Cause No. 46038

FILED
April 4, 2024
INDIANA UTILITY
REGULATORY COMMISSION

On Behalf of Petitioner,
DUKE ENERGY INDIANA, LLC

VERIFIED DIRECT TESTIMONY OF CHRISTA L. GRAFT

Petitioner's Exhibit 3

April 4, 2024

DIRECT TESTIMONY OF CHRISTA L. GRAFT
MANAGER, RATES & REGULATORY STRATEGY
DUKE ENERGY INDIANA, LLC
BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christa L. Graft, and my business address is 1000 East Main Street, Plainfield, Indiana.

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

A. I am employed by Duke Energy Indiana, LLC ("Duke Energy Indiana," "Petitioner," or "Company") as a Manager, Rates & Regulatory Strategy.

Q. PLEASE DESCRIBE YOUR DUTIES AS MANAGER OF RATES & REGULATORY STRATEGY.

A. As a Manager of Rates & Regulatory Strategy, I am responsible for the preparation of financial and accounting data used in Company rate filings, including proceedings for changes in fuel cost adjustment factors.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from Indiana University in May 1998 with a Bachelor of Science degree in Business with a major in Accounting. I have been employed by the Company since June 1998 and have held various financial and accounting positions supporting the Company and its affiliates. My first position was as an Analyst in the External Reporting department, where my responsibilities included various quarterly and annual Securities and Exchange Commission ("SEC") and Federal Energy Regulatory Commission ("FERC") filings. In 2000, I was promoted to a Senior Analyst position in the Accounting Research department, where I researched the appropriate accounting for various business transactions and reviewed new accounting guidance for applicability to the Company. I was promoted to a Lead Analyst position in 2005 and joined the Financial Planning and Analysis department in 2006, where I provided accounting and budgeting support to various business operational groups. I joined the Rates department as a Lead Rates & Regulatory Strategy Analyst in 2010 and was promoted to manager in 2020. I am a Certified Public Accountant ("CPA") and a member of the Indiana CPA Society.

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

A. I discuss Duke Energy Indiana's current retail rate structure and provide an overview of the rate case increase request. I introduce Petitioner's Exhibit 26, which includes the majority of the basic accounting exhibits required to be filed with the case-in-chief by the Minimum Standard Filing Requirements ("MSFR") pursuant to 170 IAC 1-5-6, in addition to supporting schedules and workpapers. I explain the process to develop the Company's revenue requirements and the proposed two-step implementation of base rates. I also support several accounting and ratemaking aspects of the Company's case, including:

1. Certain portions of the basic accounting exhibits required to be filed with the case-in-chief by the MSFR pursuant to 170 IAC 1-5-6;
2. The Company's overall revenue requirements;
3. Certain portions of the Company's proposed rate base;

4. Certain operating income *pro forma* adjustments;
5. The continued use of and proposed changes to the Company's Tracker No. 60 – Fuel Cost Adjustment to be effective with the implementation of the Company's revised base rates;
6. The Company's request for the continuation of the reserve accounting concept established in Cause No. 45253 for distribution vegetation management operation and management ("O&M") costs and expansion of the reserve accounting concept to include transmission vegetation management O&M costs;
7. The Company's request for new deferral authority and future recovery of costs to achieve corporate restructuring savings that are reflected in the forecasted test period; and
8. The Company's request for new deferral authority associated with potential future statutory income tax rate changes.

II. DUKE ENERGY INDIANA CURRENT RETAIL RATE STRUCTURE

Q. PLEASE DESCRIBE DUKE ENERGY INDIANA'S CURRENT RETAIL RATE STRUCTURE.

A. Duke Energy Indiana's retail electric rates are comprised of base rates and rate adjustment trackers. The Company's current base rates were approved in the Commission's June 29, 2020 order in Cause No. 45253. Adjustments to the current base rates were effected through the Company's Tracker No. 67 – Credits Adjustment effective July 1, 2022 pursuant to a 30-day filing to reflect the repeal of the utility receipts tax and effective June 2023 pursuant to the Commission's April 12, 2023 order on remand in Cause No. 45253.

Q. PLEASE PROVIDE BACKGROUND ON THE RATE ADJUSTMENT TRACKERS THAT DUKE ENERGY INDIANA CURRENTLY HAS IN PLACE.

A. The following table includes the existing rate adjustment trackers, associated cause number, a brief description, and the supporting Company witness in this proceeding.

Table 1: Duke Energy Indiana Trackers

Tracker	**Cause No.**	**Description**	**Witness**
No. 60 - Fuel Cost Adjustment (FAC)	38707	Recovers changes in the cost of fuel consumed, purchased power and fuel-related regional transmission operator ("RTO") charges and credits applicable to serving native load.	Christa L. Graft
No. 62 - Environmental Compliance Adjustment (ECR)	42061	Recovers the tracker-eligible portion of the return on and of clean energy projects and federally mandated coal ash compliance (Coal Combustion Residuals or "CCR") projects. Tracks expense for certain reagents.	Kathryn C. Lilly
No. 65 - Transmission and Distribution Infrastructure Improvement Cost Adjustment (TDSIC)	45647	Recovers the tracker-eligible portion of the return on the net depreciated value of plant-in-service and associated depreciation and plan-related O&M costs in connection with the Company's Commission-approved multi-year TDSIC plans, including targeted economic development ("TED") projects.	Kathryn C. Lilly
No. 66 - Energy Efficiency Adjustment	45803	Recovers the cost of energy efficiency programs, including lost revenues and performance incentives approved by the Commission.	Kathryn C. Lilly

Tracker	**Cause No.**	**Description**	**Witness**
No. 67 - Credits Adjustment	30-day Filing	Reduces rates to customers for various credits approved by the Commission.	Kathryn C. Lilly
No. 68 - Regional Transmission Operator (RTO) Non-Fuel Costs and Revenue Adjustment (RTO)	42736	Recovers non-fuel RTO charges and credits, netted with transmission revenues, compared to amounts included in base rates.	Suzanne E. Sieferman
No. 70 - Reliability Adjustment (SRA)	44348	Recovers and/or credits customers with the net cost of reliability purchases, costs of the PowerShare® program, net profits from traditional non-native sales, and the sharing of net profits related to short-term bundled non-native sales.	Suzanne E. Sieferman
No. 72 - Federally Mandated Cost Adjustment (FMCA)	44367	Recovers return on construction work in progress ("CWIP") and the net depreciated value of the tracker-eligible portion of certain federally mandated plant in service and operating costs, primarily the cost of certain physical and cyber-security projects.	Kathryn C. Lilly
No. 73 - Renewable Energy Project Adjustment (REP)	44932	Recovers return on CWIP and the net depreciated value of completed plant and operating costs incurred in connection with Company-owned renewable energy generation projects.	Suzanne E. Sieferman
No. 74 – Load Control Adjustment	45803	Recovers the costs of the Company's Power Manager® and Savings on Demand® programs, including lost revenues and performance incentives approved by the Commission.	Kathryn C. Lilly

III. OVERVIEW OF RATE INCREASE REQUEST

Q. WHAT IS THE OVERALL RETAIL RATE INCREASE REQUESTED BY DUKE ENERGY INDIANA IN THIS PROCEEDING AND WHEN WILL IT OCCUR?

A. The overall retail rate increase is $491.5 million, representing a 16.20% increase over *pro forma* 2025 forecasted base and tracker revenues at present rates.[1] The rate increase will be implemented in two steps, currently estimated to be in March 2025 for Step 1 and March 2026 for Step 2. The Step 1 increase is projected to be $355.4 million, representing an 11.71% increase over *pro forma* 2025 forecasted base and tracker revenues at present rates. The Step 2 increase is projected to be $136.1 million, representing a 4.49% increase over *pro forma* 2025 forecasted base and tracker revenues at present rates.

Q. WHAT IS THE PROJECTED IMPACT TO A TYPICAL RESIDENTIAL CUSTOMER USING 1,000 KWHS?

A. The projected impact of the rate increase to a typical residential customer using 1,000 kWhs is shown in the table below:

[1] As this case was being finalized and the MSFRs were being assembled, the Company discovered that there were expenses in the revenue requirement for advertising that did not provide a material benefit to customers as required by 170 IAC 1-3-3(A). This discovery was made too late in the process to correct before filing. The revenue requirement will be reduced by approximately $500,000 as a result. This adjustment will be made in rebuttal.

Table 2: Projected Residential Rate Impact

	$	%
March 2025 estimated typical bill at time of Commission Order in this proceeding (1)	$143.04	
Step 1 total bill increase	20.43	14%
Step 2 total bill increase	7.20	5%
Total bill increase	27.63	19%
Typical bill at proposed rates, base and trackers	$170.67	

(1) Reflects estimated customer bill at the time of a Commission order in this proceeding, including projections of trackers. A typical residential bill, base and trackers, as of March 2024 is $133.05.

Q. CAN YOU PLEASE ELABORATE ON THE NOTE IN THE ABOVE TABLE REGARDING RATES AT THE TIME OF A COMMISSION ORDER IN THIS PROCEEDING AND RATES IN EFFECT AS OF MARCH 2024?

A. Duke Energy Indiana's typical residential bill is anticipated to increase between March 2024 and March 2025, the estimated timing of implementation of the Commission's Order in this Cause. The increase between March 2024 and March 2025 is a result of routine tracker updates primarily related to TDSIC and federally mandated projects that have already been reviewed and approved by the Commission. In addition, March 2024 rates include credits for refunds resulting from the Commission's Order on Remand in Cause No. 45253 and the Indiana Court of Appeals opinion regarding recovery of certain coal ash costs in Cause No. 45253 S1 that will be fully refunded at the end of May 2024 and December 2024, respectively, at which time customer rates will increase to reflect removal of the credit. These increases to a typical residential bill will occur regardless of whether this rate case had been filed.

Said differently, the estimated typical bill at the time of a Commission Order in this proceeding of $143.04 reflects rates that are anticipated to be in effect at the time of Order in this Cause had this rate case not been filed. Those are not the same rates that are in effect in March 2024.

Q. WHAT ARE THE COMPONENTS OF THE PROPOSED RATE INCREASE?

A. In his testimony, Company witness Mr. Stan Pinegar (Petitioner's Exhibit 1) discusses the growth in net original cost rate base and increases to the cost of capital since the last rate case. He also discusses the recovery of costs prudently incurred or to be incurred for coal ash pond closure. Finally, he discusses that O&M expense has remained flat since the last rate case. The table below summarizes these components of the proposed rate increase and is supported by my Workpaper 1-CLG.

Table 3: Rate Increase Components

	$ (in millions)	%
Rate base:		
Return on rate base increase	$82.1	2.7%
Depreciation for rate base increase	54.1	1.8%
	136.2	4.5%
Other cost structure changes:		
Rate of return, financing costs	121.5	9.5%
Depreciation rates	286.3	4.0%
Regulatory asset amortizations	25.4	0.8%
Non-fuel operation and maintenance	(18.0)	(0.6%)
	415.2	13.7%
Offsetting credits:		
Other post-retirement benefits	(37.5)	(1.2%)

Excess deferred income taxes	(14.1)	(0.5%)
	(51.6)	(1.7%)
All other	(8.3)	(0.3%)
	$491.5	16.2%
Present revenues (base plus trackers)	$3,034.2	

Q. PLEASE DESCRIBE WHAT MAKES UP THE INCREASE IN NET ORIGINAL COST RATE BASE.

A. Forecasted net original cost rate base in this proceeding is projected to increase by $2.3 billion from the amount in current base rates, $1.6 billion of which would not be reflected in rates without this case.[2] The $1.6 billion is primarily due to increases in transmission and distribution net plant in service, partially offset by a decline in production net plant in service. Company witness Ms. Kathryn C. Lilly (Petitioner's Exhibit 5) provides additional details in her testimony.

Q. PLEASE ELABORATE ON THE COMPONENTS OF THE RATE INCREASE RELATED TO DEPRECIATION RATES.

A. Of the rate increase related to depreciation rates, approximately 50% of the increase is reflected in the production function outside of decommissioning costs, approximately 25% of the increase is for increased decommissioning costs, and approximately 25% of the increase is reflected in the transmission, distribution, and general plant functions. The increased decommissioning costs reflect the inclusion of coal ash closure costs as costs of

[2] The $0.7 billion differential is included in trackers, primarily TDSIC.

removal, among other changes, as explained by Company witnesses Mr. Jeffrey T. Kopp (Petitioner's Exhibit 11), Mr. John J. Spanos (Petitioner's Exhibit 12) and Mr. Sean P. Riley (Petitioner's Exhibit 13). Mr. Kopp supports the decommissioning study, and Mr. Spanos supports the depreciation study.

Q. WHAT IS THE PROPOSED RATE OF RETURN, AND WHAT ASSUMPTION DOES IT REFLECT FOR THE PROPOSED RETURN ON EQUITY?

A. The proposed rate of return is 6.52% and is supported by Company witness Ms. Suzanne E. Sieferman (Petitioner's Exhibit 4). The proposed rate of return reflects a proposed return on equity of 10.5%, as further discussed by Company witness Mr. Pinegar and supported by Company witness Mr. Adrien McKenzie (Petitioner's Exhibit 10).

Q. PLEASE SUMMARIZE THE REGULATORY ASSET AMORTIZATIONS THAT ARE INCLUDED IN THE RATE INCREASE.

A. Rate base includes approximately $530 million for regulatory assets. This amount includes remaining balances of regulatory assets that have existed since the last rate case in addition to regulatory assets being included in rate base for the first time in this case. The proposed amortization periods are in a range of three to twenty years. Company witness Ms. Lilly sponsors supporting testimony.

Q. HOW HAS O&M EXPENSE CHANGED SINCE THE LAST RATE CASE?

A. As discussed in the testimony of Mr. Pinegar, despite inflation's significant impact on the cost to produce and deliver power, the Company has been able to keep its day-to-day O&M costs flat since 2020.

Q. PLEASE EXPLAIN THE REDUCTION ASSOCIATED WITH OTHER POST-RETIREMENT BENEFITS ("OPRB").

A. As discussed further in the testimony of Ms. Sieferman, the Company utilizes a grantor trust to fund its OPRB obligation per the terms of a settlement agreement with the Office of Utility Consumer Counselor ("OUCC") approved by the Commission in Cause No. 40388. The settlement agreement provided that once all OPRB liabilities, taxes and expenses have been paid, any remaining retail jurisdictional assets will be credited to retail customers unless alternative treatment is agreed upon by the settling parties. After consideration of the current trust balance, estimated future payments, and estimated future earnings on the trust, the Company has determined that the grantor trust is more than sufficiently funded to meet future obligations. Therefore, the Company is proposing to return some of the excess to customers as part of the rate case. More specifically, the Company is proposing to provide customers a credit of $75 million over two years ($37.5 million per year) via Tracker No. 67, beginning when Step 1 rates are implemented.

Q. PLEASE EXPLAIN THE REDUCTION ASSOCIATED WITH EXCESS ACCUMULATED DEFERRED INCOME TAXES ("EDIT").

A. At the time of the settlement agreement approved in the Commission's August 22, 2018 Order in Cause No. 45032-S2, the Company had an estimated unprotected EDIT balance of $210 million, which was to be amortized and refunded to customers over a 10-year period at $7 million per year for the first five years and $35 million per year for the second five years. These credits are provided to customers through Tracker No. 67, and the Company is currently in the second half of the 10-year period. The settlement agreement provided that if the unprotected EDIT balance subsequently changed, the $35 million annual amortization would continue until the updated unprotected EDIT balance was fully amortized.

In October 2018, Duke Energy Corporation filed its consolidated tax return for 2017, at which time the unprotected EDIT balance was updated (an increase). The Company is proposing to increase the annual credit included in Tracker No. 67 by approximately $14 million for a $49 million annual amortization amount and to complete the amortization within the original 10-year period contemplated in the settlement agreement.

Q. HAS DUKE ENERGY INDIANA CALCULATED ITS RATE BASE AND RATE OF RETURN ON A FAIR VALUE BASIS?

A. Duke Energy Indiana has not completed a separate fair value calculation. The Company is proposing that a fair return on the fair value of its rate base will be equivalent to the weighted average cost of capital as applied to the net original cost of its rate base.

IV. TWO-STEP RATE ADJUSTMENT PROCESS

Q. HOW WILL THE COMPANY IMPLEMENT NEW BASE RATES?

A. Upon receipt of the Commission's order in this proceeding, the Company will submit a compliance filing including a complete tariff for Commission approval, reflecting the base rates supported by witness Mr. Roger A. Flick II (Petitioner's Exhibit 7), if approved, or as adjusted if required by the Commission's order. The compliance filing will also include revised tracker tariffs to reflect changes needed to the then-effective tracker rates as a result of the implementation of new base rates as well as updates to reflect the new allocation factors approved in this proceeding.

Duke Energy Indiana is proposing to implement base rates in two steps, Step 1 and Step 2. The Company's proposed base rates in this proceeding are calculated based on forecasted rate base (including forecasted net plant in service) as of December 31, 2025; however, not all of this forecasted plant will be in service at the time an order is anticipated to be received in this proceeding in early 2025. Therefore, a rate adjustment will be needed so customer rates only reflect utility property that is used and useful at the time the rates are placed in effect. The Company will utilize its Tracker No. 67 to provide any necessary rate adjustments to customers for the difference between revenue requirements approved in the Commission's order in this proceeding and the Step 1 or Step 2 revenue requirements, as applicable.

Q. PLEASE EXPLAIN THE STEP 1 RATE ADJUSTMENT AND HOW IT WILL BE IMPLEMENTED.

A. The Company will calculate revenue requirements reflecting the June 30, 2024 capital structure, June 30, 2024 net plant in service and the associated annualized depreciation expense, and the 2025 forecasted amounts for other components of rate base[3]. The output of the Step 1 revenue requirements calculation will be provided to Company witness Ms. Maria T. Diaz (Petitioner's Exhibit 6), who will calculate the Step 1 jurisdictional revenues by retail rate group. The difference between jurisdictional revenues approved in

[3] Regulatory assets, inventories, and prepaid pension asset.

the Commission's Order in this proceeding and the Step 1 jurisdictional revenues will be credited to customers in Tracker No. 67 rates.

The Company has forecasted the June 30, 2024 capital structure and net plant in service balance and the associated annualized depreciation expense for purposes of estimating the Step 1 impact in the case-in-chief. When the Company files its rebuttal testimony in August 2024, it will update these estimated amounts to the actual June 30, 2024 capital structure and net plant in service balance and the associated annualized depreciation expense. The filing of this information at rebuttal will allow ample opportunity for intervening parties to review the June 30, 2024 data. As such, the Company proposes to implement its Step 1 rates, including base rates and tracker rates, as soon as possible following issuance of the Order in this Cause and upon submission of the compliance filing and Commission approval of the tariff. The rates will be effective on a services-rendered[4] basis. Since the actual net utility plant in service and capital structure will be known at the time a few weeks before the evidentiary hearing, there should be no need to schedule a defined period for the parties to review the Step 1 compliance filing. The Company estimates these rates will be effective in or before March 2025.

Q. PLEASE EXPLAIN THE STEP 2 RATE ADJUSTMENT.

A. The Company will calculate revenue requirements reflecting its actual capital structure as of December 31, 2025, the <u>lesser of</u> the forecasted or actual net plant in service balance

[4] Services-rendered basis is based on when energy is delivered/used, rather than when bills are rendered to customers.

as of December 31, 2025, the annualized depreciation expense associated with the lesser of the forecasted or actual net plant in service balance as of December 31, 2025, and the 2025 forecasted amounts for other components of rate base. The output of the Step 2 revenue requirements calculation will be provided to Company witness Ms. Diaz, who will calculate the Step 2 jurisdictional revenues by retail rate group. The difference between jurisdictional revenues approved in the Commission's Order in this proceeding and the Step 2 jurisdictional revenues will be credited to customers in Tracker No. 67 rates.

Q. HOW WILL THE STEP 2 RATE ADJUSTMENT BE IMPLEMENTED?

A. The Company will submit a second compliance filing with the Commission in March 2026 that will remove the Step 1 rate adjustment from Tracker No. 67 and replace it with the Step 2 rate adjustment. The Step 2 rate adjustment will take effect upon submission and approval by the Commission on an interim-subject-to-refund basis pending a 30-day review process and the resolution of any potential objections.

Additionally, as was approved in Cause No. 45253 for the implementation of the Step 2 rate adjustment, the Company is proposing to collect the difference between the Step 1 rate adjustment and the Step 2 rate adjustment, with carrying costs at the December 31, 2025 actual weighted average cost of capital, from January 1, 2026 until the time the Step 2 rate adjustment is reflected in Tracker No. 67, expected to be in March 2026. The Company's second compliance filing will include an estimate of this differential in the calculation of the overall Step 2 rate adjustment using actual (or estimated[5]) kWh sales for services rendered January-February 2026. The development of the overall Step 2 rate adjustment in this way will have the practical effect of the Step 2 rate adjustment being implemented on January 1, 2026 on a services rendered basis even though mechanically, the revised Tracker No. 67 rates will be implemented on a bills-rendered basis upon Commission approval.

Q. PLEASE SUMMARIZE THE COMPANY'S OVERALL TWO-STEP RATE IMPLEMENTATION PROPOSAL.

A. The following illustrates the Company's proposal:

Table 4: Two-Step Rate Implementation

Components of Rates	Step 1 – March 2025	Step 2 – January 2026
Base Rates	Base Rates Reflecting Forecasted Rate Base as of 12/31/2025	Base Rates Reflecting Forecasted Rate Base as of 12/31/2025 **(No Change from Base Rates under Step 1)**
+	+	+
Rate Adjustment in Tracker No. 67	Credit for Difference in Revenue Requirements Using Capital Structure and Actual Net Utility Plant in Service at 6/30/2024 and Associated Annualized Depreciation Expense	Credit for Difference in Revenue Requirements Using Capital Structure and Lesser of Forecasted Net Utility Plant in Service and Actual Net Utility Plant in Service at 12/31/2025 and Associated Annualized Depreciation Expense
=	=	=
Net Rates Reflecting Actual Used and Useful	Net Rates Reflecting Actual Used and Useful	Net Rates Reflecting Lesser of Forecasted or

[5] The Company will use estimated kWh sales in this calculation for periods for which actual is unknown at the time of the compliance filing and will reconcile these estimates to actual in a future Tracker No. 67 filing.

Net Utility Plant	Net Utility Plant as of 6/30/2024	Actual Used and Useful Net Utility Plant as of 12/31/2025

V. BASIC ACCOUNTING EXHIBITS

Q. PLEASE DESCRIBE PETITIONER'S EXHIBIT 26.

A. Petitioner's Exhibit 26 is an Excel file comprised of the majority[6] of the basic accounting exhibits required to be filed with the case-in-chief by the MSFR pursuant to 170 IAC 1-5-6, in addition to supporting schedules and workpapers. Below is a summary of where the basic accounting exhibits can be located. Throughout my testimony, when I refer to these various schedules and workpapers, I am referencing these schedules and workpapers that are included in Exhibit 26, Attachments 26-A, 26-B, or 26-C as the case may be.

Table 5: Basic Accounting Exhibits

Attachment/Schedule Number	Description	Witness
Attachment 26-A Schedule FS1	Duke Energy Indiana, LLC balance sheets as of August 31, 2023 and August 31, 2022	Christa L. Graft
Attachment 26-B Schedule FS2	Duke Energy Indiana, LLC income statements for the historical base period of the twelve months ended August 31, 2023 and the comparative period of the twelve months ended August 31, 2022	Christa L. Graft
Attachment 26-C Schedule RR1	Revenue requirement calculation for the forecasted test period ending December 31, 2025	Christa L. Graft
Attachment 26-C Schedule OPIN1	Jurisdictional net operating income for the forecasted test period ending December 31, 2025	Christa L. Graft

[6] The balance sheet, cash flow statement, and income statement for the forecasted test period ending December 31, 2025 are filed with the testimony of Company witness Mr. Joel T. Rutledge (Petitioner's Exhibit 2).

Attachment/Schedule Number	**Description**	**Witness**
Attachment 26-C Schedule RB1	Jurisdictional rate base for the forecasted test period ended December 31, 2025	Kathryn C. Lilly
Attachment 26-C Schedules CS4 and CS1	Capital structure and cost of capital for the historical base period of the twelve months ended August 31, 2023 and for the forecasted test period of December 31, 2025	Suzanne E. Sieferman
Attachment 26-C Schedule RR2	Gross revenue conversion factor	Christa L. Graft
Attachment 26-C Schedule ETR	Effective tax rate for the historical base period of the twelve months ended August 31, 2023 and for the forecasted test period of December 31, 2025	Christa L. Graft

Q. PLEASE EXPLAIN THE ORGANIZATION OF EXHIBIT 26.

A. The Index tab details the contents of Exhibit 26 by attachment, schedule/workpaper, and supporting witness. The schedules and workpapers are grouped by category (for example, rate base or O&M) and have been labeled with a unique identifier by category, as follows:

Table 6: Schedule/Workpaper Categories

Category	**Identifier**
Financial Statements	FS
Revenue Requirements	RR
Operating Income	OPIN
Capital Structure & Cost of Capital	CS

Category	**Identifier**
Rate Base	RB
Revenues	REV
Cost of Goods Sold (fuel and purchased power)	COGS
O&M (excluding fuel and purchased power)	OM
Depreciation and Amortization	DA
Taxes Other than Income Taxes	OTX
Effective Tax Rate	ETR
Income Tax	TX
Step 1 Calculations	RA

Q. PLEASE EXPLAIN SCHEDULES FS1 AND FS2.

A. Schedule FS1 is Duke Energy Indiana's balance sheet as of August 31, 2023 and August 31, 2022, which with Mr. Rutledge's Attachment 2-C (JTR) (the balance sheet for the forecasted test period) is intended to comply with 170 IAC 1-5-6 (1)(A). Schedule FS2 is Duke Energy Indiana's income statement for the historical base period of the twelve months ended August 31, 2023 and the comparative period of the twelve months ended August 31, 2022, which with Mr. Rutledge's Attachment 2-B (JTR) (the income statement for the forecasted test period) is intended to comply with 170 IAC 1-5-6 (1)(C). We do not have a cash flow statement for the base period because cash flow statements are only prepared for Duke Energy Indiana at calendar quarters.

Q. WERE SCHEDULES FS1 AND FS2 PREPARED UNDER YOUR SUPERVISION?

A. No. The financial statements are prepared by Duke Energy Corporation's accounting function under the direction of the controller. The accounting function maintains the accounting books and records and prepares financial statements and reports for internal use and external distribution for Duke Energy Indiana, as well as other affiliates.

Duke Energy Indiana's accounting policies are in accordance with Generally Accepted Accounting Principles ("GAAP"). As a publicly-held company whose securities are traded in interstate commerce, Duke Energy Corporation and its subsidiaries are subject to the oversight of the SEC, and financial statements filed with the SEC must be accompanied by the opinion of an independent auditor that the statements have been prepared in accordance with GAAP.

In addition, the Company maintains its books and records in accordance with the FERC Uniform System of Accounts, which has been adopted by the Commission as the accounting standard for Indiana utilities in its administrative rules at 170 IAC 4-2-1.1. While there are some differences between GAAP financial statements and FERC financial statements, they are generally consistent with one another. GAAP financial statements differ from the FERC financial statements primarily in the classification of accumulated deferred income taxes, regulatory assets and liabilities, cost of removal obligations, maturities of long-term debt and equity treatment of post-in-service carrying costs.

VI. REVENUE REQUIREMENTS

Q. PLEASE EXPLAIN EXHIBIT 26, ATTACHMENT 26-C.

A. Exhibit 26, Attachment 26-C represents the schedules and workpapers comprising Duke Energy Indiana's calculation of revenue requirements.

Q. PLEASE DESCRIBE HOW THE REVENUE REQUIREMENTS WERE DEVELOPED.

A. The development of revenue requirements begins with the 2025 forecasted balance sheet and income statement provided by Mr. Rutledge. These forecasted financial statements are prepared and presented on a GAAP basis. Mr. Rutledge also provided supporting details for the forecasted financial statements, such as plant additions and retirements and the components of net operating income.

Next, the Rates & Regulatory Strategy team reviewed the forecasted financial statements for regulatory adjustments needed to reflect presentation differences or for items excluded from ratemaking. Examples include certain regulatory asset amortizations reflected in the interest expense line in the forecasted GAAP income statement that are reflected in the depreciation and amortization line in a FERC income statement, the breakout of certain items forecasted on a net basis into their revenue and expense components, and the removal of non-utility revenues and expenses from ratemaking. In addition to these classification differences, the Company also made adjustments for certain items for which assumptions changed after the time the forecasted financial statements were provided. The forecast adjustments are summarized on Schedule RB1 and Schedule OPIN3 and are supported by Workpaper RB23 and Workpaper OPIN1, respectively.

The last step in the determination of revenue requirements is the development of *pro forma* adjustments to the 2025 test period so that the Company's rates reflect an expected ongoing level of revenues and expenses and the appropriate level of rate base. One example is the removal of revenues and expenses in the forecast associated with items that will remain in rate adjustment trackers that therefore should not be included in the development of base rates. Other examples include adjusting accumulated depreciation and depreciation expense for the impact of new depreciation rates and adjusting regulatory asset amortizations to reflect revised amortization periods and the inclusion of new regulatory asset amortizations. The *pro forma* adjustments are summarized on Schedule RB2 and Schedule OPIN4 and are supported by multiple workpapers.

As a final step, I provided the output of the revenue requirements model to Company witness Ms. Diaz for her use in preparation of the jurisdictional separation study and cost of service study.

A. <u>Revenue Requirements Schedules</u>

Q. PLEASE EXPLAIN SCHEDULE RR1.

A. Schedule RR1 is Duke Energy Indiana's calculation of its jurisdictional revenue requirement and overall rate increase percentage and is illustrated in the following table:

Table 7: Revenue Requirements Calculation

	$ (in thousands)
Rate base at original cost	$12,482,080
Rate of return	6.52%
Required net operating income	813,832
Less: *pro forma* net operating income at present rates	408,121
Net operating income deficiency	405,711
Gross revenue conversion factor	1.33880
Revenue deficiency before effect of trackers	543,166
Less: present revenue for ongoing trackers	17,281
Plus: proposed revenue for ongoing trackers	(34,247)
Revenue deficiency after effect of trackers	$491,538
Pro forma revenues at present rates	$3,016,950
Plus: present revenues for ongoing trackers	17,281
Pro forma revenues at present rates plus trackers	$3,034,231
Percent increase	16.20%

First, forecasted jurisdictional rate base is multiplied by the forecasted rate of return to determine the required net operating income of $813,832,000. Second, the required net operating income is compared to *pro forma* net operating income at present rates of $408,121,000 to determine the net operating income deficiency of $405,711,000. Third, the net operating income deficiency is grossed up for income taxes, uncollectible accounts expense, and public utility fee to determine the revenue deficiency before the effect of trackers. This $543,166,000 revenue deficiency is the amount of additional electric operating revenue needed to be produced by proposed base rates.

To determine the percentage rate increase, the revenue deficiency before the effect of trackers is reduced by tracker revenues at present rates and increased by tracker revenues at proposed rates to determine the revenue deficiency after the effect of trackers of $491,538,000. When compared to the $3,034,231,000 of *pro forma* revenues at present rates plus trackers at present rates, the result is a rate increase of 16.20%.

Q. WHAT IS INCLUDED IN TRACKER REVENUES AT PROPOSED RATES?

A. In addition to tracker revenues at present rates of $17,281,000, tracker revenues at proposed rates reflect a credit of $37,500,000 for the refund to customers of excess funds in the grantor trust and a credit of $14,128,000 for the increased flowback of EDIT, both of which were discussed previously in my testimony.

Q. PLEASE EXPLAIN SCHEDULE RR2.

A. Schedule RR2 is the calculation of the gross revenue conversion factor for the test period. The conversion factor includes a provision for uncollectible accounts expense of 0.427% (calculated on Workpaper OM4), public utility fee of 0.151% (calculated on Workpaper OM1), state income tax (4.900%, provided by Company witness Mr. John Panizza (Petitioner's Exhibit 15)), and federal income tax (21.000%, provided by Mr. Panizza).

B. <u>Operating Income Schedules</u>

Q. PLEASE EXPLAIN SCHEDULES OPIN1 AND OPIN2.

A. Schedule OPIN1 is a summary of Duke Energy Indiana's jurisdictional net operating income for the test period at both present rates and proposed rates. The required adjustments to jurisdictional net operating income at present rates to achieve the $405,711,000 net utility operating income deficiency from Schedule RR1 is calculated on

Schedule OPIN2 and is carried forward to column B of Schedule OPIN1.

Q. PLEASE EXPLAIN SCHEDULE OPIN3.

A. Schedule OPIN3 is a total company view of Duke Energy Indiana's net operating income. Column A represents the 2025 forecasted amounts provided by Mr. Rutledge. Column B represents the regulatory adjustments to the forecast discussed previously in my testimony that are summarized on Workpaper OPIN1. Column D represents the *pro forma* adjustments to the adjusted forecast, and Column E is the 2025 forecast including regulatory adjustments and *pro forma* adjustments.

Q. PLEASE EXPLAIN SCHEDULE OPIN4.

A. Schedule OPIN4 summarizes the *pro forma* adjustments to net operating income by line item and by *pro forma*, with references to *pro forma* schedule numbers.

C. Rate Base Schedules

Q. PLEASE EXPLAIN SCHEDULE RB4.

A. Schedule RB4 is a summary of the materials and supplies inventory balance included in the Company's forecasted rate base and is further supported by Workpaper RB20. The forecasted balance is equal to the balance as of the end of the base period.

Q. PLEASE EXPLAIN SCHEDULE RB5.

A. Schedule RB5 presents the prepaid pension asset included in the Company's forecasted rate base. The Commission approved inclusion of the prepaid pension asset in the Company's rate base in its order in Cause No. 45253. The prepaid pension asset is defined as the cumulative amount of cash contributions to the pension trust fund in excess of the cumulative amount of accrued pension cost. The balance as of the end of the base period of $192,081,000 was adjusted for projected contributions and actuarial expense to arrive at the forecasted 2025 balance of $229,841,000, as detailed in Workpaper RB21.

Q. PLEASE EXPLAIN SCHEDULE RB6.

A. Schedule RB6 is a summary of the fuel inventory balance included in the Company's forecasted rate base and is further supported by Workpaper RB17 and the testimony of Mr. John Verderame (Petitioner's Exhibit 21).

D. Cost of Goods Sold Schedules

Q. PLEASE EXPLAIN SCHEDULE COGS8.

A. Schedule COGS8 shows the derivation of the proposed base cost of fuel to be included in Petitioner's schedules of rates and charges. It reflects the Company's forecasted dispatch of system resources for 2025. Company witness Mr. Rutledge explains the development of the forecasted fuel and purchased power expenses and Company witnesses Mr. John D. Swez (Petitioner's Exhibit 20) and Mr. Verderame discuss the production cost model used to simulate generation output and associated costs used in developing that forecast. The proposed base cost of fuel is 34.378 mills per kWh. By comparison, the Company's current base cost of fuel, established in Cause No. 45253, is 26.955 mills per kWh.

E. O&M Schedules

Q. PLEASE EXPLAIN SCHEDULE OM8.

A. Schedule OM8 removes $2,957,000 from test period O&M associated with non-utility lighting programs to ensure these expenses are not included in the cost of service to all customers. The Company is being reimbursed for the O&M costs for these lighting programs by specific customers under the terms of customer-specific Outdoor Lighting Equipment Service agreements.

Q. PLEASE EXPLAIN SCHEDULE OM9.

A. Schedule OM9 adds $2,096,000 to test period O&M for costs to achieve annual corporate restructuring savings that are reflected in the test period forecast. As discussed later in my testimony, the Company is proposing to defer the total costs to achieve of $6,289,000 as a regulatory asset and recover them over a three-year period.

Q. PLEASE EXPLAIN SCHEDULE OM11.

A. Schedule OM11 removes $10,667,000 from test period expenses to reflect a normalized level of outage costs, as discussed further in the testimony of Company witness Mr. William C. Luke (Petitioner's Exhibit 17).

Q. PLEASE EXPLAIN SCHEDULE OM12.

A. Schedule OM12 removes $2,672,000 from test period expenses to reflect a revised cost per mile assumption associated with transmission vegetation management work, as discussed further in the testimony of Company witness Mr. Timothy A. Abbott (Petitioner's Exhibit 22).

Q. PLEASE EXPLAIN SCHEDULE OM14.

A. The structure of the Company's sale of accounts receivable program requires below the line accounting for what would normally be in FERC account 904 as uncollectible expense. Schedule OM14 establishes a level of O&M expense of $12,893,000 associated with uncollectible accounts receivable based on revenues at present rates. The calculation of the adjustment utilizes an uncollectible accounts experience factor of 0.427% based upon a six-year (2019-2023 historical and 2024 budget) weighted average of charge off and recovery data, provided by Company witness Mr. Jacob S. Colley (Petitioner's Exhibit 24). Workpaper OM4 supports the calculation of this *pro forma* adjustment.

Q. PLEASE EXPLAIN SCHEDULE OM15.

A. As discussed in the testimony of Mr. Colley, the Company is proposing to eliminate convenience fees for individual residential customers who use credit and debit cards to pay their electric bills and instead recover these costs as part of its cost of service, which is how the Company recovers the cost associated with providing other customer payment options. Schedule OM15 increases test period operating expenses by $2,621,000 to include credit card convenience fees in the Company's cost of service. Mr. Colley provided historical and projected transaction counts and an assumed average cost of $1.25 per transaction for my use in calculating the adjustment, which is supported by Workpaper OM6.

Q. PLEASE EXPLAIN SCHEDULE OM16.

A. As discussed in the testimony of Mr. Abbott, the Company will be enhancing physical security at its transmission substations during 2025. Expected annual ongoing O&M associated with the physical security in enhancements is $347,000, but the test period reflects a lower O&M level of $175,000 because the sites will be placed into service throughout 2025 rather than all sites being in service at the beginning of the year. Schedule OM16 increases test period O&M by $172,000 to reflect the expected annual ongoing level of O&M.

F. Taxes Other Than Income Taxes Schedules

Q. PLEASE EXPLAIN SCHEDULE OTX2.

A. The Company receives a property tax incentive associated with its Edwardsport Generating Station. To ensure that customers receive the full benefit of the property tax incentive as required by the Settlement Agreement in Cause No. 43114 IGCC 4S1, the Company is proposing to continue including the property tax incentive as a credit in Tracker No. 67, as approved in Cause No 45253. Schedule OTX2 increases test period expense by $2,547,000 to remove the Edwardsport property tax incentive from the development of base rates. Workpaper OTX4 supports the calculation of this amount.

Q. PLEASE EXPLAIN SCHEDULE OTX4.

A. Schedule OTX4 adjusts and annualizes property tax expense using property tax rates based on 2022 net book value and 2023 property tax expense applied to the forecasted net book value of plant-in-service as of December 31, 2025. This adjustment increases property tax expense by $4,264,000. Company witness Mr. Panizza provided the inputs for the calculation.

G. Income Tax Schedules

Q. PLEASE EXPLAIN SCHEDULE ETR.

A. Schedule ETR presents the calculation of the effective income tax rate for the 12 months ended August 31, 2023 and for the forecasted test period of 2025 on both a total company and jurisdictional basis.

Q. PLEASE EXPLAIN SCHEDULE TX1.

A. Schedule TX1 summarizes forecasted income taxes provided by Mr. Rutledge, forecast adjustments to remove non-utility income taxes, and the *pro forma* adjustments made to income taxes. Schedule TX1 is further supported by Schedules TX2 through TX8 and Workpapers TX1 and TX2.

Q. PLEASE EXPLAIN SCHEDULE TX2.

A. Schedule TX2 shows the computation of current federal and state income tax expense at present rates. Column D shows the *pro forma* adjustments for each of the pretax book income items used in the current income tax calculation in addition to *pro forma* adjustments resulting from permanent differences, temporary differences, and interest.

Q. WAS THIS CALCULATION OF CURRENT FEDERAL AND STATE INCOME TAX EXPENSE PERFORMED USING THE RATES AND BASIC INCOME TAX COMPUTATION PROCESS EXPLAINED BY MR. PANIZZA?

A. Yes. As can be seen on line 32 of Schedule TX2, we used the 21.000% statutory rate in computing federal current income tax expense and, as can be seen on line 44, we used the 4.900% statutory rate for Indiana for 2025 for computation of state current income tax expense.

Q. DOES SCHEDULE TX2 REFLECT THE SYNCHRONIZED INTEREST EXPENSE CONCEPT PREVIOUSLY APPROVED BY THIS COMMISSION IN RETAIL ELECTRIC RATE PROCEEDINGS?

A. Yes. The application of this concept results in a determination of the interest expense deduction for the calculation of current income taxes for ratemaking purposes by applying the interest synchronization factor to *pro forma* original cost depreciated rate base. As the name implies, this results in a calculation of annualized interest expense which is synchronized with the rate base used for regulatory purposes, rather than the total company interest expense that may also include interest expense supporting non-utility items and which is not annualized. Schedule TX3 shows the computation of this interest amount which was used to calculate the pro forma adjustment amount included in column D of line 26 on Schedule TX2.

Q. DOES SCHEDULE TX2 REFLECT A DEDUCTION FOR THE "PARENT INTEREST" CONCEPT PREVIOUSLY APPROVED BY THIS COMMISSION IN RETAIL ELECTRIC RATE PROCEEDINGS?

A. Yes. The application of this "Muncie Remand"[7] concept results in an additional interest expense deduction, for ratemaking purposes only, in calculating current federal and state income taxes due to the Company's participation in a Duke Energy Corporation consolidated tax return. This adjustment reduces test period income taxes by allocating a portion of Duke Energy Indiana's parent company's interest deduction to Duke Energy Indiana for purposes of computing income tax expense, thereby providing a tax benefit to customers. The interest allocated under this procedure, as shown on Schedule TX4 and in column D of line 27 on Schedule TX2, is $32,917,000.

Schedule TX4 shows the calculation of the parent interest amount using: 1) the December 31, 2025 forecasted balance of Duke Energy Indiana's total equity capital;

[7] *Muncie Water Works Co.,* Supplemental Order on Remand, Cause No. 34571, 44 PUR4th 331 (PSCI 9/16/1981).

times 2) Duke Energy Corporation's consolidated long-term debt to equity ratio for debt applicable to support of utility operations (exclusive of merger-related debt); times 3) the average cost of the parent company's debt applicable to support of utility operations. The support for the parent debt amounts and calculations was provided by Company witness Mr. Christopher Bauer (Petitioner's Exhibit 9).

Q. PLEASE EXPLAIN SCHEDULE TX5.

A. Schedule TX5 shows the computation of deferred federal and state income tax expense. Column D shows the *pro forma* deferred income tax adjustments for each of the temporary differences giving rise to deferred income taxes that were impacted by the *pro forma* adjustments to pretax book income related to utility plant in service, depreciation, regulatory assets, and amortization of regulatory assets, the details of which are provided on Schedules TX7 and TX8. In addition, the amortization of EDIT was removed on line 14 because this credit will be provided to customers in Tracker No. 67 instead of being included in the development of base rates.

Q. WHAT INCOME TAX RATES WERE USED TO CALCULATE DEFERRED INCOME TAXES?

A. We used the 21% statutory rate in computing federal deferred income tax expense and the 4.900% statutory rate for Indiana in computing state deferred income tax expense.

Q. PLEASE EXPLAIN SCHEDULE TX6.

A. Schedule TX6 details the forecasted and *pro forma* amounts for amortization of investment tax credits. The *pro forma* adjustment removes $6,609,000 of amortization of the Edwardsport federal investment tax credit because this credit will be provided to customers in Tracker No. 67 instead of being included in the development of base rates.

Q. PLEASE EXPLAIN SCHEDULE TX7.

A. Schedule TX7 calculates the change in deferred income taxes resulting from the Company's pro forma adjustments to deferrals, depreciation expense, and regulatory asset amortizations. These details are carried forward to Schedule TX5.

Q. PLEASE EXPLAIN SCHEDULE TX8.

A. Schedule TX8 calculates the change in deferred income taxes resulting from the Company's pro forma adjustments to plant in service. These details are carried forward to Schedule TX5.

H. <u>Step 1 Rate Adjustment</u>

Q. PLEASE EXPLAIN THE PROCESS USED TO DEVELOP THE ESTIMATED STEP 1 REVENUE REQUIREMENT AND RATE ADJUSTMENTS.

A. The Company started with 2025 forecasted rate base and updated the net plant in service component to reflect forecasted balances at June 30, 2024 and determined the differential. Next, the Company calculated annualized depreciation expense based upon the forecasted plant in service balances at June 30, 2024 and determined the differential between this result and 2025 forecasted depreciation expense. Finally, the Company determined the change between 2025 forecasted current income tax expense and current income tax as adjusted for the change in depreciation expense, as well as changes in the Company's synchronized interest and parent interest deductions due to the use of the June 30, 2024 capital structure.

These differentials and the June 30, 2024 forecasted rate of return from the cost of capital calculation were provided to Company witness Ms. Diaz to perform a jurisdictional separation study reflecting the effect of these differentials. Ms. Diaz provided me the jurisdictional operating income and rate base, which I used, along with the forecasted June 30, 2024 cost of capital, to calculate revised net operating income and revenue deficiencies to determine a revised proposed revenue increase amount, in addition to the associated revised uncollectible expense, public utility fee, and current income tax amounts.

Ms. Diaz then performed the cost of service study to determine revised proposed jurisdictional revenue requirements by rate group, which she provided to me. I compared the jurisdictional revenue requirements by rate group that Ms. Diaz is supporting in this case for proposed base rates to these revised jurisdictional revenue requirements by rate group to determine the amount of the estimated Step 1 revenue requirement adjustment for each rate group. These amounts were divided by the forecasted kWh sales for 2025 for each rate group to determine the Step 1 rate adjustment.

As I explained in Section IV of my testimony, the Company will use the same methodology when implementing this Step 1 rate adjustment in March 2025 and will update the June 30, 2024 amounts from estimates to actual. The resulting Step 1 rate adjustment will be included with other credits in Tracker No. 67, with the rates implemented at the same time as the approved base rates following the Commission's order in this proceeding.

Q. PLEASE EXPLAIN SCHEDULE RA1.

A. Schedule RA1 shows the calculation of the estimated Step 1 revenue requirement adjustment and rates by rate group. It compares jurisdictional revenues proposed in this proceeding to the estimated Step 1 jurisdictional revenues to determine the credit by rate group. These amounts were divided by the forecasted kWh sales for 2025 to obtain the Step 1 rate adjustment per kWh by rate group.

To determine the related percentage rate increase, the revenue deficiency before the effect of trackers is reduced by tracker revenues at present rates and increased by tracker revenues at proposed rates to determine the required revenue increase after the effect of trackers. When compared to *pro forma* revenues at present rates plus trackers at present rates, the result is a rate increase of 16.20% in total, 11.71% of which is estimated to occur in Step 1, with the remaining 4.49% estimated to occur in Step 2.

Q. WHAT IS INCLUDED IN TRACKER REVENUES AT PROPOSED RATES?

A. In addition to tracker revenues at present rates of $17,281,000, tracker revenues at proposed rates reflect a credit of $37,500,000 for the refund to customers of excess funds in the grantor trust and a credit of $14,128,000 for the increased flowback of EDIT, both of which were discussed previously in my testimony. These components are included in the tracker amounts for both proposed retail revenues and Step 1 retail revenues.

There are two additional items in tracker revenues at proposed rates that are only applicable to Step 1 retail revenues. The first is an increase of $11,313,775 to reflect the movement of the regulatory asset amortization associated with Edwardsport deferred expenses from base rates to Tracker No. 62 – Environmental Cost Adjustment, as further discussed by Company witness Ms. Lilly. The second is a decrease of $22,504,997 to recognize that two wholesale contracts expiring at the end of 2025 will still be in place at the time Step 1 rates are implemented, therefore requiring a credit to retail customers, as further discussed by Company witness Ms. Diaz.

Q. PLEASE EXPLAIN SCHEDULE RA2.

A. Column A of Schedule RA2 is the 2025 forecasted jurisdictional revenue requirement from Schedule RR1. Column B reflects the estimated Step 1 adjustments, and column C is the estimated Step 1 jurisdictional revenue requirement.

Q. PLEASE EXPLAIN SCHEDULES RA3 AND RA4.

A. Schedule RA3 is a summary of Duke Energy Indiana's 2025 jurisdictional net operating income adjusted to reflect the June 30, 2024 forecasted capital structure and net plant in service and associated annualized depreciation expense. The required adjustments to jurisdictional net operating income at present rates to achieve the $312,394,000 net utility operating income deficiency from Schedule RA2 are calculated on Schedule RA4 and are carried forward to column B of Schedule RA3.

Q. PLEASE EXPLAIN SCHEDULE RA5.

A. Schedule RA5 presents a total company and jurisdictional view of Duke Energy Indiana's net operating income adjusted to reflect the June 30, 2024 forecasted capital structure and net plant in service and associated annualized depreciation expense.

Q. PLEASE EXPLAIN SCHEDULES RA6 THROUGH RA17.

A. Schedule RA6 compares forecasted net utility plant in service as of December 31, 2025 to June 30, 2024 to determine the Step 1 adjustment to net plant in service. Schedules

RA7 through RA11 provide the detail of Schedule RA6 by function. Schedule RA12 compares annualized 2025 forecasted depreciation expense to annualized forecasted depreciation expense based on June 30, 2024 forecasted plant in service to determine the Step 1 adjustment to depreciation expense. Schedules RA13 through RA17 provide the detail of Schedule RA12 by function. Company witness Ms. Lilly sponsors these schedules.

Q. PLEASE EXPLAIN SCHEDULES RA18 AND RA19.

A. Schedule RA18 is the Company's forecasted capital structure and rate of return at June 30, 2024 used to calculate the required net operating income associated with the forecasted June 30, 2024 net plant in service. Schedule RA19 is detail of the forecasted embedded cost of debt rate as of June 30, 2024. Company witness Ms. Sieferman sponsors these schedules.

Q. PLEASE EXPLAIN SCHEDULE RA20.

A. Column A of Schedule RA20 is the computation of 2025 forecasted current federal and state income tax expense from Schedule TX2. Column B calculates the impact to current federal and state income tax expense associated with the Step 1 depreciation expense adjustment and changes in the synchronized interest and parent interest deductions between June 30, 2024 and December 31, 2025. Column C is the computation of the estimated Step 1 forecasted current federal and state income tax expense.

Q. PLEASE EXPLAIN SCHEDULE RA21.

A. Schedule RA21 is the calculation of the synchronized interest deduction using forecasted June 30, 2024 net plant in service from Schedule RA6 and the synchronized interest rate from the June 30, 2024 capital structure calculation on Schedule RA18.

Q. PLEASE EXPLAIN SCHEDULE RA22.

A. Schedule RA22 calculates the parent interest deduction using: 1) the June 30, 2024 forecasted balance of Duke Energy Indiana's total equity capital; times 2) Duke Energy Corporation's consolidated long-term debt to equity ratio for debt applicable to support of utility operations (exclusive of merger-related debt); times 3) the average cost of the parent company's debt applicable to support of utility operations. Components 2 and 3 of the calculation are unchanged from those utilized in the calculation of the parent interest deduction for the forecasted 2025 test period on Schedule TX4.

VII. <u>TRACKER NO. 60 – FUEL COST ADJUSTMENT</u>

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS TRACKER NO. 60 – FUEL COST ADJUSTMENT?

A. As discussed earlier in my testimony, the Company is proposing to update the base cost of fuel used to calculate the FAC rate. The new proposed base cost of fuel is 34.378 mills per kWh, as compared to the current factor of 26.955 mills per kWh. In addition, as with any base rate case, upon Commission approval in this proceeding, we will reset the tariff numbering.

The Company is also proposing to track changes in coal inventory balances, both increases and decreases, through the quarterly FAC filings.

Copies of the red-lined and clean revised tariff sheets reflecting these changes to Tracker No. 60 are attached to my testimony as Attachments 3-A (CLG) and 3-B (CLG), respectively.

Q. PLEASE ELABORATE ON THE COMPANY'S PROPOSAL TO TRACK COAL INVENTORY LEVELS THROUGH THE QUARTERLY FAC FILINGS.

A. As discussed in the testimony of Mr. Verderame, the Company's coal inventory levels have experienced significant movement, both increases and decreases, as a result of volatility in the energy commodity market pricing environment and inelasticity of the coal supply chain. The Company is proposing to track its coal inventory value, both increases and decreases, from the level included in the development of base rates in this proceeding.

Mechanically, this would be accomplished via an adjustment in the Company's quarterly FAC proceedings. The Company would calculate the difference between the coal inventory balance as of the end of the FAC reconciliation period applicable to retail customers and the amount included in the development of base rates in this proceeding. The Company would then calculate the revenue requirement associated with that differential by applying the most recently approved rate of return and revenue conversion factor. The revenue requirement would be divided by the forecasted billed kWh for the period the FAC factors would be in effect to determine the impact on the overall FAC factor.

Q. WHY IS THE COMPANY'S PROPOSAL REASONABLE?

A. The Company's proposal is reasonable given the significant volatility it has experienced in its coal inventory levels in recent years, as discussed by Mr. Verderame. Additionally, this proposal will benefit customers by providing a credit in the event the coal inventory value declines from the level in base rates, while also ensuring timely recovery of financing costs for the Company in the event the coal inventory value increases from the level in base rates.

VIII. ACCOUNTING AND DEFERRAL REQUESTS

A. Vegetation Management Costs

Q. WHAT ACCOUNTING TREATMENT WAS APPROVED FOR THE COMPANY'S DISTRIBUTION VEGETATION MANAGEMENT O&M IN CAUSE NO. 45253?

A. The Commission approved a cumulative reserve accounting approach to keep track of distribution vegetation management O&M above and below the amount included in base rates of $38.9 million, subject to a cap of $49.4 million, with the length of amortization of this reserve to be determined in Duke Energy Indiana's next rate case.

Q. WHAT IS THE BALANCE OF THE RESERVE ACCOUNT AT THE END OF THE HISTORICAL BASE PERIOD IN THIS PROCEEDING?

A. At the end of the historical base period of August 31, 2023, the reserve account was in an asset position of approximately $5 million. The Company believes this is indicative of the reserve accounting approach working as intended and is not proposing to include an amortization of the reserve account balance in this rate case.

Q. WHAT ACCOUNTING TREATMENT IS THE COMPANY REQUESTING RELATED TO VEGETATION MANAGEMENT COSTS IN THIS CASE?

A. Duke Energy Indiana is proposing to continue this reserve accounting approach for its distribution vegetation management O&M costs and is proposing to expand it to include both transmission and distribution vegetation management O&M costs. More specifically, the Company is proposing to track spend both above and below the amount proposed for inclusion in base rates in this proceeding of approximately $60.1 million ($44.8 million distribution, $15.3 million transmission).

Q. IS THE COMPANY'S PROPOSAL REASONABLE?

A. Yes, the Company's proposal is reasonable. Vegetation management is key to maintaining reliability, and including both the distribution and transmission functions in the reserve accounting approach allows for additional flexibility in allocation of resources to this work.

B. <u>Costs to Achieve Corporate Restructuring Savings</u>

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL REGARDING COSTS TO ACHIEVE CORPORATE RESTRUCTURING SAVINGS.

A. In December 2023, the Company incurred $6,289,000 in costs to achieve corporate restructuring savings. The anticipated annual savings of approximately $13.5 million were reflected as a reduction in 2025 test period O&M. Said differently, 2025 test period O&M was lower than it otherwise would have been because of these expected annual cost savings. The Company is proposing to defer the costs to achieve these annual corporate restructuring savings as a regulatory asset and amortize them over a three-year period. It is reasonable for the Company to request recovery of the costs that gave rise to the annual savings reflected in its test period O&M forecast.

C. Future Statutory Income Tax Rate Changes

Q. WHAT ACTIONS WILL THE COMPANY TAKE IN THE EVENT OF FUTURE CHANGES IN STATUTORY FEDERAL OR STATE INCOME TAX RATES?

A. In the event of future changes in either the statutory federal or state income tax rate, the Company proposes to file a petition in a new docket seeking an adjustment to rates to reflect the difference between (1) the amount of federal or state income taxes that the currently effective rates were designed to recover and (2) the amount of federal or state income taxes that would have been included in the design of currently effective rates had those statutory income tax rate changes been in effect at that time. The Company would also evaluate its EDIT balances for any necessary adjustments as part of this docket. This docket would be outside of a general rate case.

Q. WHAT SPECIFIC AUTHORITY IS THE COMPANY REQUESTING IN THIS PROCEEDING IN THE EVENT OF FUTURE CHANGES IN STATUTORY FEDERAL OR STATE INCOME TAX RATES?

A. In this proceeding, the Company is requesting authority to defer all calculated income tax differences resulting from any future change in statutory income tax rates as a regulatory asset or liability, as applicable, until the effect of the statutory income tax rate change can be fully reflected in the Company's rates.

Q. WHY IS THE COMPANY'S REQUEST REASONABLE?

A. The Tax Cuts and Jobs Act of 2017 ("TCJA") and the resulting investigation taught that tax rate changes can be very material, they can take effect abruptly, and they are completely outside the Company's control. Accordingly, being prepared for future changes in the income tax rates is a "lesson learned" from the enactment of the TCJA and the ensuing investigation. As the Commission explained in rejecting one utility's objection to lowering its rates in one of the sub-dockets during the TCJA investigation: "Because taxes are a pass-through expense, a change in the federal income tax rate should have no substantive bearing on whether a utility is or is not earning its authorized return. We also note that the nature of the income tax component of the revenue requirement makes it different than many types of expenses because the rate of the burden is defined in statute rather than dependent on the management actions of the utility."[8] It is reasonable for the Company to make this request in the context of this rate case proceeding in order to be prepared for future changes.

D. Requested Accounting Treatment

Q. IS THE ACCOUNTING TREATMENT PROPOSED BY THE COMPANY IN ACCORDANCE WITH GAAP?

A. Yes. GAAP specifically discusses the accounting for a regulator's actions designed to protect a utility from the effects of regulatory lag. Topic 980 of the Financial Accounting Standards Board's Accounting Standards Codification ("ASC") covers the accounting guidance for regulated operations formerly provided in Statement of Financial Accounting Standards No. 71. Costs associated with regulatory lag can be capitalized for

[8] Cause No. 45032-S3 (IURC 10/9/2018) (Sycamore Gas), p. 6.

accounting purposes, provided the provisions of ASC 980-340-25-1 are met. The guidance states:

> Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met: (a) It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes and (b) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost. A cost that does not meet these asset recognition criteria at the date the cost is incurred shall be recognized as a regulatory asset when it does meet those criteria at a later date.

Q. DO YOU HAVE AN OPINION AS TO THE APPROPRIATENESS OF AND THE ACTION REQUIRED BY THE COMMISSION TO ALLOW FOR THE REQUESTED ACCOUNTING TREATMENT?

A. Yes. In my opinion, deferral in a regulatory asset or liability, as applicable, is appropriate from a ratemaking perspective, and such treatment will also minimize the timing differences between cost recognition on the Company's books and cost recovery. In order for the Company to defer the costs to achieve corporate restructuring savings or calculated income tax differences resulting from a change in statutory income tax rates as a regulatory asset or liability, as applicable, it must be probable that such costs will be recovered through rates in future periods. In order to satisfy the probability standard and in accordance with Indiana Code 8-1-2-10, the Commission's Order in this proceeding should specifically approve the accounting and ratemaking treatment proposed by Duke Energy Indiana.

IX. CONCLUSION

Q. WERE ATTACHMENTS 3-A (CLG) AND 3-B (CLG) PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PREPARED TESTIMONY?

A. Yes.

Cause No. 46038

VERIFICATION

I hereby verify under the penalties of perjury that the foregoing representations are true to the best of my knowledge, information and belief.

Signed: Christa L. Graft
Christa L. Graft

Dated: April 4, 2024

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

IURC No. ~~15~~ 16
~~Sixteenth Revised Sheet~~ Original Tariff No. 60
~~Canceling Fifteenth Sheet No. 60~~

~~STANDARD CONTRACT RIDER~~ TARIFF NO. 60 - FUEL COST ADJUSTMENT

Calculation of Adjustment

A. The applicable charges for electric service to the Company's retail customers shall be increased or decreased, to the nearest 0.001 mill ($0.000001) per KWH to recover and/or credit the cost for fuel in accordance with the following formula:

Fuel Cost Adjustment Factor = F/S — BF

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the first month of the billing cycle and consisting of the following costs:

   (a) the average cost of fossil fuel consumed due to the operation of Company's own generating units incurred to serve native load customers, including only those items listed in Account 151, of the Federal Energy Regulatory Commission's Uniform System of Accounts for Class A and B Public Utilities and Licensees;

   (b) the actual identifiable fossil fuel costs, or, if fuel costs are not specifically identified, costs computed in accordance with applicable Commission Orders, associated with energy purchased or transferred to serve native load customers for reasons other than identified in (c) below;

   (c) the net energy cost, exclusive of capacity or demand charges, of energy purchased or transferred to serve native load customers on an economic dispatch basis, and energy purchased or transferred to serve native load customers resulting from the scheduled outage of a Company owned generating unit, when the costs thereof are less than the Company's fuel costs of replacement net generating from its own system, as computed in accordance with applicable Commission Orders;

   (d) fuel-related Regional Transmission Operator ("RTO") costs and credits approved by the Commission for recovery in the FCA;

   (e) other revenues or costs approved by the Commission for recovery in this rider.

2. "S" is the estimated kilowatt-hour sales for the same estimated period set forth in "F."

3. "BF" is the base cost of fuel pursuant to the Commission's Order in Cause No. ~~45253~~ XXXXX equal to $0.034378 ~~$0.026955~~ per kWh.

B. The factor shall be further modified commencing with the fifth succeeding billing cycle month to reflect the difference between the estimated incremental fuel cost billed and the incremental fuel cost actually incurred during the first and succeeding billing cycle month(s) in which such estimated incremental fuel cost was billed.

C. Effective for all bills rendered beginning with and subsequent to the later of the effective date of the Commission's Order or the first billing cycle of _____ ____ the fuel cost adjustment shall be:

X.XXXXXX per kilowatt-hour.

ISSUED: **EFFECTIVE:**

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

TARIFF NO. 60 - FUEL COST ADJUSTMENT

Calculation of Adjustment

A. The applicable charges for electric service to the Company's retail customers shall be increased or decreased, to the nearest 0.001 mill ($0.000001) per KWH to recover and/or credit the cost for fuel in accordance with the following formula:

Fuel Cost Adjustment Factor = F/S — BF

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the first month of the billing cycle and consisting of the following costs:

   (a) the average cost of fossil fuel consumed due to the operation of Company's own generating units incurred to serve native load customers, including only those items listed in Account 151, of the Federal Energy Regulatory Commission's Uniform System of Accounts for Class A and B Public Utilities and Licensees;

   (b) the actual identifiable fossil fuel costs, or, if fuel costs are not specifically identified, costs computed in accordance with applicable Commission Orders, associated with energy purchased or transferred to serve native load customers for reasons other than identified in (c) below;

   (c) the net energy cost, exclusive of capacity or demand charges, of energy purchased or transferred to serve native load customers on an economic dispatch basis, and energy purchased or transferred to serve native load customers resulting from the scheduled outage of a Company owned generating unit, when the costs thereof are less than the Company's fuel costs of replacement net generating from its own system, as computed in accordance with applicable Commission Orders;

   (d) fuel-related Regional Transmission Operator ("RTO") costs and credits approved by the Commission for recovery in the FCA;

   (e) other revenues or costs approved by the Commission for recovery in this rider.

2. "S" is the estimated kilowatt-hour sales for the same estimated period set forth in "F."

3. "BF" is the base cost of fuel pursuant to the Commission's Order in Cause No. XXXXX equal to $0.034378 per kWh.

B. The factor shall be further modified commencing with the fifth succeeding billing cycle month to reflect the difference between the estimated incremental fuel cost billed and the incremental fuel cost actually incurred during the first and succeeding billing cycle month(s) in which such estimated incremental fuel cost was billed.

C. Effective for all bills rendered beginning with and subsequent to the later of the effective date of the Commission's Order or the first billing cycle of _____ ____ the fuel cost adjustment shall be:

$X.XXXXXX per kilowatt-hour.

ISSUED: **EFFECTIVE:**