Cause No. 46038

On Behalf of Petitioner,
DUKE ENERGY INDIANA, LLC

VERIFIED DIRECT TESTIMONY OF KATHRYN C. LILLY

Petitioner's Exhibit 5

April 4, 2024

DIRECT TESTIMONY OF KATHRYN C. LILLY
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 Kathryn C. Lilly, and my business address is 1000 East Main Street, Plainfield, Indiana 46168.

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

A. I am employed by Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Company") as Manager, Rates and Regulatory Planning.

Q. PLEASE DESCRIBE YOUR DUTIES AS MANAGER, RATES & REGULATORY PLANNING.

A. I have responsibility for certain regulated rate matters involving Duke Energy Indiana, including rate administration, wholesale filings, and retail rate tracker filings.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I am a graduate of Indiana State University, holding a Bachelor of Science degree in Business, with a major in Accounting. Since my employment in 1986 with the Company (then known as Public Service Company of Indiana, Inc.), I have held various financial and accounting positions supporting the Company and its affiliates. I have held positions in Corporate Accounting, Project Management, Payroll, Budgets and Forecasts, along with numerous financial system implementation teams. 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. The purpose of my testimony is to explain several accounting, revenue requirements and ratemaking aspects of the Company's case. My testimony will:

1) Discuss the rate base included in the filing;
2) Discuss certain rate base *pro forma* adjustments applicable to the Company's forecasted 2025 test period ("Test Period");
3) Discuss *pro forma* adjustments to depreciation and amortization;
4) Summarize the nature of the Coal Combustion Residuals ("coal ash" or "CCR") costs currently in customer rates and what will be effective assuming implementation of the Company's requested rate treatment included in this proceeding;
5) Explain and support the Company's request for new deferral authority for costs associated with a Carbon Capture and Sequestration study at Edwardsport;
6) Explain and support the Company's request for new deferral authority for certain remaining net book value of generation assets and cost of removal upon retirement;

7) Explain and support proposed changes to certain of the Company's existing trackers (also referred to as riders) to be effective with the implementation of the Company's revised base rates; and
8) Explain and support Step 1 adjustments related to rate base.

II. RATE BASE

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 26, ATTACHMENT 26-C SCHEDULES RB1 – RB3.

A. Petitioner's Exhibit 26, Attachment 26-C, Schedules RB1- RB6 are a series of schedules supporting the rate base included in the Cost of Service in this proceeding and is intended to comply with 170 IAC 1-5-6 (4). Schedule RB1 is a summary of the total Company Test Period forecasted rate base amounts, the amounts as adjusted for ratemaking purposes, and the retail jurisdictional amount, as adjusted. Schedule RB2 provides additional detail on the total Company adjustments for net utility plant included in rate base, and Schedule RB3 provides additional detail on the balances and adjustments for the regulatory assets included in rate base. Schedules RB4, RB5 and RB6 provide the amounts included on RB1 for M&S inventory, prepaid pension and fuel inventory, respectively.

Q. WHAT AMOUNT OF RATE BASE IS INCLUDED IN THE COMPANY'S REQUEST?

A. As shown on Schedule RB1, the total Company adjusted rate base amount included in the case is $12.8 billion and the retail jurisdictional amount included in the Cost of Service is $12.5 billion.

Q. PLEASE DESCRIBE WHAT MAKES UP THE INCREASE IN RATE BASE FROM THAT APPROVED IN CAUSE NO. 45253.

A. Proposed retail rate base in this proceeding is approximately $1.6 billion higher than amounts in current base rates and trackers for a total rate base of $12.5 billion. The components of the increase include $1.1 billion for distribution, $0.8 billion for transmission, and $0.1 billion for regulatory assets, which is offset by a decrease in production of $0.8 billion. The increase for the remaining components is $0.4 billion (this includes other plant, inventory, and prepaid pension assets.)

Q. WHAT REGULATORY ASSETS ARE INCLUDED IN RATE BASE?

A. Petitioner's Exhibit 26, Attachment 26-C Schedule RB3 details the balances of the regulatory assets included in rate base and the Commission Cause Number approving deferral and/or recovery of each. The regulatory assets consist of:

Table 1

Regulatory assets approved in the last rate case (remaining unamortized balance)	$132,433
20% deferrals of TDSIC 1.0 and 2.0 Costs	39,394
20% deferrals of CCR Federally Mandated Costs	77,001
80% of CCR Federally Mandated Costs (Moved from ECR)	233,282
Electric Transportation Program	876
Purdue CHP	13,262

Customer Connect	34,252
Total Regulatory Assets at 12/31/2025 included in rate base	$530,500

Costs for all these regulatory assets have been deferred or forecasted pursuant to the terms of the applicable statute and/or Commission order.

III. RATE BASE *PRO FORMA* ADJUSTMENTS

Q. WHICH RATE BASE *PRO FORMA* TEST PERIOD ADJUSTMENTS WILL YOU BE DISCUSSING?

A. The rate base adjustments I am discussing are summarized below. Support for the adjustments is included in Exhibit 26, Attachment 26-C.

Table 2

Attachment	***Pro Forma* Adjustments to Rate Base**
Attachment 26-C	Schedule RB2 – Pro Forma Adjustments to Plant-in-Service and Accumulated Depreciation Reserve: • Remove Asset Retirement Obligation ("ARO") Assets • Remove Gas Pipeline Lease Asset • Remove Amount of Edwardsport Station Post-In Service Ongoing Capital Plant ("Ongoing Capital") in Excess of Settlement Caps • Remove Transmission Plant Assets Recovered via the Midcontinent Independent System Operator ("MISO") • Remove Non-Utility Customer Lighting Assets

	• Adjust Accumulated Depreciation for Proposed Depreciation Rates Schedule RB3 –Adjust Regulatory Assets Included in Rate Base

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 26, ATTACHMENT 26-C SCHEDULE RB2 TO ADJUST NET UTILITY PLANT.

A. Petitioner's Exhibit 26, Attachment 26-C Schedule RB2 details six *pro forma* adjustments needed to adjust net utility plant to the Test Period ending net utility plant amount projected to be used and useful plant at December 31, 2025. The first five adjustments remove various items included in forecasted net plant that need to be excluded from rate base for the proper development of new base rates. These include adjustments to remove:

- ARO Plant Assets
- Gas Pipeline Lease Asset
- Edwardsport Station Ongoing Capital in excess of settlement caps
- The portion of (RECB/MVP) Transmission Plant Assets recovered via MISO
- Non-Utility Customer Lighting Plant

Workpapers RB2 through RB16 and RB22 are being filed to support all these adjustments.

Q. PLEASE EXPLAIN WHY ARO PLANT ASSETS WERE REMOVED FROM NET UTILITY PLANT FOR RATEMAKING.

A. GAAP, under Accounting Standards Codification (ASC) 410 covering Asset Retirement and Environmental Obligations ("ARO Accounting"), requires companies to recognize ARO liabilities on their books and records for asset retirements for long-lived assets when certain situations occur that legally commit the company to incurring costs to retire the asset. At the same time, it requires the establishment of a new offsetting ARO plant asset on their books and records, which gets depreciated over time until it is time to retire and remove the underlying asset. Although a new plant asset is established on the Company's books, it is not an asset that is appropriate to include in rate base. Accordingly, the amounts included in the adjusted forecast for the Company's ARO assets recorded on the Company's books for GAAP purposes were removed from production and general plant-in-service and associated accumulated reserve for depreciation, reducing net utility plant by $542,163,000 as of the end of the Test Period. A similar adjustment was made in the Company's last base rate case in Cause No. 45253.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE THE GAS PIPELINE LEASE ASSET FROM NET UTILITY PLANT FOR RATEMAKING.

A. As approved by the Commission in its Order in Cause No. 43601, on October 2, 2008, the Company entered into a Gas Service Contract with Southern Indiana

Gas and Electric Company, Inc., d/b/a Vectren Energy Delivery of Indiana, Inc. (now d/b/a CenterPoint Energy Indiana South ("CEI South")) to provide gas to the Edwardsport IGCC plant via a gas pipeline which CEI South constructed and owns. The pipeline was completed in the spring of 2010, with May 2010 being the first month for which a payment under the 37-year contract was required. Until the IGCC plant was in-service, the contract payments were capitalized to the IGCC Project in accordance with FERC accounting guidance, subject to the IGCC Hard Cost Cap.

Although the contract is a capital lease for GAAP and SEC reporting purposes, the Company has been treating payments under the contract for regulatory accounting and ratemaking purposes as a gas transportation charge, similar to other charges the Company incurs for gas service to its Cayuga CT and Wheatland facilities, which are charged to fuel using FERC account 547. Likewise, the Company has included such costs pursuant to the Gas Service Contract in its cost of fuel for determination of fuel adjustment charges under its Tracker No. 60 – Fuel Cost Adjustment beginning with Cause No. 38707 FAC-95.

Like my discussion of the required GAAP accounting for AROs, both a liability and an asset are set up on the accounting books and records under capital lease accounting. The lease liability has been excluded from long-term debt for the capital structure calculations in all capital tracker proceedings since it was established on the Company's books. Because it is and has historically been treated as an operating lease treatment for ratemaking purposes, it is necessary to remove both the lease liability and the lease capital asset from ratemaking. Accordingly, the Company has removed $5,750,000 from net utility production plant in-service as of the end of the Test Period. A similar adjustment was made in Cause No. 45253.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE THE EDWARDSPORT ONGOING CAPITAL IN EXCESS OF SETTLEMENT CAPS.

A. As part of a Settlement Agreement in Cause No 43114 IGCC 15, the Company agreed to certain caps on its ongoing maintenance capital and capital additions for a portion of 2015, calendar year 2016 and calendar year 2017. To the extent the Company incurred ongoing capital above those capped amounts, they have been removed for ratemaking purposes. A similar adjustment was made in Cause No. 45253.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE THE RECB/MVP TRANSMISSION ASSETS.

A. The Company recovers its costs related to Company-owned Regional Expansion and Criteria and Benefits ("RECB") and Company-owned Multi-Value Project Usage Rate ("MVP") costs through MISO's Schedules 26 and 26-A. The revenues received by the Company from MISO through this process are excluded from the RTO Tracker, but Duke Energy Indiana also contributes its portion of allocated costs to the Company by MISO as a transmission customer. As these costs are already recovered through the revenues received from MISO, they have been removed from base rates. A similar adjustment was made in Cause No. 45253.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE NON-UTILITY CUSTOMER LIGHTING FROM NET UTILITY PLANT FOR RATEMAKING.

A. The Company removed $77,252,000 of customer lighting plant from net utility distribution plant in-service as of the end of the Test Period to ensure this plant was not included in the cost of service to all customers because the Company is being reimbursed for the cost of the lighting equipment by specific customers under the terms of customer-specific Outdoor Lighting Equipment Service agreements. A similar adjustment was made in Cause No. 45253.

Q. PLEASE EXPLAIN THE REMAINING ADJUSTMENT TO NET UTILITY PLANT SHOWN ON PETITIONER'S EXHIBIT 26, ATTACHMENT 26-C SCHEDULE RB2.

A. After considering these five *pro forma* adjustments to net utility plant, the Company then factored in the difference in the accumulated depreciation balance as of December 31, 2025 that would result from application of the new depreciation rates proposed in this case (assumed for purposes of the forecast to be effective March 1, 2025) from the current rates that were used in the forecast. This resulted in an additional reduction in net utility plant in the amount of $228,615,000, for a total reduction in net utility plant for all *pro forma* adjustments of $896,023,000. Workpapers RB2 through RB16 and RB22 are being filed to support all these adjustments. I will discuss more about the impact of the proposed change in depreciation rates on depreciation expense in Section IV. of my testimony.

Q. PLEASE EXPLAIN THE ADJUSTMENT ON PETITIONER'S EXHIBIT 26, ATTACHMENT 26-C SCHEDULE RB3 TO ADJUST REGULATORY ASSETS.

A. Petitioner's Exhibit 26, Attachment 26-C Schedule RB3 details the balances of the regulatory assets included in the Company's rate base in this request and the *pro forma* adjustment amounts for each. Like the adjustment needed to net utility plant to reflect the impact on accumulated depreciation of the difference between the proposed and current depreciation rates, it was necessary to adjust the December 31, 2025 balance of the regulatory assets for the impact on the accumulated amortization balance of the difference between the proposed amortization rates assumed to be effective March 1, 2025, and current amortization rates. These *pro forma* adjustments resulted in a decrease in regulatory assets to be included in rate base in the amount of $22,772,000. Workpapers RB18 and RB19 are being filed to support these adjustments. I will discuss more about the impact of the proposed changes in amortization periods on regulatory asset amortization expense in Section IV. of my testimony.

IV. DEPRECIATION AND AMORTIZATION *PRO FORMA* ADJUSTMENTS

Q. PLEASE SUMMARIZE THE DEPRECIATION AND AMORTIZATION *PRO FORMA* TEST PERIOD ADJUSTMENTS.

A. Support for the depreciation (Schedule DA1) and regulatory assets amortization adjustments (Schedule DA9) I will discuss can be found in Exhibit 26, Attachment 26-C and are summarized below:

Table 3

Attachment	*Pro Forma* Adjustments to Operating Income
Attachment 26-C	Schedule DA2 – Adjustment to Remove Depreciation Deferrals Schedule DA3 – Adjust and Annualize Depreciation Expense for Production Plant Schedule DA4 – Adjust and Annualize Depreciation Expense for Transmission Plant Schedule DA5 – Adjust and Annualize Depreciation Expense for Distribution Plant Schedule DA6 – Adjust and Annualize Depreciation Expense for General Plant Schedule DA7 – Adjust and Annualize Depreciation Expense for Intangible Plant Schedule DA8 – Adjust General Plant Depreciation for MISO RECB/MVP Credits Schedule DA10 – Adjust and Annualize Regulatory Asset Amortization Schedule DA11 – Adjustment to Remove Regulatory Asset Amortizations in Trackers

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 26, ATTACHMENT 26-C SCHEDULES DA2 THROUGH DA7 – ADJUST AND ANNUALIZE DEPRECIATION EXPENSE FOR DEPRECIATION EXPENSE FOR PRODUCTION, TRANSMISSION, DISTRIBUTION AND GENERAL PLANT.

A. Petitioner's Exhibit 26, Attachment 26-C Schedule DA2 removes depreciation deferrals. Schedule DA3 details the *pro forma* adjustment to adjust and annualize depreciation expense for production plant based on the Company's proposed depreciation rates and forecasted adjusted depreciable plant balances as of December 31, 2025. The schedule shows the total projected depreciation included in the forecast at current rates, as-adjusted projected December 31, 2025 plant in-service, current depreciation rates, annualized depreciation calculated using current rates and as-adjusted plant balances, proposed depreciation rates, annualized depreciation calculated using proposed rates and as-adjusted plant balances, and the total pro forma adjustment. Petitioner's Exhibit 26, Attachment 26-C Schedule DA4 does the same for Transmission Plant, as do DA5 for Distribution Plant, DA6 for General Plant, and DA7 for Intangible Plant.

The development of the proposed depreciation rates for Production, Transmission, Distribution and General Plant is discussed by Company witness Mr. Spanos. The decommissioning costs included in the depreciation study are discussed by Company witness Mr. Kopp, as well as Mr. Spanos. The forecasted retirement dates for production plant that were used in the depreciation study are discussed by Company witness Mr. Luke, with modifications related to Gibson Units 1 through 4, which I will describe later in my testimony. The depreciation rates for the Electric Plant Acquisition Adjustment and Intangible Plant were provided by our internal Asset Accounting department and are unchanged from current rates.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 26, ATTACHMENT 26-C SCHEDULE DA8.

A. Petitioner's Exhibit 26, Attachment 26-C Schedule DA8 removes general plant depreciation expense associated with MISO RECB-MVP projects.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 26, ATTACHMENT 26-C SCHEDULES DA9 AND DA11.

A. Petitioner's Exhibit 26, Attachment 26-C Schedule DA9 summarizes the *pro forma* adjustments made to Regulatory Asset amortization expense. Schedule DA11 is the removal of regulatory asset amortizations that will remain in trackers rather than being embedded in base rates. I will next discuss Petitioner's Exhibit 26, Attachment 26-C Schedule DA10.

Q. PLEASE EXPLAIN PETITIONER'S EXHIBIT 26, ATTACHMENT 26-C SCHEDULE DA10 - ADJUST AND ANNUALIZE REGULATORY ASSET AMORTIZATION EXPENSE.

A. Petitioner's Exhibit 26, Attachment 26-C Schedule DA10 increases Test Period regulatory asset amortization expense by $30,888,000, due primarily to the inclusion of amortization of regulatory assets deferred since the last base rate case pursuant to various Commission orders. Workpaper DA2 provides detail for the calculation, showing the proposed amortization periods for each regulatory asset and the basis for the amortization period, which are generally based on the remaining lives of the assets included in rate base, such as deferred depreciation and post-in-service carrying costs. Smaller dollar rate base and expense items without a set amortization period in a previous order were generally proposed for amortization over 3 years. This includes the approximately $2.5 million of forecasted rate case expenses proposed to be amortized over three years in this case. Workpaper DA1 provides the support for the December 31, 2025 balance, and Workpapers DA3 and DA4 provide additional detail for the regulatory assets not included in rate base,

Q. MS. LILLY, ARE YOU PROPOSING ANY CHANGES TO THE AMORTIZATION PERIODS OF PREVIOUSLY APPROVED REGULATORY ASSETS?

A. Yes, as the asset lives related to the assets giving rise to the regulatory asset have changed, those deferrals related to those assets are also adjusted. Workpaper

RB19 outlines the determination of the amortization periods for each regulatory asset, also noting if there was no change from the last rate case.

Q. HOW DOES THE COMPANY PLAN TO HANDLE AMORTIZATIONS INCLUDED IN BASE RATES THAT BECOME FULLY AMORTIZED BEFORE THE NEXT BASE RATE CASE?

A. The Company plans to include credits in its Credits Tracker when the amortizations included in base rates end.

Q. ARE THERE ANY AMORTIZATIONS THAT WILL BE MOVED INTO OR OUT OF BASE RATES?

A. Yes, the IGCC Deferred Expenses amortization included in base rates in Cause No. 45253 will end in 2025. Therefore, this amortization will not be included in base rates in this proceeding, but it will be moved to Tracker 62 to conclude. Once this amortization is fully amortized, it will be removed from the tracker. At this time, the Company estimates that this amortization will be concluded by ECR 44, which is estimated to be effective January 2026.

In addition, the Coal Ash Closure amortization, which is currently included in Tracker 62, will move to base rates. This regulatory asset will be amortized over the life of the Company's last remaining coal unit, making it administratively easier and appropriate to be included in base rates. (Please also see Tracker 62 discussion below).

V. COAL ASH RESIDUALS

Q. PLEASE EXPLAIN WHAT THE COMPANY IS RECOVERING IN CURRENT BASE RATES AND TRACKER RATES FOR COAL ASH RESIDUALS.

A. Amortization and return on a small regulatory asset amount including costs for Gibson East and Dresser basins was included in base rates in Cause No. 45253 and adjusted for the Commission's Order on Remand approved on April 12, 2023. In addition, regulatory assets for the 80% portion of coal ash costs incurred beginning November 2021 were approved to be recovered in Tracker 62 (ECR) in Cause No. 45253 S1 (from November 2021) and coal ash costs from Cause No. 45940 (case pending) (from January 2019) are proposed to be recovered through the ECR. These costs are related to coal ash closure and coal ash management with carrying costs, which are further described by Company witness Mr. Hill. Please see the table below that outlines the current and proposed cost recovery.

Q. IS THE COMPANY REQUESTING ANY CHANGES TO THIS RECOVERY?

A. Yes. As outlined below:

1) The Gibson East/Dresser forecasted 2025 balance is included in base rates in the regulatory asset balance earning a return. The amortization will be updated to reflect the forecasted balance divided by the new amortization period for steam plant.

2) The 80% coal ash closure that is forecasted in ECR will be moved from ECR to rate base with updated amortization periods. This is discussed in more detail in Section VII related to ECR Tracker.

3) The 20% coal ash closure with carrying costs and 20% coal ash management with carrying costs deferred under the Federal Mandate Statute (approved in Cause No. 45253 S1 and as proposed in Cause No. 45940) will be included in rate base. Amortization is proposed to begin with the approval of this rate case.

4) As explained by Company witness Mr. Hill, with requested accounting treatment supported by Company witness Mr. Riley, an additional $131 million of estimated future closure costs and $92 million of previously incurred costs has been factored into the depreciation study in this case as normal costs of removal.

Please see the chart below for a summary of CCR costs currently in rates and to be recovered in rates upon Commission approval in this case.

Forecasted 2025 – Assuming No Rate Case

	Base Rates	**ECR**	**Deferred**
Expenditures prior to 2019	Not included	Not included	Not included
Gibson East and Dresser (July 2020 – December 2020)	100%	Not included	Not included
Basins approved in 45253 S1 (Expenditures starting 11/2021)	Not included	80% Closure 80% Management 80% Carrying Cost	20% Closure 20% Management 20% Carrying Costs

Basins assumed approved in 45940 (Expenditures starting 2019)	Not included	80% Closure 80% Management 80% Carrying Cost	20% Closure 20% Management 20% Carrying Costs
Future Closure	Not included	Not included	100% to the extent any are incurred
Pre-Order 45253 S1 (Expenditures 1/2019 thru 10/2021)	Not included	Not included	Not included

Forecasted 2025 – Assuming Rate Case Requests are Approved

	Base Rates	**ECR**	**Deferred**
Expenditures prior to 2019	Not included	Not included	Not included
Gibson East and Dresser (July 2020 – December 2020)	100%	Not included	Not included
Basins approved in 45253 S1	100% Closure through Test Period 20% Management through Test Period 20% Carrying costs through Test Period	80% Closure after Test Period 80% Management 80% Carrying Costs	20% Closure after Test Period 20% Management after Test Period 20% Carrying Costs after Test Period
Basins assumed approved in 45940	100% Closure through Test Period 20% Management through Test Period 20% Carrying Costs through Test Period	80% Closure after Test Period 80% Management 80% Carrying Costs	20% Closure after Test Period 20% Management after Test Period 20% Carrying Costs after Test Period
Future Closure	Included in Depreciation Study		
Pre-Order 45253 S1 expenditures	Included in Depreciation Study		

Q. DO YOU BELIEVE THE COMPANY'S REQUESTED RECOVERY FOR COAL ASH IS REASONABLE?

A. Yes. The costs have been or will be incurred as a result of Federal or state environmental mandates. The generating units giving rise to the coal ash-related costs to be recovered were built to serve customers and have reliably served them currently and/or in the past for decades. As supported by Company witness Mr. Hill, the costs have been prudently managed and incurred. The costs constitute cost of removal under traditional regulatory constructs, as explained by Company witness Mr. Riley.

Q. WOULD IT ALSO BE REASONABLE TO INCLUDE IN THE CALCULATION OF THE DEPRECIATION ACCRUAL RATES THE COSTS INCURRED AND APPROVED BY THE COMMISSION FOR RECOVERY IN CAUSE NO. 45253?

A. Yes. These are the costs that were the subject of the Indiana Supreme Court's holding in *Ind. Office of Util. Consumer Counselor v. Duke Energy Ind., LLC,* 183 N.E.3d 266 (Ind. 2022) partially reversing the Commission's Order. The Commission found in its Order in Cause No. 45253 at p. 48, "No party disputed that the CCR Rule is a federal mandate with which the Company must comply, nor did any party dispute that the Company must comply with the IDEM solid waste management rules. Additionally, no party provided evidence of any imprudence on the part of DEI with respect to its coal ash basin closure and remediation activities to date." As such, the incurrence of these costs as a debit to accumulated depreciation would be appropriate for the reasons described by Company witness Mr. Riley. However, as explained by Company witness Mr. Pinegar, the Company has elected not to do so.

VI. ACCOUNTING TREATMENT, DEFERRAL AND COST RECOVERY REQUESTS

Q. PLEASE EXPLAIN THE COMPANY'S REQUEST TO USE DEFERRAL ACCOUNTING TREATMENT FOR ITS PROPOSED EDWARDSPORT CARBON CAPTURE AND SEQUESTRATION ("CCS") STUDY COSTS.

A. As discussed in more detail by Company witness Mr. Peter Hoeflich, Duke Energy Indiana was the recipient of a federal grant to assess the potential for CCS at Edwardsport. Duke Energy Indiana will be expected to cover approximately 50% of the study costs. As such and in accordance with Indiana Code 8-1-2-10, it is requesting approval from the Commission to defer those costs in order to be able to present those costs for inclusion in rates in a future proceeding.

Q. PLEASE EXPLAIN THE COMPANY'S REQUEST TO USE DEFERRAL ACCOUNTING TREATMENT FOR THE REMAINING BALANCE OF COAL GENERATING (STEAM) PLANT.

A. Currently Duke Energy Indiana is expecting to retire Gibson Units 1, 2, 3 and 4 earlier than assumed in the depreciation study. The retirement dates assumed in Company witness Mr. Spanos's depreciation study are later than the expected retirement dates resulting from the updated Integrated Resource Plan ("IRP") modeling. Due to this difference, there is projected remaining net book value at the retirement date of the last coal-fired steam generation unit. Company witness Mr. Pinegar explains that this decision is being made to mitigate the rate increase requested in this case with a view to customer affordability. The Company is only willing to extend the useful lives beyond what results from its updated IRP modeling if the regulatory asset treatment I describe is approved. If the regulatory asset treatment as I describe it is not approved, then the depreciation rates should be calculated using the steam generation life spans that result from the IRP.

Q. WHAT IS THE REGULATORY ASSET TREATMENT THE COMPANY IS PROPOSING?

A. The Company is proposing to extend the retirement dates for depreciation purposes for Gibson Units 1 through 4 beyond the period that these units will likely remain in service. Absent an unexpected event, the Company expects that every coal-fired steam generation unit will qualify as a normal retirement at its retirement. So long as the Company has coal-fired steam generation in service, Duke Energy Indiana will simply assign sufficient depreciation reserve to the property being retired. Upon retirement of the last unit remaining, however, this normal treatment would require the allocation of depreciation reserve across functions, which is not typical practice. As such, upon retirement of the last coal-fired steam generation unit and in accordance with Indiana Code 8-1-2-10, the Company proposes that any remaining net book value in steam generation be deferred and amortized over the remaining assumed depreciable life to ensure full recovery of the cost of the asset and the cost of its removal. Any deferred net book value and cost of removal will be included in the Company's rate base for ratemaking purposes.

To the extent that any future retirement is deemed abnormal, the Company is requesting in this case for Commission approval to defer that net book value of the units that are retired and the cost of removal in the interim if any of those units are unable to be accounted for as a normal retirement. In accordance with Indiana Code 8-1-2-10, this regulatory asset would then be included in Duke Energy Indiana's rate base in a future base rate proceeding, ensuring full recovery of the costs of the asset and its decommissioning costs.

Q. WHAT IS THE COMPANY PROPOSING RELATED TO COST OF REMOVAL?

A. Upon retirement of the last coal unit, under the Company's proposal, the cost of removal embedded in accumulated depreciation will be recorded to a regulatory liability (also to be reflected in rate base for ratemaking purposes). When all decommissioning is complete (including post-closure maintenance), the remaining balance will continue to be reflected in rate base for ratemaking purposes and will be amortized over a period of time to be determined by the Commission.

Q. HOW WILL THE CAYUGA AND GIBSON UNIT 5 RETIREMENTS AFFECT THESE BALANCES?

A. The Cayuga and Gibson Unit 5 retirements should be accounted for as normal retirements. As discussed previously, with a normal retirement, the accumulated depreciation and plant in service are both reduced by the original cost of the plant. Within the depreciation study (as a normal process), any difference would be reallocated to the remaining steam plant.

Q. DO YOU BELIEVE THE COMPANY'S REQUESTED DEFERRAL IS REASONABLE?

A. Yes. The Gibson Station generating units were built to serve customers, have reliably served them for decades, and will continue to do so until their retirement. Traditional ratemaking for utility assets provides for cost recovery in full for fixed assets such as generating units, as well as for full recovery of costs to remove and decommission the assets. The shift for environmental reasons from coal generation to other cleaner sources creates a unique situation that requires certainty from the Commission that the costs will be recovered, even if the Company is not able to account for the retirements using normal accounting. Approving now the use of deferred accounting by the Company at the time of the coal units' retirement with assurance of continued cost recovery until all costs, including cost of removal, are recovered, provides a known path forward all interested parties can count on. As I noted, if the proposal is unacceptable, then the extended lives for Gibson Units 1 through 4 should not be used for purposes of setting depreciation rates in this case.

VII. TRACKERS

Q. WHICH EXISTING TRACKERS WILL YOU ADDRESS IN YOUR TESTIMONY?

A. The trackers that I will cover include the Company's:

- Tracker No. 62 – Environmental Adjustment ("Tracker 62" or "ECR Tracker");
- Tracker No. 65 – Transmission and Distribution Infrastructure Improvement Cost ("TDSIC") Rate Adjustment ("Tracker 65" or "TDSIC Tracker");
- Tracker No. 66 – Energy Efficiency ("EE") Revenue Adjustment ("Tracker 66" or "EE Tracker");
- Tracker No. 67 – ("Credits Tracker");
- Tracker No. 72 – Federal Mandate Adjustment Tracker ("Tracker 72" or "FMCA Tracker"); and
- Tracker No. 74 – Load Control Adjustment Tracker ("Tracker 74" or "LC Tracker").

Copies of the red-lined and clean revised tracker tariffs are attached to my testimony as Attachment 5-A (KCL) thru 5-L (KCL).

A. Tracker 62 - ECR Tracker

Q. WHAT IS THE COMPANY'S PROPOSAL FOR ITS CURRENT TRACKER 62?

A. The Company is proposing to roll the net book value (original cost investment less accumulated amortization) of Coal Ash Closure costs as of the end of the Test Period into base rates. Also, the amortization of Coal Ash Closure will be moving to base rates.

Q. WHAT IS THE COMPANY PROPOSING RELATED TO CERTAIN REAGENT COSTS IN THE TRACKER 62.

A. As discussed in the testimony of Duke Energy Indiana witness Mr. Luke, the Company experiences variability with respect to reagent costs in many ways. Mr. Luke states that consumption of reagents varies directly with output of the generating stations and with coal quality and explains that commodity prices and transportation prices are also variable in nature. Given this variability, in Cause No. 45253, the Company was approved to track reagents compared to what was built into base rates. The Company is proposing to update the amount included in base rates, and to continue to track costs for the reagents, both above and below the amount in base rates, in the Tracker 62. This will protect customers to the extent actual reagent costs are less than the amount in base rates, and also protects the Company in the event actual reagent costs exceed the amount in base rates. The amount included in base rates for the Test Period is $27.4 million on a total Company basis, and costs will be tracked around this amount.

Q. UNDER THE COMPANY'S PROPOSAL, ARE THERE ANY ITEMS INCLUDED CURRENTLY IN TRACKER 62, THAT WILL NOT BE INCLUDED IN BASE RATES?

A. Yes. The Company is proposing that the 80% portion of post-in-service carrying costs associated with the Coal Ash Compliance Project that was previously approved by the Commission in Cause No. 45253 S1 and proposed in Cause No. 45940 remain in Tracker 62. At the end of the Test Period, these items will have remaining amortization periods of approximately one year. Therefore, it is more administratively efficient for the Company to complete recovery of these costs through Tracker 62. Tracker 62 is reconciled, and therefore, when amortization is complete, the Company can simply remove these costs from the tracker. In addition, the Company is proposing that 80% portion of Coal Ash Management costs continue in the Tracker.

Q. ARE THERE ANY ITEMS BEING MOVED TO TRACKER 62 THAT ARE CURRENTLY INCLUDED IN BASE RATES?

A. Yes. As mentioned above, the amortization of IGCC deferred expenses will end in 2025. When new base rates are developed for this proceeding, those rates will exclude any amortization for IGCC deferred expenses. The remaining unamortized amount for IGCC deferred expenses will then be included in Tracker 62. Once this amount is fully amortized, the amortization will be removed from Tracker 62.

Q. WILL THERE BE ANY OTHER CHANGES TO TRACKER 62?

A. Yes, as discussed by Company witness Mr. Hill, the Company will be flowing back to customers their proportionate share of the net insurance proceeds associated with coal ash closure costs through the ECR.

Q. IS THE COMPANY'S RATEMAKING PROPOSAL FOR TRACKER 62 REASONABLE?

A. Yes. The Company's proposal is consistent with past practice. The Company's proposal to track reagent O&M both above and below the amount in base rates ensures that customer rates reflect actual expenses incurred for this variable cost.

Q. HOW WILL COSTS BE ALLOCATED TO RETAIL RATE GROUPS IN THE TRACKER 62?

A. The Company is not proposing any changes to the allocation to retail rate groups. Currently, return on investment, depreciation expense, and post-in-service carrying costs are allocated to retail rate groups based upon production demand. O&M costs are to retail rate groups using a production energy allocator.

Q. HOW ELSE WILL THE CALCULATION OF RATES IN THIS TRACKER CHANGE UPON APPROVAL OF NEW BASE RATES?

A. At the time of implementation of the new base rates resulting from this proceeding, the ECR Tracker will be revised to:

- remove the amounts discussed above that will be included in base rates and add the amounts for the new items discussed above;
- recalculate the amortization on the remaining regulatory assets using the new amortization lives, if appropriate;
- change the ROE and cost rate for customer deposits used in the cost of capital calculation for the ECR Tracker to the new ROE and customer deposit rates approved in this proceeding; and
- change the allocations to rate classes to reflect the allocations used in the Cost of Service Study.
- Finally, the revenue conversion factors used to calculate amounts in the ECR Tracker will reflect the provision for uncollectible accounts

expense and public utility fee approved in this proceeding.

Q. ARE YOU PROPOSING ANY CHANGES TO THE TRACKER 62 TARIFF?

A. Yes, as with any base rate case, upon Commission approval in this proceeding, we will reset the tariff numbering and update the allocation factor pages of the tariffs to reflect the approved Cost of Service study allocations to be used for the tracker. A red-lined and clean version of the tariff reflecting these changes is filed as Attachment 5-A (KCL) and 5-B (KCL). The complete tracker with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

B. <u>Tracker 72 – FMCA Tracker</u>

Q. WILL THERE BE ANY ITEMS THAT WILL REMAIN IN TRACKER 72?

A. No, Tracker 72 rates are currently at $0 and will remain there until future federally mandated costs are approved for recovery. Although this Tracker currently has no costs, the Company is proposing to continue Tracker 72 in order to have a ready mechanism via which to track likely future NERC cybersecurity costs, as well as any other federally mandated costs.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT FMCA TRACKER TARIFF?

A. Yes. As with any base rate case, upon Commission approval in this proceeding, we will reset the tariff numbering and update the allocation factor pages of the tariffs to reflect the approved cost of service study allocations to be used for the tracker. A red-lined and clean version of the tariff reflecting these changes is filed as Attachment 5-I (KCL) and 5-J (KCL). Should we need to begin using the tracker in the future for new federally mandated costs, we will incorporate the approved ROE and customer deposit cost rate and revise the revenue conversion factor to include the approved public utility fee rate and uncollectible expense rate in the revenue conversion factor used in the new rate calculation.

C. <u>Tracker 65 - TDSIC Tracker</u>

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS TDSIC TRACKER?

A. The Company is proposing to roll the original cost investment and accumulated depreciation of in-service TDSIC plant (TDSIC 1.0 and TDSIC 2.0) as of the end of the Test Period into base rates. This includes the 80% of in-service plant that is eligible for inclusion in the TDSIC Tracker, as well as the 20% that is deferred for rate case recovery pursuant to Ind. Code 8-1-39 ("TDSIC Statute").[1] Additionally, the Test Period level of property taxes will be included in base rates, as will the depreciation associated with the investment rolled in.

At the time of implementation of the new base rates resulting from this proceeding, the TDSIC Tracker will be revised to:

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[1] In addition to the net book value of the 20% amount of in-service TDSIC plant, the Company is including in rate base the projected end of Test Period balances of deferred depreciation on the 20% of investment, as well as the 20% of deferred O&M and property taxes associated with the in-service projects, the associated post-in-service carrying costs on the deferred investment, and deferred financing costs on the O&M and property taxes deferred. The deferrals are all consistent with the TDSIC statute and previous Duke Energy Indiana TDSIC plan Commission Orders. See Exhibit 26, Attachment 26-C Schedule RB3 for regulatory asset balances for these items that are being including in rate base.

- remove the investment and property tax amounts included in base rates;
- recalculate the depreciation on the remaining investment using the new depreciation rates approved in this proceeding;
- change the ROE and customer deposit cost rate used in the cost of capital calculation for the TDSIC Tracker to the new ROE and customer deposit cost rate approved in this proceeding; and
- change the allocations to rate classes used in the calculation of rates to use the final approved Transmission and Distribution revenue requirements from this proceeding instead of the revenue requirements from Cause No. 45253.

Finally, the revenue conversion factors used to calculate amounts in the TDSIC Tracker will reflect the provision for uncollectible accounts expense and public utility fee approved in this proceeding.

Q. WILL THERE BE ANY CHANGES TO THE CALCULATIONS IN FUTURE TDSIC TRACKER FILINGS?

A. No, the Company plans to continue to report total annual and cumulative investment totals in its TDSIC 2.0 plan and rates filings for purposes of determining amounts to include in the TDSIC Tracker. TDSIC 1.0 will be fully included in base rates.

Similarly, to enable comparisons of forecasted TDSIC 2.0 plan amounts to actuals by projects as is done in the rate filings, Company witnesses in the post-base rate case TDSIC filings will continue to present total cumulative amounts for each TDSIC project. For calculation of return purposes, the amount in base rates will be subtracted from the total plan investment so that only 80% of the incremental amount not currently earning a return in base rates will earn a return in the tracker. Depreciation and property taxes will then be calculated on the incremental amount of investment included in the tracker, consistent with the method currently used in the Company's TDSIC Tracker-related plant that was rolled into base rates in the Company's last base rate case.

Q. WILL THERE BE ITEMS INCLUDED IN THE TDSIC TRACKER THAT WILL REMAIN IN THE TRACKER?

A. Yes. The Company is proposing that TDSIC O&M expense and post-in-service carrying costs not be included in base rates, but rather continue to be tracked in the TDSIC Tracker. This is because, for TDSIC, the project-related O&M is non-recurring and variable in nature and the O&M for the inspection-based projects can also fluctuate depending on the number of inspections included in each plan year. The post-in-service carrying costs are also non-recurring and variable in nature, as in each annual filing the costs accrued in the prior year are included for recovery over the one-year period the tracker rates will be in effect, and the next year the costs accrued will be for a different set of projects, with differing costs, in-service dates, etc. for each year of the plan. Should the Company incur any additional costs for updated risk analyses for plan update filings, these costs will be included in normal course of business for recovery via the TDSIC Tracker.

Q. ARE THE COMPANY'S RATEMAKING PROPOSALS REGARDING TDSIC INVESTMENT AND COSTS CURRENTLY INCLUDED IN THE TDSIC TRACKER REASONABLE?

A. Yes, the Company's proposal is consistent with past practice in Indiana to subsequently include in base rates in-service plant receiving CWIP ratemaking treatment via a tracker. The Company's proposed treatment is also in accordance with the terms of the TDSIC 1.0 Settlement Agreement and the TDSIC Statute. To continue to track the 80% portion of O&M expense, post-in-service carrying costs, and any additional Plan Development costs in the TDSIC Tracker, along with the 80% portion of all incremental new investment and related depreciation and property tax, is a reasonable way to recover the non-routine and variable TDSIC costs.

Q. HOW WILL THE COMPANY IMPLEMENT THE CHANGES TO THE TDSIC TRACKER ONCE NEW BASE RATES ARE APPROVED?

A. The Company will file revised rate schedules resetting the then-current rates to remove the amounts included in base rates and update the weighted average cost of capital calculation, revenue conversion factors, and allocation factors. This will be done concurrently with filing the new base rate tariffs, with both base rates and tracker rate changes to be implemented on a service-rendered basis.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT TDSIC TRACKER TARIFF?

A. Yes. As with any base rate case, upon Commission approval in this proceeding, we will reset the tariff numbering and update the allocation factor pages of the tariffs to reflect the approved Cost of Service study allocations to be used for the tracker. A red-lined and clean version of the tariff reflecting these changes is filed as Attachment 5-C (KCL) and 5-D (KCL). The complete tracker with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

D. Tracker 66 - EE Tracker

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS EE TRACKER?

A. At the time of implementation of the new base rates resulting from this proceeding, the EE Tracker will be revised to change the revenue conversion factors used to calculate revenue requirements to reflect the provision for uncollectible accounts expense and public utility fee approved in this proceeding.

Q. IS THE COMPANY PROPOSING TO EMBED ANY LEVEL OF COSTS IN BASE RATES FOR PROGRAM COSTS, INCLUDING ADMINISTRATIVE OVERHEADS, OR SHAREHOLDER INCENTIVES?

A. No. Consistent with the treatment approved in the Company's last rate case, the Company is proposing to remove all EE program costs, including administrative and EM&V costs, and all shareholder incentives from the cost of service and track these costs in the EE Tracker from the zero base.

Q. PLEASE EXPLAIN WHAT WILL HAPPEN WITH THE LOST REVENUES CURRENTLY INCLUDED IN THE EE TRACKER WITH THE IMPLEMENTATION OF NEW BASE RATES.

A. There will be several impacts. Because the Company is using forecasted sales for 2025 in developing the new base rates:

- The persisting lower sales that resulted from Company EE programs offered up through year-end 2024 will be completely reflected in the forecasted sales used for setting new base rates. Therefore, the persisting lost revenue amounts for calendar years 2020 through 2023 and any lost revenue amounts for 2024 vintage programs in then-current EE Tracker rates will be reset to zero in the tracker and remain zero in future tracker filings.
- The 2025 impact of lower sales that result from Company EE programs offered in 2025 will be reflected in the forecasted sales. Therefore, any lost revenue amounts for 2025 vintage programs will be reset to zero in the tracker for the remainder of 2025.
- However, the 2025 impact of lower sales reflected in the 2025 forecasted sales does not fully reflect the annual sales loss that will occur as a result of 2025 energy efficiency programs, because all 2025 EE program participation was not forecasted to begin (and will not begin) on January 1, 2025. Customers decide to participate and begin installing EE program measures throughout the calendar year and the Company assumes for forecasting purposes that

customers participate in EE in equal amounts for each month throughout the year. It is not until year end that all participation has occurred, and all measures have been installed for the calendar year.

For this reason, the actual sales reductions the Company will experience in 2026 as a direct result of the 2025 Company-sponsored EE programs will be larger than the amounts that were included in the 2025 forecast used for base rate development. This creates the need for a level of lost revenues for 2025 programs to be included in the EE Tracker beginning in 2026 through the life of the measures in order for the Company to have the opportunity to earn its allowed return considering the full extent of the reductions in sales resulting from its 2025 EE programs. The Commission has ruled in its EE Orders it is appropriate to recover lost revenues in the EE Tracker for the sales reduction impacts from Company-sponsored EE programs. So, beginning with rates that incorporate the forecast for 2026 programs, the incremental sales reduction impacts achieved from 2025 EE programs will be used to develop persisting lost revenues to be included in the EE Tracker for customers eligible to participate in the 2025 EE programs.

Additionally, after the new base rates are implemented, the prices that are used to calculate the lost revenue amounts included in the EE Tracker will reflect the fixed costs approved for recovery in this base rate proceeding rather than using Cause No. 45253 costs to price the lost revenues.

Q. WILL CUSTOMERS, INCLUDING NON-RESIDENTIAL CUSTOMERS WHO HAVE OPTED OUT OF PARTICIPATING IN ENERGY EFFICIENCY PROGRAMS AT THE TIME OF THE RATE CASE FILING, CONTINUE TO BE BILLED OR CREDITED THROUGH THE EE TRACKER AFTER THE RATE CASE FOR EE TRACKER RECONCILIATIONS FOR PRIOR YEARS?

A. Yes. The Commission has approved the Company's EE Tracker reconciliation and EM&V processes and timing, most recently in its last plan approved in Cause No. 45803, including the retrospective application of EM&V for lost revenue reconciliation purposes. This can result in re-reconciling prior years when an EM&V can't be done annually due to the need to get a larger sample size.

For Residential customers, vintage years 2012 – 2018 have been fully reconciled in the tracker. There is still outstanding EM&V for the remaining vintage years that will result in additional reconciliations in the future.

For Non-Residential customers, vintage years 2012 – 2019 have been fully reconciled in the tracker. So, for the eligible customers who opted out of EE programs effective April 1, 2014 or January 1, 2015, 2016, 2017, 2018 or 2019, and who have not opted back in as of the time of implementation of base rates, there will be no further reconciliation of EE Tracker costs required, and their EE Tracker rate will remain zero if they remain opted out. Once all EM&V for additional vintage years has been received and reflected in the final EE Tracker reconciliation for that vintage year, additional customers who have opted out and not opted back in will see their tracker rate go to zero if they remain opted out. All other Non-Residential customers will continue to see additional reconciliations in the future.

Q. ARE THE COMPANY'S RATEMAKING PROPOSALS REGARDING THE EE TRACKER REASONABLE?

A. Yes, keeping all energy efficiency costs in the EE Tracker rather than embedding some level in base rates is appropriate given the statutory requirement to propose plans consistent with each Integrated Resource Plan, which are required to be updated every three years. This requirement means plans can and will change, and the levels of costs will change. Additionally, participation and results may vary materially each year, making the EE Tracker rates volatile. Further, having all EE costs in a tracker gives participating and non-participating customers a full picture of their share of the costs of the Company's EE programs.

Q. HOW WILL THE COMPANY IMPLEMENT THE CHANGES TO THE EE TRACKER ONCE NEW BASE RATES ARE APPROVED?

A. The Company will file revised rate schedules resetting the then-current rates to remove the lost revenue amounts and adjust the revenue conversion factors. This will be done concurrently with filing the new base rate tariffs, with both base rates and tracker rate changes to be implemented on a service-rendered basis.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT EE TRACKER TARIFF?

A. Yes. As with any base rate case, upon Commission approval in this proceeding, we will reset the tariff numbering and update the allocation factor pages of the tariffs to reflect the approved Cost of Service study allocations to be used for the tracker. A red-lined and clean version of the tariff reflecting these changes is filed as Attachments 5-E (KCL) and 5-F (KCL). The complete tracker with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

E. <u>Tracker 67 - Credits Tracker</u>

Q. WHAT CHANGE IS THE COMPANY EXPECTING TO MAKE TO ITS CREDITS TRACKER?

A. Several credits will remain in Tracker 67, such as the ongoing TCJA credit for unprotected and protected EDIT amortization, pursuant to the TCJA Settlement Agreement, the amortization approved in Cause No. 45253 related to the two-year deferral of protected EDIT, and certain IGCC facility tax incentive credits (namely, property tax incentives).

As described in the Commission's Order in Cause No. 43114, the Company was awarded certain federal investment tax incentives associated with the construction of Edwardsport and was ordered by the Commission to amortize the benefit of the tax credits and pass such benefits back over the life of the plant in accordance with federal tax laws. Duke Energy has not been able to realize the benefits of its investment tax credit ("ITC"). The Company expects to begin utilizing this benefit in the upcoming tax returns, and is planning to include this credit in its Credits Tracker. The IGCC ITC is explained in more detail in Company witness Ms. Graft testimony.

In addition, as discussed previously, the Company plans to include additional credits in this tracker as the regulatory assets for which amortization is being included in base rates become fully amortized.

Further, as discussed in more detail in Ms. Graft's testimony, the Credits Tracker is planned to be used during the first and second steps of implementing the new base rates by crediting customers (upon review and approval by the Commission in a compliance filing) with the difference between what final base rates are using the proposed forecasted Test Period revenue requirements, reflecting used and useful plant in-service as of December 31, 2025, and what they would be using the known actual used and useful plant in-service as of June 30, 2024 ("Step 1 Rate Adjustment"). This will ensure that customers only pay rates reflecting used and useful plant during this Step 1 period from early 2025 before final December 31, 2025 used and useful plant in-service amounts are known and until the Step 2 rates are implemented.

In addition to the inclusion of the additional TCJA credits, the credits for the IGCC facility tax incentive benefits and the Two-Step Rate Adjustment, at the time of implementation of the new base rates resulting from this proceeding, the Credits Tracker will also be revised to:

- remove the credit related to Gallagher depreciation;
- remove the credit related to utility receipts tax;
- remove the credit related to the Cause No. 45253 Rate Case Remand related to coal ash;
- remove the credit related to regulatory assets amortization;
- include the calculated revenue requirements differential by rate class for the Two-Step Rate Adjustment;
- add a credit for additional unprotected EDIT as discussed by Company witness Ms. Graft;
- add a credit for the IGCC ITC as applicable and as discussed above, which will be allocated using the production demand allocator;
- add a credit for refunding a portion of the Grantor Trust reserve for Other Post Retirement Benefits as discussed by Company witness Ms. Sieferman, which will be allocated using the Administrative and General allocator;
- add a credit for only Step 1 rates for the loss of two wholesale contracts at the end of 2025 that were factored into the Separation Study, as discussed by Company witness Ms. Diaz, which will be allocated using the production energy allocator;
- change the allocations to rate classes used in the calculation of revenue requirements for the TCJA credits to use the final approved net book value of in-service plant from this proceeding instead of from Cause

No. 45253;

- change allocations to rate classes to be used in the calculation of revenue requirements for the credits for the IGCC facility tax incentive benefits using the production demand allocators from this proceeding;

Q. ARE THE COMPANY'S RATEMAKING PROPOSALS REGARDING THE CREDITS TRACKER REASONABLE?

A. Yes, continuing the Credits Tracker is consistent with the requirements under the terms of the TCJA Settlement, and the Credits Tracker has proven to be a useful tool over time to provide credits back to customers in a timely and efficient manner. Continuing to track the IGCC facility incentive tax benefits and ITC provides transparency that the credits are indeed being provided to customers. It also provides a transparent and administratively convenient means to ensure customers are only charged for used and useful plant as a result of the use of a forecasted Test Period in this base rate proceeding without creating a new tracker (*i.e.*, the Two-Step Rate Adjustment). Having it available will also enable the Company to include additional credits when shorter term regulatory asset amortizations end prior to the next base rate case, allowing customers to benefit sooner in a planned way.

Q. HOW WILL THE COMPANY IMPLEMENT THE CHANGES TO THE CREDITS TRACKER ONCE NEW BASE RATES ARE APPROVED?

A. The Company will file revised rate schedules resetting the then-current rates to incorporate the changes discussed. This will be done concurrently with filing the new base rate tariffs, with both base rates and tracker rate changes to be implemented on a service-rendered basis.

Q. ARE YOU PROPOSING ANY CHANGES TO THE CURRENT CREDITS TRACKER TARIFF?

A. Yes. As with any base rate case, upon Commission approval in this proceeding, we will reset the tariff numbering and update the allocation factor pages of the tariffs to reflect the approved Cost of Service study allocations to be used for the tracker. A red-lined and clean version of the tariff reflecting these changes is filed as Attachments 5-G (KCL) and 5-H (KCL). The complete tracker with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

F. Tracker 74 – LC Tracker

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO ITS LC TRACKER?

A. At the time of implementation of the new base rates resulting from this proceeding, the LC Tracker will be revised to remove the level of expenses included in the base rates. It will also change the revenue conversion factors used to calculate revenue requirements to reflect the provision for uncollectible accounts expense and public utility fee approved in this proceeding.

In addition, as with any base rate case, upon Commission approval in this proceeding, we will reset the tariff numbering and update the allocation factor pages of the tariffs to reflect the approved Cost of Service study allocations to be used for the tracker. A red-lined and clean version of the tariff reflecting these changes is filed as Attachment 5-K (KCL) and 5-L (KCL). The complete tracker with revised rates and new allocation factors will be filed as a compliance filing following approval of the Company's proposed base rates.

VIII. STEP 1 RATE BASE

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 plant in service to determine the Step 1 adjustment to depreciation expense. Schedules RA13 through RA17 provide the detail of Schedule RA12 by function. I provided this information to Company witness Ms. Graft and my workpapers support these schedules.

IX. CONCLUSION

Q. WERE ATTACHMENTS 5-A (KCL) THROUGH 5-L (KCL) PREPARED UNDER YOUR DIRECT SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, it does.

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: Kathryn C Lilly
Kathryn C. Lilly

Dated: April 4, 2024

~~STANDARD CONTRACT RIDER~~TARIFF NO. 62 –
ENVIRONMENTAL COMPLIANCE ADJUSTMENT

The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased to reflect rate base treatment for environmental compliance projects, defined as qualified pollution control property, clean energy projects, and other federally-mandated environmental compliance projects in accordance with I.C. 8-1-2-6.6, I.C. 8-1-2-6.8, I.C 8-1-8.4, I.C. 8-1-8.8 and 170 IAC 4-6, and to reflect recovery of clean energy and other federally-mandated environmental compliance project operating costs, including the cost of environmental reagents and emission allowances applicable to native load customers net of realized gains and losses from sales, in accordance with Ind. Code 8-1-8.8 and Ind. Code 8-1-8.4. The revenue adjustment to the applicable charges for electric service will be determined under the following provision:

Calculation of Adjustment

The Environmental Compliance Adjustment shall be determined no more often than every six months by multiplying the Environmental Compliance 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 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.

Environmental Compliance Adjustment Factor =

$$\frac{(a \times b \times c \times h)}{i} + \frac{((d + e + f) \times g)) \times j}{k}$$

where:

1. "a" is the jurisdictional cost of the Company's net invested capital applicable to environmental compliance projects and the net balance of post-in-service carrying costs, if any. For purposes of determining the value of such capital projects for this rate mechanism, the Company's costs as recorded in its books of account in accordance with the Uniform System of Accounts prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act shall be used.

2. "b" is the Company's weighted cost of capital as of the date of valuation of the environmental compliance projects.

3. "c" is the revenue conversion factor to be used to convert return to operating revenues.

4. "d" is the Company's forecasted incremental jurisdictional operation and maintenance expense applicable to environmental compliance projects, including the cost of environmental reagents and emission allowances applicable to native load customers net of realized gains and losses from sales.

5. "e" is the Company's forecasted jurisdictional depreciation expense applicable to the investment in environmental compliance projects.

6. "f" is the Company's other incremental jurisdictional expense applicable to environmental compliance projects such as plan development costs, amortization of post-in-service

~~STANDARD CONTRACT RIDER~~TARIFF NO. 62 –
ENVIRONMENTAL COMPLIANCE ADJUSTMENT

carrying costs, and other costs or credits approved by the Commission for inclusion in this rider.

7. "g" is the revenue conversion factor used to convert operating expenses to operating revenues.

8. "h" is the individual retail rate group's production demand allocator used for allocation purposes in the cost of service study last approved by the Commission as adjusted for migrations approved by the Commission.

9. "i" is the individual retail rate group's adjusted billing cycle kilowatt-hour sales for the twelve months ending as of the date of valuation of the environmental compliance projects for all retail rate groups other than industrial customers served under Rate HLF. The revenue adjustment for industrial customers served under Rate HLF shall be based on demands within the HLF customer group such that "i" shall be the sum of kilowatts billed for the applicable twelve month period.

10. "j" is the individual retail rate group's kilowatt-hour sales allocator used for allocation purposes in the cost of service study last approved by the Commission as adjusted for migrations approved by the Commission.

11. "k" is the individual retail rate group's adjusted billing cycle kilowatt-hour sales for the applicable six month period for all retail rate groups other than industrial customers served under Rate HLF. The revenue adjustment for retail customers served under Rate HLF shall be based on demands within the HLF customer group such that "k" shall be the sum of kilowatts billed for the applicable six month period.

This factor shall be further modified to reflect the difference between estimated costs billed and costs actually experienced during the period such estimated costs were billed.

The Environmental Compliance Adjustment factor applicable to retail rate groups is as follows:

TARIFF NO. 62 – ENVIRONMENTAL COMPLIANCE ADJUSTMENT

The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased to reflect rate base treatment for environmental compliance projects, defined as qualified pollution control property, clean energy projects, and other federally-mandated environmental compliance projects in accordance with I.C. 8-1-2-6.6, I.C. 8-1-2-6.8, I.C 8-1-8.4, I.C. 8-1-8.8 and 170 IAC 4-6, and to reflect recovery of clean energy and other federally-mandated environmental compliance project operating costs, including the cost of environmental reagents and emission allowances applicable to native load customers net of realized gains and losses from sales, in accordance with Ind. Code 8-1-8.8 and Ind. Code 8-1-8.4. The revenue adjustment to the applicable charges for electric service will be determined under the following provision:

Calculation of Adjustment

The Environmental Compliance Adjustment shall be determined no more often than every six months by multiplying the Environmental Compliance 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 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.

Environmental Compliance Adjustment Factor =

$$\frac{(a \times b \times c \times h)}{i} + \frac{((d + e + f) \times g)) \times j}{k}$$

where:

1. "a" is the jurisdictional cost of the Company's net invested capital applicable to environmental compliance projects and the net balance of post-in-service carrying costs, if any. For purposes of determining the value of such capital projects for this rate mechanism, the Company's costs as recorded in its books of account in accordance with the Uniform System of Accounts prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act shall be used.

2. "b" is the Company's weighted cost of capital as of the date of valuation of the environmental compliance projects.

3. "c" is the revenue conversion factor to be used to convert return to operating revenues.

4. "d" is the Company's forecasted incremental jurisdictional operation and maintenance expense applicable to environmental compliance projects, including the cost of environmental reagents and emission allowances applicable to native load customers net of realized gains and losses from sales.

5. "e" is the Company's forecasted jurisdictional depreciation expense applicable to the investment in environmental compliance projects.

6. "f" is the Company's other incremental jurisdictional expense applicable to environmental compliance projects such as plan development costs, amortization of post-in-service carrying costs, and other costs or credits approved by the Commission for inclusion in this rider.

TARIFF NO. 62 – ENVIRONMENTAL COMPLIANCE ADJUSTMENT

7. “g” is the revenue conversion factor used to convert operating expenses to operating revenues.

8. “h” is the individual retail rate group’s production demand allocator used for allocation purposes in the cost of service study last approved by the Commission as adjusted for migrations approved by the Commission.

9. “i” is the individual retail rate group’s adjusted billing cycle kilowatt-hour sales for the twelve months ending as of the date of valuation of the environmental compliance projects for all retail rate groups other than industrial customers served under Rate HLF. The revenue adjustment for industrial customers served under Rate HLF shall be based on demands within the HLF customer group such that “i” shall be the sum of kilowatts billed for the applicable twelve month period.

10. “j” is the individual retail rate group’s kilowatt-hour sales allocator used for allocation purposes in the cost of service study last approved by the Commission as adjusted for migrations approved by the Commission.

11. “k” is the individual retail rate group’s adjusted billing cycle kilowatt-hour sales for the applicable six month period for all retail rate groups other than industrial customers served under Rate HLF. The revenue adjustment for retail customers served under Rate HLF shall be based on demands within the HLF customer group such that “k” shall be the sum of kilowatts billed for the applicable six month period.

This factor shall be further modified to reflect the difference between estimated costs billed and costs actually experienced during the period such estimated costs were billed.

The Environmental Compliance Adjustment factor applicable to retail rate groups is as follows:

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1000 East Main Street
Plainfield, IN 46168

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TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT COST ADJUSTMENT

The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased for the change in costs associated with the Company's transmission and distribution infrastructure improvement costs ("TDSIC") in accordance with I.C. 8-1-39. The revenue adjustment to the applicable charges for electric service will be determined under the following provision:

Calculation of Adjustment

The monthly billing adjustment shall be determined by multiplying the adjustment factor, as determined to the nearest 0.001 mill ($0.000001) per kilowatt-hour calculated in accordance with the following formula, by the monthly billed kilowatt-hours in the case of customers receiving metered service and by the estimated monthly billed kilowatt-hours used for rate determinations in the case of customers receiving unmetered service.

Transmission and Distribution Infrastructure Improvement Cost Adjustment Factor =

$$\frac{((a + b) \times c) + ((d + e) \times f))}{g}$$

where:

1. "a" is the twelve month return on jurisdictional invested capital applicable to the transmission system projects. For purposes of determining the value of such capital projects for this rate mechanism, the Company's costs as recorded in its books of account in accordance with the Uniform System of Accounts prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act shall be used. The net book value of the transmission system investment shall be multiplied by the weighted average cost of capital calculated in accordance with I.C. 8-1-39 as of the valuation date of the net transmission system investment, using the return on equity approved in the last retail base rate case. The after tax return shall be converted to before-income-tax revenue requirement by multiplying by the applicable revenue conversion factor.

2. "b" is the Company's forecasted incremental jurisdictional system TDSIC Plan costs such as depreciation, operation and maintenance, property tax and other costs approved by the Commission applicable to the transmission system projects.

3. "c" is the transmission system revenue requirement expressed as a percentage of the total transmission system revenue requirement.

4. "d" is the twelve month return on jurisdictional invested capital applicable to the distribution system projects. For purposes of determining the value of such capital projects for this rate mechanism, the Company's costs as recorded in its books of account in accordance with the Uniform System of Accounts prescribed for Public Utilities and Licensees subject to the provisions of the federal Power Act shall be used. The net book value of the distribution system investment shall be multiplied by the weighted average cost of capital calculated in accordance with I.C. 8-1-39 as of the valuation date of the net distribution system

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TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT COST ADJUSTMENT

investment. The after tax return shall be converted to before-income-tax revenue requirement by multiplying by the applicable revenue conversion factor.

5. “e” is the Company’s forecasted incremental jurisdictional system TDSIC Plan costs such as depreciation, operation and maintenance, property tax and other costs approved by the Commission applicable to the distribution system projects.

6. “f” is the individual rate group’s distribution system revenue requirement expressed as a percentage of the total distribution system revenue requirement.

7. “g” is the retail rate group’s adjusted kilowatt-hour sales for the applicable twelve month period for all retail rate groups other than customers served under Rate HLF. The revenue adjustment for retail customers served under Rate HLF shall be demands within the Rate HLF customer group such that “g” shall be the sum of kilowatts billed for the applicable twelve month period.

This factor shall be further modified to reflect the difference between estimated costs billed and costs actually experienced during the period such estimated costs were billed.

The Transmission and Distribution Infrastructure Improvement Cost Adjustment factor applicable to retail rate groups is as follows:

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1000 East Main Street
Plainfield, IN 46168

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TARIFF NO. 65 –TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT COST ADJUSTMENT

The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased for the change in costs associated with the Company's transmission and distribution infrastructure improvement costs ("TDSIC") in accordance with I.C. 8-1-39. The revenue adjustment to the applicable charges for electric service will be determined under the following provision:

Calculation of Adjustment

The monthly billing adjustment shall be determined by multiplying the adjustment factor, as determined to the nearest 0.001 mill ($0.000001) per kilowatt-hour calculated in accordance with the following formula, by the monthly billed kilowatt-hours in the case of customers receiving metered service and by the estimated monthly billed kilowatt-hours used for rate determinations in the case of customers receiving unmetered service.

Transmission and Distribution Infrastructure Improvement Cost Adjustment Factor =

$$\frac{((a + b) \text{ x } c) + ((d + e) \text{ x } f))}{g}$$

where:

1. "a" is the twelve month return on jurisdictional invested capital applicable to the transmission system projects. For purposes of determining the value of such capital projects for this rate mechanism, the Company's costs as recorded in its books of account in accordance with the Uniform System of Accounts prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act shall be used. The net book value of the transmission system investment shall be multiplied by the weighted average cost of capital calculated in accordance with I.C. 8-1-39 as of the valuation date of the net transmission system investment, using the return on equity approved in the last retail base rate case. The after tax return shall be converted to before-income-tax revenue requirement by multiplying by the applicable revenue conversion factor.

2. "b" is the Company's forecasted incremental jurisdictional system TDSIC Plan costs such as depreciation, operation and maintenance, property tax and other costs approved by the Commission applicable to the transmission system projects.

3. "c" is the transmission system revenue requirement expressed as a percentage of the total transmission system revenue requirement.

4. "d" is the twelve month return on jurisdictional invested capital applicable to the distribution system projects. For purposes of determining the value of such capital projects for this rate mechanism, the Company's costs as recorded in its books of account in accordance with the Uniform System of Accounts prescribed for Public Utilities and Licensees subject to the provisions of the federal Power Act shall be used. The net book value of the distribution system investment shall be multiplied by the weighted average cost of capital calculated in accordance with I.C. 8-1-39 as of the valuation date of the net distribution system investment. The after tax return shall be converted to before-income-tax revenue requirement by multiplying by the applicable revenue conversion factor.

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TARIFF NO. 65 – TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT COST ADJUSTMENT

5. “e” is the Company’s forecasted incremental jurisdictional system TDSIC Plan costs such as depreciation, operation and maintenance, property tax and other costs approved by the Commission applicable to the distribution system projects.

6. “f” is the individual rate group’s distribution system revenue requirement expressed as a percentage of the total distribution system revenue requirement.

7. “g” is the retail rate group’s adjusted kilowatt-hour sales for the applicable twelve month period for all retail rate groups other than customers served under Rate HLF. The revenue adjustment for retail customers served under Rate HLF shall be demands within the Rate HLF customer group such that “g” shall be the sum of kilowatts billed for the applicable twelve month period.

This factor shall be further modified to reflect the difference between estimated costs billed and costs actually experienced during the period such estimated costs were billed.

The Transmission and Distribution Infrastructure Improvement Cost Adjustment factor applicable to retail rate groups is as follows:

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Plainfield, Indiana 46168

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~~STANDARD CONTRACT RIDER~~TARIFF NO. 66 -
ENERGY EFFICIENCY ADJUSTMENT

The applicable charges for electric service to the Company's retail electric customers shall include an adjustment to recover or refund energy efficiency amounts as approved by the Indiana Utility Regulatory Commission. The applicable retail electric adjustment will be determined based on the following provisions:

Calculation of Adjustment

The monthly billing adjustment shall be determined by multiplying the adjustment factor, as determined to the nearest 0.001 mill ($0.000001) per kilowatt-hour calculated in accordance with the following formula, by the monthly billed kilowatt-hours in the case of customers receiving metered service and by the estimated monthly billed kilowatt-hours used for rate determinations in the case of customers receiving unmetered service.

Energy Efficiency Adjustment Factor =

$$\text{Residential} = \frac{(a*g)+c}{e}$$

$$\text{Non-Residential} = \frac{(b*g)+d}{f}$$

where:

1. "a" is the sum of estimated residential energy efficiency amounts excluding lost revenue.
2. "b" is the sum of estimated non-residential energy efficiency amounts excluding lost revenue.
3. "c" is the sum of estimated residential energy efficiency lost revenue.
4. "d" is the sum of estimated non-residential energy efficiency lost revenue.
5. "e" is the applicable billing cycle kilowatt-hour sales for residential customers.
6. "f" is the applicable billing cycle kilowatt-hour sales for non-residential customers.
7. "g" is the revenue conversion factor that includes the Public Utility Fee and Uncollectible Expense.

Estimated energy efficiency amounts shall be further modified to reflect the difference between estimated amounts billed and actual amounts.

Separate billing adjustments shall be determined for Qualifying Customers who have opted out from participation in energy efficiency programs under the terms of this tariff based on the effective date of such opt out. Such billing adjustments will contain only the energy efficiency amounts, consisting of program costs, lost revenues and shareholder incentives, and related reconciliations, applicable to periods prior to the effective date of opt out, as further defined herein.

Separate billing adjustments shall also be determined for Qualifying Customers who have opted out from participation in energy efficiency programs under the terms of this tariff, but subsequently opted back in to participation in energy efficiency programs under the terms of this tariff, based on the effective dates of such opt out and opt in. Such billing adjustments will contain only the energy efficiency amounts, consisting of program costs, lost revenues and shareholder incentives, and related reconciliations, applicable to periods prior to the effective date of opt out and subsequent to the effective date of opt in, as further defined herein.

Opt Out Provisions

~~STANDARD CONTRACT RIDER~~TARIFF NO. 66 -
ENERGY EFFICIENCY ADJUSTMENT

In order for a Customer to qualify to opt out from participation in energy efficiency programs under the terms of this tariff, all of the following conditions must be satisfied:

1. A Qualifying Customer must receive service at a Single Site constituting more than one megawatt of electric capacity.
2. The Qualifying Customer must be able to demonstrate that at least one demand meter on its Single Site has received service of more than one megawatt of electric capacity within the previous 12 months or must be a new customer who has signed a written demand contract of greater than one megawatt for at least one meter on a Single Site.
3. If a Customer has a Single Site with Qualifying Load, it may opt out all accounts receiving service at that Single Site which are billed non-residential rates. Such accounts will be opted out provided the Customer identifies the accounts in the Customer's notice to the Company of its election to opt out and provided that at least one account at the Single Site that qualified above by virtue of having more than one megawatt of electric capacity is among the accounts identified to opt out and provided that all accounts at the Single Site on a common rate have the same opt out/opt in status.
4. The Qualifying Customer must provide written notice by completing a form provided by Duke Energy Indiana, LLC, or by providing written notice to Duke Energy Indiana, LLC, in substantially the same format as the form provided. A customer who provides written notice of its desire to opt out without using the form will be asked to complete the opt out form in a timely manner consistent with the terms of this tariff, but the notice date of the customer opt out will be the date of its original notice. The notice must:
    a. indicate the Customer's desire to opt out of energy efficiency programs
    b. provide a listing of all qualifying accounts for each Single Site which the Customer intends to opt out
        i. a qualifying account is either one that is demonstrated to have received service of more than one megawatt of electric capacity at a meter at a Single Site as outlined above in item 2. or an account located on contiguous property at the same site and which is billed a non-residential rate
        ii. at least one qualifying account which was demonstrated to have received service of more than one megawatt of electric capacity at the Single Site must opt out in order for other smaller qualifying accounts at the Single Site to opt out
        iii. all accounts on the same rate as the qualifying account of more than one megawatt that opts out will also be required to opt out
        iv. any other qualifying account on a different non-residential rate may also be opted out, but all accounts on the same rate at the Single Site must also opt out
    c. contain confirmation that the signatory has authority to make that decision for the Customer

5. Written notice must be received by Duke Energy Indiana, LLC on or before November 15 of any year to be effective January 1 of the following year.

Once qualification is determined by Duke Energy Indiana, LLC, the utility will not revoke the Qualifying Customer's qualification at a later date. Qualifying Customers do not need to provide additional notice or otherwise demonstrate continued eligibility annually in order to maintain the opt out status for future energy efficiency program years, except as outlined herein for Qualifying Customers who opted back in and then wish to opt out again.

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ENERGY EFFICIENCY ADJUSTMENT

As of the effective date of the opt out, the Qualifying Customer is no longer eligible to participate in any energy efficiency program for the qualified account(s) and is not eligible to receive incentive payments for energy efficiency projects previously approved but not completed as of the effective date of the opt out.

The Qualifying Customer will be billed the approved opt out rate applicable to their effective date of opt out beginning with the first bill rendered after the effective date of opt out, unless an opt out rate has not yet been approved by the Commission for the effective date of opt out. In that case, the customer will be billed the then approved opt out rate applicable to the latest opt out effective date beginning with the first bill rendered after the Qualifying Customer's effective date of opt out until an opt out rate is approved applicable to the Qualifying Customer's effective date. The Qualifying Customer will then be billed the approved opt out rate applicable to their effective date of opt out beginning with the first bill rendered after the effective date of the approved rate.

The Qualifying Customer remains liable for energy efficiency program costs, including lost revenues, shareholder incentives and related reconciliations, that accrued or were incurred or relate to energy efficiency investments made before the date on which the opt out is effective, regardless of the date on which the rates are actually assessed. Such costs may include costs related to evaluation, measurement and verification ("EM&V") required to be conducted after a customer opts out on projects completed under an Energy Efficiency Program while the customer was a participant. In addition, such costs may include costs required by contracts executed prior to the effective date of opt out but incurred after the date of the Qualifying Customer's opt out. However, these costs shall be limited to fixed, administrative costs, including costs related to EM&V. A Qualifying Customer shall not be responsible for any program costs such as the payment of energy efficiency rebates or incentives, incurred following the effective date of its opt out with the exception of incentives or rebates that are paid on applications that have not closed out at the effective date of its opt out.

Opt In Provisions for Qualifying Customers

A Qualifying Customer who opts out under the terms of this tariff may opt back in to participation in energy efficiency programs by providing written notice which must be received by Duke Energy Indiana, LLC on or before November 15 of any year for participation to be effective January 1 of the following year.

A Qualifying Customer who opts back in is required to participate in the program for at least three years and pay related program costs including lost revenues and incentives for three years after the effective date of opting back in. The Qualifying Customer will also continue to pay for energy efficiency amounts applicable to periods prior to the effective date of their opt out.

In order to opt back in to participation, the Qualifying Customer must provide written notice by completing a form provided by Duke Energy Indiana, LLC, or by providing written notice to Duke Energy Indiana, LLC, in substantially the same format as the form provided, which:

1. unequivocally indicates the Customer's desire to opt back in to energy efficiency programs
2. provides a listing of all qualifying accounts for each Single Site which the Customer intends to opt back in to the energy efficiency programs
    a. only the qualifying accounts/sites listed will be opted back in to the energy efficiency programs
    b. a Customer opting back in an account at a Single Site must also opt back in all other accounts with the same common rate at the Single Site

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    c. a Customer may not opt back in the account which by virtue of having more than one megawatt of electric capacity qualified the Customer to opt out other accounts at the Single Site without also opting back in all other accounts at the Single Site
3. contains a statement that the Customer understands that by opting in, it is required to participate in the program for at least three years and pay related costs including lost revenues and incentives
4. contains confirmation that the signatory has authority to make that decision for the Customer.

The Qualifying Customer will be billed the rate applicable to the effective dates of their opt out and opt in beginning with the first bill rendered after both the effective date of the opt in and the effective date of an approved rate applicable to the effective dates of their opt out and opt in.

A Qualifying Customer who opts back in may only opt out again effective January 1 of the year following the third year of participation by providing notice on or before November 15 of the third year of participation. In Order to opt out again, the following conditions must be satisfied:

1. A Qualifying Customer must demonstrate that at least one demand meter on its Single Site has received service of more than one megawatt of electric capacity within the previous 12 months.
2. The Qualifying Customer must provide written notice by completing a form provided by Duke Energy Indiana, LLC, or by providing written notice to Duke Energy Indiana, LLC, in substantially the same format as the form provided, which:
    a. indicates the Customer's desire to opt out of energy efficiency programs
    b. provides a listing of all qualifying accounts for each Single Site which the Customer intends to opt out
        i. a qualifying account is either one that is demonstrated to have received service of more than one megawatt of electric capacity at a meter at a Single Site as outlined above in item 1. or an account located on contiguous property at the same site and which is billed a non-residential rate
        ii. at least one qualifying account which was demonstrated to have received service of more than one megawatt of electric capacity at the Single Site must opt out in order for other smaller qualifying accounts at the Single Site to opt out
        iii. all accounts on the same rate as the qualifying account of more than one megawatt that opts out will also be required to opt out
        iv. any other qualifying account on a different non-residential rate may also be opted out, but all accounts on the same rate at the Single Site must also opt out
    c. contains confirmation that the signatory has authority to make that decision for the Customer.

As of the effective date of the opt out, the Qualifying Customer is no longer eligible to participate in any energy efficiency program for the qualified account(s) and is not eligible to receive incentive payments for energy efficiency projects previously approved but not completed as of the effective date of the opt out.

A Qualifying Customer who elects to opt back out after the three-year period following opt in shall be responsible for energy efficiency program costs, including lost revenues, shareholder incentives and related reconciliations as outlined in the Opt Out Provisions section of this tariff for all periods other than the periods for which an opt out was effective.

The Qualifying Customer will be billed the rate applicable to the effective dates of their opt outs and opt in beginning with the first bill rendered after both the effective date of the opt out and the effective date of an approved rate applicable to the effective dates of their opt outs and opt in.

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ENERGY EFFICIENCY ADJUSTMENT

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

IURC NO. 16
Original Tariff No. 66

TARIFF NO. 66 - ENERGY EFFICIENCY ADJUSTMENT

The applicable charges for electric service to the Company's retail electric customers shall include an adjustment to recover or refund energy efficiency amounts as approved by the Indiana Utility Regulatory Commission. The applicable retail electric adjustment will be determined based on the following provisions:

Calculation of Adjustment

The monthly billing adjustment shall be determined by multiplying the adjustment factor, as determined to the nearest 0.001 mill ($0.000001) per kilowatt-hour calculated in accordance with the following formula, by the monthly billed kilowatt-hours in the case of customers receiving metered service and by the estimated monthly billed kilowatt-hours used for rate determinations in the case of customers receiving unmetered service.

Energy Efficiency Adjustment Factor =

$$\text{Residential} = \frac{(a*g)+c}{e}$$

$$\text{Non-Residential} = \frac{(b*g)+d}{f}$$

where:

1. "a" is the sum of estimated residential energy efficiency amounts excluding lost revenue.
2. "b" is the sum of estimated non-residential energy efficiency amounts excluding lost revenue.
3. "c" is the sum of estimated residential energy efficiency lost revenue.
4. "d" is the sum of estimated non-residential energy efficiency lost revenue.
5. "e" is the applicable billing cycle kilowatt-hour sales for residential customers.
6. "f" is the applicable billing cycle kilowatt-hour sales for non-residential customers.
7. "g" is the revenue conversion factor that includes the Public Utility Fee and Uncollectible Expense.

Estimated energy efficiency amounts shall be further modified to reflect the difference between estimated amounts billed and actual amounts.

Separate billing adjustments shall be determined for Qualifying Customers who have opted out from participation in energy efficiency programs under the terms of this tariff based on the effective date of such opt out. Such billing adjustments will contain only the energy efficiency amounts, consisting of program costs, lost revenues and shareholder incentives, and related reconciliations, applicable to periods prior to the effective date of opt out, as further defined herein.

Separate billing adjustments shall also be determined for Qualifying Customers who have opted out from participation in energy efficiency programs under the terms of this tariff, but subsequently opted back in to participation in energy efficiency programs under the terms of this tariff, based on the effective dates of such opt out and opt in. Such billing adjustments will contain only the energy efficiency amounts, consisting of program costs, lost revenues and shareholder incentives, and related reconciliations, applicable to periods prior to the effective date of opt out and subsequent to the effective date of opt in, as further defined herein.

Opt Out Provisions

TARIFF NO. 66 - ENERGY EFFICIENCY ADJUSTMENT

In order for a Customer to qualify to opt out from participation in energy efficiency programs under the terms of this tariff, all of the following conditions must be satisfied:

1. A Qualifying Customer must receive service at a Single Site constituting more than one megawatt of electric capacity.
2. The Qualifying Customer must be able to demonstrate that at least one demand meter on its Single Site has received service of more than one megawatt of electric capacity within the previous 12 months or must be a new customer who has signed a written demand contract of greater than one megawatt for at least one meter on a Single Site.
3. If a Customer has a Single Site with Qualifying Load, it may opt out all accounts receiving service at that Single Site which are billed non-residential rates. Such accounts will be opted out provided the Customer identifies the accounts in the Customer's notice to the Company of its election to opt out and provided that at least one account at the Single Site that qualified above by virtue of having more than one megawatt of electric capacity is among the accounts identified to opt out and provided that all accounts at the Single Site on a common rate have the same opt out/opt in status.
4. The Qualifying Customer must provide written notice by completing a form provided by Duke Energy Indiana, LLC, or by providing written notice to Duke Energy Indiana, LLC, in substantially the same format as the form provided. A customer who provides written notice of its desire to opt out without using the form will be asked to complete the opt out form in a timely manner consistent with the terms of this tariff, but the notice date of the customer opt out will be the date of its original notice. The notice must:
    a. indicate the Customer's desire to opt out of energy efficiency programs
    b. provide a listing of all qualifying accounts for each Single Site which the Customer intends to opt out
        i. a qualifying account is either one that is demonstrated to have received service of more than one megawatt of electric capacity at a meter at a Single Site as outlined above in item 2. or an account located on contiguous property at the same site and which is billed a non-residential rate
        ii. at least one qualifying account which was demonstrated to have received service of more than one megawatt of electric capacity at the Single Site must opt out in order for other smaller qualifying accounts at the Single Site to opt out
        iii. all accounts on the same rate as the qualifying account of more than one megawatt that opts out will also be required to opt out
        iv. any other qualifying account on a different non-residential rate may also be opted out, but all accounts on the same rate at the Single Site must also opt out
    c. contain confirmation that the signatory has authority to make that decision for the Customer

5. Written notice must be received by Duke Energy Indiana, LLC on or before November 15 of any year to be effective January 1 of the following year.

Once qualification is determined by Duke Energy Indiana, LLC, the utility will not revoke the Qualifying Customer's qualification at a later date. Qualifying Customers do not need to provide additional notice or otherwise demonstrate continued eligibility annually in order to maintain the opt out status for future energy efficiency program years, except as outlined herein for Qualifying Customers who opted back in and then wish to opt out again.

As of the effective date of the opt out, the Qualifying Customer is no longer eligible to participate in any energy efficiency program for the qualified account(s) and is not eligible to receive incentive payments for energy efficiency projects previously approved but not completed as of the effective date of the opt out.

TARIFF NO. 66 - ENERGY EFFICIENCY ADJUSTMENT

The Qualifying Customer will be billed the approved opt out rate applicable to their effective date of opt out beginning with the first bill rendered after the effective date of opt out, unless an opt out rate has not yet been approved by the Commission for the effective date of opt out. In that case, the customer will be billed the then approved opt out rate applicable to the latest opt out effective date beginning with the first bill rendered after the Qualifying Customer's effective date of opt out until an opt out rate is approved applicable to the Qualifying Customer's effective date. The Qualifying Customer will then be billed the approved opt out rate applicable to their effective date of opt out beginning with the first bill rendered after the effective date of the approved rate.

The Qualifying Customer remains liable for energy efficiency program costs, including lost revenues, shareholder incentives and related reconciliations, that accrued or were incurred or relate to energy efficiency investments made before the date on which the opt out is effective, regardless of the date on which the rates are actually assessed. Such costs may include costs related to evaluation, measurement and verification ("EM&V") required to be conducted after a customer opts out on projects completed under an Energy Efficiency Program while the customer was a participant. In addition, such costs may include costs required by contracts executed prior to the effective date of opt out but incurred after the date of the Qualifying Customer's opt out. However, these costs shall be limited to fixed, administrative costs, including costs related to EM&V. A Qualifying Customer shall not be responsible for any program costs such as the payment of energy efficiency rebates or incentives, incurred following the effective date of its opt out with the exception of incentives or rebates that are paid on applications that have not closed out at the effective date of its opt out.

Opt In Provisions for Qualifying Customers

A Qualifying Customer who opts out under the terms of this tariff may opt back in to participation in energy efficiency programs by providing written notice which must be received by Duke Energy Indiana, LLC on or before November 15 of any year for participation to be effective January 1 of the following year.

A Qualifying Customer who opts back in is required to participate in the program for at least three years and pay related program costs including lost revenues and incentives for three years after the effective date of opting back in. The Qualifying Customer will also continue to pay for energy efficiency amounts applicable to periods prior to the effective date of their opt out.

In order to opt back in to participation, the Qualifying Customer must provide written notice by completing a form provided by Duke Energy Indiana, LLC, or by providing written notice to Duke Energy Indiana, LLC, in substantially the same format as the form provided, which:

1. unequivocally indicates the Customer's desire to opt back in to energy efficiency programs
2. provides a listing of all qualifying accounts for each Single Site which the Customer intends to opt back in to the energy efficiency programs
    a. only the qualifying accounts/sites listed will be opted back in to the energy efficiency programs
    b. a Customer opting back in an account at a Single Site must also opt back in all other accounts with the same common rate at the Single Site
    c. a Customer may not opt back in the account which by virtue of having more than one megawatt of electric capacity qualified the Customer to opt out other accounts at the Single Site without also opting back in all other accounts at the Single Site
3. contains a statement that the Customer understands that by opting in, it is required to participate in the program for at least three years and pay related costs including lost revenues and incentives
4. contains confirmation that the signatory has authority to make that decision for the Customer.

TARIFF NO. 66 - ENERGY EFFICIENCY ADJUSTMENT

The Qualifying Customer will be billed the rate applicable to the effective dates of their opt out and opt in beginning with the first bill rendered after both the effective date of the opt in and the effective date of an approved rate applicable to the effective dates of their opt out and opt in.

A Qualifying Customer who opts back in may only opt out again effective January 1 of the year following the third year of participation by providing notice on or before November 15 of the third year of participation. In Order to opt out again, the following conditions must be satisfied:

1. A Qualifying Customer must demonstrate that at least one demand meter on its Single Site has received service of more than one megawatt of electric capacity within the previous 12 months.
2. The Qualifying Customer must provide written notice by completing a form provided by Duke Energy Indiana, LLC, or by providing written notice to Duke Energy Indiana, LLC, in substantially the same format as the form provided, which:
    a. indicates the Customer’s desire to opt out of energy efficiency programs
    b. provides a listing of all qualifying accounts for each Single Site which the Customer intends to opt out
        i. a qualifying account is either one that is demonstrated to have received service of more than one megawatt of electric capacity at a meter at a Single Site as outlined above in item 1. or an account located on contiguous property at the same site and which is billed a non-residential rate
        ii. at least one qualifying account which was demonstrated to have received service of more than one megawatt of electric capacity at the Single Site must opt out in order for other smaller qualifying accounts at the Single Site to opt out
        iii. all accounts on the same rate as the qualifying account of more than one megawatt that opts out will also be required to opt out
        iv. any other qualifying account on a different non-residential rate may also be opted out, but all accounts on the same rate at the Single Site must also opt out
    c. contains confirmation that the signatory has authority to make that decision for the Customer.

As of the effective date of the opt out, the Qualifying Customer is no longer eligible to participate in any energy efficiency program for the qualified account(s) and is not eligible to receive incentive payments for energy efficiency projects previously approved but not completed as of the effective date of the opt out.

A Qualifying Customer who elects to opt back out after the three-year period following opt in shall be responsible for energy efficiency program costs, including lost revenues, shareholder incentives and related reconciliations as outlined in the Opt Out Provisions section of this tariff for all periods other than the periods for which an opt out was effective.

The Qualifying Customer will be billed the rate applicable to the effective dates of their opt outs and opt in beginning with the first bill rendered after both the effective date of the opt out and the effective date of an approved rate applicable to the effective dates of their opt outs and opt in.

Duke Energy Indiana, LLC
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Plainfield, Indiana 46168

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TARIFF NO. 66 - ENERGY EFFICIENCY ADJUSTMENT

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~~Third Revised Sheet No. 67~~
Page 1 of 2

~~Standard Contract Rider~~Tariff No. 67 –
Credits Adjustment

The applicable energy charges for service to the Company's retail electric customers shall be decreased monthly to reflect the amortization of the Excess Accumulated Deferred Income Taxes related to the Tax Cut and Jobs Act of 2017 ("TCJA") as first approved by the Commission in Cause No. 45032-S2, certain state and federal tax incentives related to the Edwardsport IGCC facility, and other credits or charges for base rate adjustments or refunds approved by the Commission.

Calculation of Adjustment

The monthly billing adjustment shall be determined by multiplying the adjustment factor, as determined to the nearest 0.001 mil ($0.000001) per kilowatt-hour calculated in accordance with the following formula, by the monthly billed kilowatt-hours in the case of customers receiving metered service and by the estimated monthly billed kilowatt-hours used for rate determinations in the case of customers receiving unmetered service.

Credit Rate Adjustment Factor Per Rate Group =

$$\frac{((a \times b) + (c \times d) + (e \times f) + (g \times h)) \cancel{+ f}}{i\cancel{e}}$$

where:

1. "a" is the annual retail jurisdictional credit amount for credits to be allocated to the rate group using net book value~~, including those related to the TCJA and others~~ as approved by the Commission.

2. "b" is each rate group's percentage allocation using net book value as approved by the Commission in the most recent base rate case.

3. "c" is the annual retail jurisdictional credit amount for credits to be allocated to the rate group using production coincident peak demand~~, including those related to the IGCC facility tax incentive benefits and others~~ as approved by the Commission.

4. "d" is each rate group's percentage allocation using production coincident peak demand as approved by the Commission in the most recent base rate case.

5. "e" is the annual retail jurisdictional credit amount for credits to be allocated to the rate group using energy as approved by the Commission.

6. "f" is each rate group's percentage allocation using energy as approved by the Commission in the most recent base rate case.

7. "g" is the annual retail jurisdictional credit amount for credits to be allocated to the rate group using administrative and general ("A&G") as approved by the Commission.

8. "h" is each rate group's percentage allocation using A&G as approved by the Commission in the most recent base rate case.

~~5.~~9. "i~~e~~" is the retail rate group's kilowatt-hour sales for the applicable twelve-month period.

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~~Third Revised Sheet No. 67~~

~~Standard Contract Rider~~Tariff No. 67 –
Credits Adjustment

~~6.~~10. "j~~f~~" is the annual retail jurisdictional rates for other credits at the rate group level, including phase-in rate adjustments and others as approved by the Commission.

These rates will be adjusted at least annually, as needed to reflect changes in credit amounts or additions and removal of credits. Rates will be further adjusted to reflect a calendar year reconciliation of amounts refunded based on actual kilowatt-hours sales.

The Credits Adjustments factor applicable to retail rate groups shall be as follows:

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IURC NO. 16
Original Tariff No. 67

Tariff No. 67 –
Credits Adjustment

The applicable energy charges for service to the Company's retail electric customers shall be decreased monthly to reflect the amortization of the Excess Accumulated Deferred Income Taxes related to the Tax Cut and Jobs Act of 2017 ("TCJA") as first approved by the Commission in Cause No. 45032-S2, certain state and federal tax incentives related to the Edwardsport IGCC facility, and other credits or charges for base rate adjustments or refunds approved by the Commission.

Calculation of Adjustment

The monthly billing adjustment shall be determined by multiplying the adjustment factor, as determined to the nearest 0.001 mil ($0.000001) per kilowatt-hour calculated in accordance with the following formula, by the monthly billed kilowatt-hours in the case of customers receiving metered service and by the estimated monthly billed kilowatt-hours used for rate determinations in the case of customers receiving unmetered service.

Credit Rate Adjustment Factor Per Rate Group =

$$\frac{((a \times b) + (c \times d) + (e \times f) + (g \times h))}{i}$$

where:

1. "a" is the annual retail jurisdictional credit amount for credits to be allocated to the rate group using net book value as approved by the Commission.

2. "b" is each rate group's percentage allocation using net book value as approved by the Commission in the most recent base rate case.

3. "c" is the annual retail jurisdictional credit amount for credits to be allocated to the rate group using production coincident peak demand as approved by the Commission.

4. "d" is each rate group's percentage allocation using production coincident peak demand as approved by the Commission in the most recent base rate case.

5. "e" is the annual retail jurisdictional credit amount for credits to be allocated to the rate group using energy as approved by the Commission.

6. "f" is each rate group's percentage allocation using energy as approved by the Commission in the most recent base rate case.

7. "g" is the annual retail jurisdictional credit amount for credits to be allocated to the rate group using administrative and general ("A&G") as approved by the Commission.

8. "h" is each rate group's percentage allocation using A&G as approved by the Commission in the most recent base rate case.

9. "i" is the retail rate group's kilowatt-hour sales for the applicable twelve-month period.

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Tariff No. 67 –
Credits Adjustment

10. "j" is the annual retail jurisdictional rates for other credits at the rate group level, including phase-in rate adjustments and others as approved by the Commission.

These rates will be adjusted at least annually, as needed to reflect changes in credit amounts or additions and removal of credits. Rates will be further adjusted to reflect a calendar year reconciliation of amounts refunded based on actual kilowatt-hours sales.

The Credits Adjustments factor applicable to retail rate groups shall be as follows:

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IURC No. ~~15~~16
~~Third Revised Sheet~~Original Tariff No. 72
~~Cancels and Supersedes~~
~~Second Revised Sheet No. 72~~

~~STANDARD CONTRACT RIDER~~TARIFF NO. 72 –
FEDERALLY MANDATED COST ADJUSTMENT

The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased for the change in costs associated with a Commission-approved Certificate of Public Convenience and Necessity (CPCN) pursuant to Ind. Code § 8-1-8.4 et seq. and incurred in connection with the Company's compliance with federally mandated requirements for electric utilities. The revenue adjustment to the applicable charges for electric service will be determined under the following provision:

Calculation of Adjustment

The Federally Mandated Cost Adjustment shall be determined no more often than annually by multiplying the Federally Mandated Cost 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 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.

Federally Mandated Cost Adjustment Factor =

$$\frac{((a \times b \times c) + ((d + e + f) \times g)) \times (h)}{i}$$

where:

1. "a" is the jurisdictional cost of the Company's invested capital applicable to federally mandated projects. For purposes of determining the value of such capital projects for this rate mechanism, the Company's costs as recorded in its books of account in accordance with the Uniform System of Accounts prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act shall be used.

2. "b" is the Company's weighted cost of capital as of the date of valuation of the federally mandated projects investment.

3. "c" is the revenue conversion factor to be used to convert return to operating revenues.

4. "d" is the Company's forecasted incremental jurisdictional operation and maintenance expense applicable to federally mandated projects.

5. "e" is the Company's forecasted jurisdictional depreciation expense applicable to the investment in federally mandated projects.

6. "f" is the Company's forecasted incremental jurisdictional property tax expense applicable to the investment in the federally mandated projects.

7. "g" is the revenue conversion factor used to convert operating expenses to operating revenues.

8. "h" is the individual retail rate group's jurisdictional combined production and transmission plant expressed as a percent of the total jurisdictional production and transmission plant from the cost of service study last approved by the Commission.

STANDARD CONTRACT RIDER NO. 72 –
FEDERALLY MANDATED COST ADJUSTMENT

9. "i" is the individual retail rate group's adjusted kilowatt-hour sales for the applicable twelve month period for all retail rate groups other than 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 "i" shall be the sum of kilowatts billed for the applicable twelve month period.

This factor shall be further modified to reflect the difference between estimated costs billed and costs actually experienced during the period such estimated costs were billed.

The Federally Mandated Cost Adjustment factor applicable to retail rate groups is as follows:

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Original Tariff No. 72

TARIFF NO. 72 – FEDERALLY MANDATED COST ADJUSTMENT

The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased for the change in costs associated with a Commission-approved Certificate of Public Convenience and Necessity (CPCN) pursuant to Ind. Code § 8-1-8.4 et seq. and incurred in connection with the Company's compliance with federally mandated requirements for electric utilities. The revenue adjustment to the applicable charges for electric service will be determined under the following provision:

Calculation of Adjustment

The Federally Mandated Cost Adjustment shall be determined no more often than annually by multiplying the Federally Mandated Cost 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 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.

Federally Mandated Cost Adjustment Factor =

$$\frac{((a \times b \times c) + ((d + e + f) \times g)) \times (h)}{i}$$

where:

1. "a" is the jurisdictional cost of the Company's invested capital applicable to federally mandated projects. For purposes of determining the value of such capital projects for this rate mechanism, the Company's costs as recorded in its books of account in accordance with the Uniform System of Accounts prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act shall be used.

2. "b" is the Company's weighted cost of capital as of the date of valuation of the federally mandated projects investment.

3. "c" is the revenue conversion factor to be used to convert return to operating revenues.

4. "d" is the Company's forecasted incremental jurisdictional operation and maintenance expense applicable to federally mandated projects.

5. "e" is the Company's forecasted jurisdictional depreciation expense applicable to the investment in federally mandated projects.

6. "f" is the Company's forecasted incremental jurisdictional property tax expense applicable to the investment in the federally mandated projects.

7. "g" is the revenue conversion factor used to convert operating expenses to operating revenues.

8. "h" is the individual retail rate group's jurisdictional combined production and transmission plant expressed as a percent of the total jurisdictional production and transmission plant from the cost of service study last approved by the Commission.

9. "i" is the individual retail rate group's adjusted kilowatt-hour sales for the applicable twelve month period for all retail rate groups other than customers served under Rate HLF. The

TARIFF NO. 72 – FEDERALLY MANDATED COST ADJUSTMENT

revenue adjustment for retail customers served under Rate HLF shall be based on demands within the Rate HLF customer group such that "i" shall be the sum of kilowatts billed for the applicable twelve month period.

This factor shall be further modified to reflect the difference between estimated costs billed and costs actually experienced during the period such estimated costs were billed.

The Federally Mandated Cost Adjustment factor applicable to retail rate groups is as follows:

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IURC No. 16~~15~~
Original Tariff ~~Sheet~~ No. 74

~~STANDARD CONTRACT RIDER~~TARIFF NO. 74 -
LOAD CONTROL ADJUSTMENT

Calculation of Adjustment

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

Adjustment Factor:

$$\left((a * c)\right) * \left(\frac{1}{s}\right)$$

where:

1. "a" is the total year-round amount provided to customers under the Company's Demand Response programs including PowerManager®, PowerManager® for Business and additional Demand Response programs and amounts determined to be includable by the Commission.

2. "c" is the total retail rate group's allocated percentage share of the Company's average twelve monthly coincident system peak demands as developed for cost of service purposes in Cause No. 45253.

3. "s" represents actual monthly kilowatt-hour sales by individual retail rate groups for the applicable twelve-month period 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.

B. The factor as computed above shall be modified to allow for the recovery of the public utility fee and uncollectible expense and/or other similar revenue based taxes incurred due to the recovery of net reliability costs.

C. The factor shall be further modified to reflect the reconciliation of annual net costs approved for recovery, by retail rate group, and actual annual amounts billed customers.

D. The demand response factor by rate group is as follows:

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Original Tariff No. 74

TARIFF NO. 74 - LOAD CONTROL ADJUSTMENT

Calculation of Adjustment

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

Adjustment Factor:

$$\left((a * c)\right) * \left(\frac{1}{s}\right)$$

where:

1. "a" is the total year-round amount provided to customers under the Company's Demand Response programs including PowerManager®, PowerManager® for Business and additional Demand Response programs and amounts determined to be includable by the Commission.

2. "c" is the total retail rate group's allocated percentage share of the Company's average twelve monthly coincident system peak demands as developed for cost of service purposes in Cause No. 45253.

3. "s" represents actual monthly kilowatt-hour sales by individual retail rate groups for the applicable twelve-month period 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.

B. The factor as computed above shall be modified to allow for the recovery of the public utility fee and uncollectible expense and/or other similar revenue based taxes incurred due to the recovery of net reliability costs.

C. The factor shall be further modified to reflect the reconciliation of annual net costs approved for recovery, by retail rate group, and actual annual amounts billed customers.

D. The demand response factor by rate group is as follows:

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