Cause No. 45990

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a CENTERPOINT ENERGY INDIANA SOUTH
(CEI SOUTH)

DIRECT TESTIMONY
OF
JOHN D. TAYLOR
MANAGING PARTNER, ATRIUM ECONOMICS

ON

COST OF SERVICE AND RATE DESIGN

SPONSORING PETITIONER'S EXHIBIT NO. 18,
ATTACHMENTS JDT-1 THROUGH JDT-5

DIRECT TESTIMONY OF JOHN D. TAYLOR

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John D. Taylor. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head, South Carolina 29926.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am a Managing Partner with Atrium Economics LLC ("Atrium"). Atrium is a management consulting and financial advisory firm focused on the North American energy industry.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A. I am submitting testimony on behalf of Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CEI South", "Petitioner", or "Company"), which is an indirect subsidiary of CenterPoint Energy, Inc.

Q. WHAT IS YOUR ROLE WITH RESPECT TO PETITIONER CEI SOUTH?

A. CEI South has retained Atrium as a consultant in the area of utility costing and rate design. Specifically, CEI South has requested Atrium conduct a fully Allocated Cost of Service Study ("ACOSS") to determine the embedded costs of serving the Company's electric retail customers and support its rate design efforts. In this regard, I am sponsoring the ACOSS that allocates CEI South's electric utility costs to its rate classes, class revenue increase apportionment, and proposed rate design.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I received an undergraduate degree in Environmental Economics, emphasizing econometrics and regulatory policy. I also earned a Masters in Economics from American University in Washington, DC.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. As a utility pricing and policy expert, I support a variety of energy and utility related projects regarding matters pertaining to economics, finance, and public policy. In the public utility space, I have assisted with asset divestitures, allocated class cost of service studies, rate of return calculations, cash working capital impacts, tax litigation, revenue allocation, rate design, auction analysis, and affiliate cost allocation. I have reviewed and analyzed these subject matters considering the accounting treatment for, the financial investment in, and the operational configuration of a company's assets. For utility rate cases, I have performed allocated class cost of service studies, revenue allocation, rate design, valuation modeling, affiliate cost allocation, and various cost of service analyses. Also, I have filed testimony on class cost of service studies, return on equity, and statistical audit sampling. Please refer to Petitioner's Exhibit No. 18, **Attachment JDT-1** for my professional qualifications.

Q. HAVE YOU EVER TESTIFIED BEFORE THE INDIANA UTILITY REGULATORY COMMISSION ("COMMISSION" OR "IURC") OR ANY OTHER STATE REGULATORY COMMISSION?

A. Yes. I have testified before the Commission on behalf of Northern Indiana Public Service Company ("NIPSCO") in previous electric rate cases, Cause Nos. 45772 and 43969 and NIPSCO's current gas rate case in Cause No. 45967. I've also submitted testimony on behalf of Indianapolis Power & Light in Cause No. 44576. I have presented expert testimony with other utility commissions in Delaware, Florida, Illinois, Maine, Massachusetts, Minnesota, New Hampshire, North Carolina, Oregon, Pennsylvania, South Carolina, Washington, West Virginia, and before the Federal Energy Regulatory Commission ("FERC").

II. PURPOSE AND SCOPE OF TESTIMONY

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

A. First, I discuss the purpose of an ACOSS and describe the Atrium Cost of Service Model ("Atrium Model") used for CEI South's electric cost of service study. Second, I discuss various cost allocation principles, factors that influence the cost allocation framework, and the underlying methodology and basis used in the Company's electric cost of service studies. I describe the studies employed to apportion the various categories of plant and operation and maintenance ("O&M") expenses to the respective customer classes. Third, I present the class-by-class rate of return results and corresponding revenue surpluses or deficiencies from CEI South's ACOSS. This presentation discusses the resulting unit costs by class for customer, demand, and energy-related costs within the ACOSS. The detailed summary of the ACOSS results is presented in **Attachment JDT-2**. Fourth, I discuss revenue allocation and rate design principles and the appropriate guidelines for use in evaluating class revenue levels and rate structures. I explain and support the allocation of the Company's revenue deficiency to the various rate classes and discuss CEI South's rate design proposals.

Q. ARE YOU SPONSORING ANY ATTACHMENTS OR SCHEDULES IN THIS PROCEEDING?

A. Yes. Along with Petitioner's Witness Matthew A. Rice, I am sponsoring the **E Schedules** to <u>Petitioner's Exhibit No. 20</u>. I am also sponsoring the following attachments in this proceeding:

- <u>Petitioner's Exhibit No. 18</u>, **Attachment JDT-1:** Professional Qualifications
- <u>Petitioner's Exhibit No. 18</u>, **Attachment JDT-2:** Allocated Cost of Service Study, including the following reports:
    - Schedule 1 – Summary of ACOSS Under Present and Proposed Rates
    - Schedule 2 – Functionalized and Classified Results and Unit Costs by Customer Class
    - Schedule 3 – Cost of Service Allocation Study Detail by Account
    - Schedule 4 – Account Balances and Allocation Methods
    - Schedule 5 – Allocation Factors (External, Functionalization & Classification, and Internal)
- <u>Petitioner's Exhibit No. 18</u>, **Attachment JDT-3:** Revenue Apportionment.
- <u>Petitioner's Exhibit No. 18</u>, **Attachment JDT-4 (CONFIDENTIAL):** Rate Design Schedules.
- <u>Petitioner's Exhibit No. 18</u>, **Attachment JDT-5:** Updated Tracker Allocations.

Q. WERE THESE ATTACHMENTS OR SCHEDULES PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

III. PURPOSE OF AN ACOSS

Q. WHAT IS AN ACOSS?

A. An ACOSS is an analysis of costs that assigns to each customer or rate class its proportionate share of the utility's total cost of service, i.e., the utility's total revenue requirement. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility.

Q. WHAT IS THE PURPOSE OF AN ACOSS?

A. The purpose of an ACOSS is to determine what costs are incurred to serve the various classes of customers of the utility. When these costs are all tabulated, the rate of return provided by each class of service of the utility can be determined. This resulting rate of return will be impacted by the cost allocation resulting from the methodology employed. The ACOSS is a tool that the analyst uses to assist in determining revenue responsibility by rate class and rate design. The results of the ACOSS will provide the analyst with the data necessary to design cost-based rates.

IV. PRINCIPLES OF ACOSS PREPARATION

Q. IS THERE A GUIDING PRINCIPLE THAT CAN SUPPORT THE APPROPRIATE ALLOCATION OF COSTS?

A. Although there may not be a perfect methodology for allocating costs, a principle of cost causation should be followed to produce more accurate and reasonable results. Cost causation addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs. Hence, the analysis results in an appropriate allocation of the utility's total revenue requirement among the various rate classes. The analysis should result in an appropriate allocation of the utility's total revenue requirement among the various customer classes. In other words, the costs assigned or allocated to particular customers should be those that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service.

Q. WHAT ARE THE STEPS TO PERFORMING AN ACOSS?

A. To establish the cost responsibility of each customer class, initially, a three-step analysis of the utility's total operating costs must be undertaken. The three steps that comprise the ACOSS modeling are: (1) cost functionalization, (2) cost classification, and (3) cost allocation of all the costs of the utility's system.

Q. PLEASE DESCRIBE COST FUNCTIONALIZATION.

A. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. CEI South's primary functional cost categories associated with electric service include Production, Transmission, Substation, Primary Distribution, Secondary Distribution, Transformation, Onsite and Metering, Lighting, Customer Service, and Fuel Expense. In addition, various categories of costs within the distribution function are assigned to separate sub-functions to the extent that their costs vary in response to different customer class characteristics.

Q. PLEASE DESCRIBE COST CLASSIFICATION.

A. The second step, cost classification, further separates the functionalized plant and expenses according to the primary factors that determine the amount of costs incurred. These factors are: (1) the number of customers, (2) the need to meet the peak demand requirements that customers place on the system, and (3) the amount of electricity consumed by customers. These classification categories have been identified for purposes of the ACOSS as Customer Costs, Demand Costs, and Energy Costs, respectively.

Q. HOW ARE THESE CLASSIFICATION CATEGORIES RELATED TO THE COMPANY'S COSTS INCURRED?

A. Customer Costs are incurred to extend service to and attach a customer to the distribution system, meter any electric usage, and maintain the customer's account. Customer Costs largely depend on the number of customers served and continue to be incurred whether the customer uses any electricity. They may include capital costs associated with minimum-size distribution systems, line transformers, services, meters, and customer billing and accounting expenses.

Demand Costs are capacity-related costs associated with plant that is designed, installed, and operated to meet maximum hourly or daily electric usage requirements, such as generating plants, transmission lines, larger transformers, and substations, or more localized distribution facilities which are designed to satisfy individual customer maximum demands.

Energy Costs are those costs that vary with the amount of kilowatt-hours ("kWh") sold to customers. For example, included in the instant study are base fuel rates that vary with the amount of energy produced. However, except for fuel, the vast majority of CEI South's costs are fixed with respect to energy usage, and very little of its remaining cost structure is energy related.

Q. ARE THERE GENERALLY ACCEPTED METHODS FOR PREPARING CLASSIFICATION STUDIES FOR AN ELECTRIC UTILITY'S DISTRIBUTION ASSETS?

A. The generally accepted methods are set forth in the National Association of Regulatory Utility Commissioners ("NARUC") Cost Allocation Manual.[1] The NARUC Manual (pp. 96-98) specifically states that an electric utility's distribution-related facilities are, from a design and operational basis, sized to meet the maximum kilowatt ("kW") load (demand) requirements of customers. Moreover, the NARUC Manual (p. 89) also states that all distribution costs should be classified as either customer- or demand-related, or a combination of these two factors. To develop a classification of these facilities between a combination of customer and demand-related costs requires an analysis of relative unit costs for different size facilities (i.e., a minimum system study or zero-intercept study). These studies recognize that distribution assets have a dual purpose – (1) to meet peak demands and (2) to connect customers to the system – and estimates the portion of the utility's investment that is affected by both purposes. The Company only performed a minimum system study in their last distribution rate case for transformers, with poles, overhead conductors, and underground conductors and conduit classified as demand-related only. As further described below, the ACOSS is classifying poles, overhead conductors, and underground conductors and

[1] National Association of Regulatory Utility Commissioners. (January 1992). Electric Utility Cost Allocation Manual. Washington, D.C. Available for download at: https://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD, Last Accessed November 27, 2023.

conduit as demand-related and classifying transformer costs as both customer-related and demand-related in alignment with the Company's most recent ACOSS.

Q. PLEASE DESCRIBE COST ALLOCATION.

A. The final step is the allocation of each functionalized and classified cost element to the individual customer or rate class. Customers are generally divided into customer classes based on the type and character of services they require. Costs typically are allocated to these customer classes based on factors related to the number of customers, the amount of capacity demanded by customers, and the energy usage of customers. For example, much of the plant and equipment cost depends upon the customers' peak demand. These costs are allocated based on the coincident-peak or non-coincident peak demands of the rate class, depending on which characteristic more closely affects cost causation. Other portions of the cost depend upon the number of customers on the system, and these costs are allocated on a customer, or weighted-customer, basis. In addition, certain variable production costs, as well as fuel and purchased power costs, primarily depend upon the amount of energy a customer consumes. These costs are allocated based on the amount of energy consumed, adjusted for losses of energy that occur in the transmission and distribution process.

Q. HOW DOES THE COST ANALYST ESTABLISH THE COST AND UTILITY SERVICE RELATIONSHIPS?

A. To establish these relationships, the cost analyst must analyze a utility's electric system design, physical configuration and operations, accounting records, and system and customer load data, e.g., peak period electric consumption levels. From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q. PLEASE EXPLAIN THE TERM "DIRECT ASSIGNMENT."

A. The term direct assignment relates to specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing a cost of service study, the cost analyst seeks to maximize the amount of plant and expense directly assigned to a particular customer or customer classes to avoid the need to rely upon other more generalized allocation methods. An alternative to direct assignment is an allocation methodology supported by studies as is done with costs associated with meters and services.

Q. PLEASE EXPLAIN THE CONSIDERATIONS RELIED UPON IN DETERMINING THE COST ALLOCATION METHODOLOGIES THAT ARE USED TO PERFORM AN ACOSS.

A. As stated above, to allocate costs within any cost of service study, the factors that cause the costs to be incurred must be identified and understood. Additionally, the cost analyst needs to develop data in a form that is compatible with and supportive of rate design proposals. The availability of data for use in developing alternative cost allocation factors is also a consideration. In evaluating any cost allocation methodology, appropriate consideration should be given to whether it provides a sound rationale or theoretical basis, whether the results reflect cost causation and are representative of the costs of serving different types of customers, as well as the stability of the results over time. In addition, past methods and state regulatory policies, precedents, and requirements are considered.

V. <u>CEI SOUTH'S ACOSS</u>

A. Sources of Underlying Data

Q. WHAT WERE THE SOURCES OF THE COST DATA ANALYZED IN CEI SOUTH'S ACOSS?

A. All cost of service data were extracted from the Company's total cost of service (i.e., base rate revenue requirement) contained in the instant general rate case filing, which is based upon a future test year ending December 31, 2025. Where more detailed information was required to perform various subsidiary analyses related to specific plant and expense elements, the data were derived from the historical books and records of the Company.

Q. HOW ARE CEI SOUTH'S RATE CLASSES STRUCTURED FOR PURPOSES OF CONDUCTING ITS ACOSS?

A. All tariffed rate classes were included in the ACOSS as depicted in **Table JDT-1** below:

Table JDT-1 – ACOSS Customer Classes.

Rate Schedule	ACOSS Customer Class
Residential (RS)	Residential (RS)
Water Heating (B)	Water Heating (B)
Small General Service (SGS)	Small General Service (SGS)
Demand General Service (DGS)	Demand General Service (DGS)
Off-Season Service (OSS)	Demand General Service (DGS)
Large Power Service (LP)	Large Power Service (LP)
High Load Factor Service (HLF)	High Load Factor Service (HLF)
Outdoor Lighting (OL)	Outdoor Lighting (OL)
Street Lighting (SL)	Street Lighting (SL)

Q. PLEASE DESCRIBE CEI SOUTH'S DERIVATION OF ITS TOTAL REVENUE REQUIREMENT.

A. The Company's base rates are proposed to recover the revenue requirement exclusive of the costs recovered in trackers and riders and associated taxes. As explained by Petitioner's Witness Chrissy M. Behme, the Company's forecasted revenue requirement for the 12-month period ending December 31, 2025 is $860.2 million or $600 million net of fuel cost of $260.2 million. This is before revenue from any riders that would continue after retail base rates are established. In the setting of retail base rates, a base level of miscellaneous other revenue is treated as a credit. The base retail rates proposed in this proceeding are designed to recover an amount net of these credits of $511.7 billion.

B. Functionalization and Classification of Costs

Q. HOW DID YOU FUNCTIONALIZE AND CLASSIFY CEI SOUTH'S COSTS?

A. The process starts with each of the Company's FERC accounts and assigns the costs in each of these accounts to a specific function. In some instances, the costs in an account are first split into separate functions or classifications if the costs in the account are incurred to perform more than one function, or the costs in an account can be said to vary significantly with respect to more than one factor. For example, the accounts for distribution system poles, towers and fixtures, and conductors and conduits have been separated into primary distribution (600 V – 12.5 kV) and secondary distribution (≤ 600 V). In addition, the secondary distribution portion of these costs has been further separated into demand and customer classifications. Other distribution accounts are functionalized as substation transformation, onsite and metering, and lighting. Production and Transmission Plant accounts have been classified as demand-related cost. Plant and operations and maintenance costs related to production, transmission, and distribution generally can be assigned directly to specific functions. Still, various indirect costs related to overheads such as intangible plant, general plant, and common plant, as well as administrative and general expenses, are allocated to functions based on the relative amount of certain costs that have been directly assigned to each function. The specific functional allocators used to assign overhead costs have been selected to reflect the type of direct costs that each overhead account generally supports.

Q. HOW WERE TRANSFORMER COSTS (FERC ACCOUNT 368) CLASSIFIED BETWEEN CUSTOMER-RELATED AND DEMAND-RELATED COSTS?

A. The Company's plant accounting records do not include significant detail on the size of transformers for each property record. While the Company does have details on transformer sizes and locations within their GIS system, that system does not include actual unit costs. To estimate the portion of transformer costs that relate to meeting peak demands and the portion that relate to the need to connect customers, regressions were developed using replacement costs for padmounted and pole mounted transformers. The results of that analysis indicated that 56% of transformer costs are customer-related and 43% demand-related.

Q. PLEASE EXPLAIN THE PRIMARY-SECONDARY STUDY.

A. Because costs associated with distribution facilities are not explicitly identified in the financial accounting records as being Primary Distribution (600 V–12.5 kV) or Secondary Distribution (≤ 600 V), the remaining distribution costs in FERC Accounts 364, 365, and 367 have been assigned to Primary or Secondary distribution functions based on cost-related ratios that were developed from analyses of the distribution plant records. The development of the ratios used to make these Primary-Secondary assignments is shown in **Attachment JDT-2**, Schedule 5.

C. Allocations to Rate Classes

Q. WHAT WAS THE NEXT STEP IN THE ACOSS?

A. After functionalizing and classifying the costs, the final step is the allocation of each functionalized and classified cost element to the individual rate classes. Costs typically are allocated on demand, customer, and energy allocation factors. These allocation factors are either developed through special studies as presented in **Attachment JDT-2,** Schedule 5 or developed internally in the ACOSS model based on the allocations applied therein.

D. Allocation of Demand-Related Costs

Q. HOW HAVE THE DEMAND-RELATED COSTS BEEN ALLOCATED IN CEI SOUTH'S PROPOSED ACOSS?

A. I utilized a coincident peak demand method to allocate generation and transmission costs and a non-coincident peak demand method to allocate demand-related distribution system costs. "Coincident Peak" refers to the demand of a class at the time when the overall system demand is at a peak. "Non-coincident Peak" refers to the highest level of demand that an individual class experienced during the year. This non-coincident peak for a given class may coincide with the overall system peak, but in some instances, it occurs at other times that are off-peak for the system as a whole. The coincident peaks during the four summer months of the historic base period ("4CP") were used to allocate the demand-related costs associated with the production functions. The coincident peak demands during each of the twelve 12 months of the historic base period ("12CP") were utilized to allocate demand-related costs associated with the transmission functions. A summary of the firm peak load data used as a starting point to allocate demand-related costs is provided in **Attachment JDT-2**, Schedule 5.

Q. WHY DID YOU SELECT THE 4CP METHOD TO ALLOCATE THE PRODUCTION DEMAND-RELATED COSTS?

A. Several years of monthly peak loads (2010-2022) were reviewed, and the Company envaulted FERC's three peak ratios test established in Golden Spread Electric Coop., Inc., 123 FERC ¶ 61,047 at 61,249 (2008). Those three tests are as follows:

- Test No. 1 – On and Off-Peak Test: This test first compares the average of the coincident peaks in the months with the highest system peaks as a percentage of the annual system peak. Second, it compares the average of the coincident peaks in the months with the lowest system peaks as a percentage of the annual system peak. A 12CP allocation is considered appropriate where the difference between these two percentages is 19% or less.

- Test No. 2 – Low-to-Annual Peak Test: Compares the lowest monthly peak as a percentage of the annual system peak. A range of 66% or higher is considered indicative of a 12CP system.
- Test No. 3 – Average to Annual Peak Test: Compares the average of the twelve monthly peaks as a percentage of the annual system peak. A range of 81% or higher is considered indicative of a 12CP system.

As shown in **Table JDT-2** below, 2022, 2021, 2020, 2019, and 2017 failed all three tests, whereas 2018 failed two of the three tests. Thus, it is appropriate to continue to use a 4CP allocator for CEI South's demand-related production costs in this proceeding.

Table JDT-2 – FERC 12-CP Tests (2010-2021)

FERC 12-CP Tests			
	Peak - Off-Peak % Difference	Low/Annual Peak Ratio	Avg/Annual Peak Ratio
Use 12 CP if:	≤ 19.0%	≥ 66.0%	≥ 81.0%
2022	30.3%	57.1%	77.0%
2021	24.1%	61.4%	78.1%
2020	27.5%	59.4%	77.0%
2019	24.1%	63.2%	79.1%
2018	22.8%	65.6%	81.7%
2017	22.8%	64.8%	80.2%
2016	24.2%	66.8%	82.5%
2015	19.2%	65.7%	81.5%
2014	20.6%	63.5%	84.4%
2013	22.4%	69.8%	82.6%
2012	27.0%	55.4%	75.9%
2011	26.3%	64.7%	80.3%
2010	24.9%	58.8%	77.0%

Q. **WHY DID YOU SELECT THE 12CP METHOD TO ALLOCATE THE TRANSMISSION DEMAND-RELATED COSTS?**

A. The 12CP demand allocation method is based on the principle that a utility installs facilities to maintain a reasonably constant level of reliability throughout the year or that significant variations in monthly peak demands are not present. Under this method, no single peak demand or seasonal peak demands are of any significantly greater magnitude than any of the other monthly coincident peak demands. Thus, the relative importance of each month is considered. While I just demonstrated that the later requirement is not true from the perspective of the FERC test, the former certainly is – especially as it relates to the transmission system. The transmission system is designed to deliver energy generated to the load that demands it, with a reasonably constant level of reliability throughout the year. When designing the transmission system, the system must be designed such that it can be operated under any n-1 contingency without significant disruption of the transmission system (i.e., operations of transmission elements at or above emergency loading levels, voltages operating outside of design criterion, etc.). Furthermore, as more renewable (inverter based) generation is integrated to the grid, the challenges related to the operation of the transmission system shift away from single periods of peak demand to periods of high renewable production and lower loads which occur in the spring and the fall. Consequently, it is appropriate to allocate the transmission demand-related costs using the 12CP method.

Q. WHY DID YOU USE THE NON-COINCIDENT PEAK DEMANDS OF CUSTOMER CLASSES TO ALLOCATE THE COSTS OF DEMAND-RELATED DISTRIBUTION LINES AND SUBSTATIONS?

A. Although the production and transmission facilities are designed to meet the coincident peak demands of the entire system, as the system moves further from the generating plants and closer to the ultimate retail consumers, the primary factor affecting the planning and sizing of facilities is the level of peak demands in local areas. To the extent that customer classes have their individual peaks at different times, the Company must plan and install facilities to accommodate those individual peaks. In addition, to the extent that these facilities may be used jointly by different classes, the non-coincident peak method ensures that all classes share in the costs of these facilities. Consequently, the average of the 12 monthly non-coincident peak demands of each class was used in allocating costs associated with these distribution system facilities.

E. Allocation of Customer-Related Costs

Q. HOW HAVE THE CUSTOMER-RELATED COSTS BEEN ALLOCATED IN THE ACOSS?

A. Because a significant portion of the distribution system costs are incurred simply to attach a customer to the system and are the same regardless of the amount of energy that the customer might consume, significant portions of the distribution system costs and customer-specific costs are allocated to classes using allocators that are related to the number of customers in the class. However, because there generally is a wide difference between the customer classes in terms of the level of customer-related costs required per customer, many of the allocations of customer-related costs are weighted to reflect the relative differences in the average cost per customer of providing customer-related facilities or services for particular rate classes. Thus, customer-related costs such as meters, service lines, meter reading, billing, and customer service are allocated based on the cost-weighted number of customers in each class. The customer-related allocation factors and the relative-cost weights assigned to each class are shown in **Attachment JDT-2**, Schedule 5. The general methods used to develop the customer-related allocation factors are discussed below.

F. Allocation of Energy-Related Costs

Q. HOW ARE THE ENERGY-RELATED COSTS ALLOCATED IN THE ACOSS?

A. Energy-related costs are assigned to the various rate classes based on the fuel cost revenue recovered through each rate class.

G. Internal Allocations

Q. HOW ARE OVERHEAD COSTS FUNCTIONALIZED?

A. Intangible and General Plant accounts are allocated based on the labor allocator, except for DSM related General Plant Investments for Direct Load Control reflected separately in Account 398 which is allocated using the 4CP allocator. Administrative and General expenses were allocated to various functions using four different allocators: (1) Salaries, Office Supplies, Injuries and Damages, and Pensions and Benefits were allocated using the labor allocation factor; (2) Property Insurance was allocated using the relative amount of total plant in service associated with each function; (3) Outside Services, Public Utility Fees, Miscellaneous A&G, and Rents were allocated using a combination of the direct labor and the direct plant allocators, and (4) Maintenance of General Plant was allocated based on the Total General Plant assigned to each function.

H. Allocation of Depreciation Reserve and Expenses

Q. PLEASE DESCRIBE THE METHOD USED TO ALLOCATE THE RESERVE FOR DEPRECIATION AND DEPRECIATION EXPENSES.

A. These items were allocated by account in the same manner as their associated plant accounts.

I. Allocation of O&M Expenses

Q. HOW DID THE ACOSS ALLOCATE DISTRIBUTION-RELATED O&M EXPENSES?

A. In general, these expenses were allocated based on the cost allocation methods used for the Company's corresponding plant accounts. A utility's distribution-related O&M expenses generally are thought to support the utility's corresponding plant-in-service accounts. Put differently, the existence of particular plant facilities necessitates the incurrence of cost, i.e., expenses by the utility to operate and maintain those facilities. As a result, the allocation basis used to allocate a particular plant account will be the same basis used to allocate the corresponding expense account.

J. Allocation of Customer Accounting Expenses

Q. HOW DID THE ACOSS ALLOCATE CUSTOMER ACCOUNTING EXPENSES?

A. Meter Reading Expense, Account No. 902, relates to costs associated with manual meter reading and was allocated between customers in Large Power Service ("Rate LP") and High Load Factor Service ("Rate HLF") classes. Account No. 904, Uncollectible Accounts Expense is allocated based on the historical write-off records. All other accounts related to meter reading and customer account support are allocated based on the customer count in each respective customer class.

K. Allocation of Customer Information, Demonstration, and Sales Expenses

Q. HOW DID THE ACOSS ALLOCATE CUSTOMER INFORMATION, DEMONSTRATING, AND SELLING EXPENSES

A. Customer Information, Demonstration, and Sales Expenses related accounts are allocated according to the number of customers within each specific customer class.

L. Allocation of Taxes other than Income Taxes

Q. HOW DID THE ACOSS ALLOCATE TAXES OTHER THAN INCOME TAXES?

A. The ACOSS allocated all taxes, except for income taxes, to reflect the specific cost associated with the particular tax expense category. Generally, taxes can be cost classified based on the tax assessment method established for each tax category, i.e., payroll, property, or function. In the ACOSS, Payroll-related taxes were allocated based on labor expenses, and Property- and Public Utility Fee-related taxes were allocated based on total plant.

Q. HOW WERE INCOME TAXES ALLOCATED TO EACH CUSTOMER CLASS?

A. Current income taxes were allocated to each rate class based on each individual class's net operating income before income tax. For the determination of equal rates of return by class, a rate base allocator was used where income taxes are directly proportional to rate base.

Q. HOW DOES YOUR ACOSS TREAT REVENUES FOR CUSTOMERS WITH CONTRACTS APPROVED PURSUANT TO IND. CODE § 8-1-2-24 ("SECTION 24 CONTRACTS")?

A. The revenues from Section 24 contract customers were included in Other Revenues and allocated using the overall revenue requirement by class and thus credited against the overall revenue requirements for all rate classes. Other costs incurred to serve the Section 24 contract customers were not specifically identified and therefore assigned to all classes. As a result of this approach, all costs and revenue associated with the Commission-approved Section 24 contracts were shared with all rate classes through this allocation process. This approach is consistent with prior ACOSS studies filed by the Company.

VI. RESULTS OF CEI SOUTH'S ACOSS

A. Summary of CEI South's ACOSS by Rate Class

Q. HAVE YOU PREPARED A SUMMARY OF CEI SOUTH'S ACOSS RESULTS?

A. Yes. **Attachment JDT-2**, Schedule 1 presents the summary results of the ACOSS at present rates. This Schedule presents the resulting allocation by customer class of CEI South's proposed revenue requirement based strictly on the results of the computations included in the ACOSS. These results provide cost guidelines for evaluating a utility's class revenue levels and rate structures. The rate of return, current revenue, cost of service at equal rate of return, required revenue increase, and percentage increase in revenues to match revenues to cost to serve are summarized in **Table JDT-3** below.

Table JDT-3 – Results of the Cost of Service Study

Customer Classes	Current Total Revenues	Cost to Serve	Class Revenue (Deficiency)/ Excess	Percentage Change to Cost to Serve	Current Rate of Return
Residential (RS)	$ 324,435,009	$ 389,857,488	$ (65,422,479)	20.17%	2.99%
Water Heating (B)	$ 1,772,139	$ 2,616,337	(844,197)	47.64%	-3.72%
Small General Service (SGS)	$ 15,445,172	$ 17,244,814	(1,799,642)	11.65%	4.39%
Demand General Service (DGS)	$ 212,856,292	$ 234,622,588	(21,766,296)	10.23%	4.93%
Large Power Service (LP)	$ 172,728,031	$ 201,190,376	(28,462,345)	16.48%	2.78%
High Load Factor Service (HLF)	$ 9,072,475	$ 9,892,199	(819,723)	9.04%	3.75%
Outdoor Lighting (OL)	$ 1,898,526	$ 1,464,574	433,951	-22.86%	14.92%
Street Lighting (SL)	$ 3,189,691	$ 3,266,654	(76,963)	2.41%	6.82%
Toal Base Rate Margin	**$ 741,397,336**	**$ 860,155,029**	**$ (118,757,693)**	**16.02%**	**3.56%**

Table JDT-3 presents the revenue deficiency/excess for each rate class and the class rate of return on the net rate base at present rates. Regarding rate class revenue levels, the ACOSS results show that all rate classes, except for Outdoor Lighting Services are being charged rates that recover less than their indicated costs of service. **Attachment JDT-2**, Schedule 1 further summarizes the results of the ACOSS and presents the resulting allocation by customer class of the Company's proposed revenue requirement based strictly on the results of the computations included in the ACOSS. Further, this schedule summarizes the costs allocated to the customer classes on a functionalized (e.g., by distribution, secondary, metering) and classified (i.e., by demand and customer) basis. The customer-related and demand-related costs are of interest, which support the proposed levels of customer and demand rates.

Next, I explain how these ACOSS results guided the Company's determination of the revenues by rate class and the proposed rate levels.

B. Cost Guidelines for Use in Evaluating Class Revenue Levels and Rate Structures

Q. HOW CAN THE ACOSS RESULTS PROVIDE GUIDELINES FOR RATE DESIGN?

A. ACOSS results provide cost guidelines for use in evaluating class revenue levels and rate structures. When evaluating class revenue levels, the revenue-to-cost ratios show that rates charged to certain rate classes recover less than their indicated cost of service. Conversely, rates for other rate classes recover more than their indicated cost of service. By adjusting rates accordingly, class revenue levels can be brought closer to the indicated cost of service, resulting in class rates of return nearer the system average rate of return. Thus, rate levels will be more in line with the cost of providing service.

Q. DO THE ACOSS RESULTS GUIDE IN ESTABLISHING RATES WITHIN EACH RATE CLASS AS WELL?

A. Yes. The classified costs, as allocated to each class of service within the ACOSS, provide useful cost information in determining the level of customer, demand, and energy charges. As mentioned earlier, **Attachment JDT-2** summarizes the Company's functionalized revenue requirement per unit of billed demand, annual energy consumption, and customer count for each rate class.

C. Other Policy Considerations or Criteria that Should be Used in the Design of Utility Rates

Q. SHOULD OTHER FACTORS BE CONSIDERED THAT WOULD PREVENT THE COMPANY FROM SIMPLY TRANSLATING THE UNIT COSTS INTO RATES FOR THE VARIOUS TARIFF SERVICES?

A. Yes. Completely restructuring a utility's rates mechanistically to match the unit costs from the ACOSS is often not desirable due to the resulting adverse impact on certain customer classes, particularly for low use, low load factor customers. The unit costs provide useful information for designing portions of tariff services, particularly for establishing cost-based monthly fixed rates. The unit costs also can be used to design demand charges where either demand metering is available, or algorithm-based billing demands can be determined. Demand-based rates provide for a charge based upon the maximum demand imposed by a customer on the utility's system within a specified time period which establishes both the utility's responsibility to serve and the customer's obligation to pay for that level of service.

Q. PLEASE DESCRIBE OTHER CONSIDERATIONS OR CRITERIA THAT SHOULD BE USED IN THE DESIGN OF UTILITY RATES.

A. Utility rate design should recognize that rates must be just and reasonable and not cause undue discrimination. Thus, cross-subsidization within customer classes, as well as customer bill impact considerations, must be factored into the rate design process. Market conditions within the utility service territory concerning the general economic environment and competitive fuel prices, where appropriate, could be a factor. Another important consideration is the financial stability of the utility. Toward this goal, it is generally an unsound ratemaking practice to recover a substantial portion of fixed costs, such as customer-related costs, which bear no relationship to customer consumption patterns, in the volumetric portion of the rate structure. Recovery of fixed costs via volumetric rates adversely impacts earnings stability because the revenues generated from customers' volumetric use of electricity can be extremely sensitive to the vagaries of weather patterns and changing consumption characteristics due to energy conservation efforts, among other factors. Recovery of utility fixed costs in volumetric rates sends uneconomic price signals to consumers that impede their ability to make well-founded energy consumption decisions based on the actual costs of various types and levels of utility distribution service.

Q. HOW ARE THE FOREGOING GUIDELINES AND CRITERIA INCORPORATED INTO THE RATE DESIGN PROCESS?

A. A reasonable balance between the various cost guidelines and other criteria must be established in the process of designing rates, which consists of both the recovery of the revenue requirement from among the various customer classes and the determination of rate structures within tariff schedules. Economic, social, historical, and regulatory policy considerations can impact the rate design process. Both quantitative and qualitative factors must be considered in reaching a final rate design. Thus, it is necessary to allow the rate design process to be influenced by judgmental evaluations.

VII. <u>CEI SOUTH'S PROPOSED REVENUE ALLOCATION BY CLASS</u>

A. Description of Proposed Revenue Allocation Methodology Employed

Q. PLEASE DESCRIBE THE APPROACH FOLLOWED TO APPORTION THE CURRENT REVENUE RESPONSIBILITY TO THE COMPANY'S VARIOUS RATE CLASSES.

A. As described earlier in my testimony, the allocation of revenues among rate classes consists of deriving a reasonable balance between various guidelines and criteria that relate to the design of utility rates. The following criteria were considered in this process: (1) cost of service results, (2) class contribution to present revenue levels and the resulting inter-class subsidies, and (3) customer impact considerations including the Company's belief that while movement toward parity with the system-wide rate of return is the ultimate goal, moderation should be employed in accomplishing that goal.

Q. HOW WERE THE PROPOSED REVENUE RESPONSIBILITIES FOR THE VARIOUS RATE CLASSES DERIVED?

A. Using CEI South's proposed total revenue increase, and the results of its ACOSS, a few options were evaluated for the assignment of that increase among its rate schedules and, in conjunction with the Company's personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. These options and the proposed method described below are provided in **Attachment JDT-3.** The benchmark option that was evaluated under CEI South's proposed total revenue level was to adjust the revenue level for each rate schedule so that their revenues match their cost to serve and each classes revenue-to-cost (R:C) ratio would equal parity or 1.00.

A second option considered was assigning the increase in revenues to CEI South's rate schedules based on an equal percentage basis of its current margin revenues. By definition, this option resulted in each rate schedule receiving an increase in revenues equal to the system average. When this option was evaluated against the ACOSS Study results (as measured by changes in the revenue-to-cost ratio for each customer class), there was no movement towards cost of service for the rate schedules. While this option was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a range of results that provides further guidance to develop CEI South's class revenue proposal.

The third option considered, which is the proposed revenue allocation method, involves assigning the increase in revenues to CEI South's rate schedules in varying proportions to the present revenue levels. This method involves balancing a full movement to the cost to serve and customer impact considerations.

First, the Street Lighting Service ("Rate SL") schedule's revenues were set to their costs to serve and the resulting increase in revenues was used to provide a decrease in revenues to the Outdoor Lighting Service ("Rate OL") schedule. Next, the Water Heating Service ("Rate B") schedule's revenues were increased by 1.5 times the system increase which moved them closer to their cost to serve but not the full way which would have required an increase over three times the system increase. The third step was to increase the remaining rate classes' [Residential ("Rate RS"), Small General Service ("Rate SGS"), Demand General Service ("Rate DGS"), Rate LP, and Rate HLF] targeted revenues proportionately above their cost to serve to account for the deficiency in total revenues created by capping Water Heating schedule's revenues to 1.5 times the system increase.

The Company's proposed revenue allocation approach resulted in meaningful movement of the respective rate classes' revenue-to-cost ratios toward equal rates of return, while requiring some level of revenue increase responsibility from all customer classes for the Company's total proposed revenue requirement. From a class cost of service standpoint, this type of revenue-to-cost responsibility movement, and reduction in the existing interclass rate subsidies, is desirable.

B. Resulting Revenues at Proposed Rates by Customer Class

Q. HOW DOES CEI SOUTH PROPOSE TO DISTRIBUTE THE REVENUE INCREASE AMONG THE RATE CLASSES?

A. **Table JDT-4** below provides the proposed distribution of the proposed revenue increase among the rate schedule based on the process described above.

Table JDT-4 – Proposed Revenue Increase by Rate Class

Customer Classes	Current Total Revenues	Proposed Revenue	Proposed Revenue Change	Proposed Percentage Change	Proposed Rate of Return
Residential (RS)	$ 324,435,009	$ 389,885,563	$ 65,450,554	20.17%	7.06%
Water Heating (B)	1,772,139	$ 2,197,934	425,794	24.03%	2.01%
Small General Service (SGS)	15,445,172	$ 17,246,056	1,800,883	11.66%	7.06%
Demand General Service (DGS)	212,856,292	$ 234,639,484	21,783,192	10.23%	7.06%
Large Power Service (LP)	172,728,031	$ 201,204,864	28,476,833	16.49%	7.06%
High Load Factor Service (HLF)	9,072,475	$ 9,892,911	820,436	9.04%	7.05%
Outdoor Lighting (OL)	1,898,526	$ 1,821,563	(76,963)	-4.05%	12.75%
Street Lighting (SL)	3,189,691	$ 3,266,654	76,963	2.41%	7.06%
Toal Base Rate Margin	**$ 741,397,336**	**$ 860,155,029**	**$ 118,757,693**	**16.02%**	**7.06%**

Table JDT-4 indicates an expected decrease in Other Revenues which relates to an expected decrease in the Variable Production Revenue and a decrease in revenues that will result from IURC-approved Section 24 contract customers as some of those rates are based on the tariffed rate schedule. As rider costs get rolled into base rates, these IURC-approved Section 24 contract customers will provide a lower total revenue even though some of their base rates will increase.

VIII. CEI SOUTH'S PROPOSED RATE DESIGN

Q. HOW WERE THE PROPOSED RATES FOR EACH RATE SCHEDULE CALCULATED?

A. Detailed calculations for each rate component of each Rate Schedule are included in **Attachment JDT-4 (CONFIDENTIAL)**. As the attachment shows, the targeted total rate schedule revenue will be achieved using the proposed rates and volumes. Further, **Attachment JDT-4 (CONFIDENTIAL)** provides a presentation of the transition of revenues at current rates and existing rate classes to the proposed revenues at the proposed rate classes.

Q. WHAT MODIFICATIONS TO THE RATE STRUCTURE ARE PROPOSED IN THIS PROCEEDING?

A. The Company proposes to align the customer charge and demand charge between Off-Season Service ("Rate OSS") and Rate DGS. Rate OSS will continue to have a single volumetric rate that is different than the block structure in place for Rate DGS. This results in significant movement towards aligning the rates charged to customers across Rate OSS and Rate DGS while moderating bill impacts to lower volume Rate

OSS customers who, if moved to Rate DGS, would pay a volumetric rate close to twice the volumetric rate currently in place for Rate OSS. This proposal is in alignment with the Commission's Findings in the Company's last base rate case (Cause No 43839) to eliminate the discounts from standard rates for space heating customers.

Q. WHAT PROCESS DID YOU USE IN DESIGNING THE RATES?

A. Using the revenue apportioned to each rate class as described above, I generally followed the following process: First, I established the monthly customer charge as described below with the remaining revenue being collected through the energy charge. Where there are energy block rate structures in place, I retained the existing differences between the blocks on a percentage basis. The Production revenue requirement is used to develop the Variable Production Charge rate.

Q. DO THE PROPOSED RATES INCLUDE INCREASES TO THE EXISTING MONTHLY CUSTOMER CHARGE RATES?

A. Yes. During CEI South's test year the Residential customers will be paying a $10.84 customer charge rate and a fixed charge rate of $12.36 for the Transmission, Distribution, and Storage System Improvement Charge ("TDSIC"), for a total fixed monthly charge of $23.20. The proposed monthly customer charge is this same amount, $23.20 resulting in no incremental impact to CEI South's low use customers (i.e., a low use customer will see the same bill impact as an average use customer). A similar proposal is being made for the Rate SGS where the proposed monthly customer charge is the combination of the existing customer charge of $10.84 plus the fixed TDSIC charge of $11.66; resulting in a proposed rate of $22.50. Both of these changes are being made in order to more closely reflect the costs of serving each customer, as indicated by the ACOSS.

Q. WHAT IS THE COMPANY'S PROPOSAL RELATIVE TO CUSTOMERS THAT ARE ON THE RESIDENTIAL TRANSITIONAL RATE SCHEDULE?

A. The Company is proposing to continue to provide the transitional service but to move the rate structure closer to the Residential rate structure by charging the same monthly customer charge as the Residential schedule and only a single volumetric charge across all months. The full movement of customers from the current Residential Transitional rate schedule to the proposed Residential rate schedule would result in significant bill impacts for these customers that are over sixty percent higher than moving these customers to a flat volumetric rate structure. This proposal continues the Company's desire, and is in alignment with the Commission findings in the last base rate case, to move all customers served on the Residential Transitional rate schedule to the Residential rate schedule, but without doing so fully in this proceeding to mitigate impacts to these customers.

Q. WHAT PROCESS WAS EMPLOYED TO DEVELOP RATES FOR THE COMMERCIAL AND INDUSTRIAL RATE SCHEDULES?

A. Consistent with how the Company has set these rates in the past, the demand and volumetric rates for a Rate DGS customer with a 64% load factor, their bill will be 25% demand and 75% volumetric. Similarly, for a Rate LP customer with a 64% load factor, their bill would be comprised of 50% demand related costs and 50% volumetric related costs. For the Rate HLF schedule 100% of the fixed costs of providing electric utility service are recovered through the demand rate.

Q. WHAT PROCESS WAS EMPLOYED TO DEVELOP RATES FOR THE LIGHTING RATE CLASSES?

A. All Rate SL rates were increased by the percentage revenue increase resulting from the revenue apportionment provided above in **Table JDT-4**. Similarly, all Rate OL rates were decreased by the percentage revenue decrease resulting from the revenue apportionment.

Q. DO THE PROPOSED MONTHLY CUSTOMER CHARGE LEVELS REFLECT THE COMPANY'S INTENTION TO MOVE TO A GREATER RECOVERY OF FIXED DISTRIBUTION COSTS IN FIXED CHARGES?

A. Yes. The Company has proposed monthly customer charge rates at levels that reflect movement toward their full customer-related cost responsibility. The Company utilized the Unit Cost Analysis from the ACOSS (**Attachment JDT-2** Schedule 2) to identify costs related to providing both monthly distribution service to customers (customer-related costs) and annual levels of distribution capacity (demand-related costs). The level of customer-related costs is shown for the Residential class of customers in the Unit Cost Analysis to be $30.31 per customer per month and the combined customer- and demand-related costs to be $184.26 per customer per month (see **Attachment JDT-2** Schedule 2).

Q. WHY ARE SETTING CUSTOMER CHARGES MORE IN ALIGNMENT WITH THE FIXED COST OF SERVICE AN IMPORTANT OUTCOME OF RATEMAKING?

A. These proposed customer charge rates help to reduce customer bill volatility, alleviate a significant portion of the instability in the Company's margin recovery, are fair to customers, are easily understood and convey more appropriate price signals with respect to recovery of fixed distribution costs. Establishing higher monthly fixed rates helps to equalize the contribution each customer within a class makes towards recovery of the fixed costs attributable to this class. This method of cost recovery is preferable to including such costs in the volumetric block prices, which has the effect of causing some customers to pay too much while others pay too little. The customer charge rates provide for recovery of a portion of the Company's fixed costs, which are incurred solely because of the existence of customers connected to the system. These costs, such as the expense of reading meters and billing, occur regardless of whether electricity is used and are not related to demands placed on the system. The proposed customer charge increases will also help to ensure recovery by the Company of a greater portion of its fixed costs of providing service. Inasmuch as customer costs are not related to usage, they should be recovered to the extent possible through a tariff mechanism that does not depend upon volumetric billing. In terms of understandability, customers should easily understand a full customer cost-based charge. A full customer cost-based charge is easily explained since the rate is based on customer costs. Because these costs do not vary with the customer's usage, it is perfectly understandable that the charge should not vary as well. It is intuitively obvious that a customer should not pay more for being a customer when the weather is hot, and conversely should not pay less when the weather is cold.

Q. HAS THE IURC OFFERED GUIDANCE ON MOVING CUSTOMER CHARGE RATES CLOSER TO A POINT WHERE THEY RECOVER 100% OF FIXED COSTS OF SERVICE?

A. Yes. In Cause No. 43180, the Commission conducted an investigation into rate design alternatives for natural gas utilities. The investigation was commenced as a result of numerous natural gas utilities requesting various types of decoupling mechanisms. Indeed, the investigation was initiated following the approval of Indiana Gas Company, Inc. decoupling mechanism. After hearing the positions of the respondents and stakeholders, the Commission ultimately approved the basic framework for future decoupling mechanisms; however, the Commission noted that the long-term goal was Straight-Fixed-Variable ("SFV") pricing, stating:

> Going forward, the Commission finds that straight fixed-variable rate designs are attractive because they align basic cost causation principals of ratemaking. However, these designs do present concerns regarding rate shock and conservation efforts. Issues of rate shock could be tempered in a phased manner through a steady transition, reducing volumetric rate design by a fixed percentage in each rate case. This transition period would be consistent with Commission efforts to reduce inter-class subsidies, i.e., gradualism. The placement of efficiency or low-income assistance program charges on the higher usage block rates may be a reasonable means of designing intra-class subsidies while creating an inclining block rate structure conducive to conservation. All these concerns should be addressed in the context of base rate cases.[2]

CEI South's proposals to increase customer and demand rates makes some movement towards SFV pricing but does not fully move to SFV pricing.

Q. IS THE IURC GUIDANCE PRESENTED IN CAUSE NO. 43180 APPLICABLE TO ELECTRIC UTILITIES?

A. Yes. The Commission in the 2016 IP&L rate case decision stated the premises in Cause No. 43180 are reasonably applicable to electric utilities. Cost recovery design alignment with cost causation principles sends efficient price signals to customers, allowing customers to make informed decisions regarding their consumption of the service being provided. The Commission investigated the rate design issue with regard to natural gas service in Cause No. 43180, and the general premise appears to be reasonably applicable to electric utilities in the context of distribution-related costs.[3]

Q. WHAT CHANGES ARE BEING PROPOSED TO THE COMPANY'S BASE, BACKUP, AND MAINTENANCE SERVICES RATE ("RATE BAMP")?

A. The Company is proposing Rate BAMP to: (1) modify and bill all charges to a daily charge basis rather than the current monthly charge basis, (2) continue to use the applicable Rate Schedule the Customer elects for Base Service charges, (3) set Backup Service charges for Generation Capacity to 110% of the current Midcontinent Independent System Operator ("MISO") CONE (Cost of Next Entry) rate, (4) set

[2] Cause No. 43180 (IURC Oct. 21, 2009), p. 72.
[3] Cause No. 44576 (IURC Mar. 16, 2016), p. 10.

Backup Service for Energy Services to the applicable daily MISO LMP rate, and (5) set Backup Service for Transmission and Distribution Services on ACOSS unit costs. In addition to these rate changes the Company is proposing to true-up the difference between the forecasted level of Rate BAMP Backup Service revenues with actual Rate BAMP Backup Service revenues through the Company's Reliability Cost and Revenue Adjustment ("RCRA") and MISO Cost and Revenue Adjustment ("MCRA") mechanisms.

Q. WHAT STEPS WERE TAKEN TO ENSURE RATE BAMP'S RATES ARE COST BASED?

A. BAMP Base Service charges originate from other non-residential Rate Schedules, primarily DGS, LP or HLF. Within the BAMP contract, a non-residential Rate Schedule is elected by the BAMP Customer to serve as the basis for Base Service charges. BAMP Backup Generation Capacity Service charges use MISO's Cost of New Entry ("CONE") rate plus a 10% adder to reflect a component for Administrative and General (A&G) costs. The CONE rate was selected to represent an incremental daily 'rental' rate associated with a fixed cost generating unit. The CONE rate is only charged for the days when the BAMP Customer's generating unit has tripped off. However, the CONE rate is comprised of only direct costs and needs an A&G component to reflect a fully functionalized cost of service. This aligns the BAMP charge with all the other Company's base tariff rates which reflect an A&G component. In addition, BAMP Backup Transmission and Distribution Service charges are sourced from the ACOSS and are therefore cost base related. BAMP Maintenance Services are charged at the previously mentioned Base Services amounts at the same rate as the applicable rate class.

Q. IS CEI SOUTH PROPOSING UPDATES TO THE TRACKER ALLOCATORS IN THIS PRECEDING?

A. Yes. CEI South is proposing to update the tracker allocations based on proposed rate class level revenue allocations, ACOSS results, and energy allocations. **Attachment JDT-5** provides the updated allocation factors for CEI South's various trackers. The methods employed to develop these allocation factors are the same as those currently utilized by CEI South. The production demand allocators are based on the demand allocators used in the ACOSS by rate class. The energy allocators are based on the energy sales allocator from the ACOSS. The TDSIC allocators are based on the proposed revenue allocation by rate class (i.e., the mitigated allocation of the ACOSS revenue). The Company is proposing to use the production demand allocators for its Environmental Cost Adjustment ("ECA"), Clean Energy Cost Adjustment ("CECA"), and MCRA, RCRA, Securitization of Coal Plant ("SCP"), and Securitization ADIT Credit ("SAC"). In addition, in alignment with the principle of cost causation, the Company is proposing to use the total rate base allocators for its proposed Tax Adjustment Rider ("TAR").

Q. HOW DID YOU DEVELOP THE ILLUSTRATIVE RATES FOR THE INCLUSION IN THE COMPANY'S CRITICAL PEAK PRICING ("CPP") PILOT?

A. As described by Petitioner's Witness Rice, the Company is proposing a CPP pilot. The Company asked Atrium to design illustrative rates to include in this filing and to provide an estimate of consulting fees to fully develop rates for the inclusion in the CPP pilot. The illustrative rates were developed with a time differentiated volumetric charge during the summer (i.e., off-peak from 7pm to 1pm and weekends & on-peak from 1pm to 7pm), a 4:1 on-peak to off-peak ratio, and a CPP price which was set to at least a 2:1 ratio of the Summer on-peak price which is at least a 8:1 ratio of CPP to off-peak price. Atrium conducted a cursory review of the hourly load profiles of the Residential rate class to develop the illustrative pilot rates provided in the proposed tariff sponsored by Petitioner's Witness Rice. In addition, Atrium provided an estimate of $55k in consulting fees to develop the actual rates for inclusion in the Company's CPP Pilot if it is approved in this proceeding. That analysis would include a more detailed review of the Company's hourly load data, any loss of load event analysis or relative planning criteria, and a detailed review of production costs for the Company including the intersection of these costs with MISO market dynamics. The review and analyses of this data would inform the seasons, time periods, and relative rate levels across the on and off-peak periods and during CPP events.

IX. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does.

VERIFICATION

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

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH

John D. Taylor

John D. Taylor
Manager Partner, Atrium Economics

December 5, 2023

Date

ATRIUM ECONOMICS
CENTERED ON ENERGY

John D. Taylor

Managing Partner

Mr. Taylor has experience with a wide range of costing, ratemaking, and regulatory activities for gas and electric utilities. He has testified numerous times on these and other issues for clients across North America. He has extensive experience with costing and pricing rates and services, regulatory planning and strategy development, revenue recovery and tracking mechanisms, merger and acquisitions analysis, new product and service development, affiliate transaction reviews, line extension policies, market assessments, litigation support, and organizational and operations reviews. He has testified on numerous occasions as an expert witness on costing and ratemaking related issues on behalf of utilities before federal, state, and provincial regulatory bodies and has extensive experience in evaluating and implementing innovative ratemaking approaches and rate design concepts.

He has also testified on return on equity, electric vehicle and battery storage programs, time-of-use rates, and the appropriate use of statistical analysis during audit testing. Mr. Taylor has led engagements relating to gas supply planning and the review of midstream transportation and storage capacity resources. He has worked as the market monitor for New England ISO's capacity market, supported the negotiation of PPAs, and supported feasibility and prudence studies of generation investments. He has also been involved in selling generating assets and distribution companies, supporting due diligence efforts, financial analyses, and regulatory approval processes.

Mr. Taylor received a master's degree in Economics from American University and holds a bachelor's degree in Environmental Economics from the University of North Carolina at Asheville.

His consulting career includes Managing Partner with Atrium Economics, LLC; Principal Consultant – Advisory & Planning with Black & Veatch Management Consulting, LLC; Senior Project Manager & Principal of Concentric Energy Advisors, Inc.; and CEO of Nova Data Testing, Inc. Mr. Taylor started his career working on Capitol Hill working with NGOs that were seeking Public Private Partnerships with the Federal Government, World Bank, and International Monetary Fund to pursue various projects in developing countries.

EDUCATION

M.A., Economics, American University

B.A., Environmental Economics, University of North Carolina at Asheville

YEARS EXPERIENCE

18

RELEVANT EXPERTISE

Utility Costing and Pricing, Expert Witness Testimony, Transaction Facilitation, Revenue Requirements, Statistics, Valuation, Market Studies, Rate Case Management, New Product and Service Development, Strategic Business Planning, Marketing and Sales

EXPERT WITNESS TESTIMONY PRESENTATION

United States

- California – Superior Court of California
- Delaware Public Service Commission
- Florida Public Service Commission
- Federal Energy Regulatory Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Maine Public Service Commission
- Massachusetts Department of Public Utilities
- Minnesota Public Utilities Commission
- New Hampshire Public Utilities Commission
- North Carolina Utilities Commission
- Oregon Public Utility Commission
- Ohio Public Utility Commission
- Pennsylvania Public Utility Commission
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission
- Public Service Commission of West Virginia

Canada

- Alberta Utilities Commission
- British Columbia Utilities Commission
- Ontario Energy Board

REPRESENTATIVE EXPERIENCE

Rate Design and Regulatory Proceedings

Mr. Taylor has worked on dozens of electric and gas rate cases including the development of revenue requirements, class cost of service studies, and projects related to utility rate design issues. Specifically, he has:

- Lead expert and witness for class costs of service studies across North America and worked on dozens of other class cost of service and rate design projects for other lead witnesses.
- Developed WNA mechanism for a gas utility including back casting results and supporting expert witness testimony and exhibits.
- Developed revenue requirement model to comply with a new performance-based formula ratemaking process for a Midwest electric utility.
- Supported the developed of time of use rates, demand rates, economic development rates, load retention rates, and line extension policies.
- Analyzed and summarized allocation methodology for a shared services company.
- Assessed the reasonableness of costs through various benchmarking efforts.
- Led the effort to collect and organize plant addition documentation for six Midwest utilities associated with the state commission's audit of rate base.
- Supported lead-lag analyses and testimonies.
- Analyzed customer usage profiles to support reclassification of rate classes for a gas utility.
- Helped conduct a marginal cost analysis to support rate design testimony.

Litigation Support and Expert Testimony

Mr. Taylor has testified in several cases on class cost of service studies and statistical audit methods. He has also supported numerous other expert testimonies. Specifically, he has:

- Filed testimony as an expert witness on allocated class cost of service studies for both electric and gas utilities.
- Filed testimony as an expert witness on the application of statistical analysis.
- Filed testimony before FERC on the rate of return for an Annual Transmission Revenue Requirement and participated in FERC settlement conferences.
- Part of two-person expert witness team that provided an expert report to the British Columbia Utilities Commission on the use of facilities for transportation balancing services for Fortis BC.
- Part of two-person expert witness team that provided an expert report on affiliate transactions and capitalized overhead allocations for Hydro One on three separate occasions.
- Sole expert for expert report on affiliate allocations for Alectra utilities, the second largest publicly owned electric utility in North America. This was conducted shortly after the merger of four distinct utilities.
- Sole expert for expert report on the allocation of overhead costs between transmission and distribution businesses for EPCOR.

Transaction Experience

Mr. Taylor has been involved with several generating asset transactions supporting both buy side and sell side analysis and due diligence. His work has included:

- Worked as buy side advisor for a large water utility in the mid-Atlantic region including supporting the review of revenue requirements, rates, and forecasts.
- Helped facilitate and manage processes for a nuclear plant auction by processing Q&A, collecting relevant documentation and managing the virtual data room for auction participants.
- Supported the auction process for steam and chilled water distribution and generation assets in the Midwest.
- Supported the development of a financial model to ascertain the net present value of several competing wholesale power purchase agreements and guided the client with a decision matrix for the qualitative aspects of the offers.
- Provided research on comparable transactions, previous mergers and acquisitions, and potential transaction opportunities for several clients.

Financial Analysis and Market Research

Other financial analysis and market research Mr. Taylor has conducted include:

- Estimated the rate impact and costs associated with moving California energy market to 100% renewable.
- Assessed the consequences of a divestiture on the cost of service model for a New England gas distribution company.
- Developed LNG market studies for two separate utilities and two separate competitive market participants.
- Modeling alternative mechanisms for the allocation of overhead costs to a nuclear plant.

INDIANA UTILITY REGULATORY COMMISSION

CAUSE NO. XXXXX

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a
CENTERPOINT ENERGY INDIANA SOUTH

Petitioner's Exhibit No. 18, Attachment JDT-2

ALLOCATED COST OF SERVICE STUDY
TEST YEAR
ENDED DECEMBER 31, 2025

Witness: John D. Taylor

ATRIUM ECONOMICS
CENTERED ON ENERGY

Contents

I. INTRODUCTION

The purpose of this document is to discuss the development and results of the Cost of Service Study ("COSS") model and related schedules prepared for Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CEI South," "CEIS," or "the Company") based on the Test Year ended December 31, 2025 ("TY").

The document is organized into three sections. The first section discusses the purpose of cost allocation and includes an overview of Atrium's COSS model used to develop the cost allocation study. The second section, CEI South's Cost of Service Procedures, includes details of the methodologies adopted in the development of the study. The last section exhibits the results of the cost of service allocation.

1. Purpose of Cost Allocation

The purpose of the COSS is to determine the cost of service responsibilities of each customer class upon which the base rates may be established. The revenue requirement studies provide the overall level of costs of providing service, while the COSS is used to change the basic rate structures and/or the relative overall cost responsibility of each customer class. Based on the functionalization and classification of costs and allocation methodologies used in the COSS, the revenue requirement by customer class is determined and used in designing the Company's proposed base rates. In other words, the COSS measures each class's contribution to the Company's overall cost of service. Comparing the costs to serve any customer class with that class's rate revenues provides a measure of the return realized from that class and their associated revenue-to-cost ratio. This allows for a comparison across classes to ascertain the presence and extent of interclass subsidization (i.e., when one class pays more than its cost to serve and another pays less than its cost to serve).

2. COSS Procedures

Cost of service studies utilize a three-step process: functionalization, classification, and allocation.

In the first step, the functionalization sets off with assigning Federal Energy Regulatory Commission ("FERC") plant accounts and associated investment balances to appropriate cost of service functions. The expenses related to particular property investments or groups of investments can often follow the same functionalization and are allocated based on the ratios of the electric plant assigned to each function. These plant ratios can be used to functionalize most other cost items.

In the second step, classification, each functional cost category is further separated by cost causation. There are three basic cost-defining characteristics of electric services: demand, energy/commodity, and customer.

- Demand (Capacity) related costs are associated with the peak usage of the utility system. These costs are necessary to maintain the system at a level sufficient to satisfy the greatest demand that all the customers could place upon the system.
- Energy/Commodity-related costs are variable costs that vary with the quantity of electricity used. These costs reflect the number of units consumed or supplied during a period of time.

- Customer-related costs are associated with serving customers regardless of their usage or demand characteristics. They are allocated directly to the customers of a particular class of service.

The last step is to allocate these cost components among customer classes. An analysis of the utility's records may indicate specific costs that should be assigned directly to a particular customer class, including plant investments and associated expenses. All the remaining costs that cannot be directly attributable to a specific group of customers are allocated using allocation factors.

3. Atrium Economics Cost of Service Study Model Overview

The Cost of Service Study is submitted in support of the direct testimony of John D. Taylor. The COSS model presented in this proceeding is an excel based model that allows the user to modify various inputs and assumptions.

COSS Model Capabilities

The Atrium Economics' COSS model provides a large range of analytical capabilities including:

- Unbundling of operations into functions: (i.e. production/supply, storage, transmission, distribution, metering, and billing services.)
- Classification and allocation of costs into customer classes.
- Reports on Rate of Return, Revenue Requirement, and Revenue-to-Cost ratio for each function and rate class.
- Development of unit costs of each functional classification for each rate class.
- Specification of the individual rate of return targets for each function or customer class.
- Provides detailed analyses of working capital, income taxes, depreciation reserve, and depreciation expenses.
- Use of detailed analysis of labor expenses by account to facilitate the analyses of administrative and general expenses and overhead costs.
- Facilitation of direct assignment of plant investment, expenses, and revenue dollars to individual functions, classifications, or customer classes.

Follows Traditional 3-Step Allocation

The Atrium COSS Model follows the standard three-step analysis process:1) functionalization of rate base and expenses into various functional categories; 2) classification of functionalized components into demand, energy/commodity, and customer cost categories; and 3) allocation of each component among the customer classes.

As part of the functionalization process, accounts for common costs that are not specifically related to the primary functions, such as general plant and administrative and general expenses, are automatically allocated to the proper function based on internally defined allocation factors. All components of the utility's total cost of service are grouped into one of the functions.

The Atrium COSS Model provides unbundled functionalized and classified cost information by customer class; develops unbundled revenue requirements by functional classification for each customer class; and calculates unit costs by function for customer, energy/commodity, and demand categories. Accounting costs are reported by the FERC account level, and the allocation of A&G expenses, general taxes, and income taxes are clearly reported.

Revenue requirements are calculated from the allocated rate base and expenses and are adjusted to reflect the user-determined target rate of return and statutory tax adjustments. The actual revenues collected are compared to the calculated cost-based revenue requirements to determine class-specific, revenue-to-cost ratios to assist in revenue allocation and pricing activities.

Unit Cost Output Functionality

The COSS model calculates the unit cost of each functional classification separately for each rate class based on the user-specified billing determinants. These unit cost data are among the most important outputs from an embedded cost of service analysis. They are defined as the average cost of providing service to customers per measure of service (i.e., per kilowatt hour, per kilowatt of daily demand, and per customer). Unit costs are a key consideration in developing prices for bundled, unbundled, and re-bundled services.

Acceptance by Utility Regulatory Commissions

The format and presentation of the model's outputs have been used in many rate case proceedings and conform to standard utility commission requirements. Where necessary the COSS model outputs can be easily modified to meet specific jurisdictional filing requirements.

II. CEI SOUTH's COST OF SERVICE PROCEDURES

1. Functionalization

Functionalization is the process of associating each of the numerous detailed elements of the total revenue requirement with functions (and sometimes sub-functions) of the electric utility system. Costs must be first functionalized because each class's service requirement tends to have different relative impacts on each service function. As such, it is necessary to develop separate sub-parts of the total revenue requirement for each function (and sometimes sub-function). The four basic functions and the associated sub-functions are shown in the table below:

Function	Sub-Function
Generation	Production
	Fuel Expenses
	Variable Production Cost
Transmission	Transmission
Distribution	Substation
	Dist Primary
	Dist Secondary
	Transformation
Customer	Onsite & Metering
	Lighting Plant
	Customer Accounts & Service

CEIS's assigned functional categories are presented on Schedule 4.

2. Classification

The second step in the CCOSS process is to classify the functionalized costs as being associated with a measurable customer service requirement which gives rise to the costs

The table below shows how each of the functional and sub-functional costs was classified:

Function	Cost Classification		
	Demand	Energy	Customer
Production	x	x	
Transmission	x		
Substation	x		
Distribution Primary	x		
Distribution Secondary	x		
Transformation	x		x
Onsite & Metering			x
Lighting Plant			x
Customer Accounts & Service			x
Fuel Expenses		x	
VPC		x	

CEI South's assigned classification categories are presented on Schedule 4.

As shown in the table above, transformers are classified as demand and customer related using Minimum System Study. The Minimum System method involves comparing the cost of the minimum size of each type of facility used to the cost of the actual sized facilities installed. The cost of the minimum size facilities determines the "customer" component of total costs, and the "capacity" cost component is the difference between total installed cost and the minimum sized cost.

The table below shows the percent of each cost element that was classified as "customer" related based on the most recent Minimum System study.

Transformers and Transformer	Quantity	Total Replacement Cost	Zero Intercept Unit Cost	Customer Component	Customer Component (%)	Demand Component (%)
Overhead	38,002	$ 108,547,706	$ 1,600	$ 60,815,919	56%	44%
Padmount	18,992	$ 109,728,498	$ 3,238	$ 61,499,914	56%	44%
Total	**56,994**	**$218,276,204**		**$122,315,833**	**56%**	**44%**

3. Allocation

The allocation step involves assigning classified costs to the customer classes based on cost causation. Therefore, the allocation of costs is usually based on some measure of class loads or class service characteristics. The External and Internal Allocation Factors are utilized to allocate costs among various customer classes. CEIS's assigned Allocation Factors are presented on Schedule 4.

3.1. Customer Classes and Tariff Schedules

The following customer classes were identified for purposes of cost allocation:

Rate Schedule	**COSS Customer Class**
Residential (RS)	Residential (RS)
Water Heating (B)	Water Heating (B)
Small General Service (SGS)	Small General Service (SGS)
Demand General Service (DGS)	Demand General Service (DGS)
Off-Season Service (OSS)	Demand General Service (DGS)
Large Power Service (LP)	Large Power Service (LP)
High Load Factor Service (HLF)	High Load Factor Service (HLF)
Outdoor Lighting (OL)	Outdoor Lighting (OL)
Street Lighting (SL)	Street Lighting (SL)

3.2. External Allocation Factors

CEI South's External Allocation Factors are presented on Schedule 5. The External Allocation Factors are developed based on the special studies conducted using various detailed data.

ENERGY/COMMODITY AND REVENUE ALLOCATION FACTORS

Costs classified as Energy are allocated among customer classes based on the kilowatt-hour (kWh) sales for the test year.

REV	The factor directly assigns Current Annualized Revenues Less Fuel Cost Revenues to customer classes.
REV_ENERGY	The factor directly assigns total Fuel Cost Revenue to customer classes.
REV_RIDER	This factor directly assigns all rider revenues (TDSIC, CECA, etc.) less fuel cost revenue to customer classes.
ENERGY	This represents test year kWh consumption for each customer class.
REV_LATE_FEE	The factor directly assigns late fees revenue to customer classes.
REV_FORFEITED	This factor directly assigns forfeited discounts for each customer class.
REV_RECONNECT	The factor directly assigns reconnect charge revenue to each customer class.
REV_NFS	This factor directly assigns returned check charge revenue to each customer class.
REV_MISC	The factor directly assigns miscellaneous revenues collected through the customer classes.
REV_VP	The factor directly assigns variable production revenue through the customer classes.

REV_PROPOSED_VP	The factor directly assigns variable production revenues to customer classes.

CUSTOMER ALLOCATION FACTORS

Customer-related costs are generally allocated based on the number of customers within each class of service, with appropriate weighting to recognize specific service characteristics.

CUST	The factor is based on the average number of customers per customer class.
CUST_BILL	This factor is based on the number of customer bills per customer class.
CUST_PRI	The factor is based on the average number of customers per customer class using the Primary System.
CUST_SEC	The factor is based on the average number of customers per customer class using the Secondary System.
MTRS	The factor is based on the weighted customer unit cost of meters used to serve customers in different rate classes. The analysis relies upon the Company's records, which provide an inventory of each type and size of meter for a specific rate schedule. The average meter current replacement cost (including labor and overhead) was linked to the meter records dataset to develop the total current cost of the investment for each customer class. Then the relative customer class unit cost was developed and multiplied by the customer count for each customer class.
SERV	The analysis relies upon the data contained in the Company's property records which provide an inventory of the average number of service wires by customer class. Additionally, current unit costs per foot by service wire type and design (underground or overhead) were provided by the Company. The method employed to develop the service allocator was similar to that used for the meter allocator.
STREET-LIGHT	The factor is based on the average number of company-owned streetlights.
OUTDOOR-LIGHT	The factor exists to directly assign costs to the Outdoor Lighting class in ACOSS.
MTR_READ	Account 902 Meter Reading Expenses The factor is based on the special study of 902 sub-accounts.
UNCOLL	Account 904 Uncollectible Accounts. The factor is based on three-year average distribution-related write-offs by rate class.

DEMAND ALLOCATION FACTORS

NCP_SEC	Non-Coincident Peak Demand_Secondary (kW) -This factor analyzes each rate class's monthly contribution to the sum of the monthly maximum demands for all classes. The monthly demand is computed by taking a class's maximum non-coincident peak ("NCP") demand across all twelve months. This factor looks only at customers who utilize energy flowing through the secondary distribution system.

NCP_PRI	Non-Coincident Peak Demand_Primary (kW) -This factor analyzes each rate class's monthly contribution to the sum of the monthly maximum demands for all classes. The monthly demand is computed by taking a class's maximum non-coincident peak ("NCP") demand across all twelve months. This factor looks only at customers who utilize energy flowing through the primary distribution system.
12CP_DEMAND	The Twelve Monthly Coincident Peak Factor is based on the twelve months of average system peak responsibility of coincidental class demand.
4CP_DEMAND	The Four Monthly Coincident Peak Factor is based on the average of four peak months of system peak responsibility of coincidental class demand.

3.3. Internal Allocation Factors

Internal Allocation Factors are developed within the COSS model based on the cost ratios of allocated costs. The Internal Allocation Factors are provided in Schedule 5 and described below.

INT_TOTAL_PLANT	Plant Total - The factor is based on the allocated total plant balance by customer class.
INT_RATEBASE	Total Rate Base – The factor is based on the derived rate base by customer class.
INT_DIST_OPS	Distribution related Operation Expense subtotal – The factor is based on the customer class allocated Distribution-related Operation Expenses.
INT_DIST_MAINT	Distribution related Maintenance Expense subtotal – The factor is based on the customer class allocated Distribution-related Maintenance Expenses.
INT_361-364	Distribution Plant Subtotal – The factor is based on the allocated FERC Accounts 361 "Structures and improvements", 362 "Station Equipment", 363 "Storage battery equipment", 364 "Poles, Towers and Fixtures" plant balances by customer class.
INT_364	FERC 364 "Poles, Towers and Fixtures" - The factor is based on the allocated plant balance of FERC Account 364.
INT_365	FERC 365 "Overhead Conductors and Devices" - The factor is based on the allocated plant balance of FERC Account 365.
INT_367	FERC 367 "Underground Conductors and Devices" - The factor is based on the allocated plant balance of FERC Account 367.
INT_368	FERC 368 "Transformers and Transformer Installations" - The factor is based on the allocated plant balance of FERC Account 368.
INT_STNS,POLES,LINES	Distribution Plant Subtotal – The factor is based on the allocated FERC Accounts 362 "Station Equipment", 364 "Poles, Towers and Fixtures", and 365 "Overhead Conductors and Devices" plant balances by customer class.

INT_LABOR	Total Labor Expense – The factor is based on the total customer class allocated labor-related expenses.
INT_REVREQ	Total Revenue Requirement – The factor is based on the derived revenue requirement by customer class.
INT_GENPT	General Plant – The factor is based on the allocated total General Plant balance by customer class.
INT_DIST (60%)_TRANSM (40%)_PLANT	Factor calculated by taking 60% of the allocated total Distribution plant balance and 40% of the allocated total Transmission plant balance by customer class.

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1	**Rate Base**									
2	Plant in Service	$ 3,903,417,227	$ 1,890,792,021	$ 10,604,590	$ 80,518,536	$ 1,099,761,750	$ 758,812,968	$ 27,387,476	$ 8,946,173	$ 26,593,713
3	Accumulated Reserve	(1,227,300,954)	(605,930,521)	(4,175,694)	(28,979,564)	(333,956,266)	(227,404,616)	(8,311,811)	(3,861,732)	(14,680,750)
4	Other Rate Base Items	144,352,487	69,468,970	483,738	3,075,424	39,221,516	30,129,059	1,429,035	154,613	390,131
5	**Total Rate Base**	**$ 2,820,468,760**	**$ 1,354,330,471**	**$ 6,912,634**	**$ 54,614,396**	**$ 805,027,000**	**$ 561,537,411**	**$ 20,504,700**	**$ 5,239,054**	**$ 12,303,095**
6	**Margin at Current Rates**									
7	Base Rate Revenue	$ 267,328,655	$ 132,139,578	$ 530,561	$ 5,953,227	$ 75,824,903	$ 48,031,238	$ 1,868,205	$ 1,152,148	$ 1,828,794
8	Rider Revenue	118,109,906	59,668,199	479,352	3,587,192	38,038,775	15,410,774	750,947	29,159	145,507
9	Variable Production Revenue	18,054,808	6,551,059	34,459	291,427	5,155,612	5,597,499	331,601	36,004	57,149
10	Special Contract Revenue	46,020,892	20,418,261	134,463	903,619	12,615,290	11,135,081	562,703	79,779	171,695
11	Other Revenue	8,866,673	4,165,919	26,571	182,035	2,376,320	1,966,416	98,149	17,147	34,116
12	Sale for Resale and Transmission Revenue	22,823,902	10,344,727	69,424	457,585	6,225,625	5,338,514	262,486	38,862	86,679
13	**Total Margin at Current Rates**	**$ 481,204,835**	**$ 233,287,743**	**$ 1,274,829**	**$ 11,375,084**	**$ 140,236,526**	**$ 87,479,522**	**$ 3,874,091**	**$ 1,353,099**	**$ 2,323,940**
14	Fuel Cost Revenue	202,463,492	70,924,387	386,972	3,167,056	56,507,591	66,334,390	4,045,017	424,413	673,667
15	Fuel Cost Revenue_Special Contract	57,729,010	20,222,879	110,338	903,032	16,112,175	18,914,119	1,153,368	121,014	192,085
15	**Total Revenue at Current Rates**	**$ 741,397,336**	**$ 324,435,009**	**$ 1,772,139**	**$ 15,445,172**	**$ 212,856,292**	**$ 172,728,031**	**$ 9,072,475**	**$ 1,898,526**	**$ 3,189,691**
16	**Expenses at Current Rates**									
17	Fuel Cost	$ 260,192,501	$ 91,147,266	$ 497,310	$ 4,070,088	$ 72,619,766	$ 85,248,509	$ 5,198,384	$ 545,427	$ 865,751
18	Variable Production Cost	8,275,422	2,992,105	15,739	133,105	2,358,817	2,579,330	153,779	16,444	26,102
19	O&M and A&G Expenses	158,064,440	85,580,244	929,097	4,292,765	37,150,721	28,201,151	1,370,815	94,562	445,085
20	Depreciation and Amortization Expense	179,942,886	88,152,522	540,335	3,800,903	50,253,646	34,743,144	1,321,704	335,709	794,922
21	Taxes Other Than Income	12,339,079	6,088,836	41,745	271,814	3,363,913	2,379,679	93,563	23,136	76,392
22	Deferred Taxes	12,280,774	5,906,698	30,712	240,717	3,496,726	2,434,187	88,695	23,814	59,225
23	Current Income Tax	9,973,261	4,029,671	(25,570)	238,321	3,943,355	1,549,941	76,451	77,708	83,384
24	**Total Expenses at Current Rates**	**$ 641,068,364**	**$ 283,897,343**	**$ 2,029,368**	**$ 13,047,713**	**$ 173,186,943**	**$ 157,135,941**	**$ 8,303,393**	**$ 1,116,801**	**$ 2,350,862**
25	**Operating Income at Current Rates**	**$ 100,328,972**	**$ 40,537,666**	**$ (257,229)**	**$ 2,397,460**	**$ 39,669,348**	**$ 15,592,090**	**$ 769,082**	**$ 781,725**	**$ 838,829**
26	Current Rate of Return	3.56%	2.99%	-3.72%	4.39%	4.93%	2.78%	3.75%	14.92%	6.82%
27	Relative Rate of Return	1.00	0.84	(1.05)	1.23	1.39	0.78	1.05	4.19	1.92
28	Current Revenue to Cost Ratio	0.86	0.83	0.68	0.90	0.91	0.86	0.92	1.30	0.98
29	Current Parity Ratio	1.00	0.97	0.79	1.04	1.05	1.00	1.06	1.50	1.13
30	**Current Revenue at Equal Rates of Return**									
31	Current Rate of Return	3.56%	3.56%	3.56%	3.56%	3.56%	3.56%	3.56%	3.56%	3.56%
32	Current Operating Income at Equal ROR	$ 100,328,972	$ 48,175,887	$ 245,894	$ 1,942,729	$ 28,636,209	$ 19,974,861	$ 729,388	$ 186,362	$ 437,642
33	Current Income Taxes - Equal ROR	9,973,261	4,788,953	24,443	193,118	2,846,599	1,985,613	72,505	18,525	43,504
34	Expenses before Income Tax - Equal ROR	631,095,103	279,108,391	2,004,925	12,854,595	170,340,344	155,150,328	8,230,888	1,098,275	2,307,358
35	**Revenue at Equal Rates of Return**	**$ 741,397,336**	**$ 332,073,230**	**$ 2,275,263**	**$ 14,990,442**	**$ 201,823,152**	**$ 177,110,802**	**$ 9,032,781**	**$ 1,303,163**	**$ 2,788,504**

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36	**Revenue Requirement at Equal Rates of Return**									
37	Required Return	7.06%	7.06%	7.06%	7.06%	7.06%	7.06%	7.06%	7.06%	7.06%
38	Required Operating Income	$ 199,125,094	$ 95,615,731	$ 488,032	$ 3,855,776	$ 56,834,906	$ 39,644,541	$ 1,447,632	$ 369,877	$ 868,599
39	**Expenses at Required Return**									
40	Fuel Cost	$ 260,192,501	$ 91,147,266	$ 497,310	$ 4,070,088	$ 72,619,766	$ 85,248,509	$ 5,198,384	$ 545,427	$ 865,751
41	Variable Production Cost	8,275,422	2,992,105	15,739	133,105	2,358,817	2,579,330	153,779	16,444	26,102
42	O&M and A&G Expenses	158,064,440	85,580,244	929,097	4,292,765	37,150,721	28,201,151	1,370,815	94,562	445,085
43	Depreciation and Amortization Expense	179,942,886	88,152,522	540,335	3,800,903	50,253,646	34,743,144	1,321,704	335,709	794,922
44	Taxes Other Than Income	12,339,079	6,088,836	41,745	271,814	3,363,913	2,379,679	93,563	23,136	76,392
45	Deferred Taxes	2,307,513	1,117,745	6,269	47,599	650,126	448,574	16,190	5,289	15,721
46	Current Income Tax	9,973,261	4,788,953	24,443	193,118	2,846,599	1,985,613	72,505	18,525	43,504
47	Gross-up Income Tax	29,404,270	14,119,319	72,066	569,372	8,392,658	5,854,203	213,768	54,619	128,264
48	Gross-up Other Expenses	530,562	254,765	1,300	10,274	151,435	105,632	3,857	986	2,314
49	**Total Expenses at Required Return**	**$ 661,029,935**	**$ 294,241,757**	**$ 2,128,305**	**$ 13,389,038**	**$ 177,787,682**	**$ 161,545,834**	**$ 8,444,567**	**$ 1,094,697**	**$ 2,398,055**
50	Under Equal Rates of Return									
51	**Total Revenue Requirement at Equal Rates of R**	**$ 860,155,029**	**$ 389,857,488**	**$ 2,616,337**	**$ 17,244,814**	**$ 234,622,588**	**$ 201,190,376**	**$ 9,892,199**	**$ 1,464,574**	**$ 3,266,654**
52	**Total Revenue (Deficiency)/Surplus**	**$ (118,757,693)**	**$ (65,422,479)**	**$ (844,197)**	**$ (1,799,642)**	**$ (21,766,296)**	**$ (28,462,345)**	**$ (819,723)**	**$ 433,951**	**$ (76,963)**
53	**Percent Change at Equal Rates of Return**	16.02%	20.17%	47.64%	11.65%	10.23%	16.48%	9.04%	-22.86%	2.41%
54	LESS:									
55	Fuel Cost Revenue	260,192,501	91,147,266	497,310	4,070,088	72,619,766	85,248,509	5,198,384	545,427	865,751
56	Variable Production Revenue	6,549,773	2,368,171	12,457	105,349	1,866,940	2,041,470	121,712	13,015	20,659
57	Variable Production Revenue_Special Contract	1,725,649	623,935	3,282	27,756	491,877	537,860	32,067	3,429	5,443
58	Special Contract Revenue	41,181,709	18,665,237	125,263	825,631	11,233,044	9,632,407	473,610	70,120	156,398
59	Other Revenue	8,866,673	4,165,919	26,571	182,035	2,376,320	1,966,416	98,149	17,147	34,116
60	Sale for Resale and Transmission Revenue	29,935,530	13,568,008	91,055	600,162	8,165,448	7,001,924	344,273	50,971	113,688
61	**Total Base Rate Margin Requirement at Equal R**	**$ 511,703,195**	**$ 259,318,952**	**$ 1,860,399**	**$ 11,433,792**	**$ 137,869,193**	**$ 94,761,789**	**$ 3,624,004**	**$ 764,466**	**$ 2,070,600**

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62	Under Proposed Revenues									
63	**Total Proposed Revenue Increase/(Decrease)**	**$ 118,757,693**	**$ 65,450,554**	**$ 425,794**	**$ 1,800,883**	**$ 21,783,192**	**$ 28,476,833**	**$ 820,436**	**$ (76,963)**	**$ 76,963**
64	**Total Proposed Revenue**	**$ 860,155,029**	**$ 389,885,563**	**$ 2,197,934**	**$ 17,246,056**	**$ 234,639,484**	**$ 201,204,864**	**$ 9,892,911**	**$ 1,821,563**	**$ 3,266,654**
65	LESS:									
66	Fuel Cost Revenue	260,192,501	91,147,266	497,310	4,070,088	72,619,766	85,248,509	5,198,384	545,427	865,751
67	Variable Production Revenue	6,549,773	2,368,171	12,457	105,349	1,866,940	2,041,470	121,712	13,015	20,659
68	Variable Production Revenue_Special Contract	1,725,649	623,935	3,282	27,756	491,877	537,860	32,067	3,429	5,443
69	Special Contract Revenue	41,181,709	18,665,237	125,263	825,631	11,233,044	9,632,407	473,610	70,120	156,398
70	Other Revenue	8,866,673	4,165,919	26,571	182,035	2,376,320	1,966,416	98,149	17,147	34,116
71	Sale for Resale and Transmission Revenue	29,935,530	13,568,008	91,055	600,162	8,165,448	7,001,924	344,273	50,971	113,688
72	**Total Base Rate Margin as Proposed**	**511,703,195**	**259,347,028**	**1,441,996**	**11,435,034**	**137,886,089**	**94,776,277**	**3,624,716**	**1,121,454**	**2,070,600**
73	Percent Margin Change	24.68%	28.06%	33.40%	15.83%	15.53%	32.55%	21.18%	-5.69%	3.31%
74	**Operating Income at Proposed Rates**									
75	Gross-up Other Expenses	530,562	240,490	1,356	10,638	144,731	124,108	6,102	1,124	2,015
76	Operating Income Prior to Taxes	$ 238,502,625	$ 114,566,354	$ 166,083	$ 4,619,144	$ 68,097,764	$ 47,480,370	$ 1,732,372	$ 799,872	$ 1,040,666
77	Income Taxes	39,377,531	18,915,264	27,421	762,635	11,243,154	7,839,158	286,020	132,061	171,817
78	**Total Operating Income at Proposed Rates**	$ 199,125,094	$ 95,651,090	$ 138,662	$ 3,856,509	$ 56,854,610	$ 39,641,212	$ 1,446,352	$ 667,811	$ 868,848
79	Proposed Rate of Return	7.06%	7.06%	2.01%	7.06%	7.06%	7.06%	7.05%	12.75%	7.06%
80	Relative Rate of Return	1.00	1.00	0.28	1.00	1.00	1.00	1.00	1.81	1.00
81	Proposed Revenue to Cost Ratio	1.00	1.00	0.84	1.00	1.00	1.00	1.00	1.24	1.00
82	Proposed Parity Ratio	1.00	1.00	0.84	1.00	1.00	1.00	1.00	1.24	1.00
83	Class (Subsidies)/Excesses at Current Rates (at equal 3.56% ROR)	$ -	$ (7,638,221)	$ (503,123)	$ 454,731	$ 11,033,140	$ (4,382,771)	$ 39,695	$ 595,363	$ 401,187
84	Class (Subsidies)/Excesses at Proposed Rates	$ -	$ 28,075	$ (418,403)	$ 1,242	$ 16,896	$ 14,489	$ 712	$ 356,988	$ -
85	Dollar Value of Change in Subsidies	$ -	$ 7,666,297	$ 84,720	$ (453,489)	$ (11,016,244)	$ 4,397,259	$ (38,982)	$ (238,374)	$ (401,187)
86	Percent Change in Subsidies		-100%	-17%	-100%	-100%	-100%	-98%	-40%	-100%

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Line	Description	TOTAL	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
1	**Functional Rate Base**									
2	**Production**									
3	Demand	$ 1,370,715,626	$ 622,387,999	$ 2,156,159	$ 23,179,745	$ 408,413,061	$ 300,112,376	$ 14,310,381	$ 60,258	$ 95,648
4	Energy	$ 11,940,667	$ 4,280,830	$ 22,517	$ 190,434	$ 3,375,649	$ 3,778,837	$ 231,528	$ 23,527	$ 37,344
5	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Subtotal	$ 1,382,656,294	$ 626,668,829	$ 2,178,676	$ 23,370,180	$ 411,788,710	$ 303,891,213	$ 14,541,909	$ 83,785	$ 132,992
7	**Transmission**									
8	Demand	$ 446,145,665	$ 197,875,879	$ 852,680	$ 7,666,385	$ 126,511,971	$ 106,912,381	$ 5,783,458	$ 209,838	$ 333,073
9	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Subtotal	$ 446,145,665	$ 197,875,879	$ 852,680	$ 7,666,385	$ 126,511,971	$ 106,912,381	$ 5,783,458	$ 209,838	$ 333,073
12	**Substation**									
13	Demand	$ 222,157,223	$ 109,738,271	$ 468,762	$ 3,892,082	$ 62,783,203	$ 44,058,947	$ 24,187	$ 460,625	$ 731,145
14	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Subtotal	$ 222,157,223	$ 109,738,271	$ 468,762	$ 3,892,082	$ 62,783,203	$ 44,058,947	$ 24,187	$ 460,625	$ 731,145
17	**Dist Primary**									
18	Demand	$ 481,469,097	$ 237,449,080	$ 1,014,422	$ 8,432,560	$ 136,073,812	$ 95,798,249	$ 149,412	$ 986,190	$ 1,565,371
19	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	Subtotal	$ 481,469,097	$ 237,449,080	$ 1,014,422	$ 8,432,560	$ 136,073,812	$ 95,798,249	$ 149,412	$ 986,190	$ 1,565,371
22	**Dist Secondary**									
23	Demand	$ 122,983,799	$ 75,355,931	$ 321,872	$ 2,670,769	$ 43,812,206	$ -	$ -	$ 318,102	$ 504,920
24	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Subtotal	$ 122,983,799	$ 75,355,931	$ 321,872	$ 2,670,769	$ 43,812,206	$ -	$ -	$ 318,102	$ 504,920
27	**Transformation**									
28	Demand	$ 51,869,963	$ 25,644,197	$ 109,535	$ 908,883	$ 14,658,397	$ 10,268,871	$ -	$ 108,252	$ 171,828
29	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31	Subtotal	$ 51,869,963	$ 25,644,197	$ 109,535	$ 908,883	$ 14,658,397	$ 10,268,871	$ -	$ 108,252	$ 171,828

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32	**Onsite & Metering**									
33	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	Customer	$ 89,519,389	$ 72,011,952	$ 1,735,635	$ 6,960,755	$ 8,730,118	$ 80,172	$ 756	$ -	$ -
36	Subtotal	$ 89,519,389	$ 72,011,952	$ 1,735,635	$ 6,960,755	$ 8,730,118	$ 80,172	$ 756	$ -	$ -
37	**Lighting Plant**									
38	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Customer	$ 11,934,666	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,072,263	$ 8,862,403
41	Subtotal	$ 11,934,666	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,072,263	$ 8,862,403
42	**Customer Accounts & Service**									
43	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	Customer	$ 11,732,664	$ 9,586,332	$ 231,050	$ 712,782	$ 668,584	$ 527,576	$ 4,977	$ -	$ 1,364
46	Subtotal	$ 11,732,664	$ 9,586,332	$ 231,050	$ 712,782	$ 668,584	$ 527,576	$ 4,977	$ -	$ 1,364
47	**Total**									
48	Demand	$ 2,695,341,374	$ 1,268,451,357	$ 4,923,431	$ 46,750,424	$ 792,252,650	$ 557,150,825	$ 20,267,438	$ 2,143,265	$ 3,401,984
49	Energy	$ 11,940,667	$ 4,280,830	$ 22,517	$ 190,434	$ 3,375,649	$ 3,778,837	$ 231,528	$ 23,527	$ 37,344
50	Customer	$ 113,186,719	$ 81,598,284	$ 1,966,685	$ 7,673,537	$ 9,398,701	$ 607,749	$ 5,733	$ 3,072,263	$ 8,863,767
51	**TOTAL RATE BASE**	$ 2,820,468,760	$ 1,354,330,471	$ 6,912,634	$ 54,614,396	$ 805,027,000	$ 561,537,411	$ 20,504,700	$ 5,239,054	$ 12,303,095
52	**Functional Revenue Requirement**									
53	**Production**									
54	Demand	$ 290,876,972	$ 131,345,553	$ 480,991	$ 4,937,841	$ 85,671,404	$ 65,120,031	$ 3,211,622	$ 42,334	$ 67,196
55	Energy	$ 1,014,727	$ 363,788	$ 1,914	$ 16,183	$ 286,865	$ 321,128	$ 19,675	$ 1,999	$ 3,174
56	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	Subtotal	$ 291,891,699	$ 131,709,341	$ 482,904	$ 4,954,025	$ 85,958,269	$ 65,441,160	$ 3,231,297	$ 44,333	$ 70,370
58	**Transmission**									
59	Demand	$ 89,098,129	$ 39,517,072	$ 170,286	$ 1,531,026	$ 25,265,246	$ 21,351,083	$ 1,154,993	$ 41,906	$ 66,517
60	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	Subtotal	$ 89,098,129	$ 39,517,072	$ 170,286	$ 1,531,026	$ 25,265,246	$ 21,351,083	$ 1,154,993	$ 41,906	$ 66,517
63	**Substation**									
64	Demand	$ 27,513,134	$ 13,527,711	$ 57,806	$ 481,598	$ 7,776,602	$ 5,507,977	$ 19,014	$ 55,048	$ 87,378
65	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	Subtotal	$ 27,513,134	$ 13,527,711	$ 57,806	$ 481,598	$ 7,776,602	$ 5,507,977	$ 19,014	$ 55,048	$ 87,378

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68	**Dist Primary**									
69	Demand	$ 94,671,787	$ 46,293,782	$ 197,906	$ 1,655,466	$ 26,763,874	$ 19,161,299	$ 130,311	$ 181,328	$ 287,821
70	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72	Subtotal	$ 94,671,787	$ 46,293,782	$ 197,906	$ 1,655,466	$ 26,763,874	$ 19,161,299	$ 130,311	$ 181,328	$ 287,821
73	**Dist Secondary**									
74	Demand	$ 20,423,677	$ 12,514,211	$ 53,453	$ 443,529	$ 7,275,807	$ -	$ -	$ 52,826	$ 83,851
75	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
77	Subtotal	$ 20,423,677	$ 12,514,211	$ 53,453	$ 443,529	$ 7,275,807	$ -	$ -	$ 52,826	$ 83,851
78	**Transformation**									
79	Demand	$ 7,236,617	$ 3,577,740	$ 15,282	$ 126,802	$ 2,045,060	$ 1,432,657	$ -	$ 15,103	$ 23,973
80	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	Subtotal	$ 7,236,617	$ 3,577,740	$ 15,282	$ 126,802	$ 2,045,060	$ 1,432,657	$ -	$ 15,103	$ 23,973
83	**Onsite & Metering**									
84	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
85	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	Customer	$ 36,878,796	$ 30,105,013	$ 725,592	$ 2,615,005	$ 3,401,506	$ 31,383	$ 296	$ -	$ -
87	Subtotal	$ 36,878,796	$ 30,105,013	$ 725,592	$ 2,615,005	$ 3,401,506	$ 31,383	$ 296	$ -	$ -
88	**Lighting Plant**									
89	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	Customer	$ 2,264,746	$ -	$ -	$ -	$ -	$ -	$ -	$ 512,158	$ 1,752,587
92	Subtotal	$ 2,264,746	$ -	$ -	$ -	$ -	$ -	$ -	$ 512,158	$ 1,752,587
93	**Customer Accounts & Service**									
94	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
95	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96	Customer	$ 21,708,522	$ 18,473,246	$ 400,059	$ 1,234,170	$ 1,157,641	$ 436,977	$ 4,122	$ -	$ 2,305
97	Subtotal	$ 21,708,522	$ 18,473,246	$ 400,059	$ 1,234,170	$ 1,157,641	$ 436,977	$ 4,122	$ -	$ 2,305
98	**Total**									
99	Demand	$ 529,820,316	$ 246,776,069	$ 975,723	$ 9,176,262	$ 154,797,992	$ 112,573,048	$ 4,515,941	$ 388,546	$ 616,735
100	Energy	$ 1,014,727	$ 363,788	$ 1,914	$ 16,183	$ 286,865	$ 321,128	$ 19,675	$ 1,999	$ 3,174
101	Customer	$ 60,852,063	$ 48,578,259	$ 1,125,652	$ 3,849,175	$ 4,559,147	$ 468,360	$ 4,418	$ 512,158	$ 1,754,893
102	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**	$ 591,687,106	$ 295,718,116	$ 2,103,288	$ 13,041,621	$ 159,644,005	$ 113,362,537	$ 4,540,035	$ 902,703	$ 2,374,801
103	Demand	89.54%	83.45%	46.39%	70.36%	96.96%	99.30%	99.47%	43.04%	25.97%
104	Energy	0.17%	0.12%	0.09%	0.12%	0.18%	0.28%	0.43%	0.22%	0.13%
105	Customer	10.28%	16.43%	53.52%	29.51%	2.86%	0.41%	0.10%	56.74%	73.90%

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106	**Unit Costs**									
107	**Production**									
108	Demand	$ -	$ -	$ -	$ -	$ 26.27	$ 24.09	$ 33.00	$ -	$ -
109	Energy	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00
110	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
111	**Transmission**									
112	Demand	$ -	$ -	$ -	$ -	$ 7.75	$ 7.90	$ 11.87	$ -	$ -
113	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
114	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
115	**Substation**									
116	Demand	$ -	$ -	$ -	$ -	$ 2.38	$ 2.04	$ 0.20	$ -	$ -
117	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
118	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
119	**Dist Primary**									
120	Demand	$ -	$ -	$ -	$ -	$ 8.21	$ 7.09	$ 1.34	$ -	$ -
121	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
122	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
123	**Dist Secondary**									
124	Demand	$ -	$ -	$ -	$ -	$ 2.23	$ -	$ -	$ -	$ -
125	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
126	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Line	Description	TOTAL	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
127	**Transformation**									
128	Demand	$ -	$ -	$ -	$ -	$ 0.63	$ 0.53	$ -	$ -	$ -
129	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
130	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
131	**Onsite & Metering**									
132	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
133	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
134	Customer	$ 19.68	$ 18.78	$ 18.78	$ 21.94	$ 30.43	$ 24.67	$ 24.67	$ -	$ -
135	**Lighting Plant**									
136	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
137	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
138	Customer	$ 1.21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,686.79
139	**Total**									
140	Energy	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003
141	Customer (per cust month)	$ 32.47	$ 30.31	$ 29.14	$ 32.30	$ 40.78	$ 368.21	$ 368.21	$ -	$ 7,696.90
142	Onsite and Customer Servic	$ 1.21	$ 18.78	$ 18.78	$ 21.94	$ 30.43	$ 24.67	$ 24.67	$ -	$ -
143	Demand & Customer (per cu	$ 315.19	$ 184.26	$ 54.39	$ 109.29	$ 1,425.46	$ 88,869.03	$ 376,696.61	$ -	$ 10,401.88
144	Demand		$ -	$ -	$ -	$ 47.47	$ 41.65	$ 46.40	$ -	$ -
145	**BILLING DETERMINANTS**									
146	Demand		0	0	0	3,260,842	2,702,812	97,323	0	0
147	Energy	3,904,507,404	1,399,798,865	7,362,997	62,270,627	1,103,811,583	1,235,650,954	75,708,000	7,693,136	12,211,243
148	Customers (Number of Bills	1,874,048	1,602,925	38,634	119,184	111,793	1,272	12	0	228

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Petitioner's Exhibit No. 18, Attachment JDT-2: Allocated Cost of Service
Study Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
1	**RATE BASE**										
2	**Plant in Service**										
3	**Intangible Plant**										
4	Organization	301	12,151	6,368	68	325	2,939	2,280	115	6	50
5	Franchises and Consents	302	-	-	-	-	-	-	-	-	-
6	Miscellaneous Intangible Plant	303	198,547,734	104,044,878	1,117,912	5,311,743	48,022,108	37,260,261	1,884,743	93,211	812,877
7	Subtotal - Intangible Plant		198,559,885	104,051,246	1,117,980	5,312,069	48,025,047	37,262,542	1,884,858	93,217	812,927
8	**Steam Production Plant**										
9	Land and Land Rights	310	1,976,433	899,568	3,040	33,367	591,823	428,516	20,120	-	-
10	Structures and Improvements	311	96,772,607	44,045,772	148,851	1,633,768	28,977,563	20,981,514	985,139	-	-
11	Boiler Plant Equipment	312	569,693,573	259,294,383	876,273	9,617,881	170,588,886	123,516,706	5,799,445	-	-
12	Engines and Engine Driven Generators	313	-	-	-	-	-	-	-	-	-
13	Turbogenerator Units	314	48,177,832	21,928,001	74,105	813,365	14,426,357	10,445,558	490,447	-	-
14	Accessory Electric Equipment	315	33,226,393	15,122,897	51,107	560,946	9,949,302	7,203,898	338,243	-	-
15	Miscellaneous Power Plant Equipment	316	24,639,884	11,214,772	37,900	415,984	7,378,160	5,342,236	250,832	-	-
16	Asset Retirement Costs for Steam Production	317	-	-	-	-	-	-	-	-	-
17	Subtotal - Steam Production Plant		774,486,722	352,505,393	1,191,275	13,075,311	231,912,090	167,918,427	7,884,226	-	-
18	**Other Production Plant**										
19	Land and Land Rights	340	389,504	177,282	599	6,576	116,633	84,449	3,965	-	-
20	Structures and Improvements	341	2,271,907	1,034,052	3,495	38,356	680,299	492,578	23,128	-	-
21	Fuel Holders, Producers and Accessories	342	4,101,467	1,866,771	6,309	69,243	1,228,142	889,249	41,753	-	-
22	Prime Movers	343	48,262,971	21,966,752	74,236	814,802	14,451,851	10,464,017	491,314	-	-
23	Generators	344	17,496,247	7,963,366	26,912	295,381	5,239,071	3,793,406	178,111	-	-
24	Accessory Electric Equipment	345	5,263,501	2,395,667	8,096	88,861	1,576,101	1,141,193	53,582	-	-
25	Miscellaneous Power Plant Equipment	346	777,533,774	353,892,249	1,195,961	13,126,753	232,824,499	168,579,066	7,915,245	-	-
26	Asset Retirement Costs for Other Production	347	-	-	-	-	-	-	-	-	-
27	Subtotal - Other Production Plant		855,319,370	389,296,139	1,315,607	14,439,973	256,116,596	185,443,958	8,707,098	-	-
28	**Transmission Plant**										
29	Land and Land Rights	350	19,334,962	8,575,501	36,953	332,244	5,482,748	4,633,345	250,642	9,094	14,435
30	Structures and Improvements	352	6,442,051	2,857,198	12,312	110,698	1,826,750	1,543,745	83,509	3,030	4,809
31	Station Equipment	353	196,875,807	87,318,955	376,272	3,383,034	55,827,386	47,178,451	2,552,133	92,597	146,979
32	Towers and Fixtures	354	4,622,707	2,050,277	8,835	79,435	1,310,845	1,107,765	59,925	2,174	3,451
33	Poles and Fixtures	355	237,797,966	105,468,875	454,483	4,086,223	67,431,540	56,984,857	3,082,613	111,845	177,530
34	Overhead Conductors and Devices	356	106,793,870	47,365,541	204,106	1,835,102	30,283,165	25,591,612	1,384,386	50,229	79,728
35	Underground Conduit	357	1,180,974	523,789	2,257	20,293	334,885	283,003	15,309	555	882
36	Underground Conductors and Devices	358	1,356,646	601,704	2,593	23,312	384,699	325,101	17,586	638	1,013
37	Road and Trails	359	-	-	-	-	-	-	-	-	-
38	ARO for Transmission Plant	359.1	-	-	-	-	-	-	-	-	-
39	Subtotal - Transmission Plant		574,404,982	254,761,841	1,097,811	9,870,341	162,882,018	137,647,879	7,446,104	270,162	428,826

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
Petitioner's Exhibit No. 18, Attachment JDT-2: Allocated Cost of Service Study
Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
40	**Distribution Plant**										
41	Land and land rights	360	3,081,457	1,554,237	6,639	55,085	889,974	558,546	-	6,561	10,414
42	Structures and improvements	361	1,539,531	780,794	3,335	27,673	447,304	271,897	-	3,296	5,232
43	Station equipment	362	259,931,734	128,508,679	548,906	4,554,612	73,456,434	51,459,558	-	542,476	861,068
44	Storage battery equipment	363	-	-	-	-	-	-	-	-	-
45	Poles, Towers and Fixtures - PRI DEM	364	250,802,380	123,995,182	529,627	4,394,644	70,876,489	49,652,190	-	523,423	830,825
46	Poles, Towers and Fixtures - PRI CUST	364	-	-	-	-	-	-	-	-	-
47	Poles, Towers and Fixtures - SEC DEM	364	47,052,112	28,830,267	123,144	1,021,804	16,762,020	-	-	121,702	193,176
48	Poles, Towers and Fixtures - SEC CUST	364	-	-	-	-	-	-	-	-	-
49	Overhead Conductors and Devices - PRI DEM	365	265,280,976	131,153,312	560,202	4,648,343	74,968,125	52,518,566	-	553,640	878,788
50	Overhead Conductors and Devices - PRI CUST	365	-	-	-	-	-	-	-	-	-
51	Overhead Conductors and Devices - SEC DEM	365	46,814,290	28,684,546	122,522	1,016,639	16,677,297	-	-	121,087	192,200
52	Overhead Conductors and Devices - SEC CUST	365	-	-	-	-	-	-	-	-	-
53	Underground conduit	366	47,676,074	25,658,238	109,595	909,381	14,772,313	5,946,313	-	108,312	171,922
54	Underground Conductors and Devices - PRI DEM	367	104,053,705	51,443,523	219,733	1,823,264	29,405,467	20,599,861	-	217,160	344,695
55	Underground Conductors and Devices - PRI CUST	367	-	-	-	-	-	-	-	-	-
56	Underground Conductors and Devices - SEC DEM	367	61,110,906	37,444,519	159,939	1,327,111	21,770,376	-	-	158,065	250,896
57	Underground Conductors and Devices - SEC CUST	367	-	-	-	-	-	-	-	-	-
58	Transformers and Transformer Installations - DEM	368	103,114,848	50,979,358	217,751	1,806,813	29,140,147	20,413,993	-	215,200	341,585
59	Transformers and Transformer Installations - CUST	368	-	-	-	-	-	-	-	-	-
60	Services	369	103,266,723	78,847,006	1,900,374	10,461,700	11,948,298	108,324	1,022	-	-
61	Meters	370	26,328,799	21,810,074	525,667	1,684,243	2,287,399	21,216	200	-	-
62	Installations on customers premises	371	5,941,020	-	-	-	-	-	-	5,941,020	-
63	Street lighting and signal systems	373	20,653,277	-	-	-	-	-	-	-	20,653,277
64	Subtotal - Distribution Plant		1,346,647,831	709,689,734	5,027,435	33,731,313	363,401,643	201,550,464	1,222	8,511,942	24,734,078
65	**General Plant**										
66	Land and Land Rights	389	2,309,376	1,210,181	13,003	61,783	558,561	433,387	21,922	1,084	9,455
67	Structures and Improvements	390	56,222,863	29,462,441	316,560	1,504,129	13,598,445	10,551,007	533,704	26,395	230,183
68	Office Furniture and Equipment	391	23,986,173	12,569,463	135,053	641,702	5,801,459	4,501,341	227,692	11,261	98,202
69	Transportation Equipment	392	25,161,795	13,185,524	141,672	673,153	6,085,803	4,721,963	238,852	11,813	103,015
70	Stores Equipment	393	688,773	360,937	3,878	18,427	166,591	129,258	6,538	323	2,820
71	Tools, Shop and Garage Equipment	394	9,246,944	4,845,672	52,064	247,383	2,236,529	1,735,318	87,778	4,341	37,858
72	Laboratory Equipment	395	1,859,238	974,296	10,468	49,740	449,688	348,912	17,649	873	7,612
73	Power Operated Equipment	396	5,812,993	3,046,180	32,730	155,515	1,405,970	1,090,889	55,181	2,729	23,799
74	Communication Equipment	397	22,869,808	11,984,455	128,767	611,835	5,531,447	4,291,839	217,095	10,737	93,632
75	Miscellaneous Equipment	398	2,761,879	1,447,306	15,551	73,888	668,007	518,305	26,218	1,297	11,307
76	Miscellaneous Equipment-DLC	398	3,078,597	1,401,214	4,735	51,975	921,854	667,478	31,340	-	-
77	Subtotal - General Plant		153,998,437	80,487,669	854,481	4,089,530	37,424,355	28,989,699	1,463,968	70,852	617,883
78	**Total Plant in Service**		3,903,417,227	1,890,792,021	10,604,590	80,518,536	1,099,761,750	758,812,968	27,387,476	8,946,173	26,593,713

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
Petitioner's Exhibit No. 18, Attachment JDT-2: Allocated Cost of Service Study
Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
79	**Accumulated Depreciation & Amortization**										
80	**Intangible Plant**										
81	Organization	301	-	21,810,074	525,667	1,684,243	2,287,399	21,216	200	-	-
82	Franchises and Consents	302	-	-	-	-	-	-	-	-	-
83	Miscellaneous Intangible Plant	303	(120,558,306)	(63,176,114)	(678,797)	(3,225,294)	(29,159,054)	(22,624,454)	(1,144,417)	(56,598)	(493,579)
84	Subtotal - Intangible Plant		(120,558,306)	(63,176,114)	(678,797)	(3,225,294)	(29,159,054)	(22,624,454)	(1,144,417)	(56,598)	(493,579)
				-	-	-	-	-	-	-	-
85	Steam Production Plant			-	-	-	-	-	-	-	-
86	Land and Land Rights	310	142,880	65,032	220	2,412	42,784	30,978	1,455	-	-
87	Structures and Improvements	311	(46,698,062)	(21,254,488)	(71,828)	(788,382)	(13,983,255)	(10,124,725)	(475,383)	-	-
88	Boiler Plant Equipment	312	(264,136,630)	(120,221,024)	(406,281)	(4,459,300)	(79,093,000)	(57,268,131)	(2,688,894)	-	-
89	Engines and Engine Driven Generators	313	-	-	-	-	-	-	-	-	-
90	Turbogenerator Units	314	(36,101,462)	(16,431,476)	(55,529)	(609,485)	(10,810,212)	(7,827,249)	(367,511)	-	-
91	Accessory Electric Equipment	315	(3,420,234)	(1,556,710)	(5,261)	(57,742)	(1,024,154)	(741,550)	(34,818)	-	-
92	Miscellaneous Power Plant Equipment	316	(8,721,704)	(3,969,659)	(13,415)	(147,245)	(2,611,625)	(1,890,975)	(88,786)	-	-
93	Asset Retirement Costs for Steam Production	317	-	-	-	-	-	-	-	-	-
94	Subtotal - Steam Production Plant		(358,935,213)	(163,368,325)	(552,095)	(6,059,742)	(107,479,461)	(77,821,652)	(3,653,938)	-	-
				-	-	-	-	-	-	-	-
95	Other Production Plant			-	-	-	-	-	-	-	-
96	Land and Land Rights	340	38,004	17,297	58	642	11,380	8,240	387	-	-
97	Structures and Improvements	341	(2,231,173)	(1,015,512)	(3,432)	(37,668)	(668,102)	(483,746)	(22,713)	-	-
98	Fuel Holders, Producers and Accessories	342	(4,631,843)	(2,108,170)	(7,124)	(78,197)	(1,386,958)	(1,004,242)	(47,152)	-	-
99	Prime Movers	343	(42,171,802)	(19,194,374)	(64,866)	(711,968)	(12,627,913)	(9,143,375)	(429,306)	-	-
100	Generators	344	(13,256,606)	(6,033,706)	(20,391)	(223,805)	(3,969,554)	(2,874,198)	(134,951)	-	-
101	Accessory Electric Equipment	345	(4,116,286)	(1,873,516)	(6,331)	(69,493)	(1,232,580)	(892,462)	(41,904)	-	-
102	Miscellaneous Power Plant Equipment	346	(16,519,696)	(7,518,892)	(25,410)	(278,895)	(4,946,653)	(3,581,677)	(168,169)	-	-
103	Asset Retirement Costs for Other Production	347	-	-	-	-	-	-	-	-	-
104	Subtotal - Other Production Plant		(82,889,403)	(37,726,872)	(127,496)	(1,399,385)	(24,820,380)	(17,971,461)	(843,809)	-	-
				-	-	-	-	-	-	-	-
105	Transmission Plant			-	-	-	-	-	-	-	-
106	Land and Land Rights	350	(4,213,024)	(1,868,573)	(8,052)	(72,395)	(1,194,672)	(1,009,590)	(54,614)	(1,982)	(3,145)
107	Structures and Improvements	352	(2,543,412)	(1,128,062)	(4,861)	(43,705)	(721,226)	(609,492)	(32,971)	(1,196)	(1,899)
108	Station Equipment	353	(55,183,260)	(24,475,047)	(105,467)	(948,247)	(15,648,125)	(13,223,873)	(715,349)	(25,955)	(41,197)
109	Towers and Fixtures	354	(5,214,294)	(2,312,659)	(9,966)	(89,600)	(1,478,599)	(1,249,530)	(67,594)	(2,452)	(3,893)
110	Poles and Fixtures	355	(55,473,356)	(24,603,711)	(106,022)	(953,232)	(15,730,386)	(13,293,391)	(719,110)	(26,091)	(41,414)
111	Overhead Conductors and Devices	356	(27,944,809)	(12,394,166)	(53,409)	(480,192)	(7,924,212)	(6,696,571)	(362,253)	(13,143)	(20,862)
112	Underground Conduit	357	(968,589)	(429,591)	(1,851)	(16,644)	(274,659)	(232,108)	(12,556)	(456)	(723)
113	Underground Conductors and Devices	358	(1,294,260)	(574,034)	(2,474)	(22,240)	(367,009)	(310,151)	(16,778)	(609)	(966)
114	Road and Trails	359	-	-	-	-	-	-	-	-	-
115	ARO for Transmission Plant	359.1	-	-	-	-	-	-	-	-	-
116	Subtotal - Transmission Plant		(152,835,002)	(67,785,844)	(292,101)	(2,626,254)	(43,338,889)	(36,624,706)	(1,981,225)	(71,884)	(114,100)

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
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Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
				-	-	-	-	-	-	-	-
117	Distribution Plant			-	-	-	-	-	-	-	-
118	Land and land rights	360	(20,815)	(10,499)	(45)	(372)	(6,012)	(3,773)	-	(44)	(70)
119	Structures and improvements	361	(897,293)	(455,074)	(1,944)	(16,129)	(260,705)	(158,471)	-	(1,921)	(3,049)
120	Station equipment	362	(44,601,013)	(22,050,471)	(94,185)	(781,514)	(12,604,199)	(8,829,812)	-	(93,082)	(147,748)
121	Storage battery equipment	363	-	-	-	-	-	-	-	-	-
122	Poles, Towers and Fixtures	364	(90,761,034)	(46,568,362)	(198,910)	(1,650,478)	(26,704,857)	(15,129,817)	-	(196,580)	(312,030)
123	Overhead Conductors and Devices	365	(91,322,510)	(46,770,316)	(199,773)	(1,657,636)	(26,816,459)	(15,367,510)	-	(197,432)	(313,383)
124	Underground conduit	366	(18,345,845)	(9,873,340)	(42,173)	(349,931)	(5,684,415)	(2,288,153)	-	(41,679)	(66,156)
125	Underground Conductors and Devices	367	(51,477,871)	(27,704,283)	(118,335)	(981,897)	(15,950,290)	(6,420,486)	-	(116,949)	(185,632)
126	Transformers and Transformer Installations	368	(52,561,797)	(25,986,235)	(110,996)	(921,006)	(14,853,909)	(10,405,836)	-	(109,696)	(174,120)
127	Services	369	(71,529,816)	(54,614,998)	(1,316,333)	(7,246,511)	(8,276,234)	(75,033)	(708)	-	-
128	Meters	370	(2,976,324)	(2,465,507)	(59,424)	(190,394)	(258,578)	(2,398)	(23)	-	-
129	Installations on customers premises	371	(2,944,632)	-	-	-	-	-	-	(2,944,632)	-
130	Street lighting and signal systems	373	(12,598,490)	-	-	-	-	-	-	-	(12,598,490)
131	Subtotal - Distribution Plant		(440,037,441)	(236,499,085)	(2,142,117)	(13,795,869)	(111,415,656)	(58,681,289)	(730)	(3,702,016)	(13,800,677)
				-	-	-	-	-	-	-	-
132	General Plant			-	-	-	-	-	-	-	-
133	Land and Land Rights	389	(22,147)	(11,606)	(125)	(592)	(5,357)	(4,156)	(210)	(10)	(91)
134	Structures and Improvements	390	(17,518,991)	(9,180,469)	(98,640)	(468,685)	(4,237,263)	(3,287,684)	(166,302)	(8,225)	(71,725)
135	Office Furniture and Equipment	391	(15,258,932)	(7,996,131)	(85,915)	(408,222)	(3,690,629)	(2,863,552)	(144,848)	(7,164)	(62,472)
136	Transportation Equipment	392	(16,726,737)	(8,765,304)	(94,179)	(447,490)	(4,045,643)	(3,139,006)	(158,781)	(7,853)	(68,481)
137	Stores Equipment	393	(574,962)	(301,297)	(3,237)	(15,382)	(139,064)	(107,900)	(5,458)	(270)	(2,354)
138	Tools, Shop and Garage Equipment	394	(2,180,271)	(1,142,526)	(12,276)	(58,329)	(527,335)	(409,158)	(20,697)	(1,024)	(8,926)
139	Laboratory Equipment	395	(1,935,880)	(1,014,458)	(10,900)	(51,791)	(468,225)	(363,295)	(18,377)	(909)	(7,926)
140	Power Operated Equipment	396	(2,361,451)	(1,237,470)	(13,296)	(63,176)	(571,157)	(443,159)	(22,416)	(1,109)	(9,668)
141	Communication Equipment	397	(9,472,725)	(4,963,988)	(53,336)	(253,424)	(2,291,138)	(1,777,689)	(89,921)	(4,447)	(38,782)
142	Miscellaneous Equipment	398	(480,682)	(251,891)	(2,706)	(12,860)	(116,261)	(90,207)	(4,563)	(226)	(1,968)
143	Miscellaneous Equipment-DLC	398	(5,512,812)	(2,509,141)	(8,480)	(93,070)	(1,650,755)	(1,195,247)	(56,120)	-	-
144	Subtotal - General Plant		(72,045,589)	(37,374,281)	(383,089)	(1,873,020)	(17,742,826)	(13,681,054)	(687,692)	(31,235)	(272,393)
				-	-	-	-	-	-	-	-
145	**Total Accumulated Depreciation & Amortization**		(1,227,300,954)	(605,930,521)	(4,175,694)	(28,979,564)	(333,956,266)	(227,404,616)	(8,311,811)	(3,861,732)	(14,680,750)
146	**Other Rate Base Items**										
147	Fuel Stock & Expense	151	11,940,667	4,280,830	22,517	190,434	3,375,649	3,778,837	231,528	23,527	37,344
148	Materials and Supplies (Generation Inventory)	154	41,360,961	18,344,539	79,050	710,730	11,728,584	9,911,559	536,169	19,453	30,878
149	Allowance Inventory	158	1,282,707	568,910	2,452	22,042	363,733	307,382	16,628	603	958
150	Stores Expense	163	311,332	150,807	846	6,422	87,716	60,522	2,184	714	2,121
151	PISCC - AMI	182.3	10,585,830	9,054,353	218,228	673,227	631,482	7,185	68	-	1,288
152	PISCC - ECA	182.3	26,359,625	11,997,507	40,545	445,018	7,893,119	5,715,097	268,339	-	-
153	PISCC - CECA	182.3	18,045,313	8,213,272	27,756	304,651	5,403,484	3,912,450	183,700	-	-
154	PISCC - TDSIC	182.3	21,951,124	11,162,619	73,095	511,616	5,990,285	3,722,634	63,017	110,316	317,542
155	PISCC - CT	182.3	12,514,927	5,696,133	19,250	211,284	3,747,466	2,713,393	127,401	-	-
156	Total Other Rate Base Items		144,352,487	69,468,970	483,738	3,075,424	39,221,516	30,129,059	1,429,035	154,613	390,131
157	**TOTAL RATE BASE**		2,820,468,760	1,354,330,471	6,912,634	54,614,396	805,027,000	561,537,411	20,504,700	5,239,054	12,303,095

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158	**OPERATION AND MAINTENANCE EXPENSE**										
159	**Generation Production, Transmission, and Distribution Expense**										
160	**Steam Power Generation Operation Expenses**										
161	Operation Supervision and Engineering	500	743,496	329,758	1,421	12,776	210,831	178,168	9,638	350	555
162	Fuel	501	260,192,501	91,147,266	497,310	4,070,088	72,619,766	85,248,509	5,198,384	545,427	865,751
163	Fuel (Operation Related Expenses)	501	2,240,456	993,694	4,282	38,499	635,318	536,893	29,043	1,054	1,673
164	Steam Expenses	502	1,969,108	873,345	3,763	33,836	558,373	471,868	25,526	926	1,470
165	Steam Expenses - VPC	502	7,310,722	2,643,303	13,904	117,588	2,083,840	2,278,647	135,853	14,527	23,059
166	Electric Expenses	505	1,348,774	598,212	2,578	23,177	382,467	323,214	17,484	634	1,007
167	Electric Expenses - VPC	505	165,000	59,658	314	2,654	47,031	51,428	3,066	328	520
168	Miscellaneous Steam Power Expenses	506	2,163,147	959,405	4,134	37,171	613,396	518,367	28,041	1,017	1,615
169	Miscellaneous Steam Power Expenses - VPC	506	299,500	108,289	570	4,817	85,369	93,350	5,566	595	945
170	Rents	507	-	-	-	-	-	-	-	-	-
171	Allowances	509	3,519,952	1,561,180	6,727	60,485	998,141	843,506	45,630	1,656	2,628
172	Subtotal - Steam Power Generation Operation Expenses		279,952,656	99,274,110	535,003	4,401,092	78,234,532	90,543,950	5,498,231	566,514	899,223
173	**Steam Power Generation Maintenance Expenses**										
174	Maintenance Supervision and Engineering	510	492,730	218,537	942	8,467	139,722	118,076	6,387	232	368
175	Maintenance of Structures	511	1,494,465	662,830	2,856	25,680	423,780	358,127	19,373	703	1,116
176	Maintenance of Boiler Plant	512	6,725,481	2,982,906	12,854	115,568	1,907,121	1,611,665	87,183	3,163	5,021
177	Maintenance of Boiler Plant-VPC	512	500,200	180,855	951	8,045	142,576	155,905	9,295	994	1,578
178	Maintenance of Electric Plant	513	3,512,286	1,557,780	6,713	60,354	995,967	841,669	45,530	1,652	2,622
179	Maintenance of Miscellaneous Steam Plant	514	1,506,822	668,310	2,880	25,893	427,284	361,088	19,533	709	1,125
180	Subtotal - Steam Power Generation Maintenance Expenses		14,231,984	6,271,218	27,196	244,007	4,036,451	3,446,529	187,302	7,452	11,829
181	**Other Power Generation Operation Expenses**										
182	Operations Supervision and Engineering	546	20,563	9,120	39	353	5,831	4,928	267	10	15
183	Generation Expenses	548	5,608,351	2,487,433	10,719	96,372	1,590,341	1,343,961	72,702	2,638	4,187
184	Miscellaneous Other Power Generation Expenses	549	917,282	406,836	1,753	15,762	260,110	219,813	11,891	431	685
185	Subtotal - Other Power Generation Operation Expenses		6,546,196	2,903,389	12,511	112,487	1,856,282	1,568,702	84,859	3,079	4,887
186	**Other Power Generation Maintenance Expenses**										
187	Maintenance Supervision and Engineering	551	1	0	0	0	0	0	0	0	0
188	Maintenance of Structures	552	15,000	6,653	29	258	4,253	3,595	194	7	11
189	Maintenance of Generating and Electric Plant	553	8,602,756	3,815,520	16,442	147,826	2,439,453	2,061,526	111,519	4,046	6,422
190	Subtotal - Other Power Generation Maintenance Expenses		8,617,756	3,822,174	16,470	148,084	2,443,707	2,065,121	111,713	4,053	6,434
191	**Other Power Supply Expenses**										
192	System Control and Load Dispatching	556	670,659	297,453	1,282	11,524	190,176	160,714	8,694	315	501
193	All Other Expenses - Fixed	557	-	-	-	-	-	-	-	-	-
194	All Other Expenses - Variable	557	-	-	-	-	-	-	-	-	-
195	Subtotal - Other Power Supply Expenses		670,659	297,453	1,282	11,524	190,176	160,714	8,694	315	501

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196	**Transmission Operation Expenses**										
197	Operation Supervision and Engineering	560	419,171	185,912	801	7,203	118,863	100,448	5,434	197	313
198	Load Dispatching	561	19,910,336	8,830,693	38,053	342,131	5,645,905	4,771,225	258,101	9,365	14,864
199	Station Expenses	562	111,914	49,637	214	1,923	31,735	26,819	1,451	53	84
200	Overhead Line Expenses	563	(118)	(53)	(0)	(2)	(34)	(28)	(2)	(0)	(0)
201	Underground Line Expenses	564	-	-	-	-	-	-	-	-	-
202	Transmission of Electricity by Others	565	-	-	-	-	-	-	-	-	-
203	Miscellaneous Transmission Expenses	566	-	-	-	-	-	-	-	-	-
204	Rents	567	-	-	-	-	-	-	-	-	-
205	Subtotal - Transmission Operation Expenses		20,441,303	9,066,189	39,068	351,255	5,796,469	4,898,464	264,984	9,614	15,261
206	**Transmission Maintenance Expenses**										
207	Maintenance Supervision and Engineering	568	388,095	172,129	742	6,669	110,051	93,001	5,031	183	290
208	Maintenance of Structures	569	2,371,329	1,051,739	4,532	40,748	672,430	568,255	30,740	1,115	1,770
209	Maintenance of Station Equipment	570	233,432	103,533	446	4,011	66,194	55,939	3,026	110	174
210	Maintenance of Overhead Lines	571	579,737	257,127	1,108	9,962	164,394	138,926	7,515	273	433
211	Maintenance of Underground Lines	572	-	-	-	-	-	-	-	-	-
212	Maintenance of Miscellaneous Transmission Plant	573	-	-	-	-	-	-	-	-	-
213	Subtotal - Transmission Maintenance Expenses		3,572,594	1,584,528	6,828	61,390	1,013,068	856,121	46,312	1,680	2,667
214	**Distribution Operation Expenses**										
215	Operation Supervision and Engineering	580	1,941,263	1,445,917	31,150	104,467	251,537	102,206	5,474	198	315
216	Load Dispatching	581	256,022	113,552	489	4,399	72,599	61,352	3,319	120	191
217	Station Expenses	582	64,922	28,795	124	1,116	18,410	15,558	842	31	48
218	Overhead Line Expenses	583	-	-	-	-	-	-	-	-	-
219	Underground Line Expenses	584	-	-	-	-	-	-	-	-	-
220	Street Lighting and Signal System Expenses	585	-	-	-	-	-	-	-	-	-
221	Meter Expenses	586	1,157,573	958,903	23,112	74,049	100,568	933	9	-	-
222	Customer Installations Expenses	587	-	-	-	-	-	-	-	-	-
223	Miscellaneous Distribution Expenses	588	7,696,359	5,732,504	123,499	414,170	997,246	405,206	21,703	786	1,247
224	Rents	589	-	-	-	-	-	-	-	-	-
225	Subtotal - Distribution Operation Expenses		11,116,139	8,279,669	178,374	598,200	1,440,359	585,254	31,346	1,135	1,801
226	**Distribution Maintenance Expenses**										
227	Maintenance Supervision and Engineering	590	203,910	100,991	432	3,632	58,962	36,297	466	376	2,755
228	Maintenance of Structures	591	1,112,625	493,475	2,126	19,119	315,503	266,624	14,423	523	831
229	Maintenance of Station Equipment	592	815,274	361,593	1,558	14,009	231,185	195,369	10,569	383	609
230	Maintenance of Overhead Lines	593	8,631,137	4,420,389	18,881	156,668	2,534,496	1,452,425	-	18,660	29,619
231	Maintenance of Underground Lines	594	267,725	144,084	615	5,107	82,954	33,392	-	608	965
232	Maintenance of Line Transformers	595	-	-	-	-	-	-	-	-	-
233	Maintenance of Street Lighting and Signal Systems	596	115,832	-	-	-	-	-	-	-	115,832
234	Maintenance of Meters	597	-	-	-	-	-	-	-	-	-
235	Maintenance of Miscellaneous Distribution Plant	598	670,972	332,312	1,421	11,951	194,017	119,435	1,532	1,237	9,066
236	Subtotal - Distribution Maintenance Expenses		11,817,475	5,852,843	25,034	210,485	3,417,117	2,103,541	26,990	21,788	159,677
237	**Total Generation Production, Transmission, and Distributio**		47,618,170	25,080,682	250,586	1,232,855	11,857,189	8,604,093	378,326	34,533	179,907

CenterPoint Energy Indiana
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238	**Customer Accounts, Service, and Sales Expense**										
239	**Customer Account**										
240	Supervision	901	-	-	-	-	-	-	-	-	-
241	Meter Reading Expenses	902	152,498	-	-	-	-	151,073	1,425	-	-
242	Customer Billing and Accounting	903	1,155,579	988,399	23,822	73,491	68,934	784	7	-	141
243	Uncollectible Accounts	904	2,332,226	2,266,079	9,434	29,102	27,298	311	3	-	-
244	Misc. Customer Accounts Expenses	905	70,218	60,060	1,448	4,466	4,189	48	0	-	9
245	Subtotal - Customer Account		3,710,522	3,314,537	34,704	107,059	100,421	152,216	1,436	-	149
				60,060	1,448	4,466	4,189	48	0	-	9
246	**Customer Service & Information Expenses**			3,314,537	34,704	107,059	100,421	152,216	1,436	-	149
247	Supervision	907	-	-	-	-	-	-	-	-	-
248	Customer Assistance	908	14,596	12,484	301	928	871	10	0	-	2
249	Informational and Instructional Advertising	909	-	-	-	-	-	-	-	-	-
250	Miscellaneous Customer Service and Informational	910	329	281	7	21	20	0	0	-	0
251	Subtotal - Customer Service & Information Expenses		14,925	12,766	308	949	890	10	0	-	2
				281	7	21	20	0	0	-	0
252	**Sales Expenses**			12,766	308	949	890	10	0	-	2
253	Supervision	911	1,139,859	974,953	23,498	72,492	67,997	774	7	-	139
254	Demonstrating and Selling Expenses	912	13,698,564	11,716,759	282,398	871,188	817,167	9,298	88	-	1,667
255	Advertising Expenses	913	-	-	-	-	-	-	-	-	-
256	Miscellaneous Sales Expenses	916	-	-	-	-	-	-	-	-	-
257	Subtotal - Sales Expenses		14,838,423	12,691,712	305,896	943,679	885,163	10,071	95	-	1,805
				-	-	-	-	-	-	-	-
258	**Total Customer Accounts, Service, and Sales Expense**		18,563,870	16,019,015	340,907	1,051,688	986,475	162,297	1,531	-	1,956
259	**Administrative and General Expenses**										
260	Administrative and General Salaries	920	20,391,648	10,685,826	114,814	545,537	4,932,063	3,826,778	193,571	9,573	83,486
261	Office Supplies and Expenses	921	2,742,248	1,437,019	15,440	73,363	663,259	514,621	26,031	1,287	11,227
262	Administrative Expenses Transferred - Company	922	-	-	-	-	-	-	-	-	-
263	Outside Services Employed	923	340,000	178,170	1,914	9,096	82,235	63,806	3,227	160	1,392
264	Property Insurance	924	2,276,531	1,102,738	6,185	46,960	641,397	442,551	15,973	5,218	15,510
265	Injuries and Damages	925	4,010,388	2,101,562	22,580	107,290	969,980	752,606	38,069	1,883	16,419
266	Employee Pensions and Benefits	926	8,258,763	4,327,836	46,501	220,947	1,997,521	1,549,872	78,397	3,877	33,812
267	Regulatory Commission Expenses	928	625,972	300,579	1,534	12,121	178,667	124,627	4,551	1,163	2,731
268	General Advertising Expenses	930.1	26,394	12,674	65	511	7,534	5,255	192	49	115
269	Miscellaneous General Expense	930.2	6,482,923	3,140,289	17,612	133,728	1,826,520	1,260,261	45,486	14,858	44,168
270	Rents	931	4,690,415	2,457,916	26,409	125,483	1,134,456	880,222	44,524	2,202	19,203
271	Maintenance of General Plant	935	1,156,447	604,420	6,417	30,710	281,037	217,697	10,994	532	4,640
272	Total Administrative and General Expenses		51,001,731	26,349,029	259,471	1,305,745	12,714,668	9,638,297	461,015	40,802	232,702
273	**TOTAL OPERATION AND MAINTENANCE EXPENSE**		426,532,363	179,719,616	1,442,145	8,495,958	112,129,304	116,028,990	6,722,979	656,433	1,336,938

CenterPoint Energy Indiana
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274	**Adjustments, Depreciation and Amortization Expense**										
275	**Depreciation Expense**										
276	**Intangible Plant**			1,557,780	6,713	60,354	995,967	841,669	45,530	1,652	2,622
277	Organization	301	-	668,310	2,880	25,893	427,284	361,088	19,533	709	1,125
278	Franchises and Consents	302	-	-	-	-	-	-	-	-	-
279	Miscellaneous Intangible Plant	303	18,385,082	9,634,326	103,516	491,856	4,446,741	3,450,218	174,523	8,631	75,271
280	Subtotal - Intangible Plant		18,385,082	9,634,326	103,516	491,856	4,446,741	3,450,218	174,523	8,631	75,271
				-	-	-	-	-	-	-	-
281	**Other Production Plant**			-	-	-	-	-	-	-	-
282	Land and Land Rights	310	-	-	-	-	-	-	-	-	-
283	Structures and Improvements	311	5,849,994	2,662,608	8,998	98,763	1,751,721	1,268,352	59,553	-	-
284	Boiler Plant Equipment	312	22,728,275	10,344,709	34,959	383,711	6,805,749	4,927,775	231,372	-	-
285	Engines and Engine Driven Generators	313	-	-	-	-	-	-	-	-	-
286	Turbogenerator Units	314	1,076,327	489,887	1,656	18,171	322,295	233,361	10,957	-	-
287	Accessory Electric Equipment	315	2,032,532	925,101	3,126	34,314	608,621	440,679	20,691	-	-
288	Miscellaneous Power Plant Equipment	316	1,265,798	576,124	1,947	21,370	379,030	274,441	12,886	-	-
289	Asset Retirement Costs for Steam Production	317	-	-	-	-	-	-	-	-	-
290	Subtotal - Other Production Plant		32,952,926	14,998,429	50,686	556,329	9,867,415	7,144,607	335,459	-	-
				-	-	-	-	-	-	-	-
291	**Other Production Plant**			-	-	-	-	-	-	-	-
292	Land and Land Rights	340	-	-	-	-	-	-	-	-	-
293	Structures and Improvements	341	81,541	37,113	125	1,377	24,417	17,679	830	-	-
294	Fuel Holders, Producers and Accessories	342	81,617	37,148	126	1,378	24,440	17,696	831	-	-
295	Prime Movers	343	946,358	430,732	1,456	15,977	283,377	205,182	9,634	-	-
296	Generators	344	603,132	274,514	928	10,182	180,602	130,767	6,140	-	-
297	Accessory Electric Equipment	345	148,884	67,764	229	2,514	44,582	32,280	1,516	-	-
298	Miscellaneous Power Plant Equipment	346	24,352,532	11,083,984	37,458	411,133	7,292,115	5,279,934	247,907	-	-
299	Asset Retirement Costs for Other Production	347	-	-	-	-	-	-	-	-	-
300	Subtotal - Other Production Plant		26,214,065	11,931,256	40,321	442,560	7,849,532	5,683,538	266,858	-	-
				-	-	-	-	-	-	-	-
301	**Other Production Plant**			-	-	-	-	-	-	-	-
302	Land and Land Rights	350	143,300	63,557	274	2,462	40,635	34,340	1,858	67	107
303	Structures and Improvements	352	91,477	40,572	175	1,572	25,940	21,921	1,186	43	68
304	Station Equipment	353	3,720,931	1,650,319	7,112	63,939	1,055,132	891,668	48,235	1,750	2,778
305	Towers and Fixtures	354	17,043	7,559	33	293	4,833	4,084	221	8	13
306	Poles and Fixtures	355	6,806,804	3,018,975	13,009	116,965	1,930,182	1,631,153	88,238	3,201	5,082
307	Overhead Conductors and Devices	356	2,935,986	1,302,178	5,611	50,451	832,547	703,567	38,060	1,381	2,192
308	Underground Conduit	357	14,054	6,233	27	241	3,985	3,368	182	7	10
309	Underground Conductors and Devices	358	9,361	4,152	18	161	2,654	2,243	121	4	7
310	Road and Trails	359	-	-	-	-	-	-	-	-	-
311	ARO for Transmission Plant	359.1	-	-	-	-	-	-	-	-	-
312	Subtotal - Other Production Plant		13,738,956	6,093,544	26,258	236,085	3,895,908	3,292,343	178,100	6,462	10,257

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				-	-	-	-	-	-	-	-
313	**Distribution Plant**			-	-	-	-	-	-	-	-
314	Land and land rights	360	1,177	593	3	21	340	213	-	3	4
315	Structures and improvements	361	19,706	9,994	43	354	5,725	3,480	-	42	67
316	Station equipment	362	4,737,447	2,342,165	10,004	83,011	1,338,797	937,888	-	9,887	15,694
317	Storage battery equipment	363	-	-	-	-	-	-	-	-	-
318	Poles, Towers and Fixtures	364	15,005,586	7,699,180	32,886	272,875	4,415,133	2,501,423	-	32,501	51,588
319	Overhead Conductors and Devices	365	13,295,258	6,809,093	29,084	241,328	3,904,095	2,237,291	-	28,743	45,624
320	Underground conduit	366	1,015,632	546,591	2,335	19,372	314,691	126,673	-	2,307	3,662
321	Underground Conductors and Devices	367	3,435,606	1,848,969	7,898	65,531	1,064,514	428,500	-	7,805	12,389
322	Transformers and Transformer Installations	368	1,811,825	895,756	3,826	31,747	512,020	358,693	-	3,781	6,002
323	Services	369	3,025,715	2,310,217	55,681	306,528	350,085	3,174	30	-	-
324	Meters	370	1,858,813	1,539,791	37,112	118,908	161,490	1,498	14	-	-
325	Installations on customers premises	371	192,489	-	-	-	-	-	-	192,489	-
326	Street lighting and signal systems	373	431,653	-	-	-	-	-	-	-	431,653
327	Subtotal - Distribution Plant		44,830,908	24,002,350	178,871	1,139,676	12,066,891	6,598,834	44	277,559	566,683
				-	-	-	-	-	-	-	-
328	**General Plant**			-	-	-	-	-	-	-	-
329	Land and Land Rights	389	-	-	-	-	-	-	-	-	-
330	Structures and Improvements	390	1,139,965	597,375	6,419	30,497	275,720	213,930	10,821	535	4,667
331	Office Furniture and Equipment	391	1,446,588	758,055	8,145	38,701	349,882	271,472	13,732	679	5,922
332	Transportation Equipment	392	1,814,909	951,066	10,219	48,554	438,966	340,593	17,228	852	7,430
333	Stores Equipment	393	22,936	12,019	129	614	5,547	4,304	218	11	94
334	Tools, Shop and Garage Equipment	394	369,878	193,827	2,083	9,895	89,461	69,413	3,511	174	1,514
335	Laboratory Equipment	395	92,962	48,715	523	2,487	22,484	17,446	882	44	381
336	Power Operated Equipment	396	245,525	128,663	1,382	6,569	59,384	46,076	2,331	115	1,005
337	Communication Equipment	397	1,510,439	791,515	8,504	40,409	365,325	283,455	14,338	709	6,184
338	Miscellaneous Equipment	398	127,601	66,867	718	3,414	30,862	23,946	1,211	60	522
339	Miscellaneous Equipment-DLC	398	153,930	70,061	237	2,599	46,093	33,374	1,567	-	-
340	Subtotal - General Plant		6,924,734	3,618,162	38,359	183,738	1,683,725	1,304,010	65,840	3,179	27,720
				-	-	-	-	-	-	-	-
341	**Amortization Expense**			-	-	-	-	-	-	-	-
342	Regulatory Amortization - TDISC	407.4	7,935,299	4,035,270	26,424	184,949	2,165,479	1,345,727	22,781	39,879	114,791
343	Regulatory Amortization - CECA	407.4	1,079,962	491,542	1,661	18,233	323,383	234,149	10,994	-	-
344	Regulatory Amortization - ECA	407.4	25,643,336	11,671,490	39,443	432,925	7,678,634	5,559,797	261,048	-	-
345	Regulatory Amortization - AMI	407.4	1,643,527	1,405,754	33,882	104,523	98,042	1,116	11	-	200
346	Regulatory Amortization - CT	407.4	594,091	270,399	914	10,030	177,895	128,806	6,048	-	-
347	Investment Tax Credit Adjustments	407.4	-	-	-	-	-	-	-	-	-
348	Subtotal - Amortization Expense		36,896,216	17,874,455	102,323	750,659	10,443,433	7,269,595	300,880	39,879	114,991
349	**Total Adjustments, Depreciation and Amortization Expense**		179,942,886	88,152,522	540,335	3,800,903	50,253,646	34,743,144	1,321,704	335,709	794,922

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
Petitioner’s Exhibit No. 18, Attachment JDT-2: Allocated Cost of Service Study
Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
350	**Taxes**										
351	**Taxes Other Than Income Taxes**										
352	Taxes Other Than Income Taxes - Property	408.1	9,516,863	4,609,911	25,855	196,311	2,681,312	1,850,050	66,773	21,812	64,838
353	Taxes Other Than Income Taxes - Payroll	408.1	2,822,217	1,478,925	15,890	75,503	682,601	529,629	26,790	1,325	11,554
354	Taxes Other Than Income Taxes - Other	408.02	-	-	-	-	-	-	-	-	-
355	Taxes Other Than Income Taxes - Other	408.02	-	-	-	-	-	-	-	-	-
356	Investment Tax Credits		-	-	-	-	-	-	-	-	-
357	Subtotal - Taxes Other Than Income Taxes		12,339,079	6,088,836	41,745	271,814	3,363,913	2,379,679	93,563	23,136	76,392
358	**Income Taxes**										
359	State Income Tax	409.01	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
360	Federal Income Tax	409	9,973,261	4,788,953	24,443	193,118	2,846,599	1,985,613	72,505	18,525	43,504
361	Deferred Federal & State Income Taxes	410	2,307,513	1,117,745	6,269	47,599	650,126	448,574	16,190	5,289	15,721
362	Subtotal - Income Taxes		12,280,774	5,906,698	30,712	240,717	3,496,726	2,434,187	88,695	23,814	59,225
363	**Total Taxes**		24,619,853	11,995,535	72,457	512,531	6,860,639	4,813,866	182,259	46,950	135,617
364	**REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**										
365	**Test Year Expenses at Current Rates**		631,095,102	279,867,673	2,054,938	12,809,392	169,243,588	155,586,000	8,226,942	1,039,093	2,267,478
366	**Return on Rate Base**		199,125,094	95,615,731	488,032	3,855,776	56,834,906	39,644,541	1,447,632	369,877	868,599
367	**Gross Up Items**			-	-	-	-	-	-	-	-
368	Gross-up State Income Tax		5,793,129	2,781,740	14,198	112,176	1,653,493	1,153,375	42,116	10,761	25,270
369	Gross-up Federal Income Tax		23,611,140	11,337,579	57,868	457,196	6,739,165	4,700,828	171,652	43,858	102,994
370	Gross-up IURC Assessment		174,289	83,690	427	3,375	49,746	34,700	1,267	324	760
371	Gross-up Bad Debts		356,273	171,075	873	6,899	101,689	70,932	2,590	662	1,554
372	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETUR**		860,155,029	389,857,488	2,616,337	17,244,814	234,622,588	201,190,376	9,892,199	1,464,574	3,266,654

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
Petitioner's Exhibit No. 18, Attachment JDT-2: Allocated Cost of Service
Study Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
373	**INTERNAL ALLOCATION FACTORS**										
374	INT_STEAM_PROD_PT		774,486,722	352,505,393	1,191,275	13,075,311	231,912,090	167,918,427	7,884,226	0	0
375	INT_OTHER_PROD_PT		855,319,370	389,296,139	1,315,607	14,439,973	256,116,596	185,443,958	8,707,098	0	0
376	INT_TRANSMISSION_PT		574,404,982	254,761,841	1,097,811	9,870,341	162,882,018	137,647,879	7,446,104	270,162	428,826
377	INT_DIST_PLANT		1,346,647,831	709,689,734	5,027,435	33,731,313	363,401,643	201,550,464	1,222	8,511,942	24,734,078
378	INT_TOTAL_PLANT		3,903,417,227	1,890,792,021	10,604,590	80,518,536	1,099,761,750	758,812,968	27,387,476	8,946,173	26,593,713
379	INT_RATEBASE		2,820,468,760	1,354,330,471	6,912,634	54,614,396	805,027,000	561,537,411	20,504,700	5,239,054	12,303,095
380	INT_TRANS_OPS		20,022,132	8,880,277	38,267	344,052	5,677,606	4,798,015	259,550	9,417	14,948
381	INT_TRANS_MAINT		3,184,499	1,412,399	6,086	54,721	903,017	763,119	41,281	1,498	2,377
382	INT_DIST_OPS		1,478,517	1,101,249	23,725	79,564	191,577	77,842	4,169	151	240
383	INT_DIST_MAINT		10,942,593	5,419,540	23,181	194,903	3,164,137	1,947,810	24,992	20,175	147,855
384	INT_361-364		559,325,756	282,114,921	1,205,013	9,998,733	161,542,246	101,383,645	0	1,190,898	1,890,300
385	INT_364		297,854,492	152,825,448	652,772	5,416,448	87,638,508	49,652,190	0	645,125	1,024,001
386	INT_365		312,095,266	159,837,858	682,724	5,664,982	91,645,421	52,518,566	0	674,727	1,070,988
387	INT_367		165,164,611	88,888,042	379,672	3,150,375	51,175,844	20,599,861	0	375,225	595,591
388	INT_368		103,114,848	50,979,358	217,751	1,806,813	29,140,147	20,413,993	0	215,200	341,585
389	INT_STNS,POLES,LINES		869,881,492	441,171,985	1,884,402	15,636,042	252,740,364	153,630,314	0	1,862,328	2,956,056
390	INT_T&D_OH_CNDT		418,889,136	207,203,399	886,830	7,500,085	121,928,587	78,110,178	1,384,386	724,956	1,150,715
391	INT_LABOR		25,452,949	13,338,097	143,311	680,942	6,156,224	4,776,602	241,616	11,949	104,207
392	INT_REVREQ		860,155,029	389,857,488	2,616,337	17,244,814	234,622,588	201,190,376	9,892,199	1,464,574	3,266,654
393	INT_GENPT		153,998,437	80,487,669	854,481	4,089,530	37,424,355	28,989,699	1,463,968	70,852	617,883
394	INT_TOTAL_PLANT_EXCL INT		3,704,857,342	1,786,740,776	9,486,609	75,206,468	1,051,736,703	721,550,427	25,502,618	8,852,956	25,780,787
395	INT_DIST (60%)_TRANSM (40%)_PLANT		1,037,750,691	527,718,577	3,455,586	24,186,924	283,193,793	175,989,430	2,979,175	5,215,230	15,011,977
397	Operating Revenue										
398	Base Rate Revenue		267,328,655	132,139,578	530,561	5,953,227	75,824,903	48,031,238	1,868,205	1,152,148	1,828,794
399	Fuel Cost Revenue		202,463,492	70,924,387	386,972	3,167,056	56,507,591	66,334,390	4,045,017	424,413	673,667
400	Special Contract Revenue		30,156,859	13,668,324	91,728	604,600	8,225,820	7,053,693	346,818	51,348	114,528
401	Non-Firm Revenue		14,611,626	6,622,587	44,444	292,941	3,985,581	3,417,661	168,041	24,879	55,491
402	Forfeited Discounts		2,615,919	1,162,497	6,179	56,116	757,750	584,410	30,201	7,087	11,678
403	Reconnect Charge		237,837	226,325	1,642	5,065	4,751	54	1	-	-
404	Returned Check Charge		104,726	99,263	779	2,403	2,254	26	0	-	-
405	Securitization Fees		245,725	111,373	747	4,926	67,026	57,475	2,826	418	933
406	Interdepartmental Sales		100,367	45,490	305	2,012	27,377	23,476	1,154	171	381
407	Rent From Property		5,062,099	2,294,350	15,397	101,487	1,380,777	1,184,026	58,217	8,619	19,225
408	LRAM Incentive		500,000	226,620	1,521	10,024	136,384	116,950	5,750	851	1,899
409	Rider Revenue		118,109,906	59,668,199	479,352	3,587,192	38,038,775	15,410,774	750,947	29,159	145,507
410	Rider Revenue_Special Contract		10,993,441	4,982,678	33,439	220,402	2,998,656	2,571,367	126,430	18,718	41,750
411	Variable Production Revenue_Special Contract		4,870,592	1,767,260	9,296	78,617	1,390,814	1,510,021	89,455	9,713	15,417
412	Variable Production Revenue		18,054,808	6,551,059	34,459	291,427	5,155,612	5,597,499	331,601	36,004	57,149
413	Transmission Revenue		8,212,276	3,722,140	24,979	164,644	2,240,044	1,920,852	94,445	13,983	31,188
414	Fuel Cost Revenue_Special Contract		57,729,010	20,222,879	110,338	903,032	16,112,175	18,914,119	1,153,368	121,014	192,085
415	Total Operating Revenue		741,397,336	324,435,009	1,772,139	15,445,172	212,856,292	172,728,031	9,072,475	1898525.795	3189691.062
416	NET INCOME AT CURRENT RATES		110,302,234	44,567,337	(282,799)	2,635,781	43,612,704	17,142,031	845,534	859,433	922,214

Cause No. 45990

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
Petitioner's Exhibit No. 18, Attachment JDT-2: Allocated Cost of Service Study Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
1	**RATE BASE**								
2	**Plant in Service**								
3	**Intangible Plant**								
4	Organization	301.0	12,151	INT_LABOR					
5	Franchises and Consents	302.0	0						
6	Miscellaneous Intangible Plant	303.0	198,547,734	INT_LABOR					
7	Subtotal - Intangible Plant		198,559,885						
8	**Steam Production Plant**								
9	Land and Land Rights	310.0	1,976,433		PRODUCTION	DEMAND	4CP_Demand		
10	Structures and Improvements	311.0	96,772,607		PRODUCTION	DEMAND	4CP_Demand		
11	Boiler Plant Equipment	312.0	569,693,573		PRODUCTION	DEMAND	4CP_Demand		
12	Engines and Engine Driven Generators	313.0	0		PRODUCTION	DEMAND	4CP_Demand		
13	Turbogenerator Units	314.0	48,177,832		PRODUCTION	DEMAND	4CP_Demand		
14	Accessory Electric Equipment	315.0	33,226,393		PRODUCTION	DEMAND	4CP_Demand		
15	Miscellaneous Power Plant Equipment	316.0	24,639,884		PRODUCTION	DEMAND	4CP_Demand		
16	Asset Retirement Costs for Steam Production	317.0	0		PRODUCTION	DEMAND	4CP_Demand		
17	Subtotal - Steam Production Plant		774,486,722						
18	**Other Production Plant**								
19	Land and Land Rights	340.0	389,504		PRODUCTION	DEMAND	4CP_Demand		
20	Structures and Improvements	341.0	2,271,907		PRODUCTION	DEMAND	4CP_Demand		
21	Fuel Holders, Producers and Accessories	342.0	4,101,467		PRODUCTION	DEMAND	4CP_Demand		
22	Prime Movers	343.0	48,262,971		PRODUCTION	DEMAND	4CP_Demand		
23	Generators	344.0	17,496,247		PRODUCTION	DEMAND	4CP_Demand		
24	Accessory Electric Equipment	345.0	5,263,501		PRODUCTION	DEMAND	4CP_Demand		
25	Miscellaneous Power Plant Equipment	346.0	777,533,774		PRODUCTION	DEMAND	4CP_Demand		
26	Asset Retirement Costs for Other Production	347.0	0		PRODUCTION	DEMAND	4CP_Demand		
27	Subtotal - Other Production Plant		855,319,370						
28	**Transmission Plant**								
29	Land and Land Rights	350.0	19,334,962		TRANSMISSION	DEMAND	12CP_Demand		
30	Structures and Improvements	352.0	6,442,051		TRANSMISSION	DEMAND	12CP_Demand		
31	Station Equipment	353.0	196,875,807		TRANSMISSION	DEMAND	12CP_Demand		
32	Towers and Fixtures	354.0	4,622,707		TRANSMISSION	DEMAND	12CP_Demand		
33	Poles and Fixtures	355.0	237,797,966		TRANSMISSION	DEMAND	12CP_Demand		
34	Overhead Conductors and Devices	356.0	106,793,870		TRANSMISSION	DEMAND	12CP_Demand		
35	Underground Conduit	357.0	1,180,974		TRANSMISSION	DEMAND	12CP_Demand		
36	Underground Conductors and Devices	358.0	1,356,646		TRANSMISSION	DEMAND	12CP_Demand		
37	Road and Trails	359.0	0		TRANSMISSION	DEMAND	12CP_Demand		
38	ARO for Transmission Plant	359.1	0		TRANSMISSION	DEMAND	12CP_Demand		
39	Subtotal - Transmission Plant		574,404,982						

Cause No. 45990

CenterPoint Energy Indiana

Electric Class Cost of Service Study

12 Months Ended Dec 31, 2025

Petitioner's Exhibit No. 18, Attachment JDT-2: Allocated Cost of Service

Study Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
40	**Distribution Plant**								
41	Land and land rights	360.0	3,081,457	INT_361-364					
42	Structures and improvements	361.0	1,539,531	INT_STNS,POLES,LINES					
43	Station equipment	362.0	259,931,734		SUBSTATION	DEMAND	NCP_PRI		
44	Storage battery equipment	363.0	0						
45	Poles, Towers and Fixtures - PRI DEM	364.0	250,802,380		DIST PRIMARY	DEMAND	NCP_PRI		
46	Poles, Towers and Fixtures - PRI CUST	364.0	0		DIST PRIMARY	CUSTOMER			CUST_PRI
47	Poles, Towers and Fixtures - SEC DEM	364.0	47,052,112		DIST SECONDARY	DEMAND	NCP_SEC		
48	Poles, Towers and Fixtures - SEC CUST	364.0	0		DIST SECONDARY	CUSTOMER			CUST_SEC
49	Overhead Conductors and Devices - PRI DEM	365.0	265,280,976		DIST PRIMARY	DEMAND	NCP_PRI		
50	Overhead Conductors and Devices - PRI CUST	365.0	0		DIST PRIMARY	CUSTOMER			CUST_PRI
51	Overhead Conductors and Devices - SEC DEM	365.0	46,814,290		DIST SECONDARY	DEMAND	NCP_SEC		
52	Overhead Conductors and Devices - SEC CUST	365.0	0		DIST SECONDARY	CUSTOMER			CUST_SEC
53	Underground conduit	366.0	47,676,074	INT_367					
54	Underground Conductors and Devices - PRI DEM	367.0	104,053,705		DIST PRIMARY	DEMAND	NCP_PRI		
55	Underground Conductors and Devices - PRI CUST	367.0	0		DIST PRIMARY	CUSTOMER			CUST_PRI
56	Underground Conductors and Devices - SEC DEM	367.0	61,110,906		DIST SECONDARY	DEMAND	NCP_SEC		
57	Underground Conductors and Devices - SEC CUST	367.0	0		DIST SECONDARY	CUSTOMER			CUST_SEC
58	Transformers and Transformer Installations - DEM	368.0	103,114,848		TRANSFORMATION	DEMAND	NCP_PRI		
59	Transformers and Transformer Installations - CUST	368.0	0		TRANSFORMATION	CUSTOMER			CUST_SEC
60	Services	369.0	103,266,723		ONSITE & METERING	CUSTOMER			SERV
61	Meters	370.0	26,328,799		ONSITE & METERING	CUSTOMER			MTRS
62	Installations on customers premises	371.0	5,941,020		LIGHTING PLANT	CUSTOMER			OUTDOOR-LIGHT
63	Street lighting and signal systems	373.0	20,653,277		LIGHTING PLANT	CUSTOMER			STREET-LIGHT
64	Subtotal - Distribution Plant		1,346,647,831						
65	**General Plant**								
66	Land and Land Rights	389.0	2,309,376	INT_LABOR					
67	Structures and Improvements	390.0	56,222,863	INT_LABOR					
68	Office Furniture and Equipment	391.0	23,986,173	INT_LABOR					
69	Transportation Equipment	392.0	25,161,795	INT_LABOR					
70	Stores Equipment	393.0	688,773	INT_LABOR					
71	Tools, Shop and Garage Equipment	394.0	9,246,944	INT_LABOR					
72	Laboratory Equipment	395.0	1,859,238	INT_LABOR					
73	Power Operated Equipment	396.0	5,812,993	INT_LABOR					
74	Communication Equipment	397.0	22,869,808	INT_LABOR					
75	Miscellaneous Equipment	398.0	2,761,879	INT_LABOR					
76	Miscellaneous Equipment-DLC	398.0	3,078,597		PRODUCTION	DEMAND	4CP_Demand		
77	Subtotal - General Plant		153,998,437						
78	**Total Plant in Service**		3,903,417,227						

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
Petitioner's Exhibit No. 18, Attachment JDT-2: Allocated Cost of Service Study Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
79	**Accumulated Depreciation & Amortization**								
80	**Intangible Plant**								
81	Organization	301.0	0	INT_LABOR	-	-	-	-	-
82	Franchises and Consents	302.0	0	-	-	-	-	-	-
83	Miscellaneous Intangible Plant	303.0	(120,558,306)	INT_LABOR	-	-	-	-	-
84	Subtotal - Intangible Plant		(120,558,306)						
85	**Steam Production Plant**								
86	Land and Land Rights	310.0	142,880	-	PRODUCTION	DEMAND	4CP_Demand	-	-
87	Structures and Improvements	311.0	(46,698,062)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
88	Boiler Plant Equipment	312.0	(264,136,630)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
89	Engines and Engine Driven Generators	313.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
90	Turbogenerator Units	314.0	(36,101,462)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
91	Accessory Electric Equipment	315.0	(3,420,234)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
92	Miscellaneous Power Plant Equipment	316.0	(8,721,704)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
93	Asset Retirement Costs for Steam Production	317.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
94	Subtotal - Steam Production Plant		(358,935,213)						
95	**Other Production Plant**								
96	Land and Land Rights	340.0	38,004	-	PRODUCTION	DEMAND	4CP_Demand	-	-
97	Structures and Improvements	341.0	(2,231,173)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
98	Fuel Holders, Producers and Accessories	342.0	(4,631,843)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
99	Prime Movers	343.0	(42,171,802)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
100	Generators	344.0	(13,256,606)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
101	Accessory Electric Equipment	345.0	(4,116,286)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
102	Miscellaneous Power Plant Equipment	346.0	(16,519,696)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
103	Asset Retirement Costs for Other Production	347.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
104	Subtotal - Other Production Plant		(82,889,403)						
105	**Transmission Plant**								
106	Land and Land Rights	350.0	(4,213,024)	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
107	Structures and Improvements	352.0	(2,543,412)	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
108	Station Equipment	353.0	(55,183,260)	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
109	Towers and Fixtures	354.0	(5,214,294)	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
110	Poles and Fixtures	355.0	(55,473,356)	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
111	Overhead Conductors and Devices	356.0	(27,944,809)	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
112	Underground Conduit	357.0	(968,589)	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
113	Underground Conductors and Devices	358.0	(1,294,260)	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
114	Road and Trails	359.0	0	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
115	ARO for Transmission Plant	359.1	0	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
116	Subtotal - Transmission Plant		(152,835,002)						

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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
117	**Distribution Plant**								
118	Land and land rights	360.0	(20,815)	INT_361-364	-	-	-	-	-
119	Structures and improvements	361.0	(897,293)	INT_STNS,POLES,LINES	-	-	-	-	-
120	Station equipment	362.0	(44,601,013)	-	SUBSTATION	DEMAND	NCP_PRI	-	-
121	Storage battery equipment	363.0	0	-	-	-	-	-	-
122	Poles, Towers and Fixtures	364.0	(90,761,034)	INT_364					
123	Overhead Conductors and Devices	365.0	(91,322,510)	INT_365					
124	Underground conduit	366.0	(18,345,845)	INT_367	-	-	-	-	-
125	Underground Conductors and Devices	367.0	(51,477,871)	INT_367					
126	Transformers and Transformer Installations	368.0	(52,561,797)	INT_368					
127	Services	369.0	(71,529,816)	-	ONSITE & METERING	CUSTOMER	-	-	SERV
128	Meters	370.0	(2,976,324)	-	ONSITE & METERING	CUSTOMER	-	-	MTRS
129	Installations on customers premises	371.0	(2,944,632)	-	LIGHTING PLANT	CUSTOMER	-	-	OUTDOOR-LIGHT
130	Street lighting and signal systems	373.0	(12,598,490)	-	LIGHTING PLANT	CUSTOMER	-	-	STREET-LIGHT
131	Subtotal - Distribution Plant		(440,037,441)						
132	**General Plant**								
133	Land and Land Rights	389.0	(22,147)	INT_LABOR	-	-	-	-	-
134	Structures and Improvements	390.0	(17,518,991)	INT_LABOR	-	-	-	-	-
135	Office Furniture and Equipment	391.0	(15,258,932)	INT_LABOR	-	-	-	-	-
136	Transportation Equipment	392.0	(16,726,737)	INT_LABOR	-	-	-	-	-
137	Stores Equipment	393.0	(574,962)	INT_LABOR	-	-	-	-	-
138	Tools, Shop and Garage Equipment	394.0	(2,180,271)	INT_LABOR	-	-	-	-	-
139	Laboratory Equipment	395.0	(1,935,880)	INT_LABOR	-	-	-	-	-
140	Power Operated Equipment	396.0	(2,361,451)	INT_LABOR	-	-	-	-	-
141	Communication Equipment	397.0	(9,472,725)	INT_LABOR	-	-	-	-	-
142	Miscellaneous Equipment	398.0	(480,682)	INT_LABOR	-	-	-	-	-
143	Miscellaneous Equipment-DLC	398.0	(5,512,812)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
144	Subtotal - General Plant		(72,045,589)						
145	**Total Accumulated Depreciation & Amortization**		(1,227,300,954)						
146	**Other Rate Base Items**								
147	Fuel Stock & Expense	151.0	11,940,667		PRODUCTION	ENERGY		ENERGY	
148	Materials and Supplies (Generation Inventory)	154.0	41,360,961		PRODUCTION	DEMAND	12CP_Demand		
149	Allowance Inventory	158.0	1,282,707		PRODUCTION	DEMAND	12CP_Demand		
150	Stores Expense	163.0	311,332	INT_TOTAL_PLANT					
151	PISCC - AMI	182.3	10,585,830		CUST ACCTS & SRVC	CUSTOMER			CUST
152	PISCC - ECA	182.3	26,359,625		PRODUCTION	DEMAND	4CP_Demand		
153	PISCC - CECA	182.3	18,045,313		PRODUCTION	DEMAND	4CP_Demand		
154	PISCC - TDSIC	182.3	21,951,124	ST (60%)_TRANSM (40%)_PLANT					
155	PISCC - CT	182.3	12,514,927		PRODUCTION	DEMAND	4CP_Demand		
156	**Total Other Rate Base Items**		144,352,487						
157	**TOTAL RATE BASE**		2,820,468,760						

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12 Months Ended Dec 31, 2025
Petitioner's Exhibit No. 18, Attachment JDT-2: Allocated Cost of Service Study Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
158	**OPERATION AND MAINTENANCE EXPENSE**								
159	**Generation Production, Transmission, and Distribution Expense**								
160	**Steam Power Generation Operation Expenses**								
161	Operation Supervision and Engineering	500.0	743,496		PRODUCTION	DEMAND	12CP_Demand		
162	Fuel	501.0	260,192,501		FUEL EXPENSES	ENERGY		REV_ENERGY	
163	Fuel (Operation Related Expenses)	501.0	2,240,456		PRODUCTION	DEMAND	12CP_Demand		
164	Steam Expenses	502.0	1,969,108		PRODUCTION	DEMAND	12CP_Demand		
165	Steam Expenses - VPC	502.0	7,310,722		VPC	ENERGY		REV_PROPOSED_VP	
166	Electric Expenses	505.0	1,348,774		PRODUCTION	DEMAND	12CP_Demand		
167	Electric Expenses - VPC	505.0	165,000		VPC	ENERGY		REV_PROPOSED_VP	
168	Miscellaneous Steam Power Expenses	506.0	2,163,147		PRODUCTION	DEMAND	12CP_Demand		
169	Miscellaneous Steam Power Expenses - VPC	506.0	299,500		VPC	ENERGY		REV_PROPOSED_VP	
170	Rents	507.0	0		PRODUCTION	DEMAND	12CP_Demand		
171	Allowances	509.0	3,519,952		PRODUCTION	DEMAND	12CP_Demand		
172	Subtotal - Steam Power Generation Operation Expenses		279,952,656						
173	**Steam Power Generation Maintenance Expenses**								
174	Maintenance Supervision and Engineering	510.0	492,730		PRODUCTION	DEMAND	12CP_Demand		
175	Maintenance of Structures	511.0	1,494,465		PRODUCTION	DEMAND	12CP_Demand		
176	Maintenance of Boiler Plant	512.0	6,725,481		PRODUCTION	DEMAND	12CP_Demand		
177	Maintenance of Boiler Plant-VPC	512.0	500,200		VPC	ENERGY		REV_PROPOSED_VP	
178	Maintenance of Electric Plant	513.0	3,512,286		PRODUCTION	DEMAND	12CP_Demand		
179	Maintenance of Miscellaneous Steam Plant	514.0	1,506,822		PRODUCTION	DEMAND	12CP_Demand		
180	Subtotal - Steam Power Generation Maintenance Expenses		14,231,984						
181	**Other Power Generation Operation Expenses**								
182	Operations Supervision and Engineering	546.0	20,563		PRODUCTION	DEMAND	12CP_Demand		
183	Generation Expenses	548.0	5,608,351		PRODUCTION	DEMAND	12CP_Demand		
184	Miscellaneous Other Power Generation Expenses	549.0	917,282		PRODUCTION	DEMAND	12CP_Demand		
185	Subtotal - Other Power Generation Operation Expenses		6,546,196						
186	**Other Power Generation Maintenance Expenses**								
187	Maintenance Supervision and Engineering	551.0	1		PRODUCTION	DEMAND	12CP_Demand		
188	Maintenance of Structures	552.0	15,000		PRODUCTION	DEMAND	12CP_Demand		
189	Maintenance of Generating and Electric Plant	553.0	8,602,756		PRODUCTION	DEMAND	12CP_Demand		
190	Subtotal - Other Power Generation Maintenance Expenses		8,617,756						
191	**Other Power Supply Expenses**								
192	System Control and Load Dispatching	556.0	670,659		PRODUCTION	DEMAND	12CP_Demand		
193	All Other Expenses - Fixed	557.0	0						
194	All Other Expenses - Variable	557.0	0						
195	Subtotal - Other Power Supply Expenses		670,659						

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Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
196	**Transmission Operation Expenses**								
197	Operation Supervision and Engineering	560.0	419,171		TRANSMISSION	DEMAND	12CP_Demand		
198	Load Dispatching	561.0	19,910,336		TRANSMISSION	DEMAND	12CP_Demand		
199	Station Expenses	562.0	111,914		TRANSMISSION	DEMAND	12CP_Demand		
200	Overhead Line Expenses	563.0	(118)		TRANSMISSION	DEMAND	12CP_Demand		
201	Underground Line Expenses	564.0	0						
202	Transmission of Electricity by Others	565.0	0						
203	Miscellaneous Transmission Expenses	566.0	0						
204	Rents	567.0	0						
205	Subtotal - Transmission Operation Expenses		20,441,303						
206	**Transmission Maintenance Expenses**								
207	Maintenance Supervision and Engineering	568.0	388,095		TRANSMISSION	DEMAND	12CP_Demand		
208	Maintenance of Structures	569.0	2,371,329		TRANSMISSION	DEMAND	12CP_Demand		
209	Maintenance of Station Equipment	570.0	233,432		TRANSMISSION	DEMAND	12CP_Demand		
210	Maintenance of Overhead Lines	571.0	579,737		TRANSMISSION	DEMAND	12CP_Demand		
211	Maintenance of Underground Lines	572.0	0						
212	Maintenance of Miscellaneous Transmission Plant	573.0	0						
213	Subtotal - Transmission Maintenance Expenses		3,572,594						
214	**Distribution Operation Expenses**								
215	Operation Supervision and Engineering	580.0	1,941,263	INT_DIST_OPS					
216	Load Dispatching	581.0	256,022		DIST PRIMARY	DEMAND	12CP_Demand		
217	Station Expenses	582.0	64,922		SUBSTATION	DEMAND	12CP_Demand		
218	Overhead Line Expenses	583.0	0	INT_365					
219	Underground Line Expenses	584.0	0	INT_367					
220	Street Lighting and Signal System Expenses	585.0	0		LIGHTING PLANT	CUSTOMER			STREET-LIGHT
221	Meter Expenses	586.0	1,157,573		ONSITE & METERING	CUSTOMER			MTRS
222	Customer Installations Expenses	587.0	0		ONSITE & METERING	CUSTOMER			MTRS
223	Miscellaneous Distribution Expenses	588.0	7,696,359	INT_DIST_OPS					
224	Rents	589.0	0	INT_DIST_OPS					
225	Subtotal - Distribution Operation Expenses		11,116,139						
226	**Distribution Maintenance Expenses**								
227	Maintenance Supervision and Engineering	590.0	203,910	INT_DIST_MAINT					
228	Maintenance of Structures	591.0	1,112,625		DIST PRIMARY	DEMAND	12CP_Demand		
229	Maintenance of Station Equipment	592.0	815,274		DIST PRIMARY	DEMAND	12CP_Demand		
230	Maintenance of Overhead Lines	593.0	8,631,137	INT_365					
231	Maintenance of Underground Lines	594.0	267,725	INT_367					
232	Maintenance of Line Transformers	595.0	0						
233	Maintenance of Street Lighting and Signal Systems	596.0	115,832		LIGHTING PLANT	CUSTOMER			STREET-LIGHT
234	Maintenance of Meters	597.0	0		ONSITE & METERING	CUSTOMER			MTRS
235	Maintenance of Miscellaneous Distribution Plant	598.0	670,972	INT_DIST_MAINT					
236	Subtotal - Distribution Maintenance Expenses		11,817,475						
237	**Total Generation Production, Transmission, and Distribution Expense**		47,618,170						

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Petitioner's Exhibit No. 18, Attachment JDT-2: Allocated Cost of Service
Study Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
238	**Customer Accounts, Service, and Sales Expense**								
239	**Customer Account**								
240	Supervision	901.0	0						
241	Meter Reading Expenses	902.0	152,498		CUST ACCTS & SRVC	CUSTOMER			MTR_READ
242	Customer Billing and Accounting	903.0	1,155,579		CUST ACCTS & SRVC	CUSTOMER			CUST
243	Uncollectible Accounts	904.0	2,332,226		CUST ACCTS & SRVC	CUSTOMER			UNCOLL
244	Misc. Customer Accounts Expenses	905.0	70,218		CUST ACCTS & SRVC	CUSTOMER			CUST
245	Subtotal - Customer Account		3,710,522						
246	**Customer Service & Information Expenses**								
247	Supervision	907.0	0						
248	Customer Assistance	908.0	14,596		CUST ACCTS & SRVC	CUSTOMER			CUST
249	Informational and Instructional Advertising	909.0	0						
250	Miscellaneous Customer Service and Informational	910.0	329		CUST ACCTS & SRVC	CUSTOMER			CUST
251	Subtotal - Customer Service & Information Expenses		14,925						
252	**Sales Expenses**								
253	Supervision	911.0	1,139,859		CUST ACCTS & SRVC	CUSTOMER			CUST
254	Demonstrating and Selling Expenses	912.0	13,698,564		CUST ACCTS & SRVC	CUSTOMER			CUST
255	Advertising Expenses	913.0	0						
256	Miscellaneous Sales Expenses	916.0	0						
257	Subtotal - Sales Expenses		14,838,423						
258	**Total Customer Accounts, Service, and Sales Expense**		18,563,870						

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Petitioner's Exhibit No. 18, Attachment JDT-2: Allocated Cost of Service Study Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
259	**Administrative and General Expenses**								
260	Administrative and General Salaries	920.0	20,391,648	INT_LABOR					
261	Office Supplies and Expenses	921.0	2,742,248	INT_LABOR					
262	Administrative Expenses Transferred - Company	922.0	0						
263	Outside Services Employed	923.0	340,000	INT_LABOR					
264	Property Insurance	924.0	2,276,531	INT_TOTAL_PLANT					
265	Injuries and Damages	925.0	4,010,388	INT_LABOR					
266	Employee Pensions and Benefits	926.0	8,258,763	INT_LABOR					
267	Regulatory Commission Expenses	928.0	625,972	INT_RATEBASE					
268	General Advertising Expenses	930.1	26,394	INT_RATEBASE					
269	Miscellaneous General Expense	930.2	6,482,923	INT_TOTAL_PLANT					
270	Rents	931.0	4,690,415	INT_LABOR					
271	Maintenance of General Plant	935.0	1,156,447	INT_GENPT					
272	**Total Administrative and General Expenses**		51,001,731						
273	**TOTAL OPERATION AND MAINTENANCE EXPENSE**		426,532,363						
274	**Adjustments, Depreciation and Amortization Expense**								
275	**Depreciation Expense**								
276	**Intangible Plant**								
277	Organization	301.0	0	INT_LABOR	-	-	-	-	-
278	Franchises and Consents	302.0	0	-	-	-	-	-	-
279	Miscellaneous Intangible Plant	303.0	18,385,082	INT_LABOR	-	-	-	-	-
280	Subtotal - Intangible Plant		18,385,082						
281	**Other Production Plant**								
282	Land and Land Rights	310.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
283	Structures and Improvements	311.0	5,849,994	-	PRODUCTION	DEMAND	4CP_Demand	-	-
284	Boiler Plant Equipment	312.0	22,728,275	-	PRODUCTION	DEMAND	4CP_Demand	-	-
285	Engines and Engine Driven Generators	313.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
286	Turbogenerator Units	314.0	1,076,327	-	PRODUCTION	DEMAND	4CP_Demand	-	-
287	Accessory Electric Equipment	315.0	2,032,532	-	PRODUCTION	DEMAND	4CP_Demand	-	-
288	Miscellaneous Power Plant Equipment	316.0	1,265,798	-	PRODUCTION	DEMAND	4CP_Demand	-	-
289	Asset Retirement Costs for Steam Production	317.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
290	Subtotal - Other Production Plant		32,952,926						
291	**Other Production Plant**								
292	Land and Land Rights	340.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
293	Structures and Improvements	341.0	81,541	-	PRODUCTION	DEMAND	4CP_Demand	-	-
294	Fuel Holders, Producers and Accessories	342.0	81,617	-	PRODUCTION	DEMAND	4CP_Demand	-	-
295	Prime Movers	343.0	946,358	-	PRODUCTION	DEMAND	4CP_Demand	-	-
296	Generators	344.0	603,132	-	PRODUCTION	DEMAND	4CP_Demand	-	-
297	Accessory Electric Equipment	345.0	148,884	-	PRODUCTION	DEMAND	4CP_Demand	-	-
298	Miscellaneous Power Plant Equipment	346.0	24,352,532	-	PRODUCTION	DEMAND	4CP_Demand	-	-
299	Asset Retirement Costs for Other Production	347.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
300	Subtotal - Other Production Plant		26,214,065						

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Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
301	**Other Production Plant**								
302	Land and Land Rights	350.0	143,300	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
303	Structures and Improvements	352.0	91,477	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
304	Station Equipment	353.0	3,720,931	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
305	Towers and Fixtures	354.0	17,043	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
306	Poles and Fixtures	355.0	6,806,804	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
307	Overhead Conductors and Devices	356.0	2,935,986	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
308	Underground Conduit	357.0	14,054	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
309	Underground Conductors and Devices	358.0	9,361	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
310	Road and Trails	359.0	0	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
311	ARO for Transmission Plant	359.1	0	-	TRANSMISSION	DEMAND	12CP_Demand	-	-
312	Subtotal - Other Production Plant		13,738,956						
313	**Distribution Plant**								
314	Land and land rights	360.0	1,177	INT_361-364	-	-	-	-	-
315	Structures and improvements	361.0	19,706	INT_STNS,POLES,LINES	-	-	-	-	-
316	Station equipment	362.0	4,737,447	-	SUBSTATION	DEMAND	NCP_PRI	-	-
317	Storage battery equipment	363.0	0	-	-	-	-	-	-
318	Poles, Towers and Fixtures	364.0	15,005,586	INT_364	-	-	-	-	-
319	Overhead Conductors and Devices	365.0	13,295,258	INT_365	-	-	-	-	-
320	Underground conduit	366.0	1,015,632	INT_367	-	-	-	-	-
321	Underground Conductors and Devices	367.0	3,435,606	INT_367	-	-	-	-	-
322	Transformers and Transformer Installations	368.0	1,811,825	INT_368	-	-	-	-	-
323	Services	369.0	3,025,715	-	ONSITE & METERING	CUSTOMER	-	-	SERV
324	Meters	370.0	1,858,813	-	ONSITE & METERING	CUSTOMER	-	-	MTRS
325	Installations on customers premises	371.0	192,489	-	LIGHTING PLANT	CUSTOMER	-	-	OUTDOOR-LIGHT
326	Street lighting and signal systems	373.0	431,653	-	LIGHTING PLANT	CUSTOMER	-	-	STREET-LIGHT
327	Subtotal - Distribution Plant		44,830,908						
328	**General Plant**								
329	Land and Land Rights	389.0	0	INT_LABOR	-	-	-	-	-
330	Structures and Improvements	390.0	1,139,965	INT_LABOR	-	-	-	-	-
331	Office Furniture and Equipment	391.0	1,446,588	INT_LABOR	-	-	-	-	-
332	Transportation Equipment	392.0	1,814,909	INT_LABOR	-	-	-	-	-
333	Stores Equipment	393.0	22,936	INT_LABOR	-	-	-	-	-
334	Tools, Shop and Garage Equipment	394.0	369,878	INT_LABOR	-	-	-	-	-
335	Laboratory Equipment	395.0	92,962	INT_LABOR	-	-	-	-	-
336	Power Operated Equipment	396.0	245,525	INT_LABOR	-	-	-	-	-
337	Communication Equipment	397.0	1,510,439	INT_LABOR	-	-	-	-	-
338	Miscellaneous Equipment	398.0	127,601	INT_LABOR	-	-	-	-	-
339	Miscellaneous Equipment-DLC	398.0	153,930	-	PRODUCTION	DEMAND	4CP_Demand	-	-
340	Subtotal - General Plant		6,924,734						

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Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
341	**Amortization Expense**								
342	Regulatory Amortization - TDISC	407.4	7,935,299	ST (60%)_TRANSM (40%)_PLANT					
343	Regulatory Amortization - CECA	407.4	1,079,962		PRODUCTION	DEMAND	4CP_Demand		
344	Regulatory Amortization - ECA	407.4	25,643,336		PRODUCTION	DEMAND	4CP_Demand		
345	Regulatory Amortization - AMI	407.4	1,643,527		CUST ACCTS & SRVC	CUSTOMER			CUST
346	Regulatory Amortization - CT	407.4	594,091		PRODUCTION	DEMAND	4CP_Demand		
347	Investment Tax Credit Adjustments	407.4	0		PRODUCTION	DEMAND	4CP_Demand		
348	Subtotal - Amortization Expense		36,896,216						
349	**Total Adjustments, Depreciation and Amortization Expense**		179,942,886						
350	**Taxes**								
351	**Taxes Other Than Income Taxes**								
352	Taxes Other Than Income Taxes - Property	408.1	9,516,863	INT_TOTAL_PLANT					
353	Taxes Other Than Income Taxes - Payroll	408.1	2,822,217	INT_LABOR					
354	Taxes Other Than Income Taxes - Other	408.0	0						
355	Taxes Other Than Income Taxes - Other	408.0	0						
356	Investment Tax Credits		0	INT_RATEBASE					
357	Subtotal - Taxes Other Than Income Taxes		12,339,079						
358	**Income Taxes**								
359	State Income Tax	409.0	(0)	INT_RATEBASE					
360	Federal Income Tax	409.0	9,973,261	INT_RATEBASE					
361	Deferred Federal & State Income Taxes	410.0	2,307,513	INT_TOTAL_PLANT					
362	Subtotal - Income Taxes		12,280,774						
363	**Total Taxes**		24,619,853						
364	**REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**								
365	**Test Year Expenses at Current Rates**		631,095,102	n/a	n/a	n/a	n/a	n/a	n/a
366	**Return on Rate Base**		199,125,094	INT_RATEBASE					
367	**Gross Up Items**								
368	Gross-up State Income Tax		5,793,129	INT_RATEBASE					
369	Gross-up Federal Income Tax		23,611,140	INT_RATEBASE					
370	Gross-up IURC Assessment		174,289	INT_RATEBASE					
371	Gross-up Bad Debts		356,273	INT_RATEBASE					
372	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		**860,155,029**						

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Petitioner's Exhibit No. 18, Attachment JDT-2: Allocated Cost of Service Study
Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
373	**INTERNAL ALLOCATION FACTORS**								
374	INT_STEAM_PROD_PT		774,486,722						
375	INT_OTHER_PROD_PT		855,319,370						
376	INT_TRANSMISSION_PT		574,404,982						
377	INT_DIST_PLANT		1,346,647,831						
378	INT_TOTAL_PLANT		3,903,417,227						
379	INT_RATEBASE		2,820,468,760						
380	INT_TRANS_OPS		20,022,132						
381	INT_TRANS_MAINT		3,184,499						
382	INT_DIST_OPS		1,478,517						
383	INT_DIST_MAINT		10,942,593						
384	INT_361-364		559,325,756						
385	INT_364		297,854,492						
386	INT_365		312,095,266						
387	INT_367		165,164,611						
388	INT_368		103,114,848						
389	INT_STNS,POLES,LINES		869,881,492						
390	INT_T&D_OH_CNDT		418,889,136						
391	INT_LABOR		25,452,949						
392	INT_REVREQ		860,155,029						
393	INT_GENPT		153,998,437						
394	INT_TOTAL_PLANT_EXCL INT		3,704,857,342						
395	INT_DIST (60%)_TRANSM (40%)_PLANT		1,037,750,691						

Cause No. 45990

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
Petitioner's Exhibit No. 18, Attachment JDT-2: Allocated Cost of Service Study
Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
				Revenue/Margin Allocation Factor	Revenue Category				
397	**Operating Revenue**								
398	Base Rate Revenue		267,328,655	REV	Base Rate Revenue				
399	Fuel Cost Revenue		202,463,492	REV_ENERGY	Fuel Cost Revenue				
400	Special Contract Revenue		30,156,859	INT_REVREQ	Special Contract Revenue				
401	Non-Firm Revenue		14,611,626	INT_REVREQ	Sale for Resale and Transmission Revenue				
402	Forfeited Discounts		2,615,919	REV_FORFEITED	Other Revenue				
403	Reconnect Charge		237,837	REV_RECONNECT	Other Revenue				
404	Returned Check Charge		104,726	REV_NFS	Other Revenue				
405	Securitization Fees		245,725	INT_REVREQ	Other Revenue				
406	Interdepartmental Sales		100,367	INT_REVREQ	Other Revenue				
407	Rent From Property		5,062,099	INT_REVREQ	Other Revenue				
408	LRAM Incentive		500,000	INT_REVREQ	Other Revenue				
409	Rider Revenue		118,109,906	REV_RIDER	Rider Revenue				
410	Rider Revenue_Special Contract		10,993,441	INT_REVREQ	Special Contract Revenue				
411	Variable Production Revenue_Special Contract		4,870,592	REV_VP	Special Contract Revenue				
412	Variable Production Revenue		18,054,808	REV_VP	Variable Production Revenue				
413	Transmission Revenue		8,212,276	INT_REVREQ	Sale for Resale and Transmission Revenue				
414	Fuel Cost Revenue_Special Contract		57,729,010	REV_ENERGY	Fuel Cost Revenue_Special Contract				
415	**Total Operating Revenue**		741,397,336						
416	**NET INCOME AT CURRENT RATES**		110,302,234						
417	**EARNINGS (DEFICIENCY)/SURPLUS**		(88,822,861)						
418	**REQUIRED INCOME INCREASE/(DECREASE)**		88,822,861						
419	**REVENUE GROSS-UP**		29,934,832						
420	**REQUIRED REVENUE INCREASE/(DECREASE)**		118,757,693						

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
Petitioner's Exhibit No. 18, Attachment JDT-2: Allocated Cost of Service Study Schedule 5 - Allocation Factors (External, Functionalization & Classification, and Internal)

Line No.	Category Description	Total System	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
1	**Allocation Factor Basis**									
2	INT_STEAM_PROD_PT	774,486,722	352,505,393	1,191,275	13,075,311	231,912,090	167,918,427	7,884,226	-	-
3	INT_OTHER_PROD_PT	855,319,370	389,296,139	1,315,607	14,439,973	256,116,596	185,443,958	8,707,098	-	-
4	INT_TRANSMISSION_PT	574,404,982	254,761,841	1,097,811	9,870,341	162,882,018	137,647,879	7,446,104	270,162	428,826
5	INT_DIST_PLANT	1,346,647,831	709,689,734	5,027,435	33,731,313	363,401,643	201,550,464	1,222	8,511,942	24,734,078
6	INT_TOTAL_PLANT	3,903,417,227	1,890,792,021	10,604,590	80,518,536	1,099,761,750	758,812,968	27,387,476	8,946,173	26,593,713
7	INT_RATEBASE	2,820,468,760	1,354,330,471	6,912,634	54,614,396	805,027,000	561,537,411	20,504,700	5,239,054	12,303,095
8	INT_TRANS_OPS	20,022,132	8,880,277	38,267	344,052	5,677,606	4,798,015	259,550	9,417	14,948
9	INT_TRANS_MAINT	3,184,499	1,412,399	6,086	54,721	903,017	763,119	41,281	1,498	2,377
10	INT_DIST_OPS	1,478,517	1,101,249	23,725	79,564	191,577	77,842	4,169	151	240
11	INT_DIST_MAINT	10,942,593	5,419,540	23,181	194,903	3,164,137	1,947,810	24,992	20,175	147,855
12	INT_361-364	559,325,756	282,114,921	1,205,013	9,998,733	161,542,246	101,383,645	-	1,190,898	1,890,300
13	INT_364	297,854,492	152,825,448	652,772	5,416,448	87,638,508	49,652,190	-	645,125	1,024,001
14	INT_365	312,095,266	159,837,858	682,724	5,664,982	91,645,421	52,518,566	-	674,727	1,070,988
15	INT_367	165,164,611	88,888,042	379,672	3,150,375	51,175,844	20,599,861	-	375,225	595,591
16	INT_368	103,114,848	50,979,358	217,751	1,806,813	29,140,147	20,413,993	-	215,200	341,585
17	INT_STNS,POLES,LINES	869,881,492	441,171,985	1,884,402	15,636,042	252,740,364	153,630,314	-	1,862,328	2,956,056
18	INT_T&D_OH_CNDT	418,889,136	207,203,399	886,830	7,500,085	121,928,587	78,110,178	1,384,386	724,956	1,150,715
19	INT_LABOR	2545294946%	1333809746%	14331143%	68094224%	615622381%	477660224%	24161574%	1194930%	10420725%
20	INT_REVREQ	860,155,029	389,857,488	2,616,337	17,244,814	234,622,588	201,190,376	9,892,199	1,464,574	3,266,654
21	INT_GENPT	153,998,437	80,487,669	854,481	4,089,530	37,424,355	28,989,699	1,463,968	70,852	617,883
22	INT_TOTAL_PLANT_EXCL INT	3,704,857,342	1,786,740,776	9,486,609	75,206,468	1,051,736,703	721,550,427	25,502,618	8,852,956	25,780,787
23	INT_DIST (60%)_TRANSM (40%)_PLANT	1,037,750,691	527,718,577	3,455,586	24,186,924	283,193,793	175,989,430	2,979,175	5,215,230	15,011,977
24	**Allocation Factor %**									
25	INT_STEAM_PROD_PT	100.0%	45.5%	0.2%	1.7%	29.9%	21.7%	1.0%	0.0%	0.0%
26	INT_OTHER_PROD_PT	100.0%	45.5%	0.2%	1.7%	29.9%	21.7%	1.0%	0.0%	0.0%
27	INT_TRANSMISSION_PT	100.0%	44.4%	0.2%	1.7%	28.4%	24.0%	1.3%	0.0%	0.1%
28	INT_DIST_PLANT	100.0%	52.7%	0.4%	2.5%	27.0%	15.0%	0.0%	0.6%	1.8%
29	INT_TOTAL_PLANT	100.0%	48.4%	0.3%	2.1%	28.2%	19.4%	0.7%	0.2%	0.7%
30	INT_RATEBASE	100.0%	48.0%	0.2%	1.9%	28.5%	19.9%	0.7%	0.2%	0.4%
31	INT_TRANS_OPS	100.0%	44.4%	0.2%	1.7%	28.4%	24.0%	1.3%	0.0%	0.1%
32	INT_TRANS_MAINT	100.0%	44.4%	0.2%	1.7%	28.4%	24.0%	1.3%	0.0%	0.1%
33	INT_DIST_OPS	100.0%	74.5%	1.6%	5.4%	13.0%	5.3%	0.3%	0.0%	0.0%
34	INT_DIST_MAINT	100.0%	49.5%	0.2%	1.8%	28.9%	17.8%	0.2%	0.2%	1.4%
35	INT_361-364	100.0%	50.4%	0.2%	1.8%	28.9%	18.1%	0.0%	0.2%	0.3%
36	INT_364	100.0%	51.3%	0.2%	1.8%	29.4%	16.7%	0.0%	0.2%	0.3%
37	INT_365	100.0%	51.2%	0.2%	1.8%	29.4%	16.8%	0.0%	0.2%	0.3%
38	INT_367	100.0%	53.8%	0.2%	1.9%	31.0%	12.5%	0.0%	0.2%	0.4%
39	INT_368	100.0%	49.4%	0.2%	1.8%	28.3%	19.8%	0.0%	0.2%	0.3%
40	INT_STNS,POLES,LINES	100.0%	50.7%	0.2%	1.8%	29.1%	17.7%	0.0%	0.2%	0.3%
41	INT_T&D_OH_CNDT	100.0%	49.5%	0.2%	1.8%	29.1%	18.6%	0.3%	0.2%	0.3%
42	INT_LABOR	100.0%	52.4%	0.6%	2.7%	24.2%	18.8%	0.9%	0.0%	0.4%
43	INT_REVREQ	100.0%	45.3%	0.3%	2.0%	27.3%	23.4%	1.2%	0.2%	0.4%
44	INT_GENPT	100.0%	52.3%	0.6%	2.7%	24.3%	18.8%	1.0%	0.0%	0.4%
45	INT_TOTAL_PLANT_EXCL INT	100.0%	48.2%	0.3%	2.0%	28.4%	19.5%	0.7%	0.2%	0.7%
46	INT_DIST (60%)_TRANSM (40%)_PLANT	100.0%	50.9%	0.3%	2.3%	27.3%	17.0%	0.3%	0.5%	1.4%

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CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18, Attachment JDT-2: Allocated Cost of Service Study
Schedule 5 - External Allocation Factors

No.	Code	Description	Total	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	CUSTOMER EXTERNAL ALLOCATORS										
1	**CUST**		100.0%	85.5%	2.1%	6.4%	6.0%	0.1%	0.0%	0.0%	0.0%
		Number Customers	156,171	133,577	3,219	9,932	9,316	106	1	-	19
2	**CUST-BILL**		100.0%	85.5%	2.1%	6.4%	6.0%	0.1%	0.0%	0.0%	0.0%
		Number Customers Bills	1,873,820	1,602,925	38,634	119,184	111,793	1,272	12		
3	**CUST_PRI**		100.0%	85.5%	2.1%	6.4%	6.0%	0.1%	0.0%	0.0%	0.0%
		Number of Customers Using Primary System	156,146	133,577	3,219	9,932	9,316	101	-		
4	**CUST_SEC**		100.0%	85.6%	2.1%	6.4%	5.9%	0.0%	0.0%	0.0%	0.0%
		Number of Customers Using Secondary System	155,982	133,577	3,219	9,932	9,254	-	-		
5	**MTRS**		100.0%	82.8%	2.0%	6.4%	8.7%	0.1%	0.0%	0.0%	0.0%
		Relative Weighting Factor		1.00	1.00	1.04	1.50	1.23	1.23		
		Relative Cost	161,252	133,577	3,219	10,315	14,009	130	1		
6	**SERV**		100.0%	76.4%	1.8%	10.1%	11.6%	0.1%	0.0%	0.0%	0.0%
		Relative Weighting Factor		1.00	1.00	1.78	2.17	1.73	1.73		
		Relative Cost	174,947	133,577	3,219	17,723	20,242	184	2		
7	**STREET-LIGHT**		100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
		Street Lights	1	-	-	-	-	-	-	-	1
8	**OUTDOOR-LIGHT**		100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%
		Outdoor Lighting	1	-	-	-	-	-	-	1	-
9	**MTR_READ**		100.0%	0.0%	0.0%	0.0%	0.0%	99.1%	0.9%	0.0%	0.0%
		ACCT - 902_Meter reading expenses	107					106	1		
10	**UNCOLL**		100.0%	97.2%	0.4%	1.2%	1.2%	0.0%	0.0%	0.0%	0.0%
		ACCT - 904_Uncollectible accounts	(2,385,325)	(2,317,672)	(9,648)	(29,765)	(27,919)	(318)	(3)	-	-

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Schedule 5 - External Allocation Factors

No.	Code	Description	Total	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	ENERGY AND REVENUE EXTERNAL ALLOCATORS										
11	**REV**		100.0%	49.4%	0.2%	2.2%	28.4%	18.0%	0.7%	0.4%	0.7%
		Total Revenue_Less Fuel Cost	267,328,655	132,139,578	530,561	5,953,227	75,824,903	48,031,238	1,868,205	1,152,148	1,828,794
12	**REV_ENERGY**		100.0%	35.0%	0.2%	1.6%	27.9%	32.8%	2.0%	0.2%	0.3%
		Total Fuel Cost Revenue	202,463,491	70,924,387	386,972	3,167,056	56,507,590	66,334,389	4,045,017	424,413	673,667
13	**REV_RIDER**		100.0%	50.5%	0.4%	3.0%	32.2%	13.0%	0.6%	0.0%	0.1%
		Total Rider	118,109,906	59,668,199	479,352	3,587,192	38,038,775	15,410,774	750,947	29,159	145,507
14	**ENERGY**		100.0%	35.9%	0.2%	1.6%	28.3%	31.6%	1.9%	0.2%	0.3%
		kWh Sales	3,904,507,404	1,399,798,865	7,362,997	62,270,627	1,103,811,583	1,235,650,954	75,708,000	7,693,136	12,211,243
15	**REV_LATE_FEE**		100.0%	65.2%	5.0%	15.3%	14.4%	0.2%	0.0%	0.0%	0.0%
		Late Payment Fees	2,138,215	1,393,541	106,202	327,629	307,313	3,497	33	-	-
16	**REV_FORFEITED**		100.0%	44.4%	0.2%	2.1%	29.0%	22.3%	1.2%	0.3%	0.4%
		Forfeited Discounts	2,233,506	992,555	5,276	47,913	646,977	498,977	25,786	6,051	9,971
17	**REV_RECONNECT**		100.0%	95.2%	0.7%	2.1%	2.0%	0.0%	0.0%	0.0%	0.0%
		Reconnection Charge Revenue	51,711	49,208	357	1,101	1,033	12	0	-	-
18	**REV_NFS**		100.0%	94.8%	0.7%	2.3%	2.2%	0.0%	0.0%	0.0%	0.0%
		Returned Check Charge Revenue	152,777	144,808	1,137	3,506	3,289	37	0	-	-
19	**REV_MISC**		100.0%	56.4%	2.5%	8.3%	20.9%	11.0%	0.6%	0.1%	0.2%
		Total Misc Revenue	4,576,208	2,580,112	112,971	380,149	958,612	502,523	25,819	6,051	9,971
20	**REV_VP**		100.0%	36.3%	0.2%	1.6%	28.6%	31.0%	1.8%	0.2%	0.3%
		Variable Production Revenue	18,054,808	6,551,059	34,459	291,427	5,155,612	5,597,499	331,601	36,004	57,149
21	**REV_PROPOSED_VP**		100.0%	36.2%	0.2%	1.6%	28.5%	31.2%	1.9%	0.2%	0.3%
		Proposed Variable Production Revenue	6,549,773	2,368,171	12,457	105,349	1,866,940	2,041,470	121,712	13,015	20,659

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Schedule 5 - External Allocation Factors

No.	Code	Description	Total	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	DEMAND ALLOCATORS										
22	**NCP_SEC**		100.0%	61.3%	0.3%	2.2%	35.6%	0.0%	0.0%	0.3%	0.4%
		Non-Coincident Peak Demand_Secondary (kW)	739,741	453,262	1,936	16,065	263,528	-	-	1,913	3,037
23	**NCP_PRI**		100.0%	49.4%	0.2%	1.8%	28.3%	19.8%	0.0%	0.2%	0.3%
		Non-Coincident Peak Demand_Primary (kW)	916,803	453,262	1,936	16,065	259,087	181,503	-	1,913	3,037
24	**DEM_UNIT**										
		Demand kW	8	1	1	1	1	1	1	1	1
25	**12CP_Demand**		100.0%	44.4%	0.2%	1.7%	28.4%	24.0%	1.3%	0.0%	0.1%
		12_Coincident Peak Demand	678,015	300,715	1,296	11,651	192,262	162,477	8,789	319	506
26	**4CP_Demand**		100.0%	45.5%	0.2%	1.7%	29.9%	21.7%	1.0%	0.0%	0.0%
		4_Coincident Peak Demand	854,192	388,783	1,314	14,421	255,779	185,199	8,696	-	-

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Schedule 5 - Functionalization Summary

	Replacement Costs	% of Total
Poles Primary	$ 158,125,353	84%
Poles Secondary	$ 29,665,316	16%
	$ 187,790,669	100%

	Replacement Costs	% of Total
Overhead Primary	$ 263,915,794	85%
Overhead Secondary	$ 46,061,696	15%
	$ 309,977,490	100%

	Replacement Costs	% of Total
Underground Primary	$ 134,491,649	63%
Underground Secondary	$ 77,557,582	37%
	$ 212,049,231	100%

CenterPoint Energy Indiana
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Schedule 5 - Transformer Classification Summary

Transformers and Transformer Installations	Quantity	Total Replacement Cost	Zero Intercept Unit Cost	Customer Component	Customer Component (%)	Demand Component (%)
Overhead	38,002	$ 108,547,706	$ 1,600	$ 60,815,919	56.03%	43.97%
Padmount	18,992	$ 109,728,498	$ 3,238	$ 61,499,914	56.05%	43.95%
Total	**56,994**	**$ 218,276,204**	**$ -**	**$ 122,315,833**	**56.04%**	**43.96%**
					Rounded	**44.00%**

CenterPoint Energy Indiana

Electric Class Cost of Service Study

12 Months Ended Dec 31, 2025

Petitioner’s Exhibit No. 18, Attachment JDT-3: Revenue Apportionment

Schedule 1 - Proposed Revenue Apportionment

Line No.	Category Description	Total System	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
1	Total Revenue at Current Rates	$ 741,397,336	$ 324,435,009	$ 1,772,139	$ 15,445,172	$ 212,856,292	$ 172,728,031	$ 9,072,475	$ 1,898,526	$ 3,189,691
2	Total Revenue Requirement at Equal Rates of Return	$ 860,155,029	$ 389,857,488	$ 2,616,337	$ 17,244,814	$ 234,622,588	$ 201,190,376	$ 9,892,199	$ 1,464,574	$ 3,266,654
3	Total Revenue (Deficiency)/Surplus	$ (118,757,693)	$ (65,422,479)	$ (844,197)	$ (1,799,642)	$ (21,766,296)	$ (28,462,345)	$ (819,723)	$ 433,951	$ (76,963)
4	Percent Change at Equal Rates of Return	16.02%	20.17%	47.64%	11.65%	10.23%	16.48%	9.04%	-22.86%	2.41%
5	Multiple of system average increase required for parity	1.00	1.26	2.97	0.73	0.64	1.03	0.56	(1.43)	0.15
6	**Proposed Multiple of system average increase**	**1.00**	**1.26**	**1.50**	**0.73**	**0.64**	**1.03**	**0.56**	**0.00**	**0.15**
7	Target Percentage Increase	16.02%	20.17%	24.03%	11.65%	10.23%	16.48%	9.04%	0.00%	2.41%
8	Targeted Increase	$ 118,696,278	$ 65,422,479	$ 425,794	$ 1,799,642	$ 21,766,296	$ 28,462,345	$ 819,723	$ (76,963)	$ 76,963
9	Targeted Revenue	$ 860,093,614	$ 389,857,488	$ 2,197,934	$ 17,244,814	$ 234,622,588	$ 201,190,376	$ 9,892,199	$ 1,821,563	$ 3,266,654
10	*Include in Allocation of Delta*		*yes*	*no*	*yes*	*yes*	*yes*	*yes*	*no*	*no*
11	Allocation of Delta	$ 61,415	$ 28,075	$ -	$ 1,242	$ 16,896	$ 14,489	$ 712	$ -	$ -
12	**Proposed Increase/ (Decrease)**	**$ 118,757,693**	**$ 65,450,554**	**$ 425,794**	**$ 1,800,883**	**$ 21,783,192**	**$ 28,476,833**	**$ 820,436**	**$ (76,963)**	**$ 76,963**
13	Resulting Increase %	16.02%	20.17%	24.03%	11.66%	10.23%	16.49%	9.04%	-4.05%	2.41%
14	Multiple of System Increase		1.26	1.50	0.73	0.64	1.03	0.56	(0.25)	0.15
15	**Proposed Revenue**	**$ 860,155,029**	**$ 389,885,563**	**$ 2,197,934**	**$ 17,246,056**	**$ 234,639,484**	**$ 201,204,864**	**$ 9,892,911**	**$ 1,821,563**	**$ 3,266,654**
16	Proposed Rate of Return	7.06%	7.06%	2.01%	7.06%	7.06%	7.06%	7.05%	12.75%	7.06%
17	Proposed Revenue to Cost Ratio	1.000	1.000	0.840	1.000	1.000	1.000	1.000	1.244	1.000
18	Current Parity Ratio	1.000	0.965	0.786	1.039	1.053	0.996	1.064	1.504	1.133

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RESIDENTIAL SALES SERVICE		**Present**			**Proposed**		**Change in Revenue ($)**	**Change In Revenue (%)**
Customer Charge	$ 10.84	1,242,715	$ 13,471,034	$ 23.20	1,242,715	$ 28,831,538	$ 15,360,503	114.0%
Total Customer Charge		**1,242,715**	**$ 13,471,034**		**1,242,715**	**$ 28,831,538**	**$ 15,360,503**	114.0%
All kWh	$ 0.0903	992,996,302	89,627,846	$ 0.16720	992,996,302	166,028,954	76,401,108	85.2%
Total Energy Charge		**992,996,302**	**$ 89,627,846**		**992,996,302**	**$ 166,028,954**	**$ 76,401,108**	85.2%
Subtotal			**$ 103,098,880**			**$ 194,860,492**	**$ 91,761,612**	89.0%
							0	
Variable Production Charge	$ 0.0047	**992,996,302**	**4,647,223**	$ 0.001692	**992,996,302**	**1,679,945**	**(2,967,278)**	-63.9%
Riders:								
TDSIC	$ 12.3604	1,242,715	$ 15,360,503	$ -	1,242,715	$ -	$ (15,360,503)	-100.0%
TDSIC (volumetric)	$ 0.0057	992,996,302	5,689,398	$ -	992,996,302	-	(5,689,398)	-100.0%
CECA	$ 0.0149	992,996,302	14,808,862	$ -	992,996,302	-	(14,808,862)	-100.0%
ECA	$ 0.0090	992,996,302	8,975,198	$ -	992,996,302	-	(8,975,198)	-100.0%
Not Applicable	$ -	992,996,302	-	$ -	992,996,302	-	-	0.0%
SRR	$ (0.0134)	992,996,302	(13,293,241)	$ -	992,996,302	-	13,293,241	-100.0%
SAC	$ -	992,996,302	-	$ -	992,996,302	-	-	0.0%
DSMA	$ 0.0085	992,996,302	8,460,919	$ -	992,996,302	-	(8,460,919)	-100.0%
MCRA	$ 0.0049	992,996,302	4,837,994	$ -	992,996,302	-	(4,837,994)	-100.0%
RCRA	$ (0.0006)	992,996,302	(636,165)	$ -	992,996,302	-	636,165	-100.0%
Subtotal Rider Revenue			**$ 44,203,467**			**$ -**	**$ (44,203,467)**	-100.0%
Total Revenues			**$ 151,949,570**			**$ 196,540,437**	**$ 44,590,867**	29.3%
Revenue Target						**$ 194,860,492**		
Rate Rounding Difference						$ -		

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RESIDENTIAL TRANSITIONAL SALES !	Present			Proposed			Change in Revenue ($)	Change In Revenue (%)
Customer Charge	$ 10.84	360,210	$ 3,904,674	$ 23.20	360,210	$ 8,357,023	$ 4,452,350	114.0%
Total Customer Charge		**360,210**	**$ 3,904,674**		**360,210**	**$ 8,357,023**	**$ 4,452,350**	114.0%
Up to 1000 kWh	$ 0.0707	293,596,120	20,763,118	$ 0.13798	293,596,120	40,509,595	19,746,477	95.1%
Over 1000 kWh Summer	$ 0.0487	23,515,776	1,144,043	$ 0.13798	23,515,776	3,244,643	2,100,600	183.6%
Over 1000 kWh Winter	$ 0.0360	89,690,667	3,228,864	$ 0.13798	89,690,667	12,375,275	9,146,410	283.3%
Total Energy Charge		**406,802,564**	**$ 25,136,024**		**406,802,564**	**$ 56,129,512**	**$ 30,993,488**	123.3%
Subtotal			**$ 29,040,698**			**$ 64,486,535**	**$ 35,445,838**	122.1%
Variable Production Charge	$ 0.0047	**406,802,564**	**1,903,836**	$ 0.001692	**406,802,564**	**688,226**	**(1,215,610)**	-63.9%
Riders:								
TDSIC	$ 12.3604	360,210	$ 4,452,350	$ -	360,210	$ -	$ (4,452,350)	-100.0%
TDSIC (volumetric)	$ 0.0057	406,802,564	2,330,786	$ -	406,802,564	-	(2,330,786)	-100.0%
CECA	$ 0.0155	406,802,564	6,316,755	$ -	406,802,564	-	(6,316,755)	-100.0%
ECA	$ 0.0095	406,802,564	3,883,517	$ -	406,802,564	-	(3,883,517)	-100.0%
Not Applicable	$ -	406,802,564	-	$ -	406,802,564	-	-	0.0%
SRR	$ (0.0134)	406,802,564	(5,445,866)	$ -	406,802,564	-	5,445,866	-100.0%
SAC	$ -	406,802,564	-	$ -	406,802,564	-	-	0.0%
DSMA	$ 0.0054	406,802,564	2,200,898	$ -	406,802,564	-	(2,200,898)	-100.0%
MCRA	$ 0.0049	406,802,564	1,981,318	$ -	406,802,564	-	(1,981,318)	-100.0%
RCRA	$ (0.0006)	406,802,564	(255,025)	$ -	406,802,564	-	255,025	-100.0%
Subtotal Rider Revenue			**$ 15,464,732**			**$ -**	**$ (15,464,732)**	-100.0%
Total Revenues			**$ 46,409,266**			**$ 65,174,761**	**$ 18,765,496**	40.4%
Revenue Target						**$ 64,486,535**		
Rate Rounding Difference						$ -		

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WATER HEATING SALES SERVICE	Present Rate	Present Units	Present Revenue	Proposed Rate	Proposed Units	Proposed Revenue	Change in Revenue ($)	Change In Revenue (%)
Customer Charge	$ 4.93	38,634	$ 190,464	$ 14.76	38,634	$ 570,177	$ 379,712	199.4%
Total Customer Charge		**38,634**	**$ 190,464**		**38,634**	**$ 570,177**	**$ 379,712**	199.4%
All kWh	$ 0.0462	7,362,997	340,097	$ 0.11841	7,362,997	871,819	531,723	156.3%
Total Energy Charge		**7,362,997**	**$ 340,097**		**7,362,997**	**$ 871,819**	**$ 531,723**	156.3%
Subtotal			**$ 530,561**			**$ 1,441,996**	**$ 911,435**	171.8%
Variable Production Charge	$ 0.0047	**7,362,997**	**34,459**	$ 0.001692	**7,362,997**	**12,457**	**(22,002)**	-63.9%
Riders:								
TDSIC	$ 9.8285	38,634	$ 379,712	$ -	38,634	$ -	$ (379,712)	-100.0%
TDSIC (volumetric)	$ 0.0033	7,362,997	24,463	$ -	7,362,997	-	(24,463)	-100.0%
CECA	$ 0.0093	7,362,997	68,481	$ -	7,362,997	-	(68,481)	-100.0%
ECA	$ 0.0076	7,362,997	55,718	$ -	7,362,997	-	(55,718)	-100.0%
Not Applicable	$ -	7,362,997	-	$ -	7,362,997	-	-	0.0%
SRR	$ (0.0084)	7,362,997	(61,636)	$ -	7,362,997	-	61,636	-100.0%
SAC	$ -	7,362,997	-	$ -	7,362,997	-	-	0.0%
DSMA	$ 0.0033	7,362,997	24,267	$ -	7,362,997	-	(24,267)	-100.0%
MCRA	$ 0.0027	7,362,997	19,667	$ -	7,362,997	-	(19,667)	-100.0%
RCRA	$ (0.0043)	7,362,997	(31,322)	$ -	7,362,997	-	31,322	-100.0%
Subtotal Rider Revenue			**$ 479,352**			**$ -**	**$ (479,352)**	-100.0%
Total Revenues			**$ 1,044,372**			**$ 1,454,453**	**$ 410,081**	39.3%
Revenue Target						**$ 1,441,996**		
Rate Rounding Difference						$ -		

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SMALL GENERAL SERVICE	Present Rate	Present Units	Present Revenue	Proposed Rate	Proposed Units	Proposed Revenue	Change in Revenue ($)	Change In Revenue (%)
Customer Charge	$ 10.84	119,184	$ 1,291,953	$ 22.50	119,184	$ 2,681,972	$ 1,390,019	107.6%
Total Customer Charge		**119,184**	**$ 1,291,953**		**119,184**	**$ 2,681,972**	**$ 1,390,019**	107.6%
Up to 1000 kWh	$ 0.0868	41,633,388	3,614,611	$ 0.16303	41,633,388	6,787,611	3,173,000	87.8%
Next 1000 kWh	$ 0.0659	10,047,788	661,948	$ 0.12371	10,047,788	1,243,024	581,076	87.8%
Over 2000 kWh	$ 0.0363	10,589,451	384,715	$ 0.06822	10,589,451	722,427	337,713	87.8%
Total Energy Charge		**62,270,627**	**$ 4,661,274**		**62,270,627**	**$ 8,753,062**	**$ 4,091,788**	87.8%
Subtotal			**$ 5,953,227**			**$ 11,435,034**	**$ 5,481,807**	92.1%
Variable Production Charge	$ 0.0047	**62,270,627**	**291,427**	$ 0.001692	**62,270,627**	**105,349**	**(186,077)**	-63.9%
Riders:								
TDSIC	$ 11.6628	119,184	$ 1,390,019	$ -	119,184	$ -	$ (1,390,019)	-100.0%
TDSIC (volumetric)	$ 0.0055	62,270,627	342,486	$ -	62,270,627	-	(342,486)	-100.0%
CECA	$ 0.0151	62,270,627	940,489	$ -	62,270,627	-	(940,489)	-100.0%
ECA	$ 0.0097	62,270,627	601,046	$ -	62,270,627	-	(601,046)	-100.0%
Not Applicable	$ -	62,270,627	-	$ -	62,270,627	-	-	0.0%
SRR	$ (0.0134)	62,270,627	(833,804)	$ -	62,270,627	-	833,804	-100.0%
SAC	$ -	62,270,627	-	$ -	62,270,627	-	-	0.0%
DSMA	$ 0.0152	62,270,627	946,967	$ -	62,270,627	-	(946,967)	-100.0%
MCRA	$ 0.0043	62,270,627	265,075	$ -	62,270,627	-	(265,075)	-100.0%
RCRA	$ (0.0010)	62,270,627	(65,085)	$ -	62,270,627	-	65,085	-100.0%
Subtotal Rider Revenue			**$ 3,587,192**			**$ -**	**$ (3,587,192)**	-100.0%
Total Revenues			**$ 9,831,846**			**$ 11,540,383**	**$ 1,708,538**	17.4%
Revenue Target						**$ 11,435,034**		
Rate Rounding Difference						$ -		

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DEMAND GENERAL SERVICE		Present			Proposed		Change in Revenue ($)	Change In Revenue (%)
Customer Charge - Group 1	$ 14.78	86,406	$ 1,277,087	$ 17.15	86,406	$ 1,481,652	$ 204,565	16.0%
Customer Charge - Group 2	$ 34.49	12,906	445,145	$ 34.49	12,906	445,145	-	0.0%
Customer Charge - Group 3	$ 73.90	2,658	196,420	$ 73.90	2,658	196,420	-	0.0%
Total Customer Charge		**101,971**	**$ 1,918,652**		**101,971**	**$ 2,123,217**	**$ 204,565**	10.7%
Demand Charge	$ 5.11	2,975,097	**$ 15,205,718**	$ 13.23046	**2,975,097**	**39,361,894**	**$ 24,156,176**	158.9%
Discounts	$ (0.44)	252,866	(112,272)	$ (0.69)	252,866	(173,818)		
Up to 1000 kWh	$ 0.0745	85,650,242	6,380,943	$ 0.12025	85,650,242	10,299,589	3,918,646	61.4%
Up to 14000 kWh	$ 0.0534	847,529,208	45,224,159	$ 0.08613	847,529,208	72,997,086	27,772,928	61.4%
Over 15000 kWh	$ 0.0248	89,459,919	2,219,501	$ 0.04005	89,459,919	3,582,534	1,363,033	61.4%
Total Energy Charge		**1,022,639,369**	**$ 53,824,602**		**1,022,639,369**	**$ 86,879,209**	**$ 33,054,607**	61.4%
Subtotal			**$ 70,836,700**			**$ 128,190,502**	**$ 57,353,802**	81.0%
Variable Production Charge	$ 0.0047	**1,022,639,369**	**4,775,726**	$ 0.001691	**1,022,639,369**	**1,729,614**	**(3,046,112)**	-63.8%
Riders:								
TDSIC	$ 4.2961	2,975,097	$ 12,781,254	$ -	2,975,097	$ -	$ (12,781,254)	-100.0%
TDSIC (volumetric)	$ -	2,975,097	-	$ -	2,975,097	-	-	0.0%
CECA	$ 0.0138	1,022,639,369	14,102,034	$ -	1,022,639,369	-	(14,102,034)	-100.0%
ECA	$ 0.0094	1,022,639,369	9,566,060	$ -	1,022,639,369	-	(9,566,060)	-100.0%
Not Applicable	$ -	1,022,639,369	-	$ -	1,022,639,369	-	-	0.0%
SRR	$ (0.0132)	1,022,639,369	(13,529,519)	$ -	1,022,639,369	-	13,529,519	-100.0%
SAC	$ -	1,022,639,369	-	$ -	1,022,639,369	-	-	0.0%
DSMA	$ 0.0091	1,022,639,369	9,356,212	$ -	1,022,639,369	-	(9,356,212)	-100.0%
MCRA	$ 0.0040	1,022,639,369	4,049,367	$ -	1,022,639,369	-	(4,049,367)	-100.0%
RCRA	$ (0.0011)	1,022,639,369	(1,099,934)	$ -	1,022,639,369	-	1,099,934	-100.0%
Subtotal Rider Revenue			**$ 35,225,473**			**$ -**	**$ (35,225,473)**	-100.0%
Total Revenues			**$ 110,837,899**			**$ 129,920,116**	**$ 19,082,217**	17.2%
Revenue Target						**$ 128,190,502**		
Rate Rounding Difference						$ -		

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OFF SEASON SERVICE		**Present**			**Proposed**		**Change in Revenue ($)**	**Change In Revenue (%)**
Customer Charge	$ 14.78	9,823	$ 145,179	$ 17.15	9,823	$ 168,433	$ 23,255	16.0%
Total Customer Charge		**9,823**	**$ 145,179**		**9,823**	**$ 168,433**		
Demand Charge	$ 4.67	285,745	**1,335,573**	$ 13.23046	**285,745**	**3,780,540**	**2,444,967**	183.1%
All kWh	$ 0.04321	81,172,214	3,507,451	$ 0.07080	81,172,214	5,746,613	2,239,162	63.8%
Total Energy Charge		**81,172,214**	**$ 3,507,451**		**81,172,214**	**$ 5,746,613**	**$ 2,239,162**	63.8%
Subtotal			**$ 4,988,203**			**$ 9,695,587**	**$ 4,707,384**	94.4%
Variable Production Charge	$ 0.0047	**81,172,214**	**379,886**	$ 0.001692	**81,172,214**	**137,327**	**(242,559)**	-63.9%
Riders:								
TDSIC	$ 4.1488	285,745	$ 1,185,486	$ -	285,745	$ -	$ (1,185,486)	-100.0%
TDSIC (volumetric)	$ -	81,172,214	-	$ -	81,172,214	-	-	0.0%
CECA	$ 0.0142	81,172,214	1,149,541	$ -	81,172,214	-	(1,149,541)	-100.0%
ECA	$ 0.0095	81,172,214	767,251	$ -	81,172,214	-	(767,251)	-100.0%
Not Applicable	$ -	81,172,214	-	$ -	81,172,214	-	-	0.0%
SRR	$ (0.0128)	81,172,214	(1,035,433)	$ -	81,172,214	-	1,035,433	-100.0%
SAC	$ -	81,172,214	-	$ -	81,172,214	-	-	0.0%
DSMA	$ 0.0063	81,172,214	513,995	$ -	81,172,214	-	(513,995)	-100.0%
MCRA	$ 0.0037	81,172,214	303,581	$ -	81,172,214	-	(303,581)	-100.0%
RCRA	$ (0.0009)	81,172,214	(71,119)	$ -	81,172,214	-	71,119	-100.0%
Subtotal Rider Revenue			**$ 2,813,303**			**$ -**	**$ (2,813,303)**	-100.0%
Total Revenues			**$ 8,181,391**			**$ 9,832,913**	**$ 1,651,522**	20.2%
Revenue Target						**$ 9,695,587**		
Rate Rounding Difference						$ -		

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LARGE POWER SERVICE	Present			Proposed			Change in Revenue ($)	Change In Revenue (%)
Customer Charge	$ 147.80	1,272	$ 188,002	$ 171.47	1,272	$ 218,116	$ 30,114	16.0%
Total Customer Charge		**1,272**	**$ 188,002**		**1,272**	**$ 218,116**	**$ 30,114**	16.0%
Demand Charge	$ 9.17300	**2,702,812**	**24,792,890**	$ 17.81944	**2,702,812**	**48,162,582**	**23,369,691**	94.3%
Discounts	$ (2.30800)	281,386	(649,439)	$ (2.68)	281,386	$ (753,467)		
All kWh	$ 0.01918	1,235,650,954	23,699,785	$ 0.03816	1,235,650,954	47,149,047	23,449,262	98.9%
Total Energy Charge		**1,235,650,954**	**$ 23,699,785**		**1,235,650,954**	**$ 47,149,047**	**$ 23,449,262**	98.9%
Subtotal			**$ 48,031,238**			**$ 94,776,277**	**$ 46,745,039**	97.3%
Variable Production Charge	$ 0.00453	**1,235,650,954**	**5,597,499**	$ 0.001652	**1,235,650,954**	**2,041,470**	**(3,556,029)**	-63.5%
Riders:								
TDSIC	$ 1.9648	2,702,812	$ 5,310,464	$ -	2,702,812	$ -	$ (5,310,464)	-100.0%
TDSIC (volumetric)	$ -	1,235,650,954	-	$ -	1,235,650,954	-	-	0.0%
CECA	$ 0.0068	1,235,650,954	8,424,851	$ -	1,235,650,954	-	(8,424,851)	-100.0%
ECA	$ 0.0055	1,235,650,954	6,842,834	$ -	1,235,650,954	-	(6,842,834)	-100.0%
Not Applicable	$ -	1,235,650,954	-	$ -	1,235,650,954	-	-	0.0%
SRR	$ (0.0058)	1,235,650,954	(7,151,948)	$ -	1,235,650,954	-	7,151,948	-100.0%
SAC	$ -	1,235,650,954	-	$ -	1,235,650,954	-	-	0.0%
DSMA	$ 0.0018	1,235,650,954	2,166,824	$ -	1,235,650,954	-	(2,166,824)	-100.0%
MCRA	$ 0.6225	2,702,812	1,682,555	$ -	2,702,812	-	(1,682,555)	-100.0%
RCRA	$ (0.0015)	1,235,650,954	(1,864,806)	$ -	1,235,650,954	-	1,864,806	-100.0%
Subtotal Rider Revenue			**$ 15,410,774**			**$ -**	**$ (15,410,774)**	-100.0%
Total Revenues			**$ 69,039,511**			**$ 96,817,748**	**$ 27,778,237**	40.2%
Revenue Target						**$ 94,776,277**		
Rate Rounding Difference						$ -		

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HIGH LOAD FACTOR	Present			Proposed			Change in Revenue ($)	Change In Revenue (%)
Customer Charge	$ -	12	$ -		12	$ -	$ -	0.0%
Total Customer Charge		**12**	**$ -**		**12**	**$ -**	**$ -**	0.0%
Demand Charge	$ 19.19600	**97,323**	**1,868,205**	$ 37.2443	**97,323**	**3,624,716**	**1,756,511**	94.0%
Discounts			-					
All kWh	$ -	75,708,000	-		75,708,000	-	-	0.0%
Total Energy Charge		**75,708,000**	**$ -**		**75,708,000**	**$ -**	**$ -**	0.0%
Subtotal			**$ 1,868,205**			**$ 3,624,716**	**$ 1,756,511**	94.0%
Variable Production Charge	$ 0.00438	**75,708,000**	**331,601**	$ 0.001608	**75,708,000**	**121,712**	**(209,889)**	-63.3%
Riders:								
TDSIC	$ 1.2916	97,323	$ 125,707	$ -	97,323	$ -	$ (125,707)	-100.0%
TDSIC (volumetric)	$ -	75,708,000	-	$ -	75,708,000	-	-	0.0%
CECA	$ 0.0062	75,708,000	468,640	$ -	75,708,000	-	(468,640)	-100.0%
ECA	$ 0.0062	75,708,000	469,493	$ -	75,708,000	-	(469,493)	-100.0%
Not Applicable	$ -	75,708,000	-	$ -	75,708,000	-	-	0.0%
SRR	$ (0.0052)	75,708,000	(391,963)	$ -	75,708,000	-	391,963	-100.0%
SAC	$ -	75,708,000	-	$ -	75,708,000	-	-	0.0%
DSMA	$ 0.0009	75,708,000	65,743	$ -	75,708,000	-	(65,743)	-100.0%
MCRA	$ 0.9574	97,323	93,180	$ -	97,323	-	(93,180)	-100.0%
RCRA	$ (0.0011)	75,708,000	(79,853)	$ -	75,708,000	-	79,853	-100.0%
Subtotal Rider Revenue			**$ 750,947**			**$ -**	**$ (750,947)**	-100.0%
Total Revenues			**$ 2,950,753**			**$ 3,746,428**	**$ 795,675**	27.0%
Revenue Target						**$ 3,624,716**		
Rate Rounding Difference						$ -		

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner’s Exhibit No. 18, Attachment JDT-4
Schedule 1-Rate Design

OUTDOOR LIGHTING	Present			Proposed			**Change in Revenue ($)**	**Change In Revenue (%)**
Customer Charge	$ -		$ -		-	$ -	$ -	0.0%
Total Customer Charge		**-**	**$ -**		**-**	**$ -**	**$ -**	0.0%
All kWh	$ 0.14976	7,693,136	1,152,148	$ 0.14577	7,693,136	1,121,454	(30,694)	-2.7%
Total Energy Charge		**7,693,136**	**$ 1,152,148**		**7,693,136**	**$ 1,121,454**	**$ (30,694)**	-2.7%
Subtotal			**$ 1,152,148**			**$ 1,121,454**	**$ (30,694)**	-2.7%
							0	
Variable Production Charge	$ 0.00468	**7,693,136**	**36,004**	$ 0.001692	**7,693,136**	**13,015**	**(22,989)**	-63.9%
Riders:								
TDSIC	$ 11.9884	6,529	78,272	$ -	6,529	$ -	$ (78,272)	-100.0%
TDSIC (volumetric)	$ -	-	-	$ -	-	-	-	0.0%
CECA	$ -	7,693,136	-	$ -	7,693,136	-	-	0.0%
ECA	$ -	7,693,136	-	$ -	7,693,136	-	-	0.0%
Not Applicable	$ -	7,693,136	-	$ -	7,693,136	-	-	0.0%
SRR	$ (0.0064)	7,693,136	(49,113)	$ -	7,693,136	-	49,113	-100.0%
SAC	$ -	7,693,136	-	$ -	7,693,136	-	-	0.0%
DSMA	$ -	7,693,136	-	$ -	7,693,136	-	-	0.0%
MCRA	$ -	7,693,136	-	$ -	7,693,136	-	-	0.0%
RCRA	$ -	7,693,136	-	$ -	7,693,136	-	-	0.0%
Subtotal Rider Revenue			**$ 29,159**			**$ -**	**$ (29,159)**	-100.0%
Total Revenues			**$ 1,217,311**			**$ 1,134,469**	**$ (82,842)**	-6.8%
Revenue Target						**$ 1,121,454**		
Rate Rounding Difference						$ -		

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18, Attachment JDT-4
Schedule 1-Rate Design

STREET LIGHTING		**Present**			**Proposed**		**Change in Revenue ($)**	**Change In Revenue (%)**
Customer Charge	$ -		$ -	$ -	-	$ -	$ -	0.0%
Total Customer Charge		**-**	**$ -**		**-**	**$ -**	**$ -**	0.0%
All kWh	$ 0.14976	12,211,243	1,828,794	$ 0.16957	12,211,243	2,070,600	241,806	13.2%
Total Energy Charge		**12,211,243**	**$ 1,828,794**		**12,211,243**	**$ 2,070,600**	**$ 241,806**	13.2%
Subtotal			**$ 1,828,794**			**$ 2,070,600**	**$ 241,806**	13.2%
							0	
Variable Production Charge	$ 0.00468	**12,211,243**	**57,149**	$ 0.00169	**12,211,243**	**20,659**	**(36,490)**	-63.9%
Riders:								
TDSIC	$ 11.9884	18,640	$ 223,464	$ -	18,640	$ -	$ (223,464)	-100.0%
TDSIC (volumetric)	$ -	-	-	$ -	-	-	-	0.0%
CECA	$ -	12,211,243	-	$ -	12,211,243	-	-	0.0%
ECA	$ -	12,211,243	-	$ -	12,211,243	-	-	0.0%
Not Applicable	$ -	12,211,243	-	$ -	12,211,243	-	-	0.0%
SRR	$ (0.0064)	12,211,243	(77,957)	$ -	12,211,243	-	77,957	-100.0%
SAC	$ -	12,211,243	-	$ -	12,211,243	-	-	0.0%
DSMA	$ -	12,211,243	-	$ -	12,211,243	-	-	0.0%
MCRA	$ -	12,211,243	-	$ -	12,211,243	-	-	0.0%
RCRA	$ -	12,211,243	-	$ -	12,211,243	-	-	0.0%
Subtotal Rider Revenue			**$ 145,507**			**$ -**	**$ (145,507)**	-100.0%
Total Revenues			**$ 2,031,449**			**$ 2,091,259**	**$ 59,809**	2.9%
Revenue Target						**$ 2,070,600**		
Rate Rounding Difference						$ -		

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Cause 45990

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18, Attachment JDT-4 (CONFIDENTIAL)
Schedule 2-Special Contract Rate Design (Confidential)

[redacted]

Cause 45990

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18, Attachment JDT-4 (CONFIDENTIAL)
Schedule 2-Special Contract Rate Design (Confidential)

[redacted]

Cause 45990

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18, Attachment JDT-4 (CONFIDENTIAL)
Schedule 2-Special Contract Rate Design (Confidential)

[redacted]

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18, Attachment JDT-4 (CONFIDENTIAL)
Schedule 2-Special Contract Rate Design (Confidential)

[redacted]

Cause 45990

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18, Attachment JDT-4
Schedule 3-Lighting Rates

	Current Rates		Proposed Rates	
STREET LIGHTING SERVICE - RATE SL-1				
(A) Series and/or Multiple Incandescent Lamp Street Lighting Rates limited to Lamps in use and/or on Order as of August 1, 1968.				
Overhead Construction - Wood Poles	Radial Wave Reflectors	Enclosing Globe	Radial Wave Reflectors	Enclosing Globe
2500 Lumen	$15.88	$20.27	$17.98	$22.95
6000 Lumen	-	$23.94	-	$27.11
(B) Series and/or Multiple Mercury Vapor Lamp Street Lighting Rates Limited to Lamps in Use and/or on order as of December 31, 1980.				
Overhead Construction	Wood Poles	Metal Poles	Wood Poles	Metal Poles
175 Watt (Approximately 8,000 Lumens)	$62.13	$109.96	$70.34	$124.50
Twin arm 175 Watt (Approximately 16,000 Lumens)	-	$198.53	-	$224.78
250 Watt (Approximately 11,000 Lumens)	$85.37	$127.91	$96.66	$144.82
400 Watt (Approximately 20,000 Lumens)	$99.43	$119.49	$112.58	$135.29
Twin arm 400 Watt (Approximately 40,000 Lumens)	-	$213.73	-	$241.99
1000 Watt (Approximately 54,000 Lumens)	$110.29	$163.49	$124.87	$185.11
Underground Construction Where Breaking and Replacing Pavement and/or Sidewalk is Not Required		Metal Poles		Metal Poles
175 Watt (Approximately 8,000 Lumens)		$120.82		$136.80
Twin arm 175 Watt (Approximately 16,000 Lumens)		$215.91		$244.46
(C) Series and/or Multiple High Pressure Sodium Street Lighting Rates. (Restricted to Lamps in use and/or on order as of December 31, 2018)				
Overhead Construction	Wood Poles	Metal Poles	Wood Poles	Metal Poles
100 Watt (Approximately 8,000 Lumens)	$71.01	$118.89	$80.40	$134.61
Twin arm 100 Watt (Approximately 16,000 Lumens)	-	$216.08	-	$244.65
150 Watt (Approximately 15,000 Lumens)	$69.66	$117.50	$78.87	$133.04
200 Watt (Approximately 20,000 Lumens)	$120.43	$145.25	$136.35	$164.46
Twin arm 200 Watt (Approximately 40,000 Lumens)	-	$253.19	-	$286.67
400 Watt (Approximately 45,000 Lumens)	$171.22	$224.38	$193.86	$254.05
Twin arm 400 Watt (Approximately 90,000 Lumens)	-	$379.07	-	$429.19
Underground Construction Where Breaking and Replacing Pavement and/or Sidewalk is Not Required		Metal Poles		Metal Poles
100 Watt (Approximately 8,000 Lumens)		$129.53		$146.66
Twin arm 100 Watt (Approximately 16,000 Lumens)		$233.24		$264.08
200 Watt (Approximately 20,000 Lumens) (where direct burial cable and imbedded type pole is used)		$224.95		$254.69
Twin arm 200 Watt (Approximately 40,000 Lumens) (where direct burial cable and imbedded type pole is used)		$336.84		$381.38
200 Watt (Approximately 20,000 Lumens) (where conduit and anchor base pole is used)		$278.07		$314.84
400 Watt (Approximately 45,000 Lumens)		$330.61		$374.32
Twin arm 400 Watt (Approximately 90,000 Lumens)		$453.39		$513.34

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18, Attachment JDT-4
Schedule 3-Lighting Rates

	Current Rates		Proposed Rates	
(D) Series and/or Light Emitting Diode (LED) Street Lighting Rates.				
Overhead Construction	Wood Poles	Metal Poles	Wood Poles	Metal Poles
60 Watt (Approximately 5,500 Lumens)	$47.11	$94.99	$53.34	$107.55
Twin arm 60 Watt (Approximately 11,000 Lumens)	-	$168.26	-	$190.51
130 Watt (Approximately 15,000 Lumens)	$101.64	$126.46	$115.08	$143.18
Twin arm 130 Watt (Approximately 30,000 Lumens)	-	$215.63	-	$244.14
210 Watt (Approximately 24,000 Lumens)	$178.11	$231.27	$201.66	$261.85
Twin arm 210 Watt (Approximately 48,000 Lumens)	-	$392.85	-	$444.79
Underground Construction Where Breaking and Replacing Pavement and/or Sidewalk is Not Required		Metal Poles		Metal Poles
60 Watt (Approximately 5,500 Lumens)		$105.63		$119.60
Twin arm 60 Watt (Approximately 11,000 Lumens)		$185.43		$209.95
130 Watt (Approximately 15,000 Lumens) (where direct burial cable and imbedded type pole is used)		$206.16		$233.42
Twin arm 130 Watt (Approximately 30,000 Lumens) (where direct burial cable and imbedded type pole is used)		$299.28		$338.85
130 Watt (Approximately 15,000 Lumens) (where conduit and anchor base pole is used)		$259.30		$293.59
210 Watt (Approximately 24,000 Lumens)		$337.48		$382.10
Twin arm 210 Watt (Approximately 48,000 Lumens)		$467.16		$528.93

	Current Rates	Proposed Rates
RATE SL-2 ORNAMENTAL STREET LIGHTING SERVICE (Post Top Lantern Type Luminaire)		
Underground Construction	Wood Post	Wood Post
175 Watt (Approximately 8,000 Lumens) Mercury Vapor Lamps – Wood Post (Restricted to Lamps in use as of October 6, 1983)	$63.07	$71.41
100 Watt (Approximately 8,000 Lumens) High Pressure Sodium Lamp – Wood Post (Restricted to Lamps in use as of December 31, 2018)	$71.97	$81.49
60 Watt (Approximately 5,500 Lumens) Light Emitting Diode (LED) Lamps – Wood Post	$48.06	$54.41

	Current Rates	Proposed Rates
RATE SL-3 ORNAMENTAL STREET LIGHTING SERVICE (Contemporary Spherical)		
Underground Construction - Steel Post	Steel Post	Steel Post
200 Watt high pressure sodium lamp enclosed in approximately 28" diameter sphere mounted on 10' steel pole (Restricted to Lamps in use as of Dece	$201.96	$228.66
130 Watt Light Emitting Diode (LED) lamp enclosed in approximately 28" diameter sphere mounted on 10' steel pole	$183.15	$207.37

	Current Rates	Proposed Rates
RATE SL-5 EXPRESSWAY LIGHTING SERVICE		
(A) Mercury Vapor Street Lighting Rates Limited to Lamps In Use and/or On Order as of December 31, 1981.		
Underground Construction – Metal Poles	Metal Poles	Metal Poles
1,000 Watt mercury vapor lamp and fixture with an approximate 40 foot mounting height (Frangible Construction)	$409.61	$463.77
1,000 Watt mercury vapor lamp and fixture with an approximate 40 foot mounting height (Non-Frangible Construction)	$388.36	$439.71
(B) High Pressure Sodium Street Lighting Rates (Restricted to Lamps in use as of December 31, 2018)		
Underground Construction – Metal Poles	Metal Poles	Metal Poles
400 Watt high pressure sodium lamp and fixture with an approximate 40 foot mounting height (Frangible Construction)	$637.46	$721.75
Twin 400 Watt high pressure sodium lamps and fixtures with an approximate 40 foot mounting height (Frangible Construction)	$450.15	$509.67
400 Watt high pressure sodium lamp and fixture with an approximate 40 foot mounting height (Non-Frangible Construction)	$478.27	$541.51

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18, Attachment JDT-4
Schedule 3-Lighting Rates

	Current Rates	Proposed Rates
(C) Light Emitting Diode (LED) Street Lighting Rates		
Underground Construction – Metal Poles	Metal Poles	Metal Poles
210 Watt LED lamp and fixture with an approximate 40 foot mounting height (Frangible Construction)	$478.27	$541.51
Twin 210 Watt LED lamps and fixtures with an approximate 40 foot mounting height (Frangible Construction)	$651.22	$737.33
210 Watt LED lamp and fixture with an approximate 40 foot mounting height (Non-Frangible Construction)	$457.03	$517.46
RATE SL-7 ORNAMENTAL STREET LIGHTING SERVICE (Turn of the Century)		
Underground Construction – Metal Post	Metal Post	Metal Post
100 Watt high pressure sodium lamp post top fixture on 12.5' steel post with cast iron ornamental top and base (Restricted to Lamps in use as of Dece	$174.92	$198.05
60 Watt Light Emitting Diode (LED) lamp post top fixture on 16' steel post with aluminum ornamental top and base	$151.02	$170.99
RATE SL-8 ORNAMENTAL STREET LIGHTING SERVICE (Post Top Lighting Service)		
Underground Construction with Fiberglass Poles	Fiberglass Poles	Fiberglass Poles
100 Watt high pressure sodium (8,000 lumen) (Restricted to Lamps in use as of December 31, 2018)	$87.57	$99.15
60 Watt Light Emitting Diode (LED) (5,500 lumen)	$63.66	$72.08
RATE OL OUTDOOR LIGHTING SERVICE (DUSK TO DAWN)		
Mercury Vapor (Limited to lamps in use or on order as of December 31, 1981)	Lamp	Lamp
175 Watt (approximately 7,000 lumen) lamp	$4.47	$4.35
400 Watt (approximately 20,000 lumen) lamp	$5.49	$5.34
400 Watt (approximately 20,000 lumen) lamp - Directional Luminaire	$6.89	$6.71
1,000 Watt (approximately 50,000 lumen) lamp - Directional Luminaire	$9.71	$9.45
High Pressure Sodium (Limited to lamps in use or on order as of September 30, 2019)	Lamp	Lamp
100 Watt (approximately 8,000 lumen) lamp	$5.07	$4.93
100 Watt (approximately 8,000 lumen) lamp – Directional Luminaire	$5.46	$5.31
200 Watt (approximately 20,000 lumen) lamp	$7.09	$6.90
200 Watt (approximately 20,000 lumen) lamp – Directional Luminaire	$8.49	$8.26
400 Watt (approximately 45,000 lumen) lamp – Directional Luminaire	$14.52	$14.13
Light Emotting Diode (LED)	Lamp	Lamp
40 Watt (approximately 5,000 lumen) lamp	$3.28	$3.19
50 Watt (approximately 5,000 lumen) lamp – Directional Luminaire	$3.67	$3.57
90 Watt (approximately 9,800 lumen) lamp – Directional Luminaire	$6.59	$6.41
180 Watt (approximately 23,900 lumen) lamp – Directional Luminaire	$13.03	$12.68

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18, Attachment JDT-5: Updated Tracker Allocations
Schedule 1-Energy Allocation

Line	Customer Classes	Energy Usage	Resulting % Allocation
1	Residential (RS)	1,399,798,865	28.11%
2	Water Heating (B)	7,362,997	0.15%
3	Small General Service (SGS)	62,270,627	1.25%
4	Demand General Service (DGS)	1,022,639,369	20.54%
5	Off Season Service (OSS)	81,172,214	1.63%
6	Large Power Service (LP)	2,246,503,330	45.11%
7	BAMP	64,333,440	1.29%
8	High Load Factor Service (HLF)	75,708,000	1.52%
9	Outdoor Lighting (OL)	7,693,136	0.15%
10	Street Lighting (SL)	12,211,243	0.25%
11	**Total**	**4,979,693,220**	

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18, Attachment JDT-5: Updated Tracker Allocations
Schedule 2-TDSIC Allocation

Line	Customer Classes	Transmission Allocation %	Distribution Allocation %	EADIT Credit Allocation %
1	Residential (RS)	33.46%	54.67%	46.64%
2	Water Heating (B)	0.10%	0.36%	0.26%
3	Small General Service (SGS)	1.21%	2.57%	2.06%
4	Demand General Service (DGS)	21.31%	24.28%	23.15%
5	Off Season Service (OSS)	1.61%	1.84%	1.75%
6	Large Power Service (LP)/BAMP	40.70%	15.28%	24.90%
7	High Load Factor Service (HLF)	1.56%	0.12%	0.67%
8	Outdoor Lighting (OL)/Street Lighting (SL)	0.05%	0.89%	0.57%
9	**Total**	**100%**	**100%**	**100%**

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18, Attachment JDT-5: Updated Tracker Allocations
Schedule 3-Production Allocation

Line	Customer Classes	4CP for Trackers	Resulting % Allocation
1	Residential (RS)	388,783	38.31%
2	Water Heating (B)	1,314	0.13%
3	Small General Service (SGS)	14,421	1.42%
4	Demand General Service (DGS)	240,623	23.71%
5	Off Season Service (OSS)	15,156	1.49%
6	Large Power Service (LP)	331,502	32.67%
7	BAMP	14,321	1.41%
8	High Load Factor Service (HLF)	8,696	0.86%
9	Outdoor Lighting (OL)	-	0.00%
10	Street Lighting (SL)	-	0.00%
11	**Total**	**1,014,814**	

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18, Attachment JDT-5: Updated Tracker Allocations
Schedule 4-Rate Base Allocation

Line	Customer Classes	Production Rate Base	Transmission Rate Base	All Other Rate Base	Total Rate Base	Resulting % Allocation
1	Residential (RS)	$ 529,705,697	$ 163,955,222	$ 529,785,763	$ 1,223,446,683	43.38%
2	Water Heating (B)	$ 1,790,114	$ 706,511	$ 3,881,277	$ 6,377,902	0.23%
3	Small General Service (SGS)	$ 19,648,116	$ 6,352,183	$ 23,577,831	$ 49,578,131	1.76%
4	Demand General Service (DGS)	$ 327,842,069	$ 96,769,741	$ 266,726,319	$ 691,338,130	24.51%
5	Off Season Service (OSS)	$ 20,649,495	$ 8,055,053		$ 28,704,548	1.02%
6	Large Power Service (LP)	$ 451,661,838	$ 157,588,856	$ 150,733,816	$ 759,984,510	26.95%
7	BAMP	$ 19,511,430	$ 7,476,221		$ 26,987,651	0.96%
8	High Load Factor Service (HLF)	$ 11,847,534	$ 4,792,035	$ 179,333	$ 16,818,902	0.60%
9	Outdoor Lighting (OL)	$ -	$ 173,866	$ 4,945,431	$ 5,119,298	0.18%
10	Street Lighting (SL)	$ -	$ 275,976	$ 11,837,030	$ 12,113,007	0.43%
11	**Total**	**$ 1,382,656,294**	**$ 446,145,665**	**$ 991,666,802**	**$ 2,820,468,760**	