

FILED
November 10, 2020
INDIANA UTILITY
REGULATORY COMMISSION

OFFICIAL
EXHIBITS

PETITIONER'S EXHIBIT 1

IURC CAUSE NO. 42736 RTO-56
DIRECT TESTIMONY OF ART J. BUESCHER III
FILED NOVEMBER 10, 2020

TESTIMONY OF ART J. BUESCHER III
LEAD RATES AND REGULATORY STRATEGY ANALYST
DUKE ENERGY INDIANA, LLC
CAUSE NO. 42736 RTO-56

IURC
PETITIONER'S
EXHIBIT NO. 1
DATE 1-11-21 REPORTER JR

BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

1
2 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

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

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

6 A. I am employed by Duke Energy Indiana, LLC ("Duke Energy Indiana,"
7 "Petitioner" or "Company"), a wholly-owned subsidiary of Duke Energy
8 Corporation ("Duke Energy"), as Lead Rates and Regulatory Strategy Analyst in
9 Duke Energy Indiana's Rate Department.

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

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

15 **Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL AND**
16 **EDUCATIONAL BACKGROUND.**

ART J. BUESCHER III

1 A. I graduated from of the University of Indianapolis in May of 1988 with a
2 Bachelor of Science Degree in Accounting. I was employed by the Company in
3 June 1988. During my employment with the Company, I have held various
4 financial and accounting positions supporting the Company and its affiliates.
5 Prior to my move to the Rates and Regulatory Planning department in 2007, I
6 held various financial and accounting positions in Cost Accounting, Internal
7 Auditing, Energy Trading Accounting, and as Supervisor, Fuels and Joint
8 Ownership Accounting.

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

11 A. My testimony in this proceeding supports the Company's request for approval of
12 the proposed Rider No. 68 adjustment factors for the Company's Standard
13 Contract Rider No. 68 ("Rider No. 68" or "RTO"), which includes a new
14 projection as well as a reconciliation for prior historical periods. I will also
15 explain any changes the Company is making to Rider No. 68 as a result of the
16 Company's most recent retail base rate case approved by the Commission on June
17 29, 2020 in Cause No. 45253 ("June 29, 2020 Order" or "Cause No. 45253").

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

21 A. The applicable non-fuel costs and transmission revenues for the reconciliation
22 period of July 2018 through June 2020 are included in this proceeding. During the

1 pendency of its most recent retail base rate case, the Company temporarily
2 suspended the Rider No. 68 filings, and therefore, this proceeding reflects
3 reconciliation for twenty-four (24) months of historical data vs. the typical twelve
4 (12) months.

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

8 A. The forecasted amounts for applicable costs and transmission revenues are
9 included for the months of January 2021 through December 2021.

10 **II. BACKGROUND**

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

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

1 **Q. PLEASE EXPLAIN THE SPECIFIC CHANGES TO THE COMPANY'S**
2 **RTO RIDER RESULTING FROM DUKE ENERGY INDIANA'S**
3 **CURRENT BASE RATE ORDER.**

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

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

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

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

IURC CAUSE NO. 42736 RTO-56
DIRECT TESTIMONY OF ART J. BUESCHER III
FILED NOVEMBER 10, 2020

1 should continue to provide for the Company's non-fuel related MISO cost
2 recovery under Energy Markets operations.

3 The Commission later approved, in its December 19, 2007 Order in Cause
4 No. 42736, the recovery of Schedule 26 ("Network Upgrade Charge from
5 Transmission Expansion Plan") costs assessed the Company by MISO as part of
6 the Regional Expansion and Criteria and Benefits ("RECB") process through
7 Rider No. 68, whether those costs are associated with transmission projects of
8 other transmission owners or whether those costs are associated with the
9 Company's RECB projects. Furthermore in the June 25, 2008 Order in Cause No.
10 42736, the Commission approved the Company's proposal for recovery of RECB
11 Schedule 26 charges on Company-owned, MISO approved RECB transmission
12 projects. Later in my testimony I provide further discussion on the regulatory
13 treatment of the Company's RECB projects and Petitioner's Exhibit 1-H (AJB)
14 provides information on these Company-owned, MISO approved RECB projects,
15 including estimates of Schedule 26 costs.

16 In the Commission's September 24, 2008 Order in Cause No. 42736 and
17 the Commission's June 30, 2009 Order in Cause No. 42736, the Commission
18 approved the Company's recovery of charges and credits associated with its
19 participation in the MISO Ancillary Services Market ("ASM"). Specifically, the
20 Company began including the following ASM charge types in its Rider No. 68
21 filings: (a) the Real Time Revenue Neutrality Uplift Amount exclusive of the
22 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 requested regulatory treatment of the Company's MVP projects. Petitioner's Exhibit 1-I (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.

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

1 in 2011. In June of 2020, the Company submitted to MISO its revised annual
2 revenue requirement for these projects for changes in the approved return on
3 equity ("ROE"), which totaled \$3,003,270, and the Company, as a transmission
4 owner, began receiving updated revenues July 1, 2020. These RECB projects are
5 listed on Petitioner's Exhibit 1-H (AJB). The Company, as a transmission
6 customer, also pays MISO its share of the corresponding Schedule 26 costs.

7 **Q. PLEASE BRIEFLY EXPLAIN YOUR UNDERSTANDING OF THE**
8 **COMMISSION'S DECEMBER 27, 2019 ORDER IN CAUSE NO. 38707**
9 **FAC 122 ("DECEMBER 27, 2019 ORDER") PERTAINING TO THE**
10 **PROPOSED TREATMENT OF MULTI-VALUE PROJECT ("MVP")**
11 **RELATED REVENUES UNDER MISO'S SCHEDULE 26-A.**

12 A. The December 27, 2019 Order directed the Company to provide more detail in its
13 next RTO filing (RTO 56) regarding its MVP projects as it relates to the RTO
14 rider. The Company began receiving Schedule 26-A revenues from MISO in
15 June 2019 related to the Company's own MVPs. The Company proposes to retain
16 the Schedule 26-A revenues received from MISO for Company-owned MVPs,
17 similar to the treatment approved from Company-owned RECB projects.

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

20 A. Yes, the Company has two (2) MISO MVP projects. These two (2) projects
21 consist of three (3) facilities which are comprised of eight (8) separate detail
22 projects. The first detail project went in service May 2018, three (3) went in

1 service June 2018, one (1) went in service June 2019, and one (1) went in service
2 September 2019. The remaining two (2) detail projects are projected to be in
3 service by December 2020.

4 The three (3) facilities are as follows:

- 5 • MTEP Project ID 2237 is the Sugar Creek to Kansas 345 kV line
6 project known as MISO Facility ID 8313, which consists of four (4)
7 detail projects of which two (2) were in service at the end of 2019, and
8 are therefore, included in the Company's MISO Attachment MM for
9 recovery through Schedule 26-A. The final two (2) detail projects are
10 estimated to be in service by December 2020;
- 11 • MTEP Project ID 2202 is the Reconductor Wabash to Wabash
12 Container Section project known as Facility ID 7286, which consists
13 of two (2) detail projects of which both were in service as of June
14 2018.
- 15 • MTEP Project ID 2202 is the Kokomo Delco to Greentown 138 kV
16 Uprate project known as MISO Facility 7287, which consists of two
17 (2) detail projects with the first in service May 2018 and the second in
18 service June 2018.

19 In June of 2020, the Company submitted to MISO its revised annual revenue
20 requirement for these projects for changes in the approved ROE, which totaled
21 \$790,326, and the Company, as a transmission owner, began receiving revenues
22 July 1, 2020.

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

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

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

8 A. Yes, the Company has excluded the applicable revenues and expenses related to
9 its own RECB and MVP Projects from the FAC Earnings Test. See the direct
10 testimony of Company witness Suzanne E. Sieferman in Cause No. 38707 FAC-
11 126, which discusses the adjustments to the Company's Earnings Test to exclude
12 revenues and expenses associated with its own RECB and MVP projects.

13 **III. OVERVIEW OF RIDER NO. 68**

14 **Q. PLEASE BRIEFLY DESCRIBE THE COSTS AND TRANSMISSION**
15 **REVENUES COVERED BY RIDER NO. 68.**

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

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

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

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

4 A. Yes. Beginning in January 2020, MISO began assessing charges under the charge
5 type Schedule 49 Cost Allocation for Available Capacity Usage ("Schedule 49").
6 Schedule 49 compensates the Southwest Power Pool ("SPP") for available system
7 capacity usage by MISO on a North-South SPP tie line. Previously these charges
8 have been part of the Real Time Miscellaneous Amount charge type and have
9 now been moved to a separate and distinct charge type for greater transparency.
10 The reconciliation period of July 2018 through June 2020 contains \$290,523 in
11 charges under Schedule 49.

12 The Company also began receiving charges under MISO Schedule 26-C,
13 Cost Recovery For Targeted Market Efficiency Projects ("TMEPs") Constructed
14 By MISO Transmission Owners, for MISO TMEP cost-shared projects and MISO
15 Schedule 26-D, Cost Recovery for Targeted Market Efficiency Projects
16 Constructed By PJM Transmission Owners. Targeted Market Efficiency Projects
17 are FERC accepted, interregional projects in the MISO-PJM Joint Operating
18 Agreement to reduce congestion on known Reciprocal Coordinated Flowgates
19 along the border between MISO and PJM to benefit customers and improve
20 coordination between the RTOs.

21 The reconciliation period of July 2018 through June 2020 contains \$5,063
22 in charges under Schedule 26-C and \$3,347 in charges under Schedule 26-D. The

IURC CAUSE NO. 42736 RTO-56
DIRECT TESTIMONY OF ART J. BUESCHER III
FILED NOVEMBER 10, 2020

1 Company has not estimated any charges for Schedule 49, Schedule 26-C or
2 Schedule 26-D to include in the forecasted period of January through December
3 2021. Actual charges under these schedules will be reconciled in a future RTO
4 tracker filing.

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

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

16 On May 21, 2020 FERC issued Opinion No. 569-A which revised the
17 ROE methodology in Opinion No. 569. Opinion No. 569-A found that the MISO
18 Transmission Owners’ base ROE should be set at 10.02% and ordered refunds
19 with interest for the First Refund Period previously defined and the Second
20 Refund Period through the date of Opinion No. 569-A (May 21, 2020).
21 Prior to the issuance of Opinion No. 569-A, MISO had begun the refund process
22 using the ROE from Opinion No. 569. As a result, on May 28, 2020, MISO

1 announced they were pausing the current resettlement efforts under Opinion No.
2 569 due to the complexity of the resettlements with the slightly higher ROE under
3 Opinion 569-A. On August 5, 2020, MISO announced that a refund approach had
4 been developed and that the majority of the resettlement dollars would change
5 hands in 2021 and that refunds and adjustments for all applicable periods would
6 be completed by May or June 2022. Refunds and adjustments are currently due
7 for completion by December 23, 2020. On September 9, 2020, MISO submitted a
8 request for extension to FERC to approve the timelines outlined above. The
9 Company will provide all required ROE refunds to its retail customers in a timely
10 manner through the RTO tracker pursuant to the timelines established by FERC
11 and MISO.

12 MISO issued refunds related to the FERC Opinion No. 569, prior to pause,
13 in the April 2020 billing cycle. As the Company is both a transmission owner and
14 a transmission customer, both charges and credits related to the April 2020
15 portion of the ROE refund have been included in this filing. The net credit
16 included in this filing on Petitioner's Exhibit 1-D (AJB) is \$129,238.

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

19 A. For purposes of forecasting the Schedule 26 and 26-A charges, the Company
20 started with projected data available from MISO to reflect the charges by other
21 market participants that will be applicable to Duke Energy Indiana. For the
22 remaining charges, credits and revenues, the forecasted amounts were based on a

1 twenty-four (24) month history of these items and then were adjusted for any
2 known or anticipated changes. As the Company becomes more experienced with
3 forecasting these costs, the methods utilized may evolve over time.

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

6 A. There is a reconciliation step included in the Rider No. 68 process to adjust for (a)
7 any variances between the Company's projected RTO costs and transmission
8 revenues versus actual RTO costs and transmission revenues incurred and (b)
9 variances between the previous RTO tracker amounts by retail rate group
10 authorized for recovery versus the actual RTO revenues collected by retail rate
11 group. The reconciliation in the current proceeding includes the months of July
12 2018 through June 2020 and is shown in Columns C and D of Petitioner's Exhibit
13 1-B (AJB).

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

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

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

5 A. To the extent that the costs or transmission revenues identified in the formula set
6 forth in the Rider No. 68 Tariff are not accounted for separately for the
7 Company's retail electric customers, then the total Company amount of such
8 costs or transmission revenues, whichever is applicable, will be multiplied by the
9 Commission-approved retail allocator for the applicable period to determine the
10 retail electric jurisdictional portion of such costs or transmission revenues. In the
11 Company's Current Base Rate Order (Cause No. 45253) the retail allocator for
12 transmission is 100%, while the transmission allocator from the prior retail base
13 rate case (Cause No. 42359, effective through July 2020) was 96.291%.

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

16 A. The revenue conversion factor used for this proceeding is 1.00484. See
17 Petitioner's Exhibit 1-J (AJB) for the underlying calculation of this factor.

18 **IV. PROPOSED RIDER NO. 68 ADJUSTMENT FACTORS**

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

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

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

5 A. Yes, I have. Petitioner's Exhibit 1-B (AJB) includes projected RTO costs and
6 transmission revenues (Column B) and a reconciliation of prior historical amounts
7 (Columns C and D) broken down by retail rate group for those specific MISO and
8 PJM cost components I have discussed in my testimony that were previously
9 approved by the Commission, as well as the three (3) new MISO charge types
10 being requested for inclusion in Rider No. 68 rates via the current RTO
11 proceeding. The resulting revenue requirement totals for each retail rate group
12 (except for HLF) (Column E) are divided by the corresponding kWh sales for the
13 twelve (12)-months ended June 30, 2020. For developing the HLF rates, the
14 revenue requirement amount is divided by KW demands for the twelve (12)-
15 months ended June 30, 2020 to determine the proposed Rider No. 68 rate. These
16 factors by respective retail rate groups are then used on Page 3 of 3 of Petitioner's
17 Exhibit 1-A (AJB). The total amount that the Company proposes to be credited to
18 the Company's retail electric customers through Rider No. 68, taking into account
19 the reconciliation amount, is \$4,435,100.

20 The prefiled Testimony of Mr. James (Brad) Daniel, Petitioner's Exhibit
21 2, supports the reasonableness of the Company's Energy Markets and ASM non-
22 fuel related costs.

IURC CAUSE NO. 42736 RTO-56
DIRECT TESTIMONY OF ART J. BUESCHER III
FILED NOVEMBER 10, 2020

1 **Q. WAS THERE ANY SINGLE ADJUSTMENT IN EXCESS OF \$3 MILLION**
2 **INCLUDED IN THIS PROCEEDING?¹**

3 A. No.

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

5 A. Petitioner's Exhibit 1-C (AJB) compares the forecasted non-fuel RTO costs and
6 transmission revenues for the forecasted periods of January 2021 through
7 December 2021 to the Company's annual charges built into base retail electric
8 rates in Cause No. 45253. The total to be recovered from (or credited to)
9 customers is shown on Petitioner's Exhibit 1-B (AJB), Column (B).

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

11 A. Petitioner's Exhibit 1-D (AJB) compares the previously projected RTO non-fuel
12 costs and transmission revenues (developed in RTO 55) to actual non-fuel costs
13 and transmission revenues incurred during the reconciliation period of July 2018
14 through June 2020. The total to be recovered from (or credited to) customers
15 from this portion of the reconciliation is shown on Petitioner's Exhibit 1-B (AJB),
16 Column (C).

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

18 A. Petitioner's Exhibit 1-E (AJB) compares the actual amount of Rider No. 68
19 revenues charged to customers at the retail rate group level to the amounts

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.

1 approved by the Commission for recovery during the reconciliation periods of
2 July 2018 through June 2020. The total to be recovered from (or credited to)
3 customers for this item is shown on Petitioner's Exhibit 1-B (AJB), Column (D).

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

5 A. Petitioner's Exhibit 1-F (AJB) compares the bill of a typical residential customer
6 using 1000 kilowatt-hours per month based upon the proposed Rider No. 68
7 adjustment factor to the bill of a typical residential customer using 1000 kilowatt-
8 hours per month based upon the most recently approved rate. Under the proposed
9 Rider No. 68 adjustment, a typical residential customer will experience a decrease
10 of \$1.78² on his or her electric bill when compared to the bills reflecting the
11 current Rider No. 68 rate. This is a 1.4%³ decrease to each residential customer's
12 electric bill.

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

14 A. Petitioner's Exhibit 1-G (AJB) compares the projected non-fuel costs and
15 transmission revenues to the actual non-fuel charges and transmission revenues
16 incurred during the reconciliation period of July 2018 through June 2020. The
17 reconciliation amounts calculated in Column (C) of Petitioner's Exhibit 1-G
18 (AJB) were derived using the approved retail rate group allocation factors from
19 Cause No. 42359 in effect during the reconciliation period of July 2018 through

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 the time of this filing of \$127.59, excluding utility receipts and sales tax.

1 June 2020. Amounts in Column (C) of Petitioner's Exhibit 1-G (AJB) are carried
2 forward to Column (C) of Petitioner's Exhibit 1-B (AJB).

3 **Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 1-H (AJB).**

4 A. Petitioner's Exhibit 1-H (AJB) provides information relating to Company-owned,
5 MISO-approved RECB projects and provides an estimate of Schedule 26 costs to
6 be allocated to the Company based on information provided by MISO.

7 **Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 1-I (AJB).**

8 A. Petitioner's Exhibit 1-I (AJB) provides information relating to Company-owned,
9 MISO-approved MVP projects and provides an estimate of Schedule 26-A costs
10 to be allocated to the Company based on information provided by MISO.

11 **Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 1-J (AJB).**

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

18 **Q. PLEASE EXPLAIN PETITIONER'S EXHIBITS 1-K (AJB) AND 1-L**
19 **(AJB).**

20 A. The standard format for Duke Energy Indiana filings (labeled as Petitioner's
21 Exhibit 1-K (AJB) in this proceeding) and the Standard Audit Path (labeled as

Petitioner's Exhibit 1-L (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 4. The Company requests that the Commission find
that the Rider No. 68 adjustment factors for the Company's bills rendered
beginning with the March 2021 – 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-L (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

FILED
November 16, 2020
INDIANA UTILITY
REGULATORY COMMISSION

**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.

Issued:

**Effective: Bills Rendered
March 2021 - Bill Cycle 1**

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

IURC No. 15
 First Revised Sheet No. 68
 Cancels and Supersedes
 Original Sheet No. 68
 Page 2 of 3

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:

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 March 2021 - Bill Cycle 1

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

IURC No. 15
 First Revised Sheet No. 68
 Cancels and Supersedes
 Original Sheet No. 68
 Page 3 of 3

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

<u>Line No.</u>	<u>Retail Rate Group</u>	<u>RTO Non-Fuel Cost and Revenue Adjustment Factor Per KWH 1/ (A)</u>	<u>RTO Non-Fuel Cost and Revenue Adjustment Factor Per Non-Coincident KW (B)</u>	<u>Line No.</u>
1	Rate RS	(\$0.000237)		1
2	Rates CS and FOC	(0.000130)		2
3	Rate LLF	(0.000412)		3
4	Rate HLF		\$0.002183	4
5	Customer L	(0.000105)		5
6	Customer O	(0.000354)		6
7	Rate WP	(0.000347)		7
8	Rate SL	(0.000115)		8
9	Rate MHLS	(0.000226)		9
10	Rates MOLS and UOLS	(0.000076)		10
11	Rates TS, FS and MS	(0.000624)		11

1/ Proposed factors above reflect calculations, peak load allocators and base amounts approved by the Commission in Cause No. 42359 as applied to data for the historical periods of July 2018 through June 2020.

Issued:

**Effective: Bills Rendered
 March 2021 - Bill Cycle 1**

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 (A)	Projected RTO Non-Fuel Costs and Transmission Revenues By Rate Group for Calendar Year 2021 to be Collected through Standard Contract Rider No. 68 - 1/ (B)	Reconciliation of Amounts Projected for RTO Non-Fuel Costs and Transmission Revenues vs. Actual Amounts Incurred through the July 2018 through June 2020 Period - 2/ (C)	Reconciliation of RTO Non-Fuel Costs and Transmission Revenues Approved for Recovery vs. Actual RTO Revenues Collected for the July 2018 through June 2020 Period (D)	Total (E) = (B) + (C) + (D)	Actual Kilowatt-Hour Sales For The Twelve Months Ended June 30, 2020 (F)	RTO Non-Fuel Costs and Revenue Adjustment Factors Per Kilowatt-Hour By Rate Group (G)	Actual Sum of Monthly Non-Coincident Peak Demands for the Twelve Months Ended June 30, 2020 (H)	RTO Non-Fuel Costs and Revenue Adjustment Factors Per Non-Coincident Peak Demands (I)	Line No.
1	Rate RS	42.114%	\$ 1,350,785	\$ 18,534,034	\$ (22,040,989)	\$ (2,156,170)	9,082,070,680	(\$0.000237)			1
2	Rates CS	5.169%	165,793	2,627,173	(2,925,501)	(132,535)	1,018,034,163	(0.000130)			2
3	Rate LLF	20.722%	664,648	9,031,501	(11,744,806)	(2,048,557)	4,969,585,143	(0.000412)			3
4	Rate HLF	30.774%	987,060	19,511,448	(20,557,546)	40,862	9,846,518,863		18,716,412	\$0.002183	4
5	Customer L	0.296%	9,494	122,628	(142,879)	(10,757)	102,497,201	(0.000105)			5
6	Customer O	0.372%	11,932	223,052	(290,875)	(55,891)	158,042,619	(0.000354)			6
7	Rate WP	0.415%	13,311	201,857	(267,678)	(52,510)	151,361,346	(0.000347)			7
8	Rate SL	0.002%	64	25,737	(30,113)	(4,312)	37,474,042	(0.000115)			8
9	Rate MHLS	0.000%	-	3,533	(4,794)	(1,261)	5,581,904	(0.000226)			9
10	Rates MOLS and UOLS	0.113%	3,524	61,062	(72,650)	(7,954)	104,464,399	(0.000076)			10
11	Rates TS, FS and MS	0.023%	738	22,204	(28,947)	(6,005)	9,622,323	(0.000624)			11
12	TOTAL RETAIL	100.000%	\$ 3,207,449	\$ 50,464,329	\$ (58,106,878)	\$ (4,435,100)	25,485,252,583				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 in Column (B) on Line 12.

DUKE ENERGY INDIANA, LLC

DETERMINATION OF THE PROJECTED REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COSTS AND TRANSMISSION REVENUES TO BE RECOVERED OR CREDITED THROUGH RIDER 68 FOR THE TWELVE MONTHS ENDED DECEMBER 2021

Line No.	Description	January 2021	February 2021	March 2021	April 2021	May 2021	June 2021	July 2021	August 2021	September 2021	October 2021	November 2021	December 2021	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	208,333	208,333	208,334	208,333	208,333	208,334	208,333	208,333	208,334	208,333	208,333	208,334	2,500,000	1
2	Schedule 10	458,333	458,333	458,334	458,333	458,333	458,334	458,333	458,333	458,334	458,333	458,333	458,334	5,500,000	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	425,000	425,000	425,000	425,000	425,000	425,000	425,000	425,000	425,000	425,000	425,000	425,000	5,100,000	4
5	Real Time Miscellaneous	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	1,020,000	5
6	Real Time Revenue Neutrality Uplift Amount	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	3,600,000	6
7	Real Time MVP Distribution Amount	(14,167)	(14,167)	(14,166)	(14,167)	(14,167)	(14,166)	(14,167)	(14,167)	(14,166)	(14,167)	(14,167)	(14,166)	(170,000)	7
8	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	583,333	583,333	583,334	583,333	583,333	583,334	583,333	583,333	583,334	583,333	583,333	583,334	7,000,000	8
9	Schedule 26 A - Multi-Value Projects	3,425,000	3,425,000	3,425,000	3,425,000	3,425,000	3,425,000	3,425,000	3,425,000	3,425,000	3,425,000	3,425,000	3,425,000	41,100,000	9
10	Schedule 26 C	-	-	-	-	-	-	-	-	-	-	-	-	-	10
11	Schedule 49	-	-	-	-	-	-	-	-	-	-	-	-	-	11
12	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	12
13	Total RTO Non-Fuel Costs	5,637,499	5,637,499	5,637,502	5,637,499	5,637,499	5,637,502	5,637,499	5,637,499	5,637,502	5,637,499	5,637,499	5,637,502	67,650,000	13
14	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)	14
15	Total Non-Fuel Costs & Transmission Revenues	3,304,166	3,304,166	3,304,168	3,304,166	3,304,166	3,304,168	3,304,166	3,304,166	3,304,168	3,304,166	3,304,166	3,304,168	39,650,000	15
Amounts Included in Base Rates															
Non-Fuel Costs															
16	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	16
17	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	17
18	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	18
19	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	19
20	Real Time Miscellaneous	-	-	-	-	-	-	-	-	-	-	-	-	-	20
21	Real Time Revenue Neutrality Uplift Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	21
22	Real Time MVP Distribution Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	22
23	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	23
24	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	24
25	Schedule 26 C	-	-	-	-	-	-	-	-	-	-	-	-	-	25
26	Schedule 49	-	-	-	-	-	-	-	-	-	-	-	-	-	26
27	PJM Madison Non-Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	27
28	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	28
29	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)	29
30	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	30
Net Forecasted RTO Non-Fuel Costs & Transmission Revenues															
Non-Fuel Costs															
31	Schedule 10 FERC	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(39,000)	31
32	Schedule 10	(24,084)	(24,084)	(24,082)	(24,084)	(24,084)	(24,082)	(24,084)	(24,084)	(24,082)	(24,084)	(24,084)	(24,082)	(289,000)	32
33	Schedule 16	(10,250)	(10,250)	(10,250)	(10,250)	(10,250)	(10,250)	(10,250)	(10,250)	(10,250)	(10,250)	(10,250)	(10,250)	(123,000)	33
34	Schedule 17	(103,333)	(103,333)	(103,334)	(103,333)	(103,333)	(103,334)	(103,333)	(103,333)	(103,334)	(103,333)	(103,333)	(103,334)	(1,240,000)	34
35	Real Time Miscellaneous	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	1,020,000	35
36	Real Time Revenue Neutrality Uplift Amount	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	3,600,000	36
37	Real Time MVP Distribution Amount	(14,167)	(14,167)	(14,166)	(14,167)	(14,167)	(14,166)	(14,167)	(14,167)	(14,166)	(14,167)	(14,167)	(14,166)	(170,000)	37
38	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	(90,250)	(90,250)	(90,250)	(90,250)	(90,250)	(90,250)	(90,250)	(90,250)	(90,250)	(90,250)	(90,250)	(90,250)	(1,083,000)	38
39	Schedule 26 A - Multi-Value Projects	348,000	348,000	348,000	348,000	348,000	348,000	348,000	348,000	348,000	348,000	348,000	348,000	4,176,000	39
40	Schedule 26 C	-	-	-	-	-	-	-	-	-	-	-	-	-	40
41	Schedule 49	-	-	-	-	-	-	-	-	-	-	-	-	-	41
42	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	42
43	Total RTO Non-Fuel Costs	637,666	637,666	637,666	637,666	637,666	637,666	637,666	637,666	637,666	637,666	637,666	637,666	7,652,000	43
44	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)	44
45	Total Non-Fuel Costs & Transmission Revenues	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	266,000	3,192,000	45
46	Revenue Conversion Factor													1.00484	46
47	Amount to be Collected (Credited) Through Rider													3,207,449	47

DUKE ENERGY INDIANA, LLC

RECONCILIATION OF AMOUNTS PROJECTED FOR REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COSTS AND TRANSMISSION REVENUES
 VERSUS ACTUAL AMOUNTS INCURRED FOR THE JULY 2018 THROUGH JUNE 2020 PERIOD

Line No.	Description	RTO 54 - 4/						RTO 55 - 2/																		Line No.						
		July 2018	August 2018	September 2018	October 2018	November 2018	December 2018	January 2019	February 2019	March 2019	April 2019	May 2019	June 2019	July 2019	August 2019	September 2019	October 2019	November 2019	December 2019	January 2020	February 2020	March 2020	April 2020	May 2020	June 2020							
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)		(Y)	(Z)				
		Sum (A) to (F)						Sum (H) to (S)																		Sum (U) to (Z)						(G+I)-(Y)-(AA)
		(G)						(T)																		(Z)						(AB)
		(G)						(T)																		(Z)						(AB)
		(G)						(T)																		(Z)						(AB)
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		(G)						(T)																		(Z)						(AB)
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DUKE ENERGY INDIANA, LLC

RECONCILIATION OF THE REGIONAL TRANSMISSION OPERATOR ("RTO") NON-FUEL COSTS AND TRANSMISSION REVENUES
TO BE RECOVERED OR CREDITED THROUGH RIDER NO. 59 VERSUS WHAT WAS ACTUALLY COLLECTED FROM CUSTOMERS

Line No.	Description	RTO 54 - 1/										RTO 55 - 2/										Total	Line No.															
		July 2018	August 2018	September 2018	October 2018	November 2018	December 2018	Sub-Total			January 2019	February 2019	March 2019	April 2019	May 2019	June 2019	Sub-Total																					
		(A)	(B)	(C)	(D)	(E)	(F)	(G)			(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)			(S)			(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)			(AB)	(C)-(T)+(AA)
		Sum (A) to (F)										Sum (H) to (S)										Sum (U) to (Z)										(C)-(T)+(AA)						
Rider Revenues Approved for Recovery																																						
1	Rate RS	1,470,991	1,470,991	1,470,991	-	-	-	4,412,973			2,921,551	2,921,551	2,921,551	2,921,551	2,921,551	2,921,551	2,921,551	2,921,551	2,921,551	2,921,551	2,921,552	2,921,552	35,058,614			-	-	-	-	-	-	-	-	-	-	39,471,587	1	
2	Rate CS	240,764	240,764	240,764	-	-	-	740,292			420,264	420,264	420,264	420,264	420,264	420,264	420,264	420,264	420,264	420,264	420,263	420,263	420,263	5,043,165			-	-	-	-	-	-	-	-	-	-	5,792,457	2
3	Rate LFL	877,686	877,686	877,686	-	-	-	2,633,058			1,445,316	1,445,316	1,445,316	1,445,316	1,445,316	1,445,316	1,445,316	1,445,316	1,445,316	1,445,316	1,445,315	1,445,315	1,445,315	17,343,789			-	-	-	-	-	-	-	-	-	-	19,976,847	3
4	Rate HLF	2,192,216	2,192,216	2,192,217	-	-	-	6,576,649			3,163,780	3,163,780	3,163,780	3,163,780	3,163,780	3,163,780	3,163,780	3,163,780	3,163,780	3,163,779	3,163,779	3,163,779	3,163,779	36,205,357			-	-	-	-	-	-	-	-	-	-	44,782,006	4
5	Customer L	13,607	13,607	13,607	-	-	-	41,091			19,806	19,806	19,806	19,806	19,806	19,806	19,807	19,807	19,807	19,807	19,807	19,807	19,807	237,677			-	-	-	-	-	-	-	-	-	-	275,768	5
6	Customer O	23,473	23,473	23,473	-	-	-	70,419			36,178	36,178	36,178	36,178	36,178	36,178	36,178	36,178	36,178	36,177	36,177	36,177	36,177	434,132			-	-	-	-	-	-	-	-	-	-	504,551	6
7	Rate WP	20,419	20,419	20,418	-	-	-	61,258			32,553	32,553	32,553	32,553	32,553	32,553	32,553	32,553	32,554	32,554	32,554	32,554	32,554	390,641			-	-	-	-	-	-	-	-	-	-	461,897	7
8	Rate SL	2,705	2,705	2,705	-	-	-	8,136			4,173	4,173	4,173	4,173	4,173	4,173	4,173	4,173	4,173	4,173	4,174	4,174	4,174	50,078			-	-	-	-	-	-	-	-	-	-	58,464	8
9	Rate MHLS	291	291	291	-	-	-	873			577	577	577	577	577	577	577	577	577	577	578	578	578	6,926			-	-	-	-	-	-	-	-	-	-	7,799	9
10	Rate MOLS and UOLS	6,576	6,576	6,576	-	-	-	19,728			9,863	9,863	9,863	9,863	9,863	9,863	9,863	9,863	9,863	9,862	9,862	9,862	9,862	118,712			-	-	-	-	-	-	-	-	-	-	139,440	10
11	Rates TS, FS and MS	2,318	2,318	2,318	-	-	-	6,954			3,580	3,580	3,580	3,580	3,580	3,580	3,589	3,589	3,589	3,589	3,589	3,589	3,589	43,074			-	-	-	-	-	-	-	-	-	-	60,028	11
12	Total	4,860,226	4,860,226	4,860,227	-	-	-	14,580,679			8,077,581	8,077,581	8,077,581	8,077,581	8,077,581	8,077,581	8,077,580	8,077,580	8,077,580	8,077,580	8,077,580	8,077,580	8,077,580	96,932,165			-	-	-	-	-	-	-	-	-	-	111,512,844	12
Rider Revenues Actually Collected																																						
13	Rate RS	1,749,818	1,565,216	1,595,549	1,273,751	1,263,322	1,707,228	9,155,884			3,705,750	3,774,473	3,282,002	2,425,261	2,043,919	2,447,671	3,272,256	3,215,238	2,903,914	2,512,725	2,411,819	3,286,842	35,291,870	3,436,067	3,269,677	2,980,418	2,464,899	2,229,238	2,684,453	17,064,822							61,512,576	13
14	Rate CS	275,145	298,519	262,805	224,099	202,100	240,305	1,456,973			461,408	457,072	426,748	354,743	338,813	392,488	472,950	472,950	442,426	404,869	355,396	428,464	5,007,974	438,547	418,200	394,693	320,850	299,354	371,367	2,243,011							8,717,958	14
15	Rate LFL	951,568	926,807	974,943	917,988	818,526	951,810	5,451,740			1,532,536	1,505,469	1,460,429	1,405,488	1,425,835	1,545,202	1,541,651	1,676,193	1,692,009	1,600,351	1,433,937	1,575,831	18,405,989	1,469,842	1,439,379	1,383,710	1,146,442	1,070,927	1,323,025	7,833,305							31,721,853	15
16	Rate HLF	2,264,068	2,214,684	2,202,253	2,048,973	1,936,334	1,951,638	12,616,950			3,096,363	2,860,882	2,836,879	2,809,620	2,878,207	3,129,115	3,202,691	3,334,691	3,262,111	3,093,254	2,877,387	2,953,136	36,624,616	2,903,371	2,817,976	2,763,400	2,521,364	2,336,871	2,755,102	16,028,088							65,338,652	16
17	Customer L	12,665	14,353	14,321	11,621	10,675	14,519	88,054			27,543	20,880	18,701	10,084	15,483	18,128	18,426	22,161	22,125	17,616	17,648	15,121	233,036	15,551	20,577	19,293	10,050	15,676	10,510	100,557							421,647	17
18	Customer O	23,069	23,847	23,628	23,059	23,812	23,083	140,758			37,030	37,039	33,479	37,025	35,840	37,025	35,873	37,068	37,030	35,692	37,038	35,828	435,957	37,004	37,038	34,657	37,062	35,916	37,024	216,711							795,426	18
19	Rate WP	21,697	19,362	20,319	19,031	19,009	20,624	120,112			36,040	35,525	33,617	32,166	32,042	32,248	34,577	34,331	34,149	31,560	31,001	34,230	401,506	35,249	32,712	32,812	32,899	30,796	33,466	197,857							719,573	19
20	Rate SL	2,751	2,636	2,765	2,767	2,758	2,737	16,463			4,091	4,035	3,956	4,042	4,047	4,043	4,043	4,044	4,041	3,964	4,018	4,010	48,216	3,984	3,987	3,988	3,984	3,979	3,976	23,908							88,577	20
21	Rate MHLS	278	279	319	336	365	420	1,997			768	658	621	575	543	503	491	488	543	562	619	698	7,085	737	647	602	573	507	465	3,531							12,583	21
22	Rate MOLS and UOLS	6,544	6,554	6,514	6,536	6,529	6,581	39,258			9,816	9,752	9,740	9,615	9,681	9,826	9,876	9,933	9,953	9,916	9,485	9,646	115,345	9,698	9,448	9,425	9,372	9,344	9,286	56,487							211,000	22
23	Rates TS, FS and MS	2,290	2,283	2,318	2,336	2,374	2,444	14,045			3,862	3,650	3,619	3,576	3,524	3,627	3,534	3,509	3,563	3,579	3,607	3,747	43,347	3,778	3,622	3,585	3,563	3,479	3,565	21,583							78,975	23
24	Total	5,313,951	5,034,660	5,106,935	4,530,437	4,294,652	4,831,389	29,112,224			8,914,225	8,705,245	8,109,791	7,191,185	6,888,964	7,719,256	8,688,168	8,809,861	8,411,461	7,713,860	7,181,346	8,307,548	96,644,920	8,363,748	8,053,265	7,626,594	6,560,128	6,035,990	7,232,853	40,867,578							168,619,722	24
Under (Over) Collected																																						
25	Rate RS	(278,827)	(94,225)	(125,558)	(1,273,751)	(1,263,322)	(1,707,228)	(4,742,911)			(784,199)	(852,920)	(360,451)	496,290	877,632	473,880	(350,705)	(293,687)	17,537	408,826	509,739	(375,290)	(233,256)	(3,436,067)	(3,269,677)	(2,980,418)	(2,464,899)	(2,229,238)	(2,684,453)	(17,064,822)							(22,040,989)	25
26	Rate CS	(29,381)	(6,755)	(13,041)	(224,099)	(202,100)	(240,305)	(1,717,681)			(41,144)	(30,808)	(5,484)	65,521	81,451	27,795	(22,686)	(22,102)	15,394	64,657	(8,201)	(375,396)	5,007,974	(438,547)	(418,200)	(394,693)	(320,850)	299,354	371,367	2,243,011							(42,925,501)	26
27	Rate LFL	(73,860)	(49,221)	(97,257)	(917,988)	(818,526)	(951,810)	(5,451,740)			(97,200)	(90,153)	(15,113)	39,828	18,481	(159,846)	(96,335)	(230,877)	(246,690)	(155,036)	11,378	(70,516)	(1,092,169)	(1,469,842)	(1,439,379)	(1,383,710)	(1,146,442)	(1,070,927)	(1,323,025)	(7,833,305)							(11,744,806)	27
28	Rate HLF	(71,852)	(22,488)	(10,036)	(2,048,973)	(1,936,334)	(1,951,638)	(6,040,301)			88,417	322,898	346,301	284,100	205,573	54,665	(102,911)	(150,911)	(78,331)	90,725	306,412	220,643	1,580,741	(2,603,371)	(2,817,976)	(2,763,400)	(2,521,364)	(2,336,871)	(2,755,102)	(16,028,088)							(250,676,468)	28
29	Customer L	1,012	1,050	1,050	(11,521)	(10,675)	(14,519)	88,054			(3,012)	(2,880)	(2,880)	(1,084)	(1,084)	(1,084)	(1,084)	(1,084)	(1,084)	(1,084)	(1,084)	(1,084)	(1,084)	19,293			(1,084)	(1,084)	(1,084)	(1,084)							(2,000,257)	29
30	Customer O	78,852	(47,484)	(355)	(23,059)	(23,812)	(23,083)	(70,339)			(852)	(861)	2,699	(847)	339	(847)	305	(880)	(853)	485	(861)	349	(1,825)	(37,004)	(37,038)	(34,657)	(37,062)	(35,916)	(37,024)	(216,711)							(250,675)	30
31	Rate WP	1,278	1,037	96	(19,031)	(19,009)	(20,624)	(68,856)			(3,507)	(2,752)	(1,046)	397	011	305	(2,024)	(1,777)	(1,595)	694	1,553	(1,676)	(10,865)	(35,249)	(32,712)	(32,812)	(32,899)	(30,796)	(33,466)	(197,857)							(267,618)	31
32	Rate SL	12	(2,761)	(2,765)	(2,767)	(2,758)	(2,737)	16,463			12	(2,761)	138	121	131	121	131	121	131	121	131	121	1,582	(3,984)	(3,987)	(3,988)	(3,984)	(3,979)	(3,976)	(23,908)							(23,908)	32
33	Rate MHLS	1,037	96	(12)	(336)	(385)	(420)	1,997			13	(128)	(189)	(81)	0	14	74	86	91	34	15	(141)	(3,984)	(3,987)	(3,988)	(3,984)	(3,979)	(3,976)	(23,908)							(23,908)	33	
34	Rate MOLS and UOLS	32	22	62	(6,536)	(6,529)	(6,581)	39,258			77	141																										

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 (A)	Base Bill For Typical Residential Customer (1) (B)	All Other Riders Excluding Rider No. 68 (2) (C)	Total Bill for Typical Residential Customer Excluding Rider No. 68 (D)	RTO Non-Fuel Cost and Revenue Adjustment Amount for Rider No. 68 for 1,000 kWh's (E)	Total Bill Including RTO Non-Fuel Cost and Revenue Adjustment Amount Rider No. 68 (F)	Increase/ (Decrease) In Total Bill From Current Factor (3) (G)	% Increase/ (Decrease) In Total Bill From Current Factor (H)	Line No.
1	Proposed Factor	\$ (0.000237)	\$ 130.37	\$ (4.32)	\$ 126.05	\$ (0.24)	\$ 125.81	\$ (1.78)	-1.40%	1
2	Current Approved Factor	\$ 0.001542	\$ 130.37	\$ (4.32)	\$ 126.05	\$ 1.54	\$ 127.59	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

RECONCILIATION OF MIDCONTINENT ISO MANAGEMENT COSTS AND REVENUE ADJUSTMENT

Line No.	Description	Percentage Share of Retail System Peak Demand Used For Allocation Purposes in IURC Cause No. 42359 ^{1/}	Reconciliation of Amounts Projected for RTO Non-Fuel Costs and Transmission Revenues vs. Actual Amounts Incurred for the July 2018 through June 2020 Period	Line No.
		(A)	(B)	
	Retail Rate Schedules			
1	Rate RS	36.727%	\$ 18,534,034	1
2	Rates CS and FOC	5.206%	2,627,173	2
3	Rate LLF	17.897%	9,031,601	3
4	Rate HLF	38.862%	19,611,448	4
5	Customer L	0.243%	122,628	5
6	Customer D	0.000%		6
7	Customer O	0.442%	223,052	7
8	Rate WP	0.400%	201,857	8
9	Rate SL	0.051%	25,737	9
10	Rate MHLS	0.007%	3,533	10
11	Rate MOLS and UOLS	0.121%	61,062	11
12	Rate TS, FS and MS	0.044%	22,204	12
13	Total Retail	100.000%	\$ 50,464,329	13

^{1/} As adjusted for rate migration between HLF and LLF rate classes.

DUKE ENERGY INDIANA, LLC

COMPANY-OWNED SCHEDULE 26 PROJECT STATUS AND ESTIMATE OF ALLOCATED SCHEDULE 26 COSTS
CAUSE NO. 42736 - RTO 56

Line No.	Project Type	Location	Description	MISO	MTEP	Expected Construction Schedule			Estimated Total Project Costs			Actual Costs	Percentage of Completion	Line No.
				Approval Status	Project ID	Start	Finish	In-Service	Original	Revised	Date Revised			
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, MTEP07, MTEP08, MTEP09, MTEP10, MTEP11, MTEP12, MTEP 13, MTEP 14, MTEP 15, MTEP 16, MTEP 17, MTEP 18 and MTEP 19 the Midwest ISO currently estimates that Duke Energy Indiana's share of allocated project costs through 2034 is an average of approximately \$10.7 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 Midwest 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 56

Line No.	Project Type	MTEP Project ID	Facility ID #	Description	MISO Approval Status	Expected Construction Schedule			Actual Costs	Percentage of Completion	Line No.
						Start	Finish	In-Service			
1	MVP - Multi-Value Project	2237	8313	Sugar Creek 345kV Transmission Line	Approved - MTEP 11	12/2/16	6/28/19	6/21/19	\$ 5,600,168.31	100.00%	1
2	MVP - Multi-Value Project	2237	8313	Sugar Creek 345kV Transmission Line	Approved - MTEP 11	12/2/16	11/30/18	9/25/18	\$ 360,234.25	100.00%	2
3	MVP - Multi-Value Project	2202	7286	Wabash 6986 ckt Reconductor	Approved - MTEP 11	2/17/17	7/31/18	6/22/18	\$ 4,715.41	100.00%	3
4	MVP - Multi-Value Project	2202	7286	Wabash 6986 ckt Reconductor	Approved - MTEP 11	2/17/17	7/2/18	6/26/18	\$ 1,744,521.32	100.00%	4
5	MVP - Multi-Value Project	2202	7287	Kokomo Deico to Greentown 138 kV Uprate	Approved - MTEP 11	11/02/17	8/7/2018	6/5/2018	\$ 403,470.97	100.00%	5

Based on the MISO-approved MTEP06, MTEP07, MTEP08, MTEP09, MTEP10, MTEP11, MTEP12, MTEP 13, MTEP 14, MTEP 15, MTEP 16, MTEP 17, MTEP 18 and MTEP 19 the Midwest ISO currently estimates that Duke Energy Indiana's share of allocated project costs through 2040 is an average of approximately \$49.2 million annually.

DUKE ENERGY INDIANA, LLC

COMPONENTS OF REVENUE CONVERSION FACTOR

Components of Revenue Conversion Factor:

	<u>Statutory</u>	<u>Effective</u> <u>Rate</u>
Utility Receipts Tax	1.400%	1.400%
Uncollectible Accounts Expense	0.280%	0.280%
Public Utility Fee	0.127%	0.127%
Supplemental Corporate Net Income Tax _1/	5.075%	0.075%
Federal Income Tax	21.000%	-
Subtotal Effective Rate		<u>1.882%</u>
Remove Utility Receipts Tax	1.400%	1.400%
Total Effective Rate		0.482%
Complement (1 - Effective Rate)		<u>99.518%</u>
Revenue Conversion Factor (1 ÷ Complement)		<u>1.00484</u>

STANDARD FORMAT FOR
DUKE ENERGY INDIANA, LLC'S FILINGS
RIDER NO. 68 – IURC CAUSE NO. 42736 RTO-56

(1) VERIFIED PETITION

(2) TESTIMONY OF ART J. BUESCHER III

- Exhibit 1-A - Proposed Duke Energy Indiana Rider No. 68, showing proposed adjustment factors
- Exhibit 1-B - Determination of adjustment factors by rate groups for prior applicable period and forecasted period to be applied to current proposed calendar year
- Exhibit 1-C - Determination of forecasted RTO non-fuel costs and transmission revenues to be recovered or credited through Duke Energy Indiana Rider No. 68
- Exhibit 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
- Exhibit 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
- Exhibit 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
- Exhibit 1-G - Allocation of revenues by retail rate schedule for amounts prior to Cause No. 45253
- Exhibit 1-H - Schedule 26 Project Status and Estimate of Schedule 26 Costs
- Exhibit 1-I - Schedule 26-A Project Status and Estimate of Schedule 26-A Costs
- Exhibit 1-J - Components of revenue conversion factor
- Exhibit 1-K - Standard format for Duke Energy Indiana filings.
- Exhibit 1-L - Standard audit path for Duke Energy Indiana RTO filing.

(3) WORKPAPERS OF ART J. BUESCHER III

- 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 twelve months ending June 2020
- Workpaper 3 - MISO invoice detailing Schedule 10 costs for demand and energy
- Workpaper 4 - Allocation of MISO FERC fees to Operating Companies and Business Units
- Workpaper 5 - MISO FERC fee allocation percentages determination
- Workpaper 6 - Allocation to derive Duke Energy Indiana's portion of MISO Schedule 10 costs

STANDARD FORMAT FOR
DUKE ENERGY INDIANA, LLC'S FILINGS
RIDER NO. 68 – IURC CAUSE NO. 42736 RTO-56

- Workpaper 7 - Calculation of Duke Energy Indiana's wholesale MISO Schedule 10 costs
- Workpaper 8 - Data query for account 561000 and 575700 showing the wholesale and retail amounts of Schedule 10 costs
- Workpaper 9 - Restatement of detail provided by MISO for transmission revenues collected under the MISO TEMT, or any successor tariff
- Workpaper 10 - Summarized schedule of the MISO transmission revenue schedules
- Workpaper 11 - Derivation of Duke Energy Indiana's retail portion of the MISO transmission revenues
- Workpaper 12 - Determination of Duke Energy Indiana Rider No. 68 revenues charged or credited for the reconciliation months
- Workpaper 13 - 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 14 - MISO invoice detailing Schedule 26 and Schedule 26A (MVP) charges
- Workpaper 15 - Duke Energy Indiana MISO Attachment GG – Calculation of Revenue Requirement for Company-owned Schedule 26 RECB projects
- Workpaper 16 - Duke Energy Indiana MISO Attachment MM – Calculation of Revenue Requirement for Company-owned Schedule 26-A MVP projects
- Workpaper 17 – Projected January through December 2021 MISO costs and transmission revenues.

(4) TESTIMONY OF JAMES (BRAD) DANIEL

Exhibit 2-A - Rider 68 - Description of PJM Charges and Credits

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

- Workpaper 1** Kilowatt hour sales by rate schedule listed on Petitioner's Exhibit 1-B
- Workpaper 2** KW demands for HLF rate class listed on Petitioner's Exhibit 1-B
- Workpaper 3** 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 F
- Workpaper 4** Allocation of MISO FERC fees to Operating Companies and Business Units
A) Monthly MISO FERC fee amounts listed on Petitioner's Exhibit 1-B, page 1 of 2, filed with Duke Energy Indiana's Testimony
B) Operating Company allocation percentages developed on Workpaper 5
- Workpaper 5** MISO FERC fee allocation percentages determination. Allocations based on analysis of MISO Schedule 10 costs
A) Operating Company allocation ratio carried to Workpaper 4
B) Business Unit allocation ratio carried to Workpaper 4
- Workpaper 6** 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
B) Duke Energy Indiana portion of total charges less wholesale costs from Workpaper 7 equals amount journalized in account 561000 and 575700 as shown on Workpaper 8
- Workpaper 7** Calculation of Duke Energy Indiana's wholesale MISO Schedule 10 costs
A) Determination of final monthly wholesale amounts, which are carried over to Workpaper 6. Demand and energy rates listed on this Workpaper come from Workpaper 3. (WVPA and IMPA pay their own MISO Schedule 10 costs, so each of those organizations have been excluded for purposes of calculating the amounts shown on this document.)
- Workpaper 8** Data query for account 561000 and 575700 showing the wholesale and retail amounts of schedule 10 costs
A) General ledger detail for account 561000 and 575700 broken up into estimated and final amounts for retail and wholesale costs for the relevant time period
- Workpaper 9** 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 10. Allocation to Operating Company

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

- Workpaper 10** 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 11** 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, 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 (96.291%) is from the IURC Order in Cause No. 42736. (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 12** Determination of Duke Energy Indiana Rider No. 68 revenues charged or credited for the reconciliation months
- Workpaper 13** 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 (96.291%) is from the IURC Order in Cause No. 42736
- Workpaper 14** MISO invoice detailing Schedule 26 and Schedule 26A (MVP) charges
- Workpaper 15** Duke Energy Indiana MISO Attachment MM – Calculation of Revenue Requirement for Company-owned Schedule 26-A MVP projects
- Workpaper 16** Summarized schedule of HLF & LLF Rate Migrations
- Workpaper 17** Projected January through December 2019 MISO costs and transmission revenues

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: 11-10-20