOCKET NOS. EL14-12 AND EL14-45 IN THIS FILING?

A. Yes. As reported in prior RTO testimony, Opinion No. 569 lowered the base ROE from 10.32% to 9.88% effective September 28, 2016, and ordered refunds plus interest for the fifteen (15) month period of November 12, 2013 to February 11, 2015 ("First Refund Period") and for the period of September 28, 2016 to the date of the Order ("Second Refund Period"). On December 9, 2019, MISO requested an extension of time to process these refunds, which was granted on December 19, 2019. On December 23, 2019, the MISO Transmission Owners, along with several other parties in the proceeding, submitted requests for rehearing of Opinion No. 569.

On May 21, 2020, FERC issued Opinion No. 569-A, which revised the ROE methodology in Opinion No. 569. Opinion No. 569-A found that the MISO Transmission Owners' base ROE should be set at 10.02% and ordered refunds with interest for the First Refund Period previously defined and the Second Refund Period through the date of Opinion No. 569-A (May 21, 2020).

Prior to the issuance of Opinion No. 569-A, MISO had begun the refund process using the ROE from Opinion No. 569. As a result, on May 28, 2020, MISO announced they were pausing the current resettlement efforts under Opinion No. 569 due to the complexity of the resettlements with the slightly higher ROE under Opinion 569-A. On August 5, 2020, MISO announced that a refund approach had been developed and that the majority of the resettlement dollars would change hands in 2021 and that refunds and adjustments for all applicable periods would be completed by May or June 2022. On September 9, 2020, MISO submitted a request for extension to FERC to approve the timelines outlined above. On October 8, 2020, FERC granted the extension to allow refunds to be completed by September 23, 2021. On June 29, 2021, MISO submitted an additional request to extend the timeline for completion to June 30, 2022. On August 2, 2021, FERC granted a partial extension of the deadline to complete refunds by February 28, 2022. On December 16, 2021, MISO filed another motion requesting an extension from the approved February 28, 2022 deadline to May 31, 2022. Final refund amounts were settled in the January 2022 MISO billing cycle. On April 1, 2022, MISO filed its Compliance Refund Report with FERC under Docket No. EL 14-12. At this time, Duke Energy Indiana has provided all required ROE refunds to its retail customers.

On August 9, 2022, the D.C. Circuit Court of Appeals issued an opinion finding the FERC's use of a "Risk Premium" model as one of the three models to determine a just and reasonable ROE was arbitrary and capricious. As a result, the Court vacated the underlying orders (Opinions Nos. 569-A and 569-B) and remanded for FERC to reopen proceedings. The Company will continue to monitor the remand proceedings as FERC works to issue its orders pursuant to the remand. There were no additional ROE resettlements in this filing.

Duke Energy Indiana anticipates that after FERC issues its orders pursuant to the remand, MISO will resettle the ROE as directed by the new FERC orders. The Company will reflect any further resettlements in future RTO filings as that information becomes known.

Q. PLEASE BRIEFLY DESCRIBE HOW THE FORECASTED MISO COSTS AND TRANSMISSION REVENUES WERE DETERMINED.

A. For purposes of forecasting the Schedule 26 and 26-A charges, the Company started with projected data available from MISO to reflect the charges by other market participants that will be applicable to Duke Energy Indiana. For the remaining charges, credits and revenues, the forecasted amounts were based on a twenty-four (24) month history of these items and then were adjusted for any known or anticipated changes. As the Company becomes more experienced with forecasting these costs, the methods utilized may evolve over time.

Q. PLEASE BRIEFLY DESCRIBE THE RECONCILIATION STEP IN THE RIDER NO. 68 PROCESS.

A. There is a reconciliation step included in the Rider No. 68 process to adjust for (a) any variances between the Company's projected RTO costs and transmission revenues versus actual RTO costs and transmission revenues incurred and (b) variances between the previous RTO tracker amounts by retail rate group authorized for recovery versus the actual RTO revenues collected by retail rate group. The reconciliation in the current proceeding includes the months of July 2022 through June 2023 and is shown in Columns C and D of Attachment 1-B (AJB).

Q. PLEASE BRIEFLY DESCRIBE ANY SPECIAL PROVISIONS FOR COMMISSION APPROVAL OF COSTS COVERED BY RIDER NO. 68, WHICH ARE NOT BILLED BY MISO OR PJM PURSUANT TO THE SPECIFIC APPROVED SCHEDULES.

A. To the extent that any costs to be recovered pursuant to Rider No. 68 are not billed by MISO or PJM to the Company (or a designee of the Company) pursuant to the specifically approved Schedules of the MISO or PJM Tariff, or any successor Tariff, the Company will demonstrate in its applicable annual filing the amount and reasonableness of such costs. No such costs were included in the current filing.

Q. PLEASE BRIEFLY EXPLAIN HOW COSTS OR TRANSMISSION REVENUES THAT ARE NOT ACCOUNTED FOR SEPARATELY FOR THE COMPANY'S RETAIL ELECTRIC CUSTOMERS WILL BE HANDLED UNDER RIDER NO. 68.

A. To the extent that the costs or transmission revenues identified in the formula set forth in the Rider No. 68 Tariff are not accounted for separately for the Company's retail electric customers, then the total Company amount of such costs or transmission revenues, whichever is applicable, will be multiplied by the Commission-approved retail allocator for the applicable period to determine the retail electric jurisdictional portion of such costs or transmission revenues. In Cause No. 45253, the retail allocator for transmission is 100%.

Q. WHAT REVENUE CONVERSION FACTOR IS BEING USED FOR RIDER NO. 68 IN THIS PROCEEDING?

A. The revenue conversion factor used for this proceeding is 1.00429. See Attachment 1-I (AJB) for the underlying calculation of this factor.

IV. PROPOSED RIDER NO. 68 ADJUSTMENT FACTORS

Q. PLEASE EXPLAIN ATTACHMENT 1-A (AJB).

A. Attachment 1-A (AJB) is the Company's proposed revised tariff for Standard Contract Rider No. 68.

Q. HAVE YOU CALCULATED THE PROPOSED RIDER 68 ADJUSTMENT BILLING FACTORS FOR THE VARIOUS RETAIL RATE GROUPS USING THE COST COMPONENTS AND AMOUNTS YOU HAVE DESCRIBED?

A. Yes, I have. Attachment 1-B (AJB) includes projected RTO costs and transmission revenues (Column B) above what is included in base rates and a reconciliation of prior historical amounts (Columns C and D) broken down by retail rate group for those specific MISO and PJM cost components I have discussed in my testimony that were previously approved by the Commission for inclusion in Rider No. 68 rates via the current RTO proceeding. The resulting revenue requirement totals for each retail rate group (except for HLF) (Column E) are divided by the corresponding kWh sales for the twelve (12)-months ended June 30, 2023. For developing the HLF rate, the revenue requirement amount is divided by KW demands for the twelve (12)-months ended June 30, 2023 to determine the proposed Rider No. 68 rate. These factors by respective retail rate groups are then reflected on Page 3 of 3 of Attachment 1-A (AJB). The total amount that the Company proposes to be credited to the Company's retail electric customers through Rider No. 68, taking into account the reconciliation amount, is $6,810,114.

The prefiled testimony of Mr. James (Brad) Daniel, Attachment 2-A (JBD), supports the reasonableness of the Company's MISO Energy Markets and ASM and PJM non-fuel related charges and credits.

Q. PLEASE PROVIDE AN UPDATE ON THE MISO HURRICANE LAURA MAXIMUM GENERATION EMERGENCY EVENT AND THE COST ASSESSED TO DUKE ENERGY INDIANA.

A. As discussed in previous RTO filings, on August 27, 2020, MISO declared a Maximum Generation Emergency Event in response to Hurricane Laura causing system instability and threatening the reliability of the grid, directing the shedding of firm load in the affected area of western Louisiana and eastern Texas.

During the Hurricane Laura Maximum Generation Emergency Event, MISO implemented an Energy Emergency Alert 3 event, which triggered the Value of Lost Load ("VOLL") to be set at $3,500/MWh and applied to the congestion component of the Locational Marginal Price ("LMP"). This created $86 million in Real Time Congestion charges that were uplifted to the market through the Revenue Neutrality charge type. These charges were then distributed to Asset Owners through the Revenue Neutrality Uplift ("RNU") based on Load Ratio Share. Duke Energy Indiana's share was approximately $3.9 million.

Duke Energy Indiana worked with other market participants located in the Central and North Regions of MISO to argue that MISO applied its Tariff inappropriately. Duke Energy Indiana also filed an Alternative Dispute Resolution ("ADR") on March 26, 2021. On August 12, 2021, MISO issued a resettlement to the market for August 27, 2020 for a correction of the dead bus pricing between DA and RT markets, resulting in a credit of $369,677, which has already been flowed through to the Company's customers.

On September 30, 2022, MISO issued a final determination letter denying Duke Energy Indiana's ADR request as MISO has determined the application of VOLL pricing to the Hurricane Laura Load Pocket ("HLLP") in connection with the August 27, 2020 Hurricane Laura event was consistent with MISO's tariff. No further action is being taken by Duke Energy Indiana at this time.

Q. WAS THERE ANY SINGLE ADJUSTMENT IN EXCESS OF $3 MILLION INCLUDED IN THIS PROCEEDING?[1]

A. No.

[1] In Cause No. 42736 RTO-13, the Company defined the term "single adjustment" as an adjustment that is unique and/or non-recurring and outside the routine settlement and Post Analysis Cost Evaluator ("PACE") process described in testimony in the Company's FAC proceedings (Petitioner's Attachment A, p. 23). Since 2015, the PACE process is administered by the Sumatra model.

Q. PLEASE EXPLAIN ATTACHMENT 1-C (AJB).

A. Attachment 1-C (AJB) compares the forecasted non-fuel RTO costs and transmission revenues for the forecasted periods of January 2024 through December 2024 to the Company's annual charges built into base retail electric rates in Cause No. 45253. The total to be recovered from (or credited to) customers is shown on Attachment 1-B (AJB), Column (B).

Q. PLEASE EXPLAIN ATTACHMENT 1-D (AJB).

A. Attachment 1-D (AJB) compares the previously projected RTO non-fuel costs and transmission revenues (developed in RTO 57 and 58) to actual non-fuel costs and transmission revenues incurred during the reconciliation period of July 2022 through June 2023. The total to be recovered from (or credited to) customers from this portion of the reconciliation is shown on Attachment 1-B (AJB), Column (C).

Q. PLEASE EXPLAIN ATTACHMENT 1-E (AJB).

A. Attachment 1-E (AJB) compares the actual amount of Rider No. 68 amounts charged (or credited) to customers at the retail rate group level to the amounts approved by the Commission for recovery during the reconciliation periods of July 2022 through June 2023. The total to be recovered from (or credited to) customers for this item is shown on Attachment 1-B (AJB), Column (D).

Q. PLEASE EXPLAIN ATTACHMENT 1-F (AJB).

A. Attachment 1-F (AJB) compares the bill of a typical residential customer using 1000 kilowatt-hours per month based upon the proposed Rider No. 68 adjustment factor to the bill of a typical residential customer using 1000 kilowatt-hours per month based upon the most recently approved rate. Under the proposed Rider No. 68 adjustment, a typical residential customer will experience a decrease on his or her electric bill of $0.49 or 0.37% when compared to the bills reflecting the current Rider No. 68 rate.

Q. PLEASE EXPLAIN ATTACHMENT 1-G (AJB).

A. Attachment 1-G (AJB) provides information relating to Company-owned, MISO-approved RECB projects and provides an estimate of Schedule 26 costs to be allocated to the Company based on information provided by MISO.

Q. PLEASE EXPLAIN ATTACHMENT 1-H (AJB).

A. Attachment 1-H (AJB) provides information relating to Company-owned, MISO-approved MVP projects and provides an estimate of Schedule 26-A costs to be allocated to the Company based on information provided by MISO.

Q. PLEASE EXPLAIN ATTACHMENT 1-I (AJB).

A. Attachment 1-I (AJB) shows the calculation of the revenue conversion factor being used in this proceeding.

Q. PLEASE EXPLAIN ATTACHMENTS 1-J (AJB) AND 1-K (AJB).

A. The standard format for Duke Energy Indiana filings (labeled as Attachment 1-J (AJB) in this proceeding) and the Workpaper Listing (labeled as Attachment 1-K (AJB) in this proceeding) were updated to reflect my Testimony and Workpapers.

V. CONCLUSION

Q. WHAT REVISIONS TO THE COMPANY'S RETAIL ELECTRIC TARIFF ARE BEING PROPOSED TO REFLECT THE RIDER NO. 68 TREATMENT PROPOSED IN THIS PROCEEDING?

A. The Company is proposing to revise its current Standard Contract Rider No. 68, Fourth Revised Sheet No. 68, Page 1 through Page 3, as reflected in Attachment 1-A (AJB), Pages 1 through 3. The Company requests that the Commission find that the Rider No. 68 adjustment factors for the Company's bills rendered beginning with the January 2024 – Cycle 1 billing cycle, or the date of the Commission's Order if later, for the Company's retail electric customers should be as set forth on page 3 of Attachment 1-A (AJB).

Q. WERE ATTACHMENTS 1-A (AJB) THROUGH 1-K (AJB) PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, it does.

DUKE ENERGY INDIANA, LLC
1000 E. Main Street
Plainfield, IN 46168

STANDARD CONTRACT RIDER NO. 68 - REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COSTS AND REVENUE ADJUSTMENT

The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased for operation and maintenance expense treatment of RTO Non-Fuel Costs and Revenues. The revenue adjustment to the applicable charges for electric service will be determined under the following provision:

Calculation of Adjustment

A. The RTO Non-Fuel Costs and Revenue Adjustment by Rate Group shall be determined by multiplying the RTO Non-Fuel Costs and Revenue Adjustment Factor, as determined to the nearest 0.001 mill ($0.000001) per kilowatt-hour in accordance with the following formula, by the monthly billed kilowatt-hours for the applicable billing cycle months in the case of customers receiving metered service and by the estimated monthly kilowatt-hours used for rate determination in the case of customers receiving unmetered service. RTO Non-Fuel Costs and Revenue Adjustment Factor Per Rate Group =

$$\frac{(NFC - (a - b)\ c)\ d}{s}$$

where:

1. "NFC" is the net Non-Fuel Costs and Credits forecasted to be billed Duke Energy Indiana, LLC, or a designee of Duke for mandated participation in regional transmission organizations under the Open Access Transmission and Energy Markets Tariff for the MISO ("MISO TEMT") or any successor Tariff, including applicable PJM non-fuel charges and credits related to the operation of Duke Energy Indiana's Madison Generating Station.

2. "a" is the annual level of forecasted RTO Non-Fuel Costs included in the determination of basic charges for service in Cause No. 45253 ($59,998,000).

3. "b" is the annual level of forecasted RTO transmission revenues included in the determination of basic charges for service in Cause No. 45253 ($23,540,000).

4. "c" is the individual retail rate group's allocated share of the Company's retail peak demand developed for cost of service purposes in Cause No. 45253 expressed as a percentage of the Company's total retail peak demand.

5. "d" is the revenue conversion factor used to convert the applicable charges to operating revenues.

6. "s" is the individual retail rate group's reported kilowatt-hour sales for the twelve-month period from July through June as a proxy for the relevant billing cycle months for all retail rate groups other than retail customers served under Rate HLF. The revenue adjustment for retail customers served under Rate HLF shall be based on demands within the Rate HLF customer group such that "s" shall be the sum of kilowatts billed for the applicable twelve-month period.

7. The RTO Non-Fuel Costs and Revenue Adjustment Factor per Rate Group shall be further modified to reflect the difference between the incremental base monthly fees actually charged or credited to the retail electric customers and the incremental base monthly fees to be charged or credited to the retail electric customers during billing cycle months, as determined above.

Duke Energy Indiana, LLC
1000 East Main Street
Plainfield, Indiana 46168

STANDARD CONTRACT RIDER NO. 68 -
REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COSTS AND REVENUE ADJUSTMENT
APPLICABLE TO RETAIL RATE GROUPS

ALLOCATED SHARE OF SYSTEM PEAK DEMAND FOR RETAIL CUSTOMERS
BY RATE GROUP EXPRESSED AS A PERCENTAGE OF THE COMPANY'S
TOTAL RETAIL SYSTEM PEAK DEMAND AS DEVELOPED FOR COST OF
SERVICE PURPOSES IN CAUSE NO. 45253

Line No.	Rate Groups	KW Share of System Peak (4CP) Per Cause No. 45253 (A)	Percent Share Of System Peak (B)	Line No.
1	Rate RS	2,102,591	42.114%	1
2	Rates CS and FOC	258,053	5.169%	2
3	Rate LLF	1,034,546	20.722%	3
4	Rate HLF	1,536,449	30.774%	4
5	Customer L	14,800	0.296%	5
6	Customer O	18,584	0.372%	6
7	Rate WP	20,717	0.415%	7
8	Rate SL	79	0.002%	8
9	Rate MHLS	15	0.000%	9
10	Rates MOLS and UOLS	5,633	0.113%	10
11	Rates TS, FS and MS	1,141	0.023%	11
12	TOTAL RETAIL	4,992,608	100.000%	12

Issued: Pending

Effective:

Duke Energy Indiana, LLC
1000 East Main Street
Plainfield, Indiana 46168

IURC No. 15
Fifth Revised Sheet No. 68
Cancels and Supersedes
Fourth Revised Sheet No. 68

STANDARD CONTRACT RIDER NO. 68 -
REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COSTS AND REVENUE ADJUSTMENT
APPLICABLE TO RETAIL RATE GROUPS

Line No.	Retail Rate Group	RTO Non-Fuel Cost and Revenue Adjustment Factor Per KWH (A)	RTO Non-Fuel Cost and Revenue Adjustment Factor Per Non-Coincident KW (B)	Line No.
1	Rate RS	($0.000322)		1
2	Rates CS and FOC	(0.000354)		2
3	Rate LLF	(0.000280)		3
4	Rate HLF		($0.113947)	4
5	Customer L	(0.000843)		5
6	Customer O	(0.000159)		6
7	Rate WP	(0.000183)		7
8	Rate SL	0.000002		8
9	Rate MHLS	(0.000008)		9
10	Rates MOLS and UOLS	(0.000073)		10
11	Rates TS, FS and MS	(0.000263)		11

Issued: Pending

Effective:

DUKE ENERGY INDIANA, LLC

DETERMINATION OF THE REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COST AND REVENUE ADJUSTMENT FACTORS BY RATE GROUP
TO BE APPLIED TO CUSTOMER BILLS OVER A TWELVE MONTH PERIOD

Line No.	Retail Rate Group Description	Allocated Percentage Share of Retail Peak Demands for the Company's Retail Electric Customers Approved in IURC Cause No. 45253	Projected RTO Non-Fuel Costs and Revenues By Rate Group for Calendar Year 2024 to be Collected through Standard Contract Rider No. 68 _1/	Reconciliation of Amounts Projected for RTO Non-Fuel Costs and Revenues vs. Actual Amounts Incurred for the July 2022 through June 2023 Period	Reconciliation of RTO Non-Fuel Costs and Revenues Approved for Recovery vs. Actual RTO Revenues Collected for the July 2022 through June 2023 Period	Total	Actual Kilowatt-Hour Sales For The Twelve Months Ended June 30, 2023	RTO Non-Fuel Costs and Revenue Adjustment Factors Per Kilowatt-Hour By Rate Group	Actual Sum of Monthly Non-Coincident Peak Demands for the Twelve Months Ended June 30, 2023	RTO Non-Fuel Costs and Revenue Adjustment Factors Per Non-Coincident Peak Demands	Line No.
		(A)	(B)	(C)	(D)	(E) (B)+(C)+(D)+(E)	(F)	(G)	(H)	(I)	
1	Rate RS	42.114%	$ 719,010	$ (3,617,281)	$ 55,937	$ (2,842,334)	8,833,258,591	($0.000322)			1
2	Rates CS	5.169%	88,250	(443,979)	51,555	(304,174)	859,505,809	($0.000354)			2
3	Rate LLF	20.722%	353,785	(1,779,866)	(64,898)	(1,490,979)	5,322,219,297	($0.000280)			3
4	Rate HLF	30.774%	525,402	(2,643,259)	94,366	(2,023,491)	9,267,629,034		17,758,159	($0.113947)	4
5	Customer L	0.296%	5,054	(25,424)	(65,882)	(86,252)	102,305,590	($0.000843)			5
6	Customer O	0.372%	6,351	(31,952)	518	(25,083)	157,614,830	($0.000159)			6
7	Rate WP	0.415%	7,085	(35,645)	(624)	(29,184)	159,414,058	($0.000183)			7
8	Rate SL	0.002%	34	(172)	210	72	35,195,559	$0.000002			8
9	Rate MHLS	0.000%	-	-	(33)	(33)	4,336,269	($0.000008)			9
10	Rates MOLS and UOLS	0.113%	1,929	(9,706)	900	(6,877)	94,757,411	($0.000073)			10
11	Rates TS, FS and MS	0.023%	393	(1,976)	(196)	(1,779)	6,769,937	($0.000263)			11
12	**TOTAL RETAIL**	100.000%	$ 1,707,293	$ (8,589,260)	$ 71,853	$ (6,810,114)	24,843,006,385				12

_1/ The retail allocation percentages in Column (A) were used to calculate the amounts per Retail Rate Group for the projection of non-fuel costs and transmission revenues shown on Line 12 in Column (B) and Column (C).

DUKE ENERGY INDIANA, LLC

DETERMINATION OF THE FORECASTED REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COSTS AND REVENUES
TO BE RECOVERED OR CREDITED THROUGH RIDER 68 FOR THE TWELVE MONTHS ENDED DECEMBER 2024

Line No.	Description	January 2024	February 2024	March 2024	April 2024	May 2024	June 2024	July 2024	August 2024	September 2024	October 2024	November 2024	December 2024	Total	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M) SUM (A) - (L)	
	Forecasted RTO Non-Fuel Costs & Transmission Revenues														
	Non-Fuel Costs														
1	Schedule 10 FERC	216,667	216,667	216,666	216,667	216,667	216,666	216,667	216,667	216,666	216,667	216,667	216,666	2,600,000	1
2	Schedule 10	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	6,000,000	2
3	Schedule 16	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	150,000	3
4	Schedule 17	391,667	391,667	391,666	391,667	391,667	391,666	391,667	391,667	391,666	391,667	391,667	391,666	4,700,000	4
5	Real Time Miscellaneous	83,333	83,333	83,334	83,333	83,333	83,334	83,333	83,333	83,334	83,333	83,333	83,334	1,000,000	5
6	Real Time Revenue Neutrality Uplift Amount	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	7,200,000	6
7	Real Time MVP Distribution Amount	(83,333)	(83,333)	(83,334)	(83,333)	(83,333)	(83,334)	(83,333)	(83,333)	(83,334)	(83,333)	(83,333)	(83,334)	(1,000,000)	7
8	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	833,333	833,333	833,334	833,333	833,333	833,334	833,333	833,333	833,334	833,333	833,333	833,334	10,000,000	8
9	Schedule 26 A - Multi-Value Projects	3,708,333	3,708,333	3,708,334	3,708,333	3,708,333	3,708,334	3,708,333	3,708,333	3,708,334	3,708,333	3,708,333	3,708,334	44,500,000	9
10	Schedule 26 C	1,667	1,667	1,666	1,667	1,667	1,666	1,667	1,667	1,666	1,667	1,667	1,666	20,000	10
11	Schedule 26 D	833	833	834	833	833	834	833	833	834	833	833	834	10,000	11
12	Schedule 26 E	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	78,000	12
13	Schedule 49	91,667	91,667	91,666	91,667	91,667	91,666	91,667	91,667	91,666	91,667	91,667	91,666	1,100,000	13
14	PJM Madison Non-Fuel	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	1,800,000	14
15	Total RTO Non-Fuel Costs	6,513,167	6,513,167	6,513,166	6,513,167	6,513,167	6,513,166	6,513,167	6,513,167	6,513,166	6,513,167	6,513,167	6,513,166	78,158,000	15
16	*Transmission Revenues*	(3,333,333)	(3,333,333)	(3,333,334)	(3,333,333)	(3,333,333)	(3,333,334)	(3,333,333)	(3,333,333)	(3,333,334)	(3,333,333)	(3,333,333)	(3,333,334)	(40,000,000)	16
17	Total Non-Fuel Costs & Transmission Revenues	3,179,834	3,179,834	3,179,832	3,179,834	3,179,834	3,179,832	3,179,834	3,179,834	3,179,832	3,179,834	3,179,834	3,179,832	38,158,000	17
	Amounts Included in Base Rates														
	Non-Fuel Costs														
18	Schedule 10 FERC	211,583	211,583	211,584	211,583	211,583	211,584	211,583	211,583	211,584	211,583	211,583	211,584	2,539,000	18
19	Schedule 10	482,417	482,417	482,416	482,417	482,417	482,416	482,417	482,417	482,416	482,417	482,417	482,416	5,789,000	19
20	Schedule 16	26,917	26,917	26,916	26,917	26,917	26,916	26,917	26,917	26,916	26,917	26,917	26,916	323,000	20
21	Schedule 17	528,333	528,333	528,334	528,333	528,333	528,334	528,333	528,333	528,334	528,333	528,333	528,334	6,340,000	21
22	Real Time Miscellaneous	-	-	-	-	-	-	-	-	-	-	-	-	-	22
23	Real Time Revenue Neutrality Uplift Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	23
24	Real Time MVP Distribution Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	24
25	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	673,583	673,583	673,584	673,583	673,583	673,584	673,583	673,583	673,584	673,583	673,583	673,584	8,083,000	25
26	Schedule 26 A - Multi-Value Projects	3,077,000	3,077,000	3,077,000	3,077,000	3,077,000	3,077,000	3,077,000	3,077,000	3,077,000	3,077,000	3,077,000	3,077,000	36,924,000	26
27	Schedule 26 C	-	-	-	-	-	-	-	-	-	-	-	-	-	27
28	Schedule 26 D	-	-	-	-	-	-	-	-	-	-	-	-	-	28
29	Schedule 26 E	-	-	-	-	-	-	-	-	-	-	-	-	-	29
30	Schedule 49	-	-	-	-	-	-	-	-	-	-	-	-	-	30
31	PJM Madison Non-Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	31
32	Total RTO Non-Fuel Costs	4,999,833	4,999,833	4,999,834	4,999,833	4,999,833	4,999,834	4,999,833	4,999,833	4,999,834	4,999,833	4,999,833	4,999,834	59,998,000	32
33	*Transmission Revenues*	(1,961,667)	(1,961,667)	(1,961,666)	(1,961,667)	(1,961,667)	(1,961,666)	(1,961,667)	(1,961,667)	(1,961,666)	(1,961,667)	(1,961,667)	(1,961,666)	(23,540,000)	33
34	Total Non-Fuel Costs & Transmission Revenues	3,038,166	3,038,166	3,038,168	3,038,166	3,038,166	3,038,168	3,038,166	3,038,166	3,038,168	3,038,166	3,038,166	3,038,168	36,458,000	34
	Net Forecasted RTO Non-Fuel Costs & Transmission Revenues														
	Non-Fuel Costs														
35	Schedule 10 FERC	5,084	5,084	5,082	5,084	5,084	5,082	5,084	5,084	5,082	5,084	5,084	5,082	61,000	35
36	Schedule 10	17,583	17,583	17,584	17,583	17,583	17,584	17,583	17,583	17,584	17,583	17,583	17,584	211,000	36
37	Schedule 16	(14,417)	(14,417)	(14,416)	(14,417)	(14,417)	(14,416)	(14,417)	(14,417)	(14,416)	(14,417)	(14,417)	(14,416)	(173,000)	37
38	Schedule 17	(136,666)	(136,666)	(136,668)	(136,666)	(136,666)	(136,668)	(136,666)	(136,666)	(136,668)	(136,666)	(136,666)	(136,668)	(1,640,000)	38
39	Real Time Miscellaneous	83,333	83,333	83,334	83,333	83,333	83,334	83,333	83,333	83,334	83,333	83,333	83,334	1,000,000	39
40	Real Time Revenue Neutrality Uplift Amount	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	7,200,000	40
41	Real Time MVP Distribution Amount	(83,333)	(83,333)	(83,334)	(83,333)	(83,333)	(83,334)	(83,333)	(83,333)	(83,334)	(83,333)	(83,333)	(83,334)	(1,000,000)	41
42	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	159,750	159,750	159,750	159,750	159,750	159,750	159,750	159,750	159,750	159,750	159,750	159,750	1,917,000	42
43	Schedule 26 A - Multi-Value Projects	631,333	631,333	631,334	631,333	631,333	631,334	631,333	631,333	631,334	631,333	631,333	631,334	7,576,000	43
44	Schedule 26 C	1,667	1,667	1,666	1,667	1,667	1,666	1,667	1,667	1,666	1,667	1,667	1,666	20,000	44
45	Schedule 26 D	833	833	834	833	833	834	833	833	834	833	833	834	10,000	45
46	Schedule 26 E	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	78,000	46
47	Schedule 49	91,667	91,667	91,666	91,667	91,667	91,666	91,667	91,667	91,666	91,667	91,667	91,666	1,100,000	47
48	PJM Madison Non-Fuel	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	1,800,000	48
49	Total RTO Non-Fuel Costs	1,513,334	1,513,334	1,513,332	1,513,334	1,513,334	1,513,332	1,513,334	1,513,334	1,513,332	1,513,334	1,513,334	1,513,332	18,160,000	49
50	*Transmission Revenues*	(1,371,666)	(1,371,666)	(1,371,668)	(1,371,666)	(1,371,666)	(1,371,668)	(1,371,666)	(1,371,666)	(1,371,668)	(1,371,666)	(1,371,666)	(1,371,668)	(16,460,000)	50
51	Total Non-Fuel Costs & Transmission Revenues	141,668	141,668	141,664	141,668	141,668	141,664	141,668	141,668	141,664	141,668	141,668	141,664	1,700,000	51
52	Revenue Conversion Factor													1.00429	52
53	Amount to be Collected (Credited) Through Rider													1,707,293	53

DUKE ENERGY INDIANA, LLC

RECONCILIATION OF AMOUNTS FORECASTED FOR REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COSTS AND REVENUES VERSUS ACTUAL AMOUNTS INCURRED FOR THE JULY 2022 THROUGH JUNE 2023 PERIOD

Line No.	Description	RTO 57 July 2022 (A)	August 2022 (B)	September 2022 (C)	October 2022 (D)	November 2022 (E)	December 2022 (F)	Sub-Total (G) Sum (A) to (F)	RTO 58 January 2023 (H)	February 2023 (I)	March 2023 (J)	April 2023 (K)	May 2023 (L)	June 2023 (M)	Sub-Total (N) Sum (H) to (M)	Total (O) (G)+(N)	Line No.
	Actual RTO Non-Fuel Costs & Transmission Revenues																
	Non-Fuel Costs																
1	Schedule 10 FERC	277,103	301,609	246,963	232,692	173,184	186,825	1,418,376	241,610	200,999	187,703	192,194	160,088	205,416	1,188,010	2,606,386	1
2	Schedule 10	531,281	527,746	549,324	288,837	389,335	453,084	2,739,607	512,609	335,354	349,858	525,364	513,969	387,088	2,624,242	5,363,849	2
3	Schedule 16	21,537	10,444	11,239	8,503	8,335	11,359	71,417	13,173	13,699	9,508	10,606	10,849	12,610	70,445	141,862	3
4	Schedule 17	604,454	307,750	422,825	279,905	388,971	368,426	2,372,331	325,880	405,559	353,294	365,006	366,903	432,474	2,249,116	4,621,447	4
5	Real Time Miscellaneous	3,302	(5,125)	17,821	1,102,399	(46,896)	(35,607)	1,035,894	107,883	30,124	130	(220,455)	12,536	65	(69,717)	966,177	5
6	Real Time Revenue Neutrality Uplift Amount	865,333	(75,922)	421,055	452,577	(262,294)	(711,020)	689,729	(258,344)	(26,214)	1,071,468	1,039,905	497,839	684,173	3,008,827	3,698,556	6
7	Real Time MVP Distribution Amount	(28,941)	(29,081)	(29,304)	(24,795)	(23,986)	(24,518)	(160,625)	(113,455)	(113,735)	(114,912)	(78,712)	(76,072)	(76,616)	(573,502)	(734,127)	7
8	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	848,414	929,603	861,067	811,128	605,139	656,755	4,712,106	846,174	690,300	646,284	660,370	545,354	700,571	4,089,053	8,801,159	8
9	Schedule 26 A - Multi-Value Projects	3,938,992	4,407,073	4,353,772	3,538,640	3,304,654	3,307,565	22,850,696	3,715,412	4,100,747	3,669,927	3,585,828	3,204,862	3,478,344	21,755,120	44,605,816	9
10	Schedule 26 C	1,706	1,769	1,710	1,731	1,735	1,720	10,371	1,676	1,371	1,409	1,415	1,402	1,402	8,675	19,046	10
11	Schedule 26 D	967	1,003	970	982	983	972	5,877	949	627	647	648	646	643	4,160	10,037	11
12	Schedule 26 E	500	518	501	507	509	504	3,039	491	6,560	6,625	6,778	6,629	6,714	33,797	36,836	12
13	Schedule 49	79,064	76,304	89,002	119,330	88,807	97,285	549,792	99,257	88,321	77,250	276,843	113,845	122,387	777,903	1,327,695	13
14	PJM Madison Non-Fuel	148,547	161,614	145,897	132,771	128,150	136,036	853,015	144,003	131,346	118,557	148,390	147,701	153,920	843,917	1,696,932	14
15	Total RTO Non-Fuel Costs	7,292,259	6,615,305	7,092,842	6,945,207	4,756,626	4,449,386	37,151,625	5,637,318	5,865,058	6,377,748	6,514,180	5,506,551	6,109,191	36,010,046	73,161,671	15
16	*Transmission Revenues*	(4,382,222)	(3,403,685)	(3,565,850)	(2,900,372)	(2,792,650)	(4,173,020)	(21,217,799)	(3,072,465)	(3,262,604)	(2,939,454)	(2,687,016)	(2,951,067)	(3,566,835)	(18,479,441)	(39,697,240)	16
17	Total Non-Fuel Costs & Transmission Revenues	2,910,037	3,211,620	3,526,992	4,044,835	1,963,976	276,366	15,933,826	2,564,853	2,602,454	3,438,294	3,827,164	2,555,484	2,542,356	17,530,605	33,464,431	17
18	Less: Amount in Base Rates	3,038,166	3,038,166	3,038,168	3,038,166	3,038,166	3,038,168	18,229,000	3,038,166	3,038,166	3,038,168	3,038,166	3,038,166	3,038,168	18,229,000	36,458,000	18
19	Net Total Actual	(128,129)	173,454	488,824	1,006,669	(1,074,190)	(2,761,802)	(2,295,174)	(473,313)	(435,712)	400,126	788,998	(482,682)	(495,812)	(698,395)	(2,993,569)	19
	Forecasted RTO Non-Fuel Costs & Transmission Revenues																
	Non-Fuel Costs																
20	Schedule 10 FERC	200,000	200,000	200,000	200,000	200,000	200,000	1,200,000	216,666	216,667	216,667	216,666	216,667	216,667	1,300,000	2,500,000	20
21	Schedule 10	475,000	475,000	475,000	475,000	475,000	475,000	2,850,000	500,000	500,000	500,000	500,000	500,000	500,000	3,000,000	5,850,000	21
22	Schedule 16	16,667	16,667	16,666	16,667	16,667	16,666	100,000	12,500	12,500	12,500	12,500	12,500	12,500	75,000	175,000	22
23	Schedule 17	416,667	416,667	416,666	416,667	416,667	416,666	2,500,000	391,666	391,667	391,667	391,666	391,667	391,667	2,350,000	4,850,000	23
24	Real Time Miscellaneous	-	-	-	-	-	-	-	83,333	83,333	83,334	83,333	83,333	83,334	500,000	500,000	24
25	Real Time Revenue Neutrality Uplift Amount	383,333	383,333	383,334	383,333	383,333	383,334	2,300,000	750,000	750,000	750,000	750,000	750,000	750,000	4,500,000	6,800,000	25
26	Real Time MVP Distribution Amount	(12,500)	(12,500)	(12,500)	(12,500)	(12,500)	(12,500)	(75,000)	(12,500)	(12,500)	(12,500)	(12,500)	(12,500)	(12,500)	(75,000)	(150,000)	26
27	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	625,000	625,000	625,000	625,000	625,000	625,000	3,750,000	833,333	833,333	833,334	833,333	833,333	833,334	5,000,000	8,750,000	27
28	Schedule 26 A - Multi-Value Projects	3,766,667	3,766,667	3,766,666	3,766,667	3,766,667	3,766,666	22,600,000	3,708,333	3,708,333	3,708,334	3,708,333	3,708,333	3,708,334	22,250,000	44,850,000	28
29	Schedule 26 C	1,333	1,333	1,334	1,333	1,333	1,334	8,000	1,666	1,667	1,667	1,666	1,667	1,667	10,000	18,000	29
30	Schedule 26 D	667	667	666	667	667	666	4,000	833	833	834	833	833	834	5,000	9,000	30
31	Schedule 26 E	-	-	-	-	-	-	-	500	500	500	500	500	500	3,000	3,000	31
32	Schedule 49	10,333	10,333	10,334	10,333	10,333	10,334	62,000	50,000	50,000	50,000	50,000	50,000	50,000	300,000	362,000	32
33	PJM Madison Non-Fuel	125,000	125,000	125,000	125,000	125,000	125,000	750,000	125,000	125,000	125,000	125,000	125,000	125,000	750,000	1,500,000	33
34	Total RTO Non-Fuel Costs	6,008,167	6,008,167	6,008,166	6,008,167	6,008,167	6,008,166	36,049,000	6,661,330	6,661,333	6,661,337	6,661,330	6,661,333	6,661,337	39,968,000	76,017,000	34
35	*Transmission Revenues*	(2,333,333)	(2,333,333)	(2,333,334)	(2,333,333)	(2,333,333)	(2,333,334)	(14,000,000)	(3,333,333)	(3,333,333)	(3,333,334)	(3,333,333)	(3,333,333)	(3,333,334)	(20,000,000)	(34,000,000)	35
36	Total Non-Fuel Costs & Transmission Revenues	3,674,834	3,674,834	3,674,832	3,674,834	3,674,834	3,674,832	22,049,000	3,327,997	3,328,000	3,328,003	3,327,997	3,328,000	3,328,003	19,968,000	42,017,000	36
37	Less: Amount in Base Rates	3,038,166	3,038,166	3,038,168	3,038,166	3,038,166	3,038,168	18,229,000	3,038,166	3,038,166	3,038,168	3,038,166	3,038,166	3,038,168	18,229,000	36,458,000	37
38	Net Total Actual	636,668	636,668	636,664	636,668	636,668	636,664	3,820,000	289,831	289,834	289,835	289,831	289,834	289,835	1,739,000	5,559,000	38
	Under (Over) Collected																
	Non-Fuel Costs																
39	Schedule 10 FERC	77,103	101,609	46,963	32,692	(26,816)	(13,175)	218,376	24,944	(15,668)	(28,964)	(24,472)	(56,579)	(11,251)	(111,990)	106,386	39
40	Schedule 10	56,281	52,746	74,324	(186,163)	(85,665)	(21,916)	(110,393)	12,609	(164,646)	(150,142)	25,364	13,969	(112,912)	(375,758)	(486,151)	40
41	Schedule 16	4,870	(6,223)	(5,427)	(8,164)	(8,332)	(5,307)	(28,583)	673	1,199	(2,992)	(1,894)	(1,651)	110	(4,555)	(33,138)	41
42	Schedule 17	187,787	(108,917)	6,159	(136,762)	(27,696)	(48,240)	(127,669)	(65,786)	13,892	(38,373)	(26,660)	(24,764)	40,807	(100,884)	(228,553)	42
43	Real Time Miscellaneous	3,302	(5,125)	17,821	1,102,399	(46,896)	(35,607)	1,035,894	24,550	(53,209)	(83,204)	(303,788)	(70,797)	(83,269)	(569,717)	466,177	43
44	Real Time Revenue Neutrality Uplift Amount	482,000	(459,255)	37,721	69,244	(645,627)	(1,094,354)	(1,610,271)	(1,008,344)	(776,214)	321,468	289,905	(252,161)	(65,827)	(1,491,173)	(3,101,444)	44
45	Real Time MVP Distribution Amount	(16,441)	(16,581)	(16,804)	(12,295)	(11,486)	(12,018)	(85,625)	(100,955)	(101,235)	(102,412)	(66,212)	(63,572)	(64,116)	(498,502)	(584,127)	45
46	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	223,414	304,603	236,067	186,128	(19,861)	31,755	962,106	12,841	(143,033)	(187,050)	(172,963)	(287,979)	(132,763)	(910,947)	51,159	46
47	Schedule 26 A - Multi-Value Projects	172,325	640,406	587,106	(228,027)	(462,013)	(459,101)	250,696	7,079	392,414	(38,407)	(122,505)	(503,471)	(229,990)	(494,880)	(244,184)	47
48	Schedule 26 C	373	436	376	398	402	386	2,371	10	(296)	(258)	(251)	(265)	(265)	(1,325)	1,046	48
49	Schedule 26 D	300	336	304	315	316	306	1,877	116	(206)	(187)	(185)	(187)	(191)	(840)	1,037	49
50	Schedule 26 E	500	518	501	507	509	504	3,039	(9)	6,060	6,125	6,278	6,129	6,214	30,797	33,836	50
51	Schedule 49	68,731	65,971	78,668	108,997	78,474	86,951	487,792	49,257	38,321	27,250	226,843	63,845	72,387	477,903	965,695	51
52	PJM Madison Non-Fuel	23,547	36,614	20,897	7,771	3,150	11,036	103,015	19,003	6,346	(6,443)	23,390	22,701	28,920	93,917	196,932	52
53	Total RTO Non-Fuel Costs	1,284,092	607,138	1,084,676	937,040	(1,251,541)	(1,558,780)	1,102,625	(1,024,012)	(796,275)	(283,589)	(147,150)	(1,154,782)	(552,146)	(3,957,954)	(2,855,329)	53
54	*Transmission Revenues*	(2,048,889)	(1,070,352)	(1,232,516)	(567,039)	(459,317)	(1,839,686)	(7,217,799)	260,868	70,729	393,880	646,317	382,266	(233,501)	1,520,559	(5,697,240)	54
55	Total Non-Fuel Costs & Transmission Revenues	(764,797)	(463,214)	(147,840)	370,001	(1,710,858)	(3,398,466)	(6,115,174)	(763,144)	(725,546)	110,291	499,167	(772,516)	(785,647)	(2,437,395)	(8,552,569)	55
56	Less: Amount in Base Rates	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	56
57	Net Total Actual	(764,797)	(463,214)	(147,840)	370,001	(1,710,858)	(3,398,466)	(6,115,174)	(763,144)	(725,546)	110,291	499,167	(772,516)	(785,647)	(2,437,395)	(8,552,569)	57
58	Revenue Conversion Factor															1.00429	58
59	Amount to be Collected (Credited) Through Rider															(8,589,260)	59

DUKE ENERGY INDIANA, LLC

RECONCILIATION OF THE REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COSTS AND REVENUES TO BE RECOVERED OR CREDITED THROUGH RIDER NO. 68 VERSUS WHAT WAS ACTUALLY COLLECTED FROM CUSTOMERS

Line No.	Description	RTO 57 July 2022	August 2022	September 2022	October 2022	November 2022	December 2022	Sub-Total	RTO 58 January 2023	February 2023	March 2023	April 2023	May 2023	June 2023	Sub-Total	Total	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G) Sum (A) to (F)	(H)	(I)	(J)	(K)	(L)	(M)	(N) Sum (H) to (M)	(O) (G)+(N)	
	Rider Revenues Approved for Recovery																
1	Rate RS	132,154	132,153	132,154	132,153	132,154	132,153	792,921	135,199	135,198	135,199	135,198	135,199	135,198	811,191	1,604,112	1
2	Rate CS	20,790	20,791	20,790	20,791	20,790	20,791	124,743	17,369	17,370	17,369	17,370	17,369	17,370	104,217	228,960	2
3	Rate LLF	90,689	90,689	90,689	90,689	90,689	90,689	544,134	62,255	62,255	62,255	62,255	62,255	62,255	373,530	917,664	3
4	Rate HLF	159,660	159,660	159,660	159,660	159,660	159,659	957,959	173,339	173,339	173,339	173,339	173,339	173,339	1,040,034	1,997,993	4
5	Customer L	5,403	5,403	5,402	5,403	5,403	5,402	32,416	(3,552)	(3,552)	(3,553)	(3,552)	(3,552)	(3,553)	(21,314)	11,102	5
6	Customer O	365	365	364	365	365	364	2,188	1,053	1,053	1,052	1,053	1,053	1,052	6,316	8,504	6
7	Rate WP	1,417	1,416	1,417	1,416	1,417	1,416	8,499	1,164	1,165	1,165	1,165	1,165	1,164	6,988	15,487	7
8	Rate SL	(461)	(462)	(461)	(462)	(461)	(462)	(2,769)	55	55	55	55	55	55	330	(2,439)	8
9	Rate MHLS	(43)	(43)	(43)	(43)	(43)	(42)	(257)	(4)	(4)	(3)	(4)	(4)	(3)	(22)	(279)	9
10	Rate MOLS and UOLS	356	356	356	356	356	355	2,135	404	404	405	404	404	405	2,426	4,561	10
11	Rates TS, FS and MS	(133)	(132)	(132)	(132)	(132)	(131)	(792)	(25)	(25)	(25)	(25)	(25)	(25)	(150)	(942)	11
12	Total	410,197	410,196	410,196	410,196	410,198	410,194	2,461,177	387,257	387,258	387,258	387,258	387,258	387,257	2,323,546	4,784,723	12
	Rider Revenues Actually Collected																
13	Rate RS	153,824	145,060	149,752	97,990	97,414	152,724	796,764	164,695	137,604	130,157	109,861	93,458	115,636	751,411	1,548,175	13
14	Rate CS	(15,830)	22,564	25,699	18,781	17,051	22,529	90,794	16,617	14,698	14,858	13,261	12,498	14,679	86,611	177,405	14
15	Rate LLF	101,793	100,088	131,889	98,303	84,148	95,519	611,740	72,909	57,299	59,862	58,958	56,175	65,619	370,822	982,562	15
16	Rate HLF	159,787	125,907	232,379	157,038	133,676	99,732	908,519	214,914	156,805	159,036	153,077	161,302	149,974	995,108	1,903,627	16
17	Customer L	13,054	(26,612)	59,613	15,216	13,518	13,139	87,928	10,730	(4,509)	(3,544)	(4,720)	(4,285)	(4,616)	(10,944)	76,984	17
18	Customer O	37	(84)	1,261	397	414	385	2,410	382	1,064	963	1,067	1,033	1,067	5,576	7,986	18
19	Rate WP	1,443	1,381	1,785	1,614	1,285	1,409	8,917	1,386	1,083	1,206	1,216	1,047	1,256	7,194	16,111	19
20	Rate SL	(448)	(387)	(652)	(422)	(383)	(407)	(2,699)	(158)	26	66	15	67	34	50	(2,649)	20
21	Rate MHLS	(30)	(27)	(31)	(33)	(34)	(43)	(198)	(31)	(4)	(4)	(3)	(3)	(3)	(48)	(246)	21
22	Rate MOLS and UOLS	241	252	324	286	274	282	1,659	344	326	342	339	333	318	2,002	3,661	22
23	Rates TS, FS and MS	(95)	(76)	(113)	(75)	(90)	(97)	(546)	(65)	(25)	(34)	(27)	(28)	(21)	(200)	(746)	23
24	Total	413,776	368,066	601,906	389,095	347,273	385,172	2,505,288	481,723	364,367	362,908	333,044	321,597	343,943	2,207,582	4,712,870	24
	Under (Over) Collected																
25	Rate RS	(21,670)	(12,907)	(17,598)	34,163	34,740	(20,571)	(3,843)	(29,496)	(2,406)	5,042	25,337	41,741	19,562	59,780	55,937	25
26	Rate CS	36,620	(1,773)	(4,909)	2,010	3,739	(1,738)	33,949	752	2,672	2,511	4,109	4,871	2,691	17,606	51,555	26
27	Rate LLF	(11,104)	(9,399)	(41,200)	(7,614)	6,541	(4,830)	(67,606)	(10,654)	4,956	2,393	3,297	6,080	(3,364)	2,708	(64,898)	27
28	Rate HLF	(127)	33,753	(72,719)	2,622	25,984	59,927	49,440	(41,575)	16,534	14,303	20,262	12,037	23,365	44,926	94,366	28
29	Customer L	(7,651)	32,015	(54,211)	(9,813)	(8,115)	(7,737)	(55,512)	(14,282)	957	(9)	1,168	733	1,063	(10,370)	(65,882)	29
30	Customer O	328	449	(897)	(32)	(49)	(21)	(222)	671	(11)	89	(14)	20	(15)	740	518	30
31	Rate WP	(26)	35	(368)	(198)	132	7	(418)	(222)	82	(41)	(51)	118	(92)	(206)	(624)	31
32	Rate SL	(13)	(75)	191	(40)	(78)	(55)	(70)	213	29	(11)	40	(12)	21	280	210	32
33	Rate MHLS	(13)	(16)	(12)	(10)	(9)	1	(59)	27	-	1	(1)	(1)	-	26	(33)	33
34	Rate MOLS and UOLS	115	104	32	70	82	73	476	60	78	63	65	71	87	424	900	34
35	Rates TS, FS and MS	(38)	(56)	(19)	(57)	(42)	(34)	(246)	40	-	9	2	3	(4)	50	(196)	35
36	Total	(3,579)	42,130	(191,710)	21,101	62,925	25,022	(44,111)	(94,466)	22,891	24,350	54,214	65,661	43,314	115,964	71,853	36

DUKE ENERGY INDIANA, LLC

Comparison of the Effect of a Change in the Regional Transmission Operator ("RTO") Non-Fuel Cost and Revenue Adjustment (Rider No. 68) on the Bill of a Typical Residential Customer Using 1,000 kWh

Line No.	Description	RTO Non-Fuel Cost and Revenue Adjustment Factor Rider No. 68	Base Bill For Typical Residential Customer (1)	All Other Riders Excluding Rider No. 68 (2)	Total Bill for Typical Residential Customer Excluding Rider No. 68	RTO Non-Fuel Cost and Revenue Adjustment Amount for Rider No. 68 for 1,000 kWh's	Total Bill Including RTO Non-Fuel Cost and Revenue Adjustment Amount Rider No. 68	Increase/ (Decrease) In Total Bill From Current Factor (3)	% Increase/ (Decrease) In Total Bill From Current Factor	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
1	Proposed Factor	$ (0.000322)	$ 130.99	$ 0.16	$ 131.15	$ (0.32)	$ 130.83	$ (0.49)	-0.37%	1
2	Current Approved Factor	$ 0.000174	$ 130.99	$ 0.16	$ 131.15	$ 0.17	$ 131.32	NA	NA	2

(1) Reflects base rates approved in the Company's Compliance filing in Cause No. 45253, effective July 30, 2020.
(2) Reflects current rates in effect for all riders, excluding Rider No. 68, as of the date of this filing.
(3) Line 1, column G equals line 1, column F less line 2, column F.

DUKE ENERGY INDIANA, LLC

COMPANY-OWNED SCHEDULE 26 PROJECT STATUS AND ESTIMATE OF ALLOCATED SCHEDULE 26 COSTS
CAUSE NO. 42736 - RTO 59

				MISO	MTEP	Expected Construction Schedule			Estimated Total Project Costs			Actual	Percentage	
Line No.	Project Type	Location	Description	Approval Status	Project ID	Start	Finish	In-Service	Original	Revised	Date Revised	Costs	of Completion	Line No.
1	RECB 1 - Baseline Reliability Project	Lafayette SE to Concord	138 KV Reconductor with 954 ACSR (4.3 miles)	Approved - MTEP 07	852	2/5/08	4/24/09	4/30/09	$ 2,000,000	-	-	$ 1,257,394.14	100.00%	1
2	RECB 1 - Baseline Reliability Project	Concord to Crawfordsville	138 KV Reconductor with 954 ACSR (17.36 miles)	Approved - MTEP 07	852	5/15/08	5/15/13	6/1/13	$ 8,200,000	8,920,355	Apr-13	$ 7,174,167.73	100.00%	2
3	RECB 1 - Generator Interconnection Project	Knox County	IGCC 345 KV Switching Station [1]	Approved - MTEP 07	1263	4/14/08	4/20/10	6/1/10	$ 9,198,424	11,857,496	Jan-10	$ 11,983,364.56	100.00%	3
4	RECB 1 - Generator Interconnection Project	Knox County	IGCC 34528 Line Termination [1]	Approved - MTEP 07	1263	5/6/08	3/8/10	6/1/10	$ 168,576	192,757	Dec-09	$ 145,205.77	100.00%	4
5	RECB 1 - Baseline Reliability Project	Vigo County	Add a 3rd 345/138 kv transformer at Dresser Sub	Approved - MTEP 10	2050	12/22/09	12/31/2011	12/31/2011	$ 12,700,000	$13,443,888	Jun-11	$ 13,833,026.42	100.00%	5

Based on the MISO-approved MTEP06 through MTEP 22 the Midcontinent ISO currently estimates that Duke Energy Indiana's share of allocated project costs through 2037 is an average of approximately $10.6 million annually.

[1] In accordance with the Commission's Order dated November 20, 2007 in Cause Nos. 43114 and 43114-S1, page 59, Duke Energy Indiana will seek reimbursement of these costs under the Midcontinent ISO's RECB process.

DUKE ENERGY INDIANA, LLC

COMPANY-OWNED SCHEDULE 26-A PROJECT STATUS AND ESTIMATE OF ALLOCATED SCHEDULE 26-A COSTS
CAUSE NO. 42736 - RTO 59

Line No.	Project Type	MTEP Project ID	Facility ID #	Description	MISO Approval Status	Expected Construction Schedule Start	Finish	In-Service	Actual Costs	Percentage of Completion	Line No.
1	MVP - Multi-Value Project	2237	8313	Sugar Creek 345kV Transmission Line	Approved - MTEP 11	12/2/16	12/14/20	12/14/20	$ 7,786,154.71	100.00%	1
2	MVP - Multi-Value Project	2237	8313	Sugar Creek 345kV Transmission Line	Approved - MTEP 11	12/2/16	6/28/19	6/28/19	$ 5,566,614.39	100.00%	2
3	MVP - Multi-Value Project	2237	8313	Sugar Creek 345kV Transmission Line	Approved - MTEP 11	12/2/16	11/30/18	10/1/18	$ 360,234.25	100.00%	3
4	MVP - Multi-Value Project	2237	8313	Sugar Creek 345kV Transmission Line	Approved - MTEP 11	1/14/17	1/29/21	11/30/20	$ 152,023.38	100.00%	4
5	MVP - Multi-Value Project	2202	7286	Wabash 6986 ckt Reconductor	Approved - MTEP 11	2/17/17	7/31/18	6/1/18	$ 4,715.41	100.00%	5
6	MVP - Multi-Value Project	2202	7286	Wabash 6986 ckt Reconductor	Approved - MTEP 11	2/17/17	7/2/18	7/2/18	$ 1,744,593.87	100.00%	6
7	MVP - Multi-Value Project	2202	7287	Kokomo Delco to Greentown 138 kV Uprate	Approved - MTEP 11	11/02/17	8/7/2018	6/8/2018	$ 403,470.97	100.00%	7

Based on the MISO-approved MTEP06 through MTEP 22 the Midcontinent ISO currently estimates that Duke Energy Indiana's share of allocated project costs through 2043 is an average of approximately $41.6 million annually.

DUKE ENERGY INDIANA, LLC

COMPONENTS OF REVENUE CONVERSION FACTOR

Components of Revenue Conversion Factor:	Statutory	Effective Rate
Uncollectible Accounts Expense	0.280%	0.280%
Public Utility Fee	0.147%	0.147%
State Income Tax	4.900%	-
Federal Income Tax	21.000%	-
Subtotal Effective Rate		0.427%
Complement (1 - Effective Rate)		99.573%
Revenue Conversion Factor (1 ÷ Complement)		1.00429

STANDARD FORMAT FOR DUKE ENERGY INDIANA FILINGS
RIDER NO. 68 – IURC CAUSE NO. 42736-RTO

(1) **VERIFIED PETITION**
Petitioner's Attachment 1-A – Proposed Duke Energy Indiana Rider No. 68, showing proposed adjustment factors

(2) **TESTIMONY OF ART BUESCHER**
Attachment 1-A - Proposed Duke Energy Indiana Rider No. 68, showing proposed adjustment factors
Attachment 1-B - Determination of adjustment factors by rate groups for prior applicable period and forecasted period to be applied to current proposed calendar year
Attachment 1-C - Determination of forecasted RTO non-fuel costs and transmission revenues to be recovered or credited through Duke Energy Indiana Rider No. 68
Attachment 1-D - Comparison of projected RTO non-fuel costs and transmission revenues to actual non-fuel costs and transmission revenues incurred during the reconciliation period
Attachment 1-E - Comparison of the actual amount of revenues charged or credited and the amount approved to be charged or credited during the reconciliation period
Attachment 1-F - Comparison of the effect of a proposed change in Duke Energy Indiana Rider No. 68 adjustment factor on the bill of a typical residential customer using 1,000 Kilowatt-hours of electricity
Attachment 1-G - Schedule 26 Project Status and Estimate of Schedule 26 Costs
Attachment 1-H - Schedule 26-A Project Status and Estimate of Schedule 26-A Costs
Attachment 1-I - Components of revenue conversion factor
Attachment 1-J - Standard format for Duke Energy Indiana filings.
Attachment 1-K - Standard workpaper listing for Duke Energy Indiana RTO filing.

(3) **WORKPAPERS OF ART BUESCHER**
Workpaper 1 – Kilowatt-hour sales by rate schedule for the twelve months ending June 2020
Workpaper 2 – KW demands for HLF rate class for the tweleve months ending June 2020
Workpaper 3 - Derivation of Duke Energy Indiana Rider No. 68 revenues charged or credited for the reconciliation months
Workpaper 4 - MISO invoice detailing MISO Schedule 10 FERC and MISO Schedule 10 costs for demand and energy
Workpaper 5 – Derivation of MISO FERC fees and MISO Schedule 10 costs
Workpaper 6 - Restatement of detail provided by MISO for transmission revenues collected under the MISO TEMT, or any successor tariff

STANDARD FORMAT FOR DUKE ENERGY INDIANA FILINGS
RIDER NO. 68 – IURC CAUSE NO. 42736-RTO

Workpaper 7 - Summarized schedule of the MISO transmission revenue schedules
Workpaper 8 - Derivation of Duke Energy Indiana's retail portion of the MISO transmission revenues
Workpaper 9 – Derivation of Duke Energy Indiana's retail portion of PJM charges and credits associated with Madison Generating Station
Workpaper 10 - Calculation of Duke Energy Indiana's retail portion of MISO Administrative Fees, Schedules 16 and 17 cost, as well as, Real-Time Revenue Neutrality Uplift Amount, Real-Time Miscellaneous Amount and Real-Time MVP Distribution Amount
Workpaper 11 - MISO invoice detailing Schedule 26 and Schedule 26A (MVP) charges
Workpaper 12 - Duke Energy Indiana MISO Attachment GG – Calculation of Revenue Requirement for Company-owned Schedule 26 RECB projects
Workpaper 13 - Duke Energy Indiana MISO Attachment MM – Calculation of Revenue Requirement for Company-owned Schedule 26-A MVP projects
Workpaper 14 – Duke Energy Indiana Estimated Bill Impact By Customer Class

(4) TESTIMONY OF BRAD (JAMES) DANIELS

WORKPAPER LISTING DUKE ENERGY INDIANA
RIDER NO. 68 – IURC CAUSE NO. 42736-RTO

Workpaper 1 Kilowatt hour sales by rate schedule listed on Petitioner's Attachment 1-B

Workpaper 2 KW demands for HLF rate class listed on Petitioner's Attachment 1-B

Workpaper 3 Determination of Duke Energy Indiana Rider No. 68 revenues charged or credited for the reconciliation months as listed on Petitioner's Attachment 1-E

Workpaper 4 MISO invoice detailing Schedule 10 FERC and Schedule 10 costs for demand and energy

A) Current month Native Load Schedule 10 FERC costs for demand and energy, plus any adjustments carried to Workpaper 5

B) Current month Native Load Schedule 10 costs for demand and energy, plus any adjustments carried to Workpaper 5

Workpaper 5 Derivation of MISO Schedule 10 FERC Fees and MISO Schedule 10 costs for demand and energy

A) Monthly MISO Schedule 10 FERC fee amounts listed on Petitioner's Attachment 1-C, filed with Duke Energy Indiana's Testimony

B) Monthly MISO Schedule 10 amounts listed on Petitioner's Attachment 1-C, filed with Duke Energy Indiana's Testimony

Workpaper 6 Restatement of detail provided by MISO for transmission revenues collected under the MISO TEMT, or any successor Tariff

A) Schedules of estimated and final MISO transmission revenue amounts collected under the MISO TEMT, or any successor Tariff, which are carried forward to Workpaper 9. Allocation to Operating Company

Workpaper 7 Summarized schedule of the MISO transmission revenue schedules

A) Reconciled monthly revenues added to current month's revenue to derive the amount journalized in account 456850

Workpaper 8 Derivation of Duke Energy Indiana's retail portion of the MISO transmission revenues for the reconciliation period as reported on Petitioner's Attachment 1-E, filed with Duke Energy Indiana's Testimony

A) Total Duke Energy Indiana MISO transmission revenues, less WVPA's and IMPA's revenue portion, multiplied by the retail allocation percent to create the retail portion of MISO transmission revenue. Retail allocation percentage from the IURC Order in Cause No. 45253 is 100.000%. (Amounts attributable to WVPA and IMPA need to be excluded because MISO includes such amounts in MISO's transmission revenues for the Cinergy Control Area/Zone.)

WORKPAPER LISTING DUKE ENERGY INDIANA
RIDER NO. 68 – IURC CAUSE NO. 42736-RTO

Workpaper 9 Derivation of Duke Energy Indiana's retail portion of PJM charges and credits associated with Madison Generating as approved in Cause No. 45253.

Workpaper 10 Calculation of Duke Energy Indiana's retail portion of MISO Administrative Fees for each month of the reconciliation period as billed per Schedules 16 and 17. In addition, the calculation of Duke Energy Indiana's Other MISO Standard Market Design Costs for each month as billed per MISO's Real-Time Revenue Neutrality Uplift Amount, Real-Time Miscellaneous Amount and Real-Time MVP Distribution Amount

A) Total Duke Energy Indiana MISO Administrative Fees and Other Standard Market Design Costs multiplied by the retail allocation percent to calculate the retail portion of MISO charges. Retail allocation percentage from the IURC Order in Cause No. 45253 is 100.000%.

Workpaper 11 MISO invoice detailing Schedule 26, Schedule 26A, Schedule 26C, Schedule 26D and Schedule 26-E charges

Workpaper 12 Duke Energy Indiana MISO Attachment GG – Calculation or Revenue Requirement for Company-owned Schedule 26 RECB projects

Workpaper 13 Duke Energy Indiana MISO Attachment MM – Calculation of Revenue Requirement for Company-owned Schedule 26-A MVP projects

Workpaper 14 Duke Energy Indiana Estimated Bill Impact By Customer Class

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: ______________________ Dated: August 29, 2023
Art J. Buescher III