TESTIMONY OF ART J. BUESCHER III
LEAD RATES AND REGULATORY STRATEGY ANALYST
DUKE ENERGY INDIANA, LLC
CAUSE NO. 42736 RTO-57
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"), a wholly-owned subsidiary of Duke Energy Corporation ("Duke Energy"), 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. I will also explain any changes the Company is making to Rider No. 68 as a result of the Company's most recent retail base rate case approved by the Commission on June 29, 2020, in Cause No. 45253 ("June 29, 2020 Order" or "Cause No. 45253").

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 2020 through June 2021 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 2022 through December 2022.

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 ("Current Base Rate Order"), 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. PLEASE EXPLAIN THE SPECIFIC CHANGES TO THE COMPANY'S RTO RIDER RESULTING FROM DUKE ENERGY INDIANA'S CURRENT BASE RATE ORDER.

A. The Company's Current Base Rate Order made several prospective changes to the Company's Rider No. 68 filing, including the following:

- Added non-fuel related PJM charges and credits on a prospective basis to the comparable MISO amounts currently included in the rider;
- Updated the proposed annual base amounts for RTO non-fuel costs and RTO transmission revenues used in the rider calculation; and
- Modified the factor calculation for HLF customers to be billed on KW demand rather than on kWh sales.

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, 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, 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 Petitioner's Exhibit 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 and the Commission's June 30, 2009 Order in Cause No. 42736, 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, 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. Petitioner's Exhibit 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, the Commission determined that the Real-Time MVP Distribution charge type assessed by MISO was properly includable in Rider No. 68. Furthermore, in the February 24, 2021 Order in Cause No. 42736, 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.

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 of the end of 2016: (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 2021, the Company submitted to MISO its revised annual revenue requirement for these projects for changes in the approved return on equity ("ROE"), which totaled $3,010,499, and the Company, as a transmission owner, began receiving updated revenues July 1, 2021. These RECB projects are listed on Petitioner's Exhibit 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 are projected to be 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 are therefore, included in the Company's MISO Attachment MM for recovery through Schedule 26-A. The final two (2) detail projects are estimated to be 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 2021, the Company submitted to MISO its revised annual revenue requirement for these projects for changes in the approved ROE, which totaled $1,489,235, and the Company, as a transmission owner, began receiving revenues July 1, 2021.

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 Suzanne E. Sieferman in Cause No. 38707 FAC-129, which discusses the adjustments to the Company's Earnings Test to exclude revenues and expenses associated with its own RECB and MVP projects.

III. OVERVIEW OF RIDER NO. 68

Q. PLEASE BRIEFLY DESCRIBE THE COSTS 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 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. 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. Refunds and adjustments are currently due for completion by December 23, 2020. 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. The Company will continue to provide all required ROE refunds to its retail customers in a timely manner through the RTO tracker pursuant to the timelines established by FERC and MISO.

MISO issued ROE refunds, related to the FERC Opinion No. 569 processed during the reconciliation months of July 2020 through June 2021, have been included in this filing. The net credit included in this filing on Petitioner's Exhibit 1-D (AJB) is $360,057.

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 2020 through June 2021 and is shown in Columns C and D of Petitioner's Exhibit 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.

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 the Company's Current Base Rate Order (Cause No. 45253), the retail allocator for transmission is 100%, while the transmission allocator from the prior retail base rate case (Cause No. 42359, effective through July 2020) was 96.291%.

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 1.00482. See Petitioner's Exhibit 1-I (AJB) for the underlying calculation of this factor.

IV. <u>PROPOSED RIDER NO. 68 ADJUSTMENT FACTORS</u>

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 1-A (AJB).

A. Petitioner's Exhibit 1-A (AJB) is the Company's revised Standard Contract Rider No. 68. Page 2 of this Exhibit shows the Percent Share of Retail Peak developed for cost of service purposes in Cause No. 45253.

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. Petitioner's Exhibit 1-B (AJB) includes projected RTO costs and transmission revenues (Column B) 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, 2021. For developing the HLF rate, the revenue requirement amount is divided by KW demands for the twelve (12)-months ended June 30, 2021 to determine the proposed Rider No. 68 rate. These factors by respective retail rate groups are then used on Page 3 of 3 of Petitioner's Exhibit 1-A (AJB). The total amount that the Company proposes to be charged to the Company's retail electric customers through Rider No. 68, taking into account the reconciliation amount, is $4,922,351.

The prefiled Testimony of Mr. James (Brad) Daniel, Petitioner's Exhibit 2, supports the reasonableness of the Company's Energy Markets and ASM non-fuel related costs.

Q. WERE THERE ANY EMERGENCY EVENTS IN THE MISO FOOTPRINT DURING THE JULY 2020 THROUGH JUNE 2021 RECONCILIATION PERIOD?

A. Yes. 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. In addition, in February 2021, the MISO region experienced unusually cold weather resulting in higher demand coupled with supply issues due to generation performance and fuel availability.

Q. WHAT WERE THE IMPACTS FROM THE EXTREME WEATHER EVENTS DURING THE RECONCILIATION PERIOD?

A. 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 and is included in Petitioner's Exhibit 1-D (AJB).

Duke Energy Indiana has been working with twenty plus market participants located in the Central and North Regions of MISO. Together, this coalition believes that MISO applied its Tariff inappropriately, resulting in settlements that do not align with cost causation and allocation principles and ignore the tariff provisions that cover catastrophic events. Duke Energy Indiana filed an Alternative Dispute Resolution ("ADR") on March 26, 2021. The Company continues to monitor the issue but does not expect resolution until the fourth quarter of 2021. If Duke Energy Indiana receives a refund from MISO as a result of the ADR process, the Company will provide a refund through the RTO adjustment rider.

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

A. No.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 1-C (AJB).

A. Petitioner's Exhibit 1-C (AJB) compares the forecasted non-fuel RTO costs and transmission revenues for the forecasted periods of January 2022 through December 2022 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 Petitioner's Exhibit 1-B (AJB), Column (B).

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 1-D (AJB).

A. Petitioner's Exhibit 1-D (AJB) compares the previously projected RTO non-fuel costs and transmission revenues (developed in RTO 55 and 56) to actual non-fuel costs and transmission revenues incurred during the reconciliation period of July 2020 through June 2021. The total to be recovered from (or credited to) customers from this portion of the reconciliation is shown on Petitioner's Exhibit 1-B (AJB), Column (C).

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 1-E (AJB).

A. Petitioner's Exhibit 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

[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 Exhibit A, p. 23). Since 2015, the PACE process is administered by the Sumatra model.

amounts approved by the Commission for recovery during the reconciliation periods of July 2020 through June 2021. The total to be recovered from (or credited to) customers for this item is shown on Petitioner's Exhibit 1-B (AJB), Column (D).

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 1-F (AJB).

A. Petitioner's Exhibit 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 an increase of \$0.41[2] on his or her electric bill when compared to the bills reflecting the current Rider No. 68 rate. This is a 0.31%[3] increase to each residential customer's electric bill.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 1-G (AJB).

A. Petitioner's Exhibit 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 PETITIONER'S EXHIBIT 1-H (AJB).

A. Petitioner's Exhibit 1-H (AJB) provides information relating to Company-owned,

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[2] The change is defined as the proposed change in factor from this proceeding compared to what the customer is paying today for this rider.

[3] The change is defined as the proposed factor from this proceeding compared to what the customer is paying today for this rider as a percentage of the total monthly bill of a 1000 kWh customer as of August 1, 2021 of \$132.48, excluding utility receipts and sales tax.

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 PETITIONER'S EXHIBIT 1-I (AJB).

A. Petitioner's Exhibit 1-I (AJB) shows the calculation of the revenue conversion factor being used in this proceeding. Note that the Commission's Order in Cause No. 45253 approved the Company's proposal to remove Utility Receipts Tax recovery from base and rider rates and show it as a separate line on the Company's bills. As a result, the revenue conversion factor will no longer include a gross-up intended to cover URT recovery.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBITS 1-J (AJB) AND 1-K (AJB).

A. The standard format for Duke Energy Indiana filings (labeled as Petitioner's Exhibit 1-J (AJB) in this proceeding) and the Standard Audit Path (labeled as Petitioner's Exhibit 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 Standard Contract Rider No. 68, First Revised Sheet No. 68, Page 1 through Page 3, as reflected in Petitioner's Exhibit 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 2022 – 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 Petitioner's Exhibit 1-A (AJB).

Q. WERE PETITIONER'S EXHIBITS 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
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IURC No. 15
Second Revised Sheet No.68
Cancels and Supersedes
First Revised Sheet No. 68

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
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IURC No. 15
Second Revised Sheet No. 68
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**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
Second Revised Sheet No. 68
Cancels and Supersedes
First 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	$0.000172		1
2	Rates CS and FOC	0.000247		2
3	Rate LLF	0.000215		3
4	Rate HLF		$0.106090	4
5	Customer L	0.001523		5
6	Customer O	0.000028		6
7	Rate WP	0.000109		7
8	Rate SL	(0.000150)		8
9	Rate MHLS	(0.000096)		9
10	Rates MOLS and UOLS	0.000042		10
11	Rates TS, FS and MS	(0.000164)		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 2022 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 2020 through June 2021 Period	Reconciliation of RTO Non-Fuel Costs and Revenues Approved for Recovery vs. Actual RTO Revenues Collected for the July 2020 through June 2021 Period	Total	Actual Kilowatt-Hour Sales For The Twelve Months Ended June 30, 2021	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, 2021	RTO Non-Fuel Costs and Revenue Adjustment Factors Per Non-Coincident Peak Demands	Line No.
		(A)	(B)	(C)	(D)	(E) = (B) + (C) + (D)	(F)	(G)	(H)	(I)	
1	Rate RS	42.114%	$ 3,233,017	$ 2,464,713	$ (4,111,888)	$ 1,585,842	9,218,229,683	$0.000172			1
2	Rates CS	5.169%	396,815	302,515	(449,845)	249,486	1,011,836,654	0.000247			2
3	Rate LLF	20.722%	1,590,792	1,212,750	(1,715,275)	1,088,268	5,053,737,270	0.000215			3
4	Rate HLF	30.774%	2,362,466	1,801,041	(2,247,588)	1,915,919	9,701,028,474		18,059,291	$0.106090	4
5	Customer L	0.296%	22,723	17,323	24,786	64,832	42,579,677	0.001523			5
6	Customer O	0.372%	28,558	21,771	(45,953)	4,376	156,236,642	0.000028			6
7	Rate WP	0.415%	31,859	24,288	(39,150)	16,998	155,234,106	0.000109			7
8	Rate SL	0.002%	154	117	(5,810)	(5,539)	36,806,363	(0.000150)			8
9	Rate MHLS	0.000%	-	-	(515)	(515)	5,354,633	(0.000096)			9
10	Rates MOLS and UOLS	0.113%	8,675	6,613	(11,019)	4,270	101,472,808	0.000042			10
11	Rates TS, FS and MS	0.023%	1,766	1,346	(4,697)	(1,585)	9,667,284	(0.000164)			11
12	**TOTAL RETAIL**	100.000%	$ 7,676,825	$ 5,852,477	$ (8,606,951)	$ 4,922,351	25,492,183,594				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 2022

Line No.	Description	January 2022	February 2022	March 2022	April 2022	May 2022	June 2022	July 2022	August 2022	September 2022	October 2022	November 2022	December 2022	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	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	2,400,000	1
2	Schedule 10	475,000	475,000	475,000	475,000	475,000	475,000	475,000	475,000	475,000	475,000	475,000	475,000	5,700,000	2
3	Schedule 16	16,667	16,667	16,666	16,667	16,667	16,666	16,667	16,667	16,666	16,667	16,667	16,666	200,000	3
4	Schedule 17	416,667	416,667	416,666	416,667	416,667	416,666	416,667	416,667	416,666	416,667	416,667	416,666	5,000,000	4
5	Real Time Miscellaneous	-	-	-	-	-	-	-	-	-	-	-	-	-	5
6	Real Time Revenue Neutrality Uplift Amount	383,333	383,333	383,334	383,333	383,333	383,334	383,333	383,333	383,334	383,333	383,333	383,334	4,600,000	6
7	Real Time MVP Distribution Amount	(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)	7
8	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	625,000	625,000	625,000	625,000	625,000	625,000	625,000	625,000	625,000	625,000	625,000	625,000	7,500,000	8
9	Schedule 26 A - Multi-Value Projects	3,766,667	3,766,667	3,766,666	3,766,667	3,766,667	3,766,666	3,766,667	3,766,667	3,766,666	3,766,667	3,766,667	3,766,666	45,200,000	9
10	Schedule 26 C	1,333	1,333	1,334	1,333	1,333	1,334	1,333	1,333	1,334	1,333	1,333	1,334	16,000	10
11	Schedule 26 D	667	667	666	667	667	666	667	667	666	667	667	666	8,000	11
12	Schedule 49	10,333	10,333	10,334	10,333	10,333	10,334	10,333	10,333	10,334	10,333	10,333	10,334	124,000	12
13	PJM Madison Non-Fuel	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	1,500,000	13
14	Total RTO Non-Fuel Costs	6,008,167	6,008,167	6,008,166	6,008,167	6,008,167	6,008,166	6,008,167	6,008,167	6,008,166	6,008,167	6,008,167	6,008,166	72,098,000	14
15	*Transmission Revenues*	(2,333,333)	(2,333,333)	(2,333,334)	(2,333,333)	(2,333,333)	(2,333,334)	(2,333,333)	(2,333,333)	(2,333,334)	(2,333,333)	(2,333,333)	(2,333,334)	(28,000,000)	15
16	Total Non-Fuel Costs & Transmission Revenues	3,674,834	3,674,834	3,674,832	3,674,834	3,674,834	3,674,832	3,674,834	3,674,834	3,674,832	3,674,834	3,674,834	3,674,832	44,098,000	16
	Amounts Included in Base Rates														
	Non-Fuel Costs														
17	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	17
18	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	18
19	Schedule 16	26,917	26,917	26,917	26,917	26,917	26,917	26,917	26,917	26,917	26,917	26,917	26,917	323,004	19
20	Schedule 17	528,333	528,333	528,333	528,333	528,333	528,333	528,333	528,333	528,333	528,333	528,333	528,333	6,339,996	20
21	Real Time Miscellaneous	-	-	-	-	-	-	-	-	-	-	-	-	-	21
22	Real Time Revenue Neutrality Uplift Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	22
23	Real Time MVP Distribution Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	23
24	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	24
25	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	25
26	Schedule 26 C	-	-	-	-	-	-	-	-	-	-	-	-	-	26
27	Schedule 26 D	-	-	-	-	-	-	-	-	-	-	-	-	-	27
28	Schedule 49	-	-	-	-	-	-	-	-	-	-	-	-	-	28
29	PJM Madison Non-Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	29
30	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	30
31	*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)	31
32	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	32
	Net Forecasted RTO Non-Fuel Costs & Transmission Revenues														
	Non-Fuel Costs														
33	Schedule 10 FERC	(11,583)	(11,583)	(11,584)	(11,583)	(11,583)	(11,584)	(11,583)	(11,583)	(11,584)	(11,583)	(11,583)	(11,584)	(139,000)	33
34	Schedule 10	(7,417)	(7,417)	(7,416)	(7,417)	(7,417)	(7,416)	(7,417)	(7,417)	(7,416)	(7,417)	(7,417)	(7,416)	(89,000)	34
35	Schedule 16	(10,250)	(10,250)	(10,251)	(10,250)	(10,250)	(10,251)	(10,250)	(10,250)	(10,251)	(10,250)	(10,250)	(10,251)	(123,004)	35
36	Schedule 17	(111,666)	(111,666)	(111,667)	(111,666)	(111,666)	(111,667)	(111,666)	(111,666)	(111,667)	(111,666)	(111,666)	(111,667)	(1,339,996)	36
37	Real Time Miscellaneous	-	-	-	-	-	-	-	-	-	-	-	-	-	37
38	Real Time Revenue Neutrality Uplift Amount	383,333	383,333	383,334	383,333	383,333	383,334	383,333	383,333	383,334	383,333	383,333	383,334	4,600,000	38
39	Real Time MVP Distribution Amount	(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)	39
40	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	(48,583)	(48,583)	(48,584)	(48,583)	(48,583)	(48,584)	(48,583)	(48,583)	(48,584)	(48,583)	(48,583)	(48,584)	(583,000)	40
41	Schedule 26 A - Multi-Value Projects	689,667	689,667	689,666	689,667	689,667	689,666	689,667	689,667	689,666	689,667	689,667	689,666	8,276,000	41
42	Schedule 26 C	1,333	1,333	1,334	1,333	1,333	1,334	1,333	1,333	1,334	1,333	1,333	1,334	16,000	42
43	Schedule 26 D	667	667	666	667	667	666	667	667	666	667	667	666	8,000	43
44	Schedule 49	10,333	10,333	10,334	10,333	10,333	10,334	10,333	10,333	10,334	10,333	10,333	10,334	124,000	44
45	PJM Madison Non-Fuel	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	1,500,000	45
46	Total RTO Non-Fuel Costs	1,008,334	1,008,334	1,008,332	1,008,334	1,008,334	1,008,332	1,008,334	1,008,334	1,008,332	1,008,334	1,008,334	1,008,332	12,100,000	46
47	*Transmission Revenues*	(371,666)	(371,666)	(371,668)	(371,666)	(371,666)	(371,668)	(371,666)	(371,666)	(371,668)	(371,666)	(371,666)	(371,668)	(4,460,000)	47
48	Total Non-Fuel Costs & Transmission Revenues	636,668	636,668	636,664	636,668	636,668	636,664	636,668	636,668	636,664	636,668	636,668	636,664	7,640,000	48
49	Revenue Conversion Factor													1.00482	49
50	Amount to be Collected (Credited) Through Rider													7,676,825	50

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 2020 THROUGH JUNE 2021 PERIOD

Line No.	Description	RTO 55 July 2020 (A)	August 2020 (B)	September 2020 (C)	October 2020 (D)	November 2020 (E)	December 2020 (F)	Sub-Total (G) Sum (A) to (F)	RTO 56 January 2021 (H)	February 2021 (I)	March 2021 (J)	April 2021 (K)	May 2021 (L)	June 2021 (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	179,587	202,040	236,005	215,477	160,314	177,175	1,170,598	190,728	196,769	186,954	182,249	162,582	214,114	1,133,396	2,303,994	1
2	Schedule 10	253,880	425,111	521,128	335,916	397,106	511,515	2,444,656	577,342	507,868	430,138	517,659	672,786	520,791	3,226,584	5,671,240	2
3	Schedule 16	22,221	21,180	17,237	12,013	8,707	20,313	101,671	13,306	8,542	11,661	8,991	7,053	11,844	61,397	163,068	3
4	Schedule 17	393,120	423,387	404,206	444,748	333,022	578,615	2,577,098	443,462	367,933	317,104	339,943	409,555	437,850	2,315,847	4,892,945	4
5	Real Time Miscellaneous	322,652	1,600	375	(3,920)	4,676	1,332	326,715	1,686	2,483	739	9,431	(2,721)	5,720	17,338	344,053	5
6	Real Time Revenue Neutrality Uplift Amount	269,444	42,106	4,437,006	563,257	619,595	750,488	6,681,896	409,712	(1,715,946)	1,444,699	369,880	610,332	763,510	1,882,187	8,564,083	6
7	Real Time MVP Distribution Amount	(2,406)	(2,292)	(2,509)	(3,035)	(2,767)	(2,740)	(15,749)	(23,500)	(23,822)	(23,599)	(18,312)	(18,155)	(18,251)	(125,639)	(141,388)	7
8	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	526,934	606,648	681,070	655,532	480,495	532,240	3,482,919	571,939	709,162	600,898	591,549	492,927	689,025	3,655,500	7,138,419	8
9	Schedule 26 A - Multi-Value Projects	3,081,287	3,185,423	3,694,816	3,948,752	3,469,211	3,606,839	20,986,328	3,875,531	4,300,424	3,892,542	3,663,518	3,089,559	3,328,681	22,150,255	43,136,583	9
10	Schedule 26 C	-	1,012	1,050	1,059	1,058	1,039	5,218	1,048	1,594	1,604	1,669	1,682	1,719	9,316	14,534	10
11	Schedule 26 D	-	665	690	692	690	677	3,414	683	821	795	830	839	856	4,824	8,238	11
12	Schedule 49	-	-	-	-	9,705	10,150	19,855	10,525	10,297	10,402	10,677	10,762	10,834	63,497	83,352	12
13	PJM Madison Non-Fuel	-	-	116,309	100,316	108,861	153,355	478,841	163,107	118,411	112,943	118,970	129,787	133,328	776,546	1,255,387	13
14	Total RTO Non-Fuel Costs	5,046,719	4,906,880	10,107,383	6,270,807	5,590,673	6,340,998	38,263,460	6,235,569	4,484,536	6,986,880	5,797,054	5,566,988	6,100,021	35,171,048	73,434,508	14
15	*Transmission Revenues*	(381,044)	(2,247,074)	(1,972,132)	(2,033,446)	(2,360,245)	(2,519,027)	(11,512,968)	(2,522,058)	(3,556,690)	(2,550,578)	(2,357,986)	(2,698,438)	(3,220,391)	(16,906,141)	(28,419,109)	15
16	Total Non-Fuel Costs & Transmission Revenues	4,665,675	2,659,806	8,135,251	4,237,361	3,230,428	3,821,971	26,750,492	3,713,511	927,846	4,436,302	3,439,068	2,868,550	2,879,630	18,264,907	45,015,399	16
17	Less: Amount in Base Rates	(385,916)	3,038,166	3,038,168	3,038,166	3,038,166	3,038,168	14,804,918	3,038,166	3,038,166	3,038,168	3,038,166	3,038,166	3,038,168	18,229,000	33,033,918	17
18	Net Total Actual	5,051,591	(378,360)	5,097,083	1,199,195	192,262	783,803	11,945,574	675,345	(2,110,320)	1,398,134	400,902	(169,616)	(158,538)	35,907	11,981,481	18
	Forecasted RTO Non-Fuel Costs & Transmission Revenues																
	Non-Fuel Costs																
19	Schedule 10 FERC	-	185,834	185,833	185,833	185,833	185,833	929,166	185,833	185,833	208,334	208,333	208,333	208,334	1,205,000	2,134,166	19
20	Schedule 10	-	452,250	452,250	452,250	452,250	452,250	2,261,250	452,250	452,250	458,334	458,333	458,333	458,334	2,737,834	4,999,084	20
21	Schedule 16	-	12,250	12,250	12,250	12,250	12,250	61,250	12,250	12,250	16,666	16,667	16,667	16,666	91,166	152,416	21
22	Schedule 17	-	397,000	397,000	397,000	397,000	397,000	1,985,000	397,000	397,000	425,000	425,000	425,000	425,000	2,494,000	4,479,000	22
23	Real Time Miscellaneous	-	84,916	84,917	84,917	84,916	84,917	424,583	84,917	84,917	85,000	85,000	85,000	85,000	509,834	934,417	23
24	Real Time Revenue Neutrality Uplift Amount	-	331,167	331,166	331,167	331,167	331,166	1,655,833	331,166	331,166	300,000	300,000	300,000	300,000	1,862,332	3,518,165	24
25	Real Time MVP Distribution Amount	-	(14,334)	(14,333)	(14,333)	(14,333)	(14,333)	(71,666)	(14,333)	(14,333)	(14,166)	(14,167)	(14,167)	(14,166)	(85,332)	(156,998)	25
26	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	-	700,000	700,000	700,000	700,000	700,000	3,500,000	700,000	700,000	583,334	583,333	583,333	583,334	3,733,334	7,233,334	26
27	Schedule 26 A - Multi-Value Projects	-	3,950,000	3,950,000	3,950,000	3,950,000	3,950,000	19,750,000	3,950,000	3,950,000	3,425,000	3,425,000	3,425,000	3,425,000	21,600,000	41,350,000	27
28	Schedule 26 C	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28
29	Schedule 26 D	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29
30	Schedule 49	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30
31	PJM Madison Non-Fuel	-	-	-	-	-	-	-			150,000	150,000	150,000	150,000	600,000	600,000	31
32	Total RTO Non-Fuel Costs	-	6,099,083	6,099,083	6,099,084	6,099,083	6,099,083	30,495,416	6,099,083	6,099,083	5,637,502	5,637,499	5,637,499	5,637,502	34,748,168	65,243,584	32
33	*Transmission Revenues*	-	(2,333,334)	(2,333,334)	(2,333,334)	(2,333,334)	(2,333,334)	(11,666,670)	(2,333,334)	(2,333,334)	(2,333,334)	(2,333,333)	(2,333,333)	(2,333,334)	(14,000,002)	(25,666,672)	33
34	Total Non-Fuel Costs & Transmission Revenues	-	3,765,749	3,765,749	3,765,750	3,765,749	3,765,749	18,828,746	3,765,749	3,765,749	3,304,168	3,304,166	3,304,166	3,304,168	20,748,166	39,576,912	34
35	Less: Amount in Base Rates	-	3,038,166	3,038,168	3,038,166	3,038,166	3,038,168	15,190,834	3,038,166	3,038,166	3,038,168	3,038,166	3,038,166	3,038,168	18,229,000	33,419,834	35
36	Net Total Actual	-	727,583	727,581	727,584	727,583	727,581	3,637,912	727,583	727,583	266,000	266,000	266,000	266,000	2,519,166	6,157,078	36
	Under (Over) Collected																
	Non-Fuel Costs																
37	Schedule 10 FERC	179,587	16,206	50,172	29,644	(25,519)	(8,658)	241,432	4,895	10,936	(21,380)	(26,084)	(45,751)	5,780	(71,604)	169,828	37
38	Schedule 10	253,880	(27,139)	68,878	(116,334)	(55,144)	59,265	183,406	125,092	55,618	(28,196)	59,326	214,453	62,457	488,750	672,156	38
39	Schedule 16	22,221	8,930	4,987	(237)	(3,543)	8,063	40,421	1,056	(3,708)	(5,005)	(7,676)	(9,614)	(4,822)	(29,769)	10,652	39
40	Schedule 17	393,120	26,387	7,206	47,748	(63,978)	181,615	592,098	46,462	(29,067)	(107,896)	(85,057)	(15,445)	12,850	(178,153)	413,945	40
41	Real Time Miscellaneous	322,652	(83,316)	(84,542)	(88,837)	(80,240)	(83,585)	(97,868)	(83,231)	(82,434)	(84,261)	(75,569)	(87,721)	(79,280)	(492,496)	(590,364)	41
42	Real Time Revenue Neutrality Uplift Amount	269,444	(289,061)	4,105,840	232,090	288,428	419,322	5,026,063	78,546	(2,047,112)	1,144,699	69,880	310,332	463,510	19,855	5,045,918	42
43	Real Time MVP Distribution Amount	(2,406)	12,042	11,824	11,298	11,566	11,593	55,917	(9,167)	(9,489)	(9,433)	(4,145)	(3,988)	(4,085)	(40,307)	15,610	43
44	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	526,934	(93,352)	(18,930)	(44,468)	(219,505)	(167,760)	(17,081)	(128,061)	9,162	17,564	8,216	(90,406)	105,691	(77,834)	(94,915)	44
45	Schedule 26 A - Multi-Value Projects	3,081,287	(764,577)	(255,184)	(1,248)	(480,789)	(343,161)	1,236,328	(74,469)	350,424	467,542	238,518	(335,441)	(96,319)	550,255	1,786,583	45
46	Schedule 26 C	-	1,012	1,050	1,059	1,058	1,039	5,218	1,048	1,594	1,604	1,669	1,682	1,719	9,316	14,534	46
47	Schedule 26 D	-	665	690	692	690	677	3,414	683	821	795	830	839	856	4,824	8,238	47
48	Schedule 49	-	-	-	-	9,705	10,150	19,855	10,525	10,297	10,402	10,677	10,762	10,834	63,497	83,352	48
49	PJM Madison Non-Fuel	-	-	116,309	100,316	108,861	153,355	478,841	163,107	118,411	(37,057)	(31,030)	(20,213)	(16,672)	176,546	655,387	49
50	Total RTO Non-Fuel Costs	5,046,719	(1,192,203)	4,008,300	171,723	(508,410)	241,915	7,768,044	136,486	(1,614,547)	1,349,378	159,555	(70,511)	462,519	422,880	8,190,924	50
51	*Transmission Revenues*	(381,044)	86,260	361,202	299,888	(26,911)	(185,693)	153,702	(188,724)	(1,223,356)	(217,244)	(24,653)	(365,105)	(887,057)	(2,906,139)	(2,752,437)	51
52	Total Non-Fuel Costs & Transmission Revenues	4,665,675	(1,105,943)	4,369,502	471,611	(535,321)	56,222	7,921,746	(52,238)	(2,837,903)	1,132,134	134,902	(435,616)	(424,538)	(2,483,259)	5,438,487	52
53	Less: Amount in Base Rates	(385,916)	-	-	-	-	-	(385,916)	-	-	-	-	-	-	-	(385,916)	53
54	Net Total Actual	5,051,591	(1,105,943)	4,369,502	471,611	(535,321)	56,222	8,307,662	(52,238)	(2,837,903)	1,132,134	134,902	(435,616)	(424,538)	(2,483,259)	5,824,403	54
55	Revenue Conversion Factor															1.00482	55
56	Amount to be Collected (Credited) Through Rider															5,852,477	56

PETITIONER'S EXHIBIT 1-E (AJB)
CAUSE NO. 42736 RTO-57

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

		RTO 55 _1/							RTO 56 _2/								
Line No.	Description	July 2020	August 2020 _3/	September 2020	October 2020	November 2020	December 2020	Sub-Total	January 2021	February 2021	March 2021	April 2021	May 2021	June 2021	Sub-Total	Total	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	
								Sum (A) to (F)							Sum (H) to (M)	(G)+(N)	
	Rider Revenues Approved for Recovery																
1	Rate RS	-	2,053,437	1,185,322	1,185,323	1,185,323	1,185,322	6,794,727	1,185,323	1,185,322	(179,681)	(179,681)	(179,681)	(179,680)	1,651,922	8,446,649	1
2	Rate CS	-	282,875	145,484	145,485	145,485	145,484	864,813	145,485	145,484	(11,044)	(11,045)	(11,044)	(11,045)	246,791	1,111,604	2
3	Rate LLF	-	1,014,275	583,232	583,233	583,233	583,232	3,347,205	583,233	583,232	(170,713)	(170,713)	(170,713)	(170,713)	483,613	3,830,818	3
4	Rate HLF	-	2,024,966	866,152	866,152	866,152	866,151	5,489,573	866,152	866,151	3,405	3,405	3,406	3,405	1,745,924	7,235,497	4
5	Customer L	-	14,069	8,331	8,331	8,331	8,332	47,394	8,331	8,332	(897)	(896)	(896)	(897)	13,077	60,471	5
6	Customer O	-	23,324	10,470	10,470	10,470	10,471	65,205	10,470	10,471	(4,657)	(4,658)	(4,658)	(4,657)	2,311	67,516	6
7	Rate WP	-	22,117	11,681	11,680	11,681	11,681	68,840	11,681	11,681	(4,376)	(4,376)	(4,376)	(4,375)	5,859	74,699	7
8	Rate SL	-	2,115	57	56	56	56	2,340	56	56	(360)	(359)	(359)	(360)	(1,326)	1,014	8
9	Rate MHLS	-	289	-	-	-	-	289	-	-	(105)	(105)	(105)	(105)	(420)	(132)	9
10	Rate MOLS and UOLS	-	6,537	3,181	3,180	3,181	3,181	19,260	3,181	3,181	(663)	(664)	(664)	(663)	3,708	22,968	10
11	Rates TS, FS and MS	-	2,119	648	647	647	648	4,709	647	648	(501)	(500)	(500)	(501)	(707)	4,002	11
12	Total	-	5,446,119	2,814,558	2,814,557	2,814,559	2,814,558	16,704,351	2,814,559	2,814,558	(369,592)	(369,592)	(369,590)	(369,591)	4,150,752	20,855,103	12
	Rider Revenues Actually Collected																
13	Rate RS	3,438,849	2,257,484	1,228,330	863,316	929,333	1,288,500	10,005,812	1,609,371	1,485,659	(105,091)	(142,399)	(129,334)	(165,481)	2,552,725	12,558,537	13
14	Rate CS	460,599	301,014	150,535	118,861	117,291	138,224	1,286,524	160,052	146,607	(3,498)	(8,863)	(8,572)	(10,802)	274,924	1,561,448	14
15	Rate LLF	1,544,749	1,084,852	642,630	574,209	561,830	597,181	5,005,451	614,624	553,489	(125,176)	(162,104)	(159,347)	(180,845)	540,641	5,546,092	15
16	Rate HLF	3,055,316	1,762,448	887,863	794,282	773,121	742,760	8,015,790	719,798	693,731	53,341	(6,951)	4,069	3,307	1,467,295	9,483,085	16
17	Customer L	11,969	7,078	3,018	2,911	3,063	2,958	30,997	3,042	3,044	(325)	(362)	(350)	(361)	4,688	35,685	17
18	Customer O	31,857	36,196	10,721	10,363	10,778	10,416	110,331	10,751	10,753	(4,284)	(4,745)	(4,592)	(4,745)	3,138	113,469	18
19	Rate WP	35,504	22,453	12,390	11,790	11,390	12,296	105,823	13,298	11,906	(3,869)	(4,336)	(4,282)	(4,692)	8,025	113,848	19
20	Rate SL	3,971	3,956	50	52	50	52	8,131	51	51	(352)	(351)	(357)	(350)	(1,308)	6,823	20
21	Rate MHLS	465	288	-	-	-	-	753	-	-	(103)	(98)	(86)	(83)	(370)	383	21
22	Rate MOLS and UOLS	9,272	9,251	2,986	2,920	2,964	2,991	30,384	2,983	2,843	(488)	(585)	(578)	(573)	3,602	33,986	22
23	Rates TS, FS and MS	3,517	3,087	657	653	657	695	9,266	709	647	(469)	(490)	(483)	(482)	(568)	8,698	23
24	Total	8,596,068	5,488,107	2,939,180	2,379,357	2,410,477	2,796,073	24,609,262	3,134,679	2,908,730	(190,314)	(331,284)	(303,912)	(365,107)	4,852,792	29,462,054	24
	Under (Over) Collected																
25	Rate RS	(3,438,849)	(204,047)	(43,008)	322,007	255,990	(103,178)	(3,211,085)	(424,048)	(300,337)	(74,590)	(37,282)	(50,347)	(14,199)	(900,803)	(4,111,888)	25
26	Rate CS	(460,599)	(18,140)	(5,051)	26,624	28,194	7,260	(421,712)	(14,567)	(1,123)	(7,546)	(2,182)	(2,472)	(243)	(28,133)	(449,845)	26
27	Rate LLF	(1,544,749)	(70,578)	(59,398)	9,024	21,403	(13,949)	(1,658,247)	(31,391)	29,743	(45,537)	(8,609)	(11,366)	10,132	(57,028)	(1,715,275)	27
28	Rate HLF	(3,055,316)	262,518	(21,711)	71,870	93,031	123,391	(2,526,217)	146,354	172,420	(49,936)	10,356	(663)	98	278,629	(2,247,588)	28
29	Customer L	(11,969)	6,991	5,313	5,420	5,268	5,374	16,397	5,289	5,288	(572)	(534)	(546)	(536)	8,389	24,786	29
30	Customer O	(31,857)	(12,872)	(251)	107	(308)	55	(45,126)	(281)	(282)	(373)	87	(66)	88	(827)	(45,953)	30
31	Rate WP	(35,504)	(337)	(709)	(110)	291	(615)	(36,984)	(1,617)	(225)	(507)	(40)	(94)	317	(2,166)	(39,150)	31
32	Rate SL	(3,971)	(1,842)	7	4	6	4	(5,792)	5	5	(8)	(8)	(2)	(10)	(18)	(5,810)	32
33	Rate MHLS	(465)	1	-	-	-	-	(465)	-	-	(2)	(7)	(19)	(22)	(50)	(515)	33
34	Rate MOLS and UOLS	(9,272)	(2,715)	195	260	217	190	(11,125)	198	338	(175)	(79)	(86)	(90)	106	(11,019)	34
35	Rates TS, FS and MS	(3,517)	(969)	(9)	(6)	(10)	(47)	(4,558)	(62)	1	(32)	(10)	(17)	(19)	(139)	(4,697)	35
36	Total	(8,596,068)	(41,988)	(124,622)	435,200	404,082	18,485	(7,904,911)	(320,120)	(94,172)	(179,278)	(38,308)	(65,678)	(4,484)	(702,040)	(8,606,951)	36

_1/ During the pendency of the Company's most recent retail base rate case filing in Cause No. 45253, the Company suspended its RTO filings therefore the RTO55 rates have remained in effect until approval of new RTO rates in the Company's Compliance filing which was approved for billing effective July 30, 2020. Compliance filing rates remained in effect until approval of RTO 56 rates approved for billing March 2021 - Billing Cycle 1.

_2/ The Company's rates in RTO 56 were approved on February 24, 2021 and began billing March 2021 - Billing Cycle 1.

_3/ August 2020 approved rider revenues for recovery have been pro-rated to reflect the services-rendered implementation of rates as approved in the Company's Compliance Filing in Cause No. 45253 dated June 29, 2020 (50% RTO-55 and 50% RTO-55 Compliance Filing)

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's

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	$ 0.000172	$ 130.99	$ 1.73	$ 132.72	$ 0.17	$ 132.89	$ 0.41	0.31%	1
2	Current Approved Factor	$ (0.000237)	$ 130.99	$ 1.73	$ 132.72	$ (0.24)	$ 132.48	NA	NA	2

(1) Reflects base rates approved in the Company's Compliance filing in Cause No. 45253, effective July 30, 2020.
(2) Reflects Rider No. 68 rates in effect 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 57

				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 20 the Midcontinent ISO currently estimates that Duke Energy Indiana's share of allocated project costs through 2035 is an average of approximately $11.1 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 57

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	$ 7,910,823.95	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	$ 5,556,058.50	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 20 the Midcontinent ISO currently estimates that Duke Energy Indiana's share of allocated project costs through 2041 is an average of approximately $48.3 million annually.

PETITIONER'S EXHIBIT 1-I (AJB)
CAUSE NO. 42736 RTO-57
PAGE 1 OF 1

DUKE ENERGY INDIANA, LLC

COMPONENTS OF REVENUE CONVERSION FACTOR

Components of Revenue Conversion Factor:	Statutory	Effective Rate
Utility Receipts Tax	1.400%	1.400%
Uncollectible Accounts Expense	0.280%	0.280%
Public Utility Fee	0.128%	0.128%
Supplemental Corporate Net Income Tax	4.900%	0.072%
Federal Income Tax	21.000%	-
Subtotal Effective Rate		1.880%
Remove Utility Receipts Tax	1.400%	1.400%
Total Effective Rate		0.480%
Complement (1 - Effective Rate)		99.520%
Revenue Conversion Factor (1 ÷ Complement)		1.00482

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

(1) VERIFIED PETITION

Petitioner's Exhibit 1-A – Proposed Duke Energy Indiana Rider No. 68, showing proposed adjustment factors

(2) DIRECT TESTIMONY OF ART J. BUESCHER III

Petitioner's Exhibit 1-A (AJB):	Proposed Duke Energy Indiana Rider No. 68, showing proposed adjustment factors.
Petitioner's Exhibit 1-B (AJB):	Determination of the Regional Transmission Operator ("RTO") Non-Fuel Costs and Revenue Adjustment Factors by Rate Group to be Applied to Customer Bills Over a Twelve Month Period.
Petitioner's Exhibit 1-C (AJB):	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 2022.
Petitioner's Exhibit 1-D (AJB):	Reconciliation of Amounts Forecasted for Regional Transmission Operator ("RTO") Non-Fuel Costs and Revenues Versus Actual Amounts Incurred for the July 2020 Through June 2021 Period.
Petitioner's Exhibit 1-E (AJB):	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.
Petitioner's Exhibit 1-F (AJB):	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's.
Petitioner's Exhibit 1-G (AJB):	Company-Owned Schedule 26 Project Status and Estimate of Allocated Schedule 26 Costs.
Petitioner's Exhibit 1-H (AJB):	Company-Owned Schedule 26-A Project Status and Estimate of Allocated Schedule 26-A Costs.
Petitioner's Exhibit 1-I (AJB):	Components of Revenue Conversion Factor.
Petitioner's Exhibit 1-J (AJB):	Standard Format for Duke Energy Indiana Filings - Rider No. 68 - IURC Cause No. 42736-RTO.
Petitioner's Exhibit 1-K (AJB):	Standard Audit Path for Duke Energy Indiana - Rider No. 68 - IURC Cause No. 42736-RTO.

(3) WORKPAPERS OF ART BUESCHER

Workpaper 1 (AJB):	Kilowatt-Hour Sales by Rate Schedule for the Twelve Months Ended June 30, 2021.
Workpaper 2 (AJB):	Twelve Months Ended June 2021 HLF Billing KW (NCP).

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

Workpaper 3 (AJB):	Aggregation of Regional Transmission Operator Non-Fuel Cost and Revenue Adjustment Revenues Collected During the Twelve Month Period Ending June 2021.
Workpaper 4 (AJB):	MISO Invoice Detailing Schedule 10 Costs for Demand and Energy.
Workpaper 5 (AJB):	Allocation of MISO FERC Fees to Operating Companies and Business Units.
Workpaper 6 (AJB):	Allocation to Derive Duke Energy Indiana's Portion of MISO Schedule 10 Costs.
Workpaper 7 (AJB):	Data Query for Accounts 561400, 561800 and 575700 Showing the Wholesale and Retail Amounts of Schedule 10 Costs.
Workpaper 8 (AJB):	Restatement of Detail Provided by MISO for Transmission Revenues Collected Under the MISO TEMT, or Any Successor Tariff.
Workpaper 9 (AJB):	Summarized Schedule of the MISO Transmission Revenue Schedules.
Workpaper 10 (AJB):	Derivation of Duke Energy Indiana's Retail Portion of the MISO Transmission Revenues.
Workpaper 11 (AJB):	Derivation of Duke Energy Indiana's Retail Portion of PJM Charges and Credits Associated with Madison Generating Station.
Workpaper 12 (AJB):	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 13 (AJB):	MISO Invoice Detailing Schedule 26 and Schedule 26A (MVP) Charges.
Workpaper 14 (AJB):	Duke Energy Indiana MISO Attachment GG – Calculation of Revenue Requirement for Company-Owned Schedule 26 RECB Projects.
Workpaper 15 (AJB):	Duke Energy Indiana MISO Attachment MM – Calculation of Revenue Requirement for Company-Owned Schedule 26-A MVP Projects.

(4) DIRECT TESTIMONY OF JAMES (BRAD) DANIEL

Petitioner's Exhibit 2-A (JBD): Appendix A: Description of PJM Charges and Credits.

STANDARD AUDIT PATH FOR DUKE ENERGY INDIANA
RIDER NO. 68 – IURC CAUSE NO. 42736-RTO

Workpaper 1 (AJB): Kilowatt Hour Sales by Rate Schedule for the Twelve Months Ended June 30 2021 Listed on Petitioner's Exhibit 1-B (AJB).

Workpaper 2 (AJB): KW Demands for HLF Rate Class Listed on Petitioner's Exhibit 1-B (AJB).

Workpaper 3 (AJB): Determination of Duke Energy Indiana Rider No. 68 Revenues Charged or Credited for the Reconciliation Months as Listed on Petitioner's Exhibit 1-E (AJB).

Workpaper 4 (AJB): Miso Invoice Detailing Schedule 10 Costs for Demand and Energy.

A) Current Month Native Load Schedule 10 Costs for Demand and Energy, Plus Any Adjustments Carried to Workpaper 5 (AJB).

Workpaper 5 (AJB): Allocation of MISO FERC Fees to Operating Companies and Business Units.

A) Monthly MISO FERC Fee Amounts listed on Petitioner's Exhibit 1-B (AJB), Page 1 of 2, Filed with Duke Energy Indiana's Testimony.

Workpaper 6 (AJB): Allocation to Derive Duke Energy Indiana's Portion of MISO Schedule 10 Costs.

A) Native Load Schedule 10 Demand and Energy Costs and Rates from Workpaper 3 (AJB).

B) Duke Energy Indiana Portion of Total Charges Less Wholesale Costs From Workpaper 7 (AJB) equals amount journalized in account 561000 and 575700 as Shown on Workpaper 7 (AJB).

Workpaper 7 (AJB): Data Query for Accounts 561400, 561800 and 575700 Showing the Wholesale and Retail Amounts of Schedule 10 Costs.

A) General Ledger Detail for Accounts 561400, 561800 and 575700 Broken Up Into Estimated and Final Amounts for Retail and Wholesale Costs for the Relevant Time Period.

Workpaper 8 (AJB): 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 (AJB). Allocation to Operating Company.

Workpaper 9 (AJB): 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 10 (AJB): Derivation of Duke Energy Indiana's Retail Portion of the MISO Transmission Revenues for the Reconciliation Period as Reported on Petitioner's Exhibit 1-E (AJB), filed with Duke Energy Indiana's Direct 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 for July 2020

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(96.291%) from the IURC Order in Cause No. 42736 and for August 2020 through June 2021 (100.000%) from IURC Order in Cause No. 45253. (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 11 (AJB): Derivation of Duke Energy Indiana's Retail Portion of PJM Charges and Credits Associated with Madison Generating as Approved in Cause No. 45253.

Workpaper 12 (AJB): Calculation of Duke Energy Indiana's Retail Portion of MISO Administrative Fees, Schedules 16 and 17 Costs, as well as, 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 for July 2020 (96.291%) is from the IURC Order in Cause No. 42736 and for August 2020 through June 2021 (100.000%) from IURC Order in Cause No. 45253.

Workpaper 13 (AJB): MISO Invoice Detailing Schedule 26 and Schedule 26A (MVP) Charges.

Workpaper 14 (AJB): Duke Energy Indiana MISO Attachment GG – Calculation or Revenue Requirement for Company-Owned Schedule 26 RECB Projects.

Workpaper 15 (AJB): Duke Energy Indiana MISO Attachment MM – Calculation of Revenue Requirement for Company-Owned Schedule 26-A MVP Projects.

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: Art J Buescher III
Art J. Buescher III

Dated: 8-31-21