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INDIANA UTILITY
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INDIANAPOLIS POWER AND LIGHT COMPANY
(D/B/A AES INDIANA)

VERIFIED DIRECT TESTIMONY

OF

BICKEY RIMAL
VICE PRESIDENT
CONCENTRIC ENERGY ADVISORS, INC.

Cause No. 46258

<u>SPONSORING WITNESS BR ATTACHMENTS 1 THROUGH 13</u>

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VERIFIED DIRECT TESTIMONY OF BICKEY RIMAL

ON BEHALF OF AES INDIANA

I. INTRODUCTION AND QUALIFICATIONS

Q1. Please state your name and business address.

A1. My name is Bickey Rimal and my business address is 1300 19th Street, Suite 620, Washington, DC 20036.

Q2. By whom are you employed and in what capacity?

A2. I am employed by Concentric Energy Advisors, Inc. ("Concentric") as a Vice President.

Q3. Please describe your professional background and education.

A3. I have over 14 years of experience in the utility industry. I hold a Bachelor of Arts degree from Colgate University. I hold a Masters in International Public Affairs with a focus on Energy Policy from the University of Wisconsin in Madison. I have provided expert testimony on cost allocation issues on multiple occasions for various electric, gas, water, and wastewater utility clients. A summary of my education and experience is provided as AES Indiana Attachment BR-1.

Q4. Have you presented expert testimony in other proceedings?

A4. Yes. I have testified before the Indiana Utility Regulatory Commission ("IURC" or the "Commission"). In addition to the IURC, I have testified previously before the Regulatory Commission of Alaska, Arizona Corporation Commission, Connecticut Public Utilities Regulatory Authority, Maine Public Utilities Commission, Massachusetts Department of

Public Utilities, Public Utilities Commission of Nevada, New York State Department of Public Service, and Nova Scotia Utility and Review Board.

Q5. On whose behalf are you testifying?

A5. I am testifying on behalf of Indianapolis Power & Light Company d/b/a AES Indiana ("Company").

Q6. What is your assignment in this proceeding?

A6. AES Indiana retained Concentric to conduct a fully allocated cost-of-service study ("ACOSS") to determine the embedded costs of serving its various retail electric customers, and design rates that would be reasonable and appropriate for recovering the test year revenue requirements from the various customers. In this regard, I am sponsoring the class cost of service study and rate design filed in this proceeding. I am also presenting the Company's findings associated with the potential creation of a residential multi-family rate classification.

Q7. Please summarize the nature and purpose of your testimony.

A7. My testimony addresses the Company's cost of service and rate design studies. First, I discuss the purpose of an ACOSS and describe the Concentric Cost of Service Model ("Concentric Model") used in conducting AES Indiana's electric cost of service study.

Second, I discuss various principles of cost allocation, factors that influence the cost allocation framework, and the underlying methodology and basis used in the Company's electric cost of service study.

Third, I describe the studies of relative costs and other analyses employed to assign the various categories of plant and operation and maintenance (“O&M”) expenses to the respective customer classes.

Fourth, I present the class-by-class rate of return results and corresponding revenue surpluses or deficiencies from AES Indiana’s ACOSS. This presentation will include the resulting unit costs by class for customer, demand, and energy-related costs within the ACOSS.

Fifth, I describe the method used to apportion the Company’s revenue deficiency to the various rate schedules. In particular, I describe the principles and methods used to mitigate the impacts on those classes that would otherwise receive large rate increases if the unmitigated results of the ACOSS were to be used to apportion the revenue requirement and set the rates in this proceeding.

Sixth, I describe the process used to design the rates that are being proposed in this proceeding.

Finally, I discuss the bill impacts on customers resulting from the proposed rates.

Q8. Are you sponsoring any attachments?

A8. Yes. I am sponsoring the following attachments:

Attachment No.	**Name**
AES Indiana Attachment BR-1	Résumé
AES Indiana Attachment BR-2	Description of the ACOSS Model
AES Indiana Attachment BR-3	Summary of Class Cost Allocation and Unit Costs
AES Indiana Attachment BR-4	Proposed Mitigated Revenue Requirement by Class
AES Indiana Attachment BR-5	Industrial Rate Design
AES Indiana Attachment BR-6	Class Revenue Summary

AES Indiana Attachment BR-7	Test Year Revenue Proofs at Current and Proposed Rates
AES Indiana Attachment BR-8	Summary of Proposed Rate Design
AES Indiana Attachment BR-9	Residential Bill Impacts
AES Indiana Attachment BR-10	Residential Multi-Family Rate Evaluation
AES Indiana Attachment BR-11	Phase 1 Credit Calculations
AES Indiana Attachment BR-12	LED versus non-LED Comparison
AES Indiana Attachment BR-13	TDSIC Allocation Factors

Q9. Are you submitting any workpapers?

A9. Yes. I am submitting the following workpapers:

Workpapers	**Name**
AES Indiana Confidential Workpaper BR-1.0C	CONFIDENTIAL Cost of Service Model [Excel file]
AES Indiana Workpaper BR-1.1	Functionalization, Classification, and Allocation Factor Assignment
AES Indiana Workpaper BR-1.2	Internal Allocation Factors
AES Indiana Workpaper BR-1.3	Detail Results of ACOSS
AES Indiana Workpaper BR-2.0	Class Allocation Factors – External [Excel file]
AES Indiana Workpaper BR-2.1	Class Allocation Factors Summary
AES Indiana Workpaper BR-2.2	Primary Secondary Study
AES Indiana Workpaper BR-2.3	Minimum System Study
AES Indiana Workpaper BR-2.4	Peak Demands
AES Indiana Workpaper BR-2.5	Customer Account Analysis
AES Indiana Workpaper BR-2.6	Uncollectibles Analysis
AES Indiana Workpaper BR-2.7	Meters and Services Study
AES Indiana Confidential Workpaper BR-3.0C	CONFIDENTIAL Rate Design and Revenue Proof Calculations [Excel file]
AES Indiana Workpaper BR-4.0	Lighting LED v/s Non-LED Comparison [Excel file]
AES Indiana Workpaper BR-5.0	Residential Bill Impact Calculations [Excel file]

The workpapers that end in zero (e.g., 1.0) are provided as Excel files, while the workpapers with a non-zero suffix (e.g., 1.1) are provided as hardcopy excerpts from the Excel files.

Q10. Are you sponsoring any financial exhibits in this case?

A10. Yes. I sponsor AES Indiana Financial Exhibit AESI-OPER, Schedule REV10 – Electric Operating Revenue Adjustment at Proposed Rates.

Q11. Were the attachments, workpapers, and financial exhibits that you sponsor prepared or assembled by you or under your direction and supervision?

A11. Yes.

II. ALLOCATED COST OF SERVICE STUDY

A. Introduction to ACOSS

Q12. Please describe the general approach used to develop the ACOSS.

A12. The purpose of the ACOSS in this proceeding is to allocate AES Indiana's overall revenue requirement to the various classes of service in a manner that reflects the relative costs of providing service to each class. This is accomplished through analyzing costs and assigning each customer or rate class its proportionate share of the utility's total revenues and costs within the test year. The results of these studies can be utilized to determine the relative cost of service for each customer class and help to determine the individual class revenue responsibility. The results also provide useful guidance in terms of designing rates for each class.

To allocate costs to the various classes, I reviewed AES Indiana's expense and plant accounts and worked with various AES Indiana personnel to develop studies of the relative costs of providing facilities and services for each rate class and analyzed the key factors that cause the costs to vary.

Q13. Please describe the Concentric Model that was used in conducting the ACOSS filed in this proceeding.

A13. AES Indiana has selected the Concentric Model for purposes of conducting the electric ACOSS in this general rate case. The same model was used in AES Indiana's most recent rate cases in Cause Nos. 45911, 45029, and 44576. Concentric has developed a proprietary model for the purpose of conducting allocated cost of service and Concentric is using that model for purposes of conducting the electric ACOSS in this rate case. A brief description of the Concentric Model is provided with this testimony as AES Indiana Attachment BR-2.

Q14. Is an electronic copy of the Concentric Model provided to the Commission?

A14. Yes. The Concentric Model in Excel format with formulas intact is included with the workpapers provided to the Commission as AES Indiana Confidential Workpaper BR - 1.0C supporting my Direct Testimony. In addition, hardcopy details of the cost functionalization, classification, and allocation results produced by the model are provided in my workpaper labeled as AES Indiana Workpaper BR-1.3.

B. Principles of ACOSS Preparation

Q15. What is the guiding principle that should be followed when performing an ACOSS?

A15. The fundamental principle underlying an ACOSS is that cost allocation should follow cost causation. Cost causation addresses the question of which customer or group of customers causes the utility to incur particular types of costs. In order to answer this question, it is necessary to establish a relationship between the services used by a utility's customers and the particular costs incurred by the utility in serving those customers.

Q16. What are the steps to performing an ACOSS?

A16. To establish the cost responsibility of each customer class, a three-step analysis of the utility's total operating costs must be undertaken. The three steps which are the predicate for an ACOSS are: (1) cost functionalization; (2) cost classification; and (3) cost allocation.

Q17. Please describe cost functionalization.

A17. The first step is cost functionalization, where the plant investment costs and operating expenses are categorized by the operational functions with which they are associated. AES Indiana's primary functional cost categories associated with electric service include Production, Transmission, Primary Distribution, Secondary Distribution, and Customer Accounts and Services. In addition, various categories of costs within the distribution function are assigned to separate sub-functions to the extent their costs vary in response to different customer class characteristics. Indirect costs that support these functions, such as General Plant, and Administrative and General Expenses, are allocated to functions using allocation factors related to plant and/or labor ratios.

Q18. Please describe cost classification.

A18. The second step, cost classification, further separates the functionalized plant and expenses according to the primary driver of the costs. 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 1) Customer Costs, 2) Demand Costs, and 3) Energy Costs, respectively.

Q19. How are these classification categories 1) Customer Costs; 2) Demand Costs and 3) Energy Costs related to the amount of costs incurred by the Company?

A19. *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 are largely a function of 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, 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 and substations, or more localized distribution facilities which are designed to satisfy individual customer maximum demands. Demand costs are fixed in nature, and do not vary with the number of customers or the amount of energy that customers consume.

Energy Costs are those costs which vary with the amount of kilowatt hours ("kWh") sold to customers. For example, included in the instant study are base fuel rates as well as some production operating costs that tend to vary with the amount of energy produced. However, except for fuel, the vast majority of AES Indiana's costs are fixed with respect to energy usage and very little of its remaining delivery service cost structure is energy related.

Q20. What is the process followed to appropriately classify costs as Customer, Demand, and Energy?

A20. Usually, a determination on the classification of costs can be made simply by knowing the type of activities or assets that reside within a particular FERC account. In these instances, the entire account can be classified into a single category. However, for some FERC account functions it is beneficial to conduct classification studies to determine which portion of an account is associated with each classification category. Further discussion of the classification studies used in AES Indiana's ACOSS is provided in the section discussing studies of relative costs below.

Q21. Please describe cost allocation.

A21. The third and final step, cost allocation, is the allocation of each functionalized and classified cost element to the individual customer or rate class that cause the cost to be incurred. Customers generally are divided into customer classes based on the type and character of services that they require. Costs typically are allocated to these customer classes based on factors related to the number of customers and the amount of energy and capacity demanded by customers. For example, much of the plant and equipment cost depends upon the peak demand of the customers and these costs were allocated based on the peak demands of the rate class. Other portions of the cost depend upon the number of customers on the system and these costs were 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 consumed by customers. These costs were allocated based on the amount of energy consumed, adjusted for losses of energy that occur across the transmission and distribution system.

Q22. How do you then establish the fully allocated costs related to various utility services?

A22. To establish these relationships, one must analyze a utility's electric system design, physical configuration and operations, its accounting records, and its system and customer load data. From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for each of the utility's plant and expense elements.

Q23. Please explain the term "direct assignment."

A23. The term "direct assignment" means the assignment of costs to a specific customer or class of customers based on that customer's or class's exclusive identification with the particular plant or expense at issue. Usually, costs that are directly assigned relate to costs incurred exclusively to serve a specific customer or class of customer. Direct assignments best reflect the cost causative characteristics of serving individual customers or classes of customers. Therefore, in performing a cost of service study, one 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 based on an analysis of factors that affect the relative costs of serving particular customer classes.

Q24. What prompts the need to perform a study of the relative costs?

A24. When direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, further analysis will need to be conducted to derive an appropriate basis for cost allocation. For example, in evaluating the costs charged to certain operating or administrative expense accounts, it is customary to assess the underlying activities, the related services provided, and for whose benefit the services were performed.

Q25. Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned to a specific customer or certain customer classes?

A25. No. The nature of utility operations is characterized by the existence of facilities used jointly or commonly by multiple customers and classes. To the extent that a utility's plant and expenses cannot be directly assigned to customer classes, allocation methods based on cost causation must be derived to assign or allocate the remaining costs appropriately to the customer classes. The analyses discussed above facilitate the derivation of reasonable allocation factors based on cost causation for cost allocation purposes.

Q26. Please explain the considerations relied upon in determining the cost allocation methodologies that are used to perform an ACOSS.

A26. 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. 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.

III. AES INDIANA'S ACOSS

Q27. What attachments and workpapers show the allocation of costs to the various rate classes?

A27. The results of the ACOSS are summarized in AES Indiana Attachment BR-3. The assignment of functionalization, classification and allocation factors to each cost item is shown on AES Indiana Workpaper BR-1.1 and the internal allocators used to assign various overhead costs to rate classes are shown on AES Indiana Workpaper BR-1.2. Once the costs are functionalized and classified, they are allocated to rate classes. The details of those allocations are shown on AES Indiana Workpaper BR-1.3 and the primary class-cost allocation factors are shown on AES Indiana Workpaper BR-2.1. In addition, various special studies of relative costs used in the classification and allocation of costs are presented further in my testimony.

A. Sources of the Underlying Data

Q28. What is the source of the cost data analyzed in AES Indiana's ACOSS?

A28. All cost of service data have been extracted from the Company's total cost of service (*i.e.*, the base rate revenue requirement) contained in this general rate case filing. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company and information provided by relevant company personnel.

Q29. Did you make any adjustments to the total cost of service as provided by AES Indiana?

A29. I made an adjustment to eliminate negative rate base that occurs for the APL lighting rate codes. This is the result of negative net plant balances associated with FERC account 371 – Installations on Customer Premises. A negative rate base incorrectly suggests a negative cost to providing lamps and equipment to these customers. To remedy this, I set the rate base for FERC account 371 to zero. As a result of this remedy, I needed to redistribute the negative rate base value to the other distribution accounts to ensure the total rate base was correct. This is similar to how the Company treated the negative rate base associated with FERC account 371 in its two most recent rate cases[1].

B. Functionalization and Classification of Costs

Q30. How did you functionalize and classify AES Indiana's costs?

A30. The process starts with the assignment of the Company's FERC 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 two functions: primary distribution and secondary distribution. In addition, these costs have been further separated into demand and customer classifications. Similarly, a portion of the production O&M expenses other than fuel have been classified as either fixed (demand-related) costs or variable (energy-related) costs.

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[1] Cause Nos. 44576 and 45029.

Plant and O&M costs related to production, transmission and distribution generally can be assigned directly to specific functions, but various indirect costs related to overhead such as intangible plant and general plant, as well as administrative and general expenses are allocated to functions using "internal allocators" that are based on the relative amount of certain costs that have been directly assigned to each function. The specific functionalization allocators used to assign overhead costs have been selected to reflect the type of direct costs that each overhead account generally supports.

Q31. Do you have a workpaper that provides details of the functionalization and classification process?

A31. Yes. The assignment of functionalization and classification factors are shown on AES Indiana Workpaper BR-1.1. Each cost item and the amount of dollars therein, is shown in the first column of costs shown on the workpaper. If an account is split into sub-functions, or into separate classifications, those splits are also shown in that first column. As mentioned previously, a few accounts, such as poles and conductors, have split classifications to reflect the fact that a portion of the costs are demand-related, and a portion of the costs are customer-related. Similarly, a portion of the O&M expenses of the generating plants are classified as either fixed (demand-related) costs or variable (energy-related) costs.

Q32. Please explain the primary-secondary study.

A32. Since the costs associated with distribution facilities are not specifically identified in the financial accounting records as being Primary Distribution (480 V – 34.5 kV) or Secondary Distribution (< 480 V), the distribution costs in Accounts 364–367 have been assigned to

Primary or Secondary distribution functions based on cost-related ratios that were developed from analyses of the distribution plant records.

Distribution poles were functionalized between primary and secondary voltages based on the relative cost of replacing all primary poles versus secondary poles. Using AES Indiana's Geographic Information System ("GIS"), the number of poles carrying primary versus secondary voltage by height and class was obtained. For each category of pole, the pole count was multiplied by the replacement cost of that pole type to obtain the total replacement cost of that pole type. For pole types that are no longer used, a replacement pole was identified and the cost of that replacement pole was used in the analysis. Using the total costs of all poles by voltage, the ratio of primary poles to secondary poles was calculated. The results of this analysis are provided on AES Indiana Workpaper BR-2.2 - Primary Secondary Study.

Distribution conductors were functionalized between primary and secondary voltages by utilizing length of conductors and replacement costs of conductors serving primary versus secondary distribution systems. Using AES Indiana's GIS, the length of conductors carrying primary versus secondary voltage was obtained. For each conductor type, the length of the conductor was multiplied by the replacement cost of that conductor to obtain the total cost of that conductor type. For conductor types that are no longer used, a replacement conductor was identified and the cost of that replacement conductor was used in the analysis. Using the total costs of all conductors by voltage, the ratio of primary conductors to secondary conductors was calculated. The results of this analysis are also provided on AES Indiana Workpaper BR-2.2 - Primary Secondary Study.

Q33. Please explain the Minimum System Study.

A33. The costs associated with a distribution system are related to both the peak amount of load that the system is designed to deliver and the number of customers and premises that it is designed to serve. Consequently, it is appropriate to allocate a portion of the distribution system costs on a demand-related basis and a portion on a customer-related basis. In order to classify a certain portion of the distribution system costs as demand-related or customer-related, a Minimum System Study was conducted which included an analysis for poles and an analysis for conductors. The minimum system analysis compares the cost of a hypothetical minimum system (*i.e.*, a system sized to simply connect customers) to the total cost of the entire system. The minimum system cost represents the customer-related costs; whereas the total costs less the minimum system costs represent the demand-related costs (*i.e.*, total cost is split between the customer component and the demand component).

The Primary and Secondary Analysis for poles described above provided the total cost and total count of primary and secondary poles. This total count of primary poles was multiplied by the replacement cost of a minimum sized primary pole to calculate the minimum system replacement cost of primary poles. This was then compared to the total replacement cost of primary poles to determine the portion of primary poles that is customer related and demand related. A similar analysis was conducted for secondary poles. The results of this analysis are provided on AES Indiana Workpaper BR-2.3 – Minimum System Study.

The Primary and Secondary Analysis for conductors described above provided the total cost and total circuit miles of primary and secondary conductors. A hypothetical minimum system replacement cost was calculated by taking the total circuit feet of conductor that related to the primary system and multiplying it by the replacement cost of a minimum sized primary conductors. The minimum system replacement cost was then compared to the total system replacement costs to arrive at the customer related and demand related costs for primary conductors. A similar analysis was conducted for secondary conductors. The results of this analysis are provided on AES Indiana Workpaper BR-2.3 – Minimum System Study.

Q34. Please explain the functionalization of production O&M into fixed and variable components.

A34. As a general matter, with the exception of fuel costs, most production O&M expenses tend to fluctuate very little in response to changes in a generating plant's output. In reviewing production O&M expenses with Company personnel, it was determined that certain production operating expenses related to materials such as limestone and chemicals are clearly variable; specifically, certain portions of FERC Accounts 502, and 506. These expenses were calculated for the test year, and it was determined that about 1.6 percent of non-fuel production O&M expense was variable.

Q35. How are the costs then assigned to functions?

A35. The next step in the process is to spread the costs listed in the first column of costs on AES Indiana Workpaper BR-1.1 to the various columns that designate the classifications and functions. In addition, several categories of revenue are designated on AES Indiana Workpaper BR-1.1 so that they ultimately will be credited to the cost of service of the various rate classes.

Q36. How were direct costs functionalized?

A36. The direct costs of distribution plant and O&M expenses are directly assigned to their proper function and classification. O&M costs that are readily-identified with a specific function are assigned directly to the corresponding function. Distribution Supervision and Engineering expenses (Accounts 580 and 590) are allocated to functions using factors based on direct distribution operation labor and direct distribution maintenance labor. Miscellaneous Distribution Expense (Accounts 588) and Rents (Account 589) are allocated to distribution functions using factors based on total distribution plant.

Q37. How did the ACOSS allocate distribution-related O&M expenses?

A37. In general, these expenses were allocated based on the cost allocation methods used for the Company's corresponding plant accounts. This is based on the assumption that a utility's distribution-related O&M expenses are generally thought to support the utility's corresponding plant in service accounts. Put differently, the existence of particular plant facilities necessitates the incurrence of operating and maintenance cost (*i.e.*, expenses by the utility to operate and maintain those facilities). Thus, the allocation basis for a particular expense account will be the same basis as that used to allocate the corresponding plant account.

Q38. How are overhead costs functionalized?

A38. Indirect plant costs are allocated to functions based on ratios derived from direct plant costs. For example, Intangible Plant is allocated based on the relative amount of production, transmission and distribution plant directly assigned to each function. General Plant is assigned using the "Direct Labor" allocator.

Administrative and General Expenses were allocated to various functions using three different allocators. First, Salaries, Office Supplies, Administrative Expenses Transferred, Injuries and Damages, Employee Pensions and Benefits, and Maintenance of General Plant were allocated using the direct labor allocation factor. Second, Property Insurance was allocated using the relative amount of rate base associated with each function. Third, Outside Services, Regulatory Commission Expense, General Advertising Expense, and Rents were allocated using a combination of the direct labor and the direct plant allocators.

Q39. How were taxes other than income taxes assigned to functions?

A39. All taxes, except for income taxes, were functionalized in a manner that reflects the specific cost associated with the particular tax expense category. Generally, taxes can be functionalized using the tax assessment method established for each tax category, (*e.g.*, payroll, property, or sales taxes). Depending on the method of assessment, other taxes were assigned or allocated to functions using either: (1) direct labor ratios; or (2) plant ratios.

Q40. How were income taxes assigned to functions?

A40. Because income taxes are a function of the return on rate base, income taxes were allocated to functions based on the amount of rate base associated with each function.

C. Allocations to Rate Classes

Q41. What was the next step in the ACOSS?

A41. After functionalizing and classifying the costs as shown on AES Indiana Workpaper BR-1.1, the functionalized and classified costs were allocated to the individual rate codes or classes on AES Indiana Workpaper BR-1.3 – Detail Results of ACOSS.

(1) Allocation of Demand-related Costs

Q42. How were the demand-related costs allocated in the proposed ACOSS?

A42. I utilized a coincident peak demand method to allocate production 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 its peak. "Non-coincident Peak" refers to the highest level of demand that an individual class experienced during the year or month. This non-coincident peak for a given class may coincide with the overall system peak but, generally, it occurs at other times than the system peak. The factors used to allocate costs to rate classes are developed in AES Indiana Workpaper BR-2.0, and the resulting allocation factors are shown on AES Indiana Workpaper BR-2.1 – Class Allocation Factors Summary. Coincident and Non-Coincident peak demands for each of the classes are also shown on AES Indiana Workpaper BR-2.4.

Q43. What was the source of the data used to develop the demand-related allocation factors?

A43. This data was provided to Concentric by AES Indiana based on information collected and calculated as part of the Company's ongoing load research program. The peak demand allocators utilized in the ACOSS are shown on AES Indiana Workpaper BR-2.4. The determination of peak demand allocators is described in more detail by AES Indiana witness Russo.

Q44. Which coincident peak demand allocation method did you utilize to allocate production and transmission demand-related costs?

A44. I utilized the coincident peaks during each of the twelve months of the test period ("12CP") to allocate demand-related costs associated with the production and transmission functions. This is the method the Company used in its three most recent rate cases[2]. In addition, I applied the FERC's cost allocation tests to AES Indiana's load characteristics. As shown in the table below, AES Indiana met all three criteria of the FERC 12-CP tests, which indicates that the 12CP method continues to be appropriate.

	Peak - Off-Peak % Difference	Low/Annual Peak Ratio	Avg/Annual Peak Ratio
Use 12 CP if:	≤ 19.0%	≥ 66.0%	≥ 81.0%
Test Year	18.9%	66.0%	82.9%

Q45. Which peak demand method did you use to allocate the costs of demand-related distribution costs?

A45. I used the non-coincident peak demands of customer classes to allocate the costs of demand-related distribution costs, similar to how these costs have been allocated in the past. 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

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[2] Cause Nos. 44576, 45029, and 45911.

method ensures that all classes share in the costs of these facilities. As a result, non-coincident peak demands of each class were used in allocating demand-related costs associated with these distribution system facilities.

(2) Allocation of Energy-related Costs

Q46. How are the energy-related costs allocated in the ACOSS?

A46. Energy-related costs are allocated to the various rate classes based on the amount of energy used by each class during the test year, adjusted for abnormal weather effects, where appropriate, and energy losses that occur in serving customers at different voltage levels.

Q47. Were the energy and demand cost allocation data adjusted for line losses in the electric system?

A47. Yes. Because some energy and power are lost in the process of transmitting and distributing electricity to customers, the amount of usage that is recorded at a meter is less than the amount of energy, power and capacity that is required at the production and transmission levels. The amount of system losses is greatest for customers that take service at the secondary voltage levels, and somewhat less for customers at primary, sub-transmission and transmission levels, respectively. To account for the different amount of losses experienced in serving customers at different voltage levels, the factors used to allocate demand- and energy-related costs to the various classes have been adjusted for the line losses that occur at each stage in the distribution system. The result is to appropriately allocate somewhat more of these costs to customers who take service at successively lower voltage levels.

(3) Allocation of Customer-related Costs

Q48. How have the customer-related costs been allocated in the ACOSS?

A48. 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-related costs are allocated to classes using allocators that are related to the number of customers in the class. However, because there generally is a very 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 codes or classes. Thus, customer-related costs such as meters, service lines, 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 AES Indiana Workpaper BR-2.1 – Class Allocation Factors Summary. The general methods used to develop the customer-related allocation factors are discussed below.

Q49. How were metering costs allocated to rate classes?

A49. Every customer, except lighting customers, requires a meter, but Commercial and Industrial meters generally cost considerably more and require more equipment compared to Residential meters. For this reason, meter weights were developed for each of the customer classes based on a list of the number and types of meters installed for each rate code and the associated embedded costs of each type of meter. In addition, an analysis was conducted to account for cabinets and transformers required by some meters by rate code. The embedded meter cost along with cabinet and transformer requirement provided an estimate of the relative cost of providing metering service for each rate code. The relative-weight factor was then multiplied times the number of customers in the class to develop the factors shown on AES Indiana Workpaper BR-2.1 – Class Allocation Factors Summary that were used to allocate metering costs to each class. Further details supporting the meter allocator are provided as AES Indiana Workpaper BR-2.7 – Meters and Services Study.

Q50. How were service lines allocated to each class?

A50. AES Indiana provided an estimate of the costs per service for residential and commercial customers for those served from overhead systems and those served from underground systems. This provided a relative weighting between residential and commercial customers which was multiplied by the number of customers in the class. The weighting factors and the allocation factors used for services are shown on AES Indiana Workpaper BR-2.1 – Class Allocation Factors Summary and the additional backup is provided as AES Indiana Workpaper BR-2.7 – Meters and Services Study.

Q51. How were customer service costs allocated?

A51. AES Indiana conducted an analysis of various Company departments and sub-functions dedicated to the customer service functions. In the course of the analysis, the costs of certain departments or sub-functions were allocated based on the estimates of department managers as to the proportion of the time and expenses incurred that are related to a particular customer class. For other departments or sub-functions, the costs were allocated on customer counts or allocated based on the results of combined departments. The relative weighting and allocation factors used are presented on AES Indiana Workpaper BR-2.1 – Class Allocation Factors Summary with additional information provided as AES Indiana Workpaper BR-2.5 – Customer Account Analysis.

Q52. Are there any other methods used to assign customer-related costs?

A52. Yes. The costs associated with meter reading and customer-related primary and secondary distribution costs were allocated on the basis of customer counts. Meter reading is an automated process for AES Indiana so there is no expectation that meter reading costs vary materially between rate classes. Uncollectible costs were allocated based on the amount of uncollectibles by rate class category. Details relating to uncollectibles are provided in AES Indiana Workpaper BR-2.6 – Uncollectibles Analysis.

IV. RESULTS OF AES INDIANA'S ACOSS

Q53. Please describe the results of the ACOSS with respect to rate of return under the Company's rate classes.

A53. The summary of the results of the ACOSS and the relative rates of return produced by each class for the forecasted test year ending December 31, 2026, are presented in <u>AES Indiana Attachment BR-3</u> and summarized in Table 1 below. This attachment is organized into two sections: the first half shows the costs and revenues of serving each of the four consolidated rate classes (Residential, Small Commercial and Industrial, Large Commercial and Industrial, and Lighting); and the second half shows the same information broken out into separate rate codes (RS, SS, SH, etc.). As shown on line 18 of this attachment (on pages 8 and 13) and table below, at present rates the ACOSS shows a wide variation in the rates of return by rate schedule.

Table 1: Rate of Return and Subsidy at Current Rates

Rate Class	Rate Code	Return at Current Rates	Relative Rate of Return	Current Subsidy
Residential	RS	3.48%	0.71	($51,220,162)
Secondary Small	SS	8.26%	1.68	$23,872,370
Small Metered Service	MD	14.77%	3.00	$125,509
Space Conditioning	SH	5.63%	1.14	$2,053,834
Space Conditioning – Schools	SE	11.79%	2.40	$404,082
Water Heating – Controlled	CB	-0.50%	-0.10	($18,335)
Water Heating – Uncontrolled	UW	4.13%	0.84	($5,003)
Secondary Large	SL	6.12%	1.24	$15,766,710
Primary Large	PL-HL	7.23%	1.47	$19,138,676
Process Heating	PH	8.36%	1.70	$295,462
Automatic Protective Lighting	APL	-9.12%	-1.85	($4,023,621)
Municipal Lighting	MU1	-6.68%	-1.36	($6,389,522)
Total System		4.92%	1.00	$0

Q54. What is the amount of the rate increase or decrease that each customer class would need in order for each class to produce the system average required rate of return?

A54. Line 31 of AES Indiana Attachment BR-3 indicates the current subsidy received (negative) or provided (positive) by each class. The current subsidy is the amount of rate increase or decrease that would be required for each rate class if the goal were to have all classes produce equal rates of return at the current level of cost recovery. Line 44 shows the amount of increase that would be required for each class to pay its fully-allocated cost of service at proposed revenue requirement.

V. DESCRIPTION OF PROPOSED CLASS REVENUE REQUIREMENTS

Q55. What total electric revenue requirement is the Company proposing in this proceeding?

A55. The Company has a total revenue requirement of approximately $2,111 million as shown on line 46 of AES Indiana Attachment BR-3. Because the Company collects miscellaneous other revenue including ancillary charges and off-system sales margin that are reflected as a credit against that total revenue requirement, the proposed rates are designed to collect Base Rate revenue of approximately $2,060 million from the retail customers, as shown on line 49 of AES Indiana Attachment BR-3.

Q56. Have you examined the percentage rate increases that would be required for each rate schedule according to the Allocated Cost of Service Study?

A56. Yes. Column C of AES Indiana Attachment BR-4 presents normalized base rate revenues that AES Indiana can expect to recover from each rate schedule at current rates, while column D of that attachment shows the allocated cost of service for each schedule. Column F shows the percentage increase/decrease in base rates that would be required if unmitigated ACOSS results were to be applied. Although the overall rate increase that the Company is requesting is approximately 10.34 percent, the unmitigated ACOSS indicates that the residential class would require a rate increase of around 18.15 percent and the Municipal Lighting rate schedule would require a rate increase of as much as 78.12 percent. Column G shows the subsidy that each class and rate schedule is paying or receiving at current rates. Even though the goal is to move all rate classes to their cost of service, consistent with the policy of the state, the Company considered affordability for each of the customer classes and determined that the percentage rate increases experienced by individual rate schedules should be mitigated to moderate the impacts on individual rate schedules.

A. Mitigation of Class Impacts

Q57. How did you go about mitigating the class rate increases?

A57. The proposed revenue allocation to each rate class was derived based on discussion with the Company. The criteria used for the proposed revenue allocation are: 1) eliminate 50% of the current subsidy subject to an increase cap of 1.3 times the overall system increase to any rate schedule; and 2) no rate schedule receives a rate reduction.[3] I believe that this approach reduces the inter-class subsidies and moves classes closer to their cost of service, while ensuring that impacts on any one particular class is moderated.

Q58. Did you consider other alternate revenue allocation approaches?

A58. Yes. I also considered applying simply a subsidy reduction approach that the IURC has approved in prior rates cases for AES Indiana as well as in rate cases for other utilities. This subsidy reduction approach first calculates the subsidy that each rate schedule is currently paying, which is equal to the difference between the revenue collected during the test year and the amount of revenue that was required in order for each rate schedule to generate the system-wide average rate of return. This approach then determines a proportion of the subsidy at current rates to be eliminated. However, given the wide disparity in the rate of return at current rates by rate schedule, this approach still resulted

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[3] Rate MD (Small Metered Service) was an exception to the no rate reduction rule since this is a rate designed to accommodate small devices that do not belong in Rate SS.

in certain rate schedules getting very large increases. As a result, I implemented an additional criterion that capped the increase to any one rate schedule to 1.3 times the system increase.

Q59. Please describe the results of your mitigation approach.

A59. Column V of AES Indiana Attachment BR-4 shows the final mitigated revenue requirement by rate class and rate schedule. Column W shows the final rate increase for each rate class and rate schedule. Column X shows the percentage of current subsidy removed as a result of the proposed mitigation approach. Finally, Column Y shows the ratio of final mitigated revenue requirement to revenue requirement resulting from the ACOSS. This ratio ranges from 0.64 to 1.25 based on the proposed mitigated revenue requirement. Page 3 of AES Indiana Attachment BR-4 supports AES Financial Exhibit AES-OPER, Schedule REV10.

Q60. What rate of return would be generated by each rate schedule at the proposed mitigated revenue requirements?

A60. The pro forma rates of return that would be generated by each rate schedule at the proposed mitigated revenue requirements are shown on line 64 of AES Indiana Attachment BR-3.

VI. RATE DESIGN

A. Rate Design Objectives and Principles

Q61. Are there general rate design principles that are accepted by the utility industry?

A61. Yes. As a general matter, utility rate analysts have followed the general rate design criteria proposed by Professor James C. Bonbright in his seminal book “Principles of Public Utility

Rates" first published in 1961.[4] The following eight rate design criteria have remained viable for more than five decades now and are still as relevant:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretations.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amount of use.

Q62. Are these general rate criteria for rate structures all consistent with one another?

A62. No, they are not required to be. For example, designing rates strictly based on cost of serving a particular class could conflict with the goal of achieving rate stability and gradualism. Hence, there will be conflict among these rate criteria, based on the specific facts and circumstances of any company.

Q63. Are some of these general rate design criteria more important than others?

A63. Yes. I agree with Professor Bonbright's assessment (page 292) that the rate criteria designated as items (3), (6), and (8) above are considered to be the primary ones. Item (3) relates to the recovery of the authorized revenue requirement under the "fair return" standard; item (6) relates to the "fair cost apportionment objective" and item (8) relates to the efficiency objective. Even within these three criteria, the "fair return" standard is

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[4] Bonbright, James C. (1961). *Principles of Public Utility Rates*, New York: Columbia University Press.

paramount because a rate structure that meets all the other rate design criteria but fails to recover the required return on and return of capital, will threaten the basic viability of the utility and its ability to provide service.

Q64. What are the principles and objectives of AES Indiana for designing rates in this proceeding?

A64. AES Indiana had three primary policy objectives in the development of the rates proposed in this proceeding, which are in alignment with the Bonbright criteria mentioned above: (1) the charge for any service provided is just and reasonable; (2) the rates and charges should provide AES Indiana an opportunity to recover its revenue requirement; (3) the rates should provide incentives for efficient usage of the system by promoting justified usage while discouraging wastefulness. In addition, gradualism in rate changes on customers was another important objective of the Company. In light of gradualism and affordability considerations, the Company proposes to mitigate the impact of rate changes on any one rate schedule in this rate case. This results in proposed rates that are adjusted only part of the way in the direction of fully-allocated costs. To achieve that goal, I have capped the increases to any rate schedule and ensured that no customer class receives a revenue decrease. In addition, I did not increase the level of customer charges for the residential and small commercial rate classes to a level that fully recovers fixed costs at this time and retained the current inclining block structure of the customer charges, so as to mitigate the impacts on smaller customers in the residential and small commercial rate classes.

B. Proposed Rate Design

Q65. Are there any unique considerations regarding rate design in this case as compared to the prior cases?

A65. Yes. Since the Company is utilizing a forward-looking Test Year, with end-state (Phase 2) revenue requirement and an intermediate period (Phase 1) revenue requirement, I designed rates for Phase 2 initially, and a crediting mechanism for Phase 1 to account for lower revenue requirement in Phase 1. After that I designed credits that would apply during the Phase 1 period such that the Company will credit back the difference between Phase 1 and Phase 2 revenue requirement during this period. I will discuss the rate design process for Phase 2 rates followed by the design of Phase 1 credit.

Q66. Were there certain general principles that you followed in designing rates for individual rate schedules?

A66. One principle that I applied was to move towards alignment of the rate structures with cost structures. I relied on the results of the ACOSS to inform changes to the magnitude of individual rate components for each rate schedule. To increase the alignment of rate structures and cost structures, I generally increased the customer charges and/or the demand charges to a level that recovers a higher proportion of the fixed costs of service. As a result, I have attempted to reduce the proportion of the fixed costs recovered through variable energy charges.

I started with the amount of the revenue requirement for each rate schedule and subtracted out the base fuel costs to derive the amount of the margin that would need to be collected. If a particular rate had a customer charge and demand charge, I changed the customer charge to be closer to the level of customer-related costs calculated by the ACOSS, which is presented on AES Indiana Attachment BR-3. For rate schedules that have demand charges, I designed the rates to recover most of the remaining fixed costs in a demand charge. Energy charges for these rate schedules (i.e., rate classes with demand charges) are designed to recover the fuel and variable energy costs, plus a margin of approximately one mill per kWh. For rate schedules that do not have demand charges, I set the energy charge at a level that would recover the remaining portion of the revenue requirement not recovered from customer charge, generally through a declining block energy charge.

Q67. Did you have additional considerations for residential rate design?

A67. Yes. I designed residential rates such that customers who consume more energy receive larger increases in dollar terms in their monthly bill as compared to the smaller customers. This resulted in larger residential customers experiencing a larger dollar increase, but a lower percentage increase, in their monthly bills than smaller customers. I also ensured that the smallest customers (customers using less than 325 kWh per month) receive increases of less than $8.35 per month.

Q68. How were the proposed rates for each rate schedule calculated?

A68. Detailed calculations for each rate component of each rate schedule and a proof of proposed revenues by rate schedule is shown on AES Indiana Attachment BR-7 and in AES Indiana Workpaper BR-3.0C. As the attachment shows, the proposed total revenue requirement for each rate schedule will be achieved by implementing the proposed rates.

Q69. What levels of monthly customer charges are you proposing for the residential and small commercial rate schedules?

A69. The proposed rates would increase the Residential monthly customer charge, which is a discrete charge within the total residential rate structure, for the small customers (< 325 kWh/month) from its current level of $12.50 to the proposed level of $15.00, and the customer charge for the larger customers (> 325 kWh/month) would be increased from $17.00 to $20.00. It is important to clarify that this proposed change in this isolated component (*i.e.*, customer charge) does not reflect the Company's proposed change in the overall residential rate. I discuss the residential rate impact from proposed rates later in my testimony. I am proposing to change the monthly customer charge for the Small Secondary service from $40 to $44. All of these changes are being made in order to more closely reflect the costs of serving each customer, as indicated by the ACOSS, while accounting for gradualism considerations. For example, the unit costs resulting from the ACOSS are shown near the bottom of AES Indiana Attachment BR-3. To reflect the actual fixed costs to serve customers, for the Residential class the cost-based customer charge would be approximately $120 and for the Small Secondary rate schedule the cost-based customer charge would be approximately $242. Thus, although the increases in customer charges for these rate schedules move in the direction of recovering more of the actual fixed costs in the customer charge, a substantial portion of fixed costs will still be recovered in the variable energy charge component of the rates for these customers. For the Residential class, the proposed $20 customer charge only recovers about 17% of the fixed costs and for the Small Secondary rate schedule, the proposed $44 customer charge only recovers about 18% of the fixed costs. The increase in customer charges as proposed is consistent with the Commission's recognition that "[c]ost 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."[5]

Q70. How are you proposing to recover the remaining fixed costs in the variable energy charge component of the residential and small commercial rate schedules?

A70. The existing declining-block rate structure for these two rate schedules (*i.e.*, RS and SS) is retained in the proposed rates. For the residential (RS) class the rates per kWh are higher for the first 500 kWh and lower for amounts over 500 kWh. Residential water heating (RC) and space heating (RH) customers also are eligible for a lower third block for consumption over 1,000 kWh in a month. For the small commercial (SS) customers, the first 5,000 kWh consumed each month will be charged at a higher rate, and a lower rate will be charged for amounts over 5,000 kWh.

Since the residential and small commercial customers do not have a demand charge, a declining block rate structure is an alternative way to recover the fixed costs that are not recovered in the customer charge. AES Indiana's declining block rate structure for these rate schedules helps ensure that an appropriate level of fixed costs is recovered from each customer while also reducing the amount of fixed costs loaded into the marginal energy charges. This blocking structure provides better price signals for efficient consumption and also reduces the variability of the Company's earnings that may result from year-to-year fluctuations in consumption, in spite of the fixed nature of the costs incurred.

Q71. How did you design the rates for large industrial customers?

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[5] *Indianapolis Power and Light Company,* Cause No. 44576 (IURC Mar. 16, 2016), page 72.

A71. Similar to AES Indiana's last rate filing, costs were allocated to the PL and HL classes as a single group in the cost allocation process. The calculation of the cost of service for each of the rate codes in this group are shown on AES Indiana Attachment BR-5 and the "Industrial Cost Allocation" tab of AES Indiana Workpaper BR-3.0C.

First, the allocated Production and Transmission costs were assigned to each rate code based on the loss-adjusted demand billing determinants. This resulted in each rate code having a Production and Transmission Demand Charge component that was distinguished by the level of line losses incurred in providing service at different voltage levels.

Second, the allocated Distribution demand-related costs were assigned only to the PL and HL1 customers. None of these costs were assigned to the HL2 or HL3 customers, who take service at sub-transmission and transmission voltages and therefore do not use the distribution system.

Third, the allocated Distribution customer-related costs were assigned to the PL and HL1 rate codes based on the number of customers so that the same customer-related Distribution costs would be reflected in the rates for each of these rate codes.

Fourth, the allocated Meter costs were assigned to each rate code based on the weighted average cost of meters for customers on each rate code because meters for sub-transmission and transmission voltage customers tend to cost considerably more than meters for primary voltage customers.

Fifth, allocated fuel and energy costs were assigned to each rate code based on the loss-adjusted energy usage of each class. This ensured that the fuel and energy costs per kWh appropriately reflected the differences in line losses attributable to each rate code.

Sixth, credits for Other Revenues, and adjustments for rate mitigation were assigned to each rate code based on rate code specific ratios.

Finally, additional mitigation was implemented to ensure that no individual industrial rate code receives large increases.

Once the total revenue requirement for each of these large industrial rate codes was determined, the final rates were calculated on the corresponding tab of AES Indiana Workpaper BR-3.0C. These final rate design calculations are also shown in AES Indiana Attachment BR-8.

Q72. How were the proposed lighting rates determined?

A72. The proposed rates for the Automatic Protective Lights (APL) and Municipal Lights (MU) were determined by applying an across the board increase to each light to recover the revenue allocated to APL and MU rate classifications.

Q73. How did you determine the Phase 1 credit that would be applicable to all rate schedules during the Phase 1 period?

A73. I distributed the Phase 1 revenue requirement proportionately to all rate schedules based on mitigated Phase 2 revenue requirement associated with each rate schedule. I then determined the amount of Phase 1 credit associated with each rate schedule by calculating the difference between Phase 2 and Phase 1 revenue requirement allocated to each rate schedule. For rate schedules that do not have demand charges, I calculated the volumetric charge credit for Phase 1 by dividing the total credit by the total volumes. For rate schedules with a demand charge, I first allocated the total credit between demand and energy buckets using the proposed revenues to be collected from proposed demand and energy charges respectively using the proposed Phase 2 rates. Then I calculated the volumetric charge credit and demand charge credit for Phase 1 by dividing the volumetric credit amount and demand credit amount by the appropriate billing units. The details of the determination of the Phase 1 credit are provided as AES Indiana Attachment BR-11.

C. Other Rate Matters

Q74. Are there other rate related matters that you want to address?

A74. Yes. There are certain specific rate related matters that arose from the Settlement Agreement approved by the Commission in AES Indiana's last rate case in Cause No. 45911.

Q75. Were there any other considerations specifically regarding lighting?

A75. Yes. The Settlement Agreement approved by the Commission in AES Indiana's last rate case in Cause No. 45911 states, "*In its next basic rate case, AES Indiana will present an analysis of LED street lighting O&M versus other street lighting O&M and an analysis of whether LED street lighting should be treated as a separate class or subclass of street lighting. Within this analysis, the Company will differentiate the energy, customer accounts, O&M, and depreciation. While AES Indiana has agreed to conduct the aforementioned analysis, the Settling Parties agree that AES Indiana is not obligated to propose that LED street lighting be treated as a separate class or subclass or take a position in support of or against any particular rate structure in its next basic rate case. The Settling Parties further agree that Settling Parties, including AES Indiana, will have the opportunity to take any position with respect to the aforementioned analysis as they* *deem appropriate in the next basic rate case, and each Settling Party reserves the right to present its own alternative analysis and proposal.*"

Q76. Are there factors that make the comparison of LED street lighting versus other street lighting less relevant currently?

A76. Yes. The comparison of LED street lighting to other street lighting is not very relevant currently because the Company is unable to provide non-LED street lighting services to customers for majority of light types. The Company personnel indicated that they are unable to procure non-LED lights in any meaningful quantity at this time and for certain light types the Company is unable to procure non-LED lights at all. The Company is unable to provide like for like replacements for non-LED lights currently and as a result if a non-LED light fails, the Company can provide LED as an alternate or if the customer refuses LED, then the Company is unable to offer Company supplied lighting services to those customers. As a result, I do not think the LED versus non-LED comparison contemplated by the Settlement Agreement from the last case is as relevant. Notwithstanding this concern, the Company did conduct an analysis to compare the LED versus non-LED O&M as well as the other analysis contemplated in the Settlement Agreement. The results of the comparison are provided as <u>AES Indiana Attachment BR-12</u>. As shown by this attachment, the O&M per fixture associated with LED lighting is larger than the O&M per fixture associated with non-LED lighting for MU, while the reverse is true for APL.

Q77. Did you also calculate the "*the energy, customer accounts, O&M, and depreciation*" costs between LED and non-LED lights?

A77. Yes. I calculated the illustrative rates associated with new installation by light type based on the revenue requirement associated with each fixture, which is composed of return on capital, energy costs, demand costs, customer accounts costs, O&M costs, and depreciation costs. These illustrative rates were calculated for LED fixtures and equivalent non-LED fixtures. AES Indiana Attachment BR-12 shows the comparison of illustrative new installation rates between LED and equivalent non-LED fixtures. The non-LED fixtures tend to have higher illustrative rates as compared to the LED fixtures.

Q78. Is this cost differential represented in the proposed lighting rates you have designed?

A78. Yes. I have also compared the proposed rates between LED and equivalent non-LED fixtures in AES Indiana Attachment BR-12. This attachment shows that the proposed rates for LED are lower than the equivalent non-LED fixtures.

Q79. Did you perform any rate design scenario analysis associated with industrial low load factor customers?

A79. Yes. As a part of the Settlement Agreement approved by the Commission in AES Indiana's last rate case in Cause No. 45911, AES Indiana agreed to prepare a low load factor analysis, provide this analysis to the Settling Parties, and seek input on eligibility criteria and other related issues in a timely manner sufficient to afford the Settling Parties a reasonable opportunity to provide meaningful input prior to filing its next basic rate case. In compliance with this provision, the Company met with the relevant stakeholders seeking input on eligibility criteria and then conducted a scenario cost allocation and rate design analysis that reflects large low load factor customers as a separate rate classification.[6] In accordance with the Settlement Agreement, the Company shared the results of the analysis with the relevant stakeholders. The Company is not proposing a low load factor rate in this filing.

Q80. Did you perform any rate design analysis associated with residential Multi-Family rate classification?

A80. Yes. The Settlement Agreement approved by the Commission in AES Indiana's last rate case in Cause No. 45911, states "*AES will collect data on residential customer housing types and analyze cost differentials between single- and multi-family residential customers. AES will consider a new multi-family rate for qualifying residential customers in its next rate case. In advance of its next rate case, AES will meet with CAC to discuss a potential multi-family rate and will also provide CAC and any other interested Settling Party the results of its analysis.*" The Company conducted cost allocation and designed illustrative rates to evaluate the difference between residential multi-family and non-multi-family customers. The results of this analysis and a summary of the results of the cost allocation study and the illustrative rate design are filed as AES Indiana Attachment BR-10. Additionally, the Company met with the Citizens Action Coalition of Indiana, Inc. ("CAC") to present the results of this analysis and subsequently provided the results of the analysis to CAC.

Q81. Please describe the analysis you conducted.

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[6] The Company met with the relevant stakeholders virtually through Microsoft Teams on August 26, 2024 and April 18, 2025.

A81. The Company identified the population of potential multi-family customers based on how multi-family customers are defined in its DSM programs. The Company then randomly sampled customers from this group to develop the allocators (demand, energy, and customer) needed to allocate costs separately to the multi-family class. Using this data, I first analyzed the profile of the multi-family customers and compared that to the non-multi-family customers. Not surprisingly, multi-family customers consume less energy on average and also have a lower contribution to system peak on a per-customer basis when compared to the non-multi-family customers. However, multi-family customers have a larger non-coincident peak per customer than non-multi-family customers. These demand and energy-related characteristics result in multi-family customers getting a smaller portion of the cost associated with coincident demand and energy and a larger portion of cost associated with non-coincident demand as compared to non-multi-family customers.

Q82. What did you conclude from the analysis?

A82. The results of the analysis indicated that the cost of serving a multi-family customer is very similar to the cost of serving a non-multi-family customer. The unitized revenue requirement ($/kWh) for multi-family customers and non-multi-family customers were very similar to the unitized revenue associated with a unified residential class as shown by the table below.

Table 2: Unitized Revenue Requirement – Multi-Family v/s Non-Multi-Family

Revenue Requirement per kWh		
	Un-Mitigated	Mitigated
RS-NMF	$0.133280	$0.127502
RS-MF	$0.132919	$0.127170
RS Unified	$0.132905	$0.127432

% Difference from Residential		
RS-NMF	0.28%	0.05%
RS-MF	0.01%	-0.21%

I also designed illustrative rates to evaluate the potential bill impacts on multi-family and non-multi-family customers resulting from the creation of separate rate for multi-family and non-multi-family customers. The monthly bill impacts on average multi-family and non-multi-family customers were not significantly different between these two groups of customers. An average multi-family customer would save about $1.14 per month while a non-multi-family customer would pay about 32 cents more per month. Based on my analysis, it is fair to conclude that the cost to serve a multi-family customer is very similar to the cost of serving a non-multi-family customer and as result a distinct and separate multi-family rate is not necessary at this time. Also, it is important to note that as a result of the current rate structure, an average multi-family customer will have a lower bill than an average non-multi-family customer because of their lower average usage, under these illustrative rates.

Table 3: Illustrative Monthly Bill Impacts

	Average Usage (kWh)	Change from R ($)	Change from R (%)
RS-NMF	929	0.32	0.25%
RS-MF	863	(1.14)	-0.92%

Q83. Is AES Indiana proposing to update the Transmission, Distribution, and Storage System Improvement Charge (“TDSIC”) revenue allocation factors?

A83. Yes. Using the results of the ACOSS, I have developed the updated TDSIC revenue allocation factors by rate code based on firm load. AES Indiana Attachment BR-13 shows the TDSIC revenue allocation factors by rate class and code.

Q84. Is AES Indiana proposing to make changes to any of the rate components in Rate CGS?

A84. Yes. Rate CGS allows a customer to receive a cost-justified reduction in their demand charge by taking back-up or maintenance power as curtailable power, subject to certain conditions specified in the Rate CGS tariff. The daily generation component as well as the transmission and distribution component of the demand charge of Rate CGS are being updated to reflect the results of the ACOSS.

VII. REVENUE PROOF AND TYPICAL BILLS

Q85. Do you have an attachment that shows the rate components and revenue that will be collected from each rate schedule at the proposed rates?

A85. Yes. AES Indiana Attachment BR-7 demonstrates that the targeted total revenue for each rate schedule will be achieved using the proposed rates and normalized test period billing determinants. Note that detailed calculations for customers taking service at transmission voltage levels are considered confidential and are omitted from AES Indiana Attachment BR-7; instead, those calculations can be found in AES Indiana Workpaper BR-3.0C. AES Indiana Attachment BR-8 summarizes the new rates that are being proposed in this proceeding.

Q86. Do you have an attachment that shows how the proposed rates will affect various residential customers?

A86. Yes. The bill impacts for residential customers are shown on AES Indiana Attachment BR-9. The current bill calculations are based on pro forma current rate.[7] The proposed bill calculations are based on rates associated with Phase 2, which will become effective as of January 1, 2027. It can be seen in Col. E of that attachment that the smallest residential customers (customers consuming about 325 kWh per month) will experience an increase in their monthly bill of less than $8.35 per month and a majority of customers will experience a rate increase of less than $17.79 per month. A residential customer who uses 1,000 kWh per month will experience an increase of $21.02 per month, which is an increase of approximately 13.4%. My attachment details how these rate impacts were calculated and also indicates the impact under the Phase 1 credit.

VIII. SUMMARY AND CONCLUSIONS

Q87. Please provide a summary of your testimony.

A87. Using the Concentric Cost of Service Model, I have allocated AES Indiana's overall revenue requirements to the various classes of service in a manner that reflects the relative costs of providing service to each class. This is accomplished through analyzing costs and assigning each customer or rate class its proportionate share of the utility's total revenues and costs within the test year. The ACOSS follows the industry standard three step approach of functionalization, classification, and allocation to establish cost responsibility of each rate class. The results of the ACOSS indicate that at present rates, there is a wide

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[7] The pro forma current rates include riders rolled into base rates (TDSIC, ECCR, DSM, CAP, RTO and FAC).

variation in the rates of return by rate schedule. Even though the goal is to move each rate code to its cost of providing service, the proposed revenue allocation moves classes closer to their cost of service due to gradualism and affordability considerations. Using the results of the ACOSS as a guide and in collaboration with the Company, I allocated the revenue requirement to classes such that the current subsidy associated with each class was reduced. I then designed rates to increase the alignment of rate structures and cost structures by reducing the proportion of the fixed costs recovered through variable energy charges. Even though my proposed increases to customer charges for residential and small commercial customers move in the direction of recovering more of the fixed costs in the customer charge, a substantial portion of fixed costs will still be recovered in the variable energy charge component of the rates for these customers. My proposed rates and rate structures for large industrial customers are very closely aligned with the unit costs resulting from the ACOSS. As a result, I believe that my proposed rate structure and rates are just, reasonable, and not unreasonably preferential or discriminatory. Further, the proposed rate structure and rates are expected to provide AES Indiana with a reasonable opportunity to earn the required return on its invested capital and recover its necessary and reasonable operating expenses.

Q88. Does this conclude your prepared Direct Testimony?

A88. Yes, it does.

VERIFICATION

I, Bickey Rimal, Vice President for Concentric Energy Advisors, Inc., affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

B Rimal

Bickey Rimal
Dated: May 30, 2025

BICKEY RIMAL

VICE PRESIDENT

Mr. Rimal has over 17 years of progressive experience in the energy and environmental sector. He is a testifying expert on matters related to cost of service and rate design, and has contributed to engagements related to energy market assessments, valuations of energy assets, and utility performance benchmarking. His work often involves financial modeling, statistical analysis, and regulatory research. Mr. Rimal has provided expert testimony on cost allocation issues on multiple occasions on behalf of electric, natural gas, water, and wastewater utilities. He has extensively used Concentric's Excel-based macro-driven Allocated Class Cost-of-Service ("ACCOS") model for various electric, gas, and water utility clients, modifying and updating the model as needed to suit the specific needs of the clients. Mr. Rimal has a Masters in International Public Affairs with a focus on Energy Policy from the University of Wisconsin in Madison. Prior to enrolling in the graduate program, Mr. Rimal worked at a global energy and environmental consulting firm for three years. While there, Mr. Rimal was extensively involved in projects dealing with policy design and implementation, economic impact analysis, regulatory evaluation, and environmental risk assessment.

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Proceedings and Litigation Support

Mr. Rimal has been involved in projects dealing with all aspects of regulatory ratemaking process. Mr. Rimal has extensively used Concentric's excel-based macro driven Allocated Class Cost-of-Service ("ACCOS") model for various utility clients. He has modified and updated the model as needed to suit the specific needs of the clients.

Representative engagements have included:

- Conducted various cost allocation studies, functional studies, and minimum system studies and filed testimony supporting those studies for a vertically integrated Midwest electric utility.
- Supported the development of an allocated class cost of service study and rate design for another vertically integrated Midwest electric utility. Mr. Rimal was directly involved in conducting special cost allocations and functional studies; developing cost of service studies; designing the rates and calculating the associated bill impacts.
- Supported the development of an allocated class cost of service study and rate design for a distribution only electric utility in Pennsylvania. Mr. Rimal modified Concentric's ACCOS model to incorporate three distinct test years simultaneously and automated the results creation process.
- Responsible for the development of various cost allocation studies for two electric utilities in New York as part of the cost of service study.
- Supported the developed revenue requirement model to comply with a new performance based formula ratemaking process for a Midwest electric utility.

- Supported cash working capital studies on multiple cases by conducting billing lag analysis involving extremely large data sets utilizing SPSS and R software.
- Created model in R to statistically compare hourly load data between two distinct types of meters to assist a utility in its load research program.
- Created an excel based benchmarking model that have been used on multiple occasions to assess performance of several utilities against various peer groups.
- Supported the development of a rate model to calculate the annual cost of service rates as well as a levelized rate for conversion of an oil pipeline into a natural gas pipeline.

Market Assessment and Asset Optimization Review

- Involved on projects, with two different gas utilities in the Northwest, that forecasted the evolution of demand for compressed natural gas and liquefied natural gas in the transportation sector in their respective territories. Mr. Rimal developed models to analyze the market penetration of different transportation fuels under various fuel price spread scenarios and other market dynamics.
- Estimated the impact on electricity prices due to pre-mature closure of certain nuclear facilities using regression analysis. Validated the price impacts by analyzing the generation supply curve for the location in question.
- Annual assessment of asset manager’s performance on multiple occasions by conducting asset optimization analysis of client’s natural gas portfolio consisting of both transportation and storage assets.

Valuation

- Created a Discounted Cash Flow (“DCF”) model to value a generic regulated natural gas local distribution company (“LDC”). The model was customized to create valuation for any LDC covered by SNL Financial by automating the data retrieval process from SNL based on user input. The model had an added functionality of triggering a revenue enhancement when the earned ROE was outside certain pre-established thresholds.
- Created Discounted Cash Flow (“DCF”) models to assess the profitability of various generic units operating in the New York Control Area for NYISO.

Capacity Price Forecasting

- Updated and modified Concentric’s Capacity model used to forecast capacity prices for various regions within NYISO based on existing and planned generation, planned retirements, transmission constraints, market mitigation rules, gross and net CONE estimates, and other relevant demand curve parameters.

Relevant ICF Experience

- While at ICF, Mr. Rimal was part of a team that assisted the EPA’s Clean Air Market Division (CAMD) in analyzing the effect of environmental policies on power generation sector. As a part of this effort, he was significantly involved in executing as well as maintaining and updating the Technology Retrofit and Updating Model (TRUM). The TRUM model simulates the action of the electric utilities industry under a multi-pollutant emissions trading program.

- Assisted in the creation of an excel model that assessed the impacts of GHG mitigation policies on the competitiveness of the US manufacturing industries.
- Provided support to the Hours of Service regulation by analyzing different crash related data to identify main causes of fatigue among drivers by utilizing logistic regression models.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2011 – Present)
Vice President
Assistant Vice President
Senior Project Manager
Project Manager
Senior Consultant
Consultant
Assistant Consultant
Associate

ICF International (2006 – 2009)
Associate
Analyst
Research Assistant

EDUCATION

University of Wisconsin – Madison
M.A., International Public Affairs, 2011

Colgate University
B.A., Chemistry, Colgate University, 2006

ARTICLES AND PUBLICATIONS

Nemet Gregory F., Braden Peter, Cubero Ed, Rimal Bickey. Four decades of multiyear targets in energy policy: aspirations or credible commitments? WIREs Energy Environ. 2014, 3: 522-533.

AVAILABLE UPON REQUEST

Extensive client and project references, and specific references.

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
The Regulatory Commission of Alaska				
Golden Heart Utilities, Inc. and College Utilities Corporation	2024	Golden Heart Utilities, Inc. and College Utilities Corporation	Docket Nos. U-24-030 and U-24-031	Embedded Cost of Service and Rate Design; Weather Normalization Adjustment
Arizona Corporation Commission				
Epcor Water Arizona Inc.	2020	Epcor Water Arizona Inc.	Docket No. WS-01303A-20-0177	Embedded Cost of Service, Rate Design and Rate Consolidation; Weather Normalization Adjustment
Epcor Water Arizona Inc.	2022	Epcor Water Arizona Inc.	Docket No. WS-01303A-22-0236, et al.	Embedded Cost of Service, Rate Design, and Rate Consolidation
Epcor Water Arizona Inc.	2024	Epcor Water Arizona Inc.	Docket No. WS-01303A-24-0130	Embedded Cost of Service and Rate Design
Connecticut Public Utilities Regulatory Authority				
The Connecticut Water Company	2021	The Connecticut Water Company	Docket No. 20-12-30	Allocated Cost of Service, Rate Design and Rate Consolidation
The United Illuminating Company	2022	The United Illuminating Company	Docket No. 22-08-08	Allocated Cost of Service and Rate Design
Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company	2023	Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company	Docket No, 23-11-02	Allocated Cost of Service and Rate Design
The United Illuminating Company	2024	The United Illuminating Company	Docket No. 24-10-04	Allocated Cost of Service and Advanced Rate Design
Indiana Utility Regulatory Commission				
Northern Indiana Public Service Co.	2015	Northern Indiana Public Service Co.	Cause No. 44688	Cost Allocation

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Northern Indiana Public Service Co.	2018	Northern Indiana Public Service Co.	Cause No. 45159	Cost Allocation
Indianapolis Power & Light Co.	2019	Indianapolis Power & Light Co.	Cause No. 45211	Cost Allocation as it relates to a Special Contract
AES Indiana	2023	AES Indiana	Cause No. 45911	Embedded Cost of Service and Rate Design
Duke Energy Indiana	2024	Duke Energy Indiana	Cause No. 46038	Minimum System Study
Maine Public Utilities Commission				
Central Maine Power Company	2022	Central Main Power Company	Docket No. 2022-00152	Embedded Cost of Service Study
Massachusetts Department of Public Utilities				
Boston Gas Company d/b/a National Grid	2020	Boston Gas Company d/b/a National Grid	DPU 20-120	Embedded Cost of Service and Rate Design
The Berkshire Gas Company	2022	The Berkshire Gas Company	DPU 22-20	Embedded Cost of Service
Public Utilities Commission of Nevada				
Great Basin Water Co.	2024	Great Basin Water Co.	Docket No. 24-12003	Embedded Cost of Service, Rate Design, and Rate Consolidation
New York State Department of Public Service				
New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation	2022	New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation	Case 22-E-0317	Embedded Cost of Service
National Fuel Gas Distribution Corporation	2023	National Fuel Gas Distribution Corporation	Case 23-G-0627	Embedded Cost of Service
St. Lawrence Gas	2024	St. Lawrence Gas	Case 24-G-0668	Embedded Cost of Service and Rate Design

Attributes of the Concentric Cost of Service Model

The Concentric Energy Advisors ("Concentric") allocated cost of service model (the "Model") contains many features that promote ease of use, efficiency and adaptability. These include:

- **Information linked, not transferred** – Rather than transferring or copying tables of data between worksheets, the Concentric model uses the linking capabilities of the software to directly reference information in one area that is used later in the cost of service process.

- **Color Coding** – Cells are shaded specific colors to indicate factor related inputs, data related inputs, data transferred from another worksheet, data checking and formulas that shouldn't normally be modified.

- **Expandable customer class specification** – The model is configured to allow up to 19 rate classes. Additional customer classes can be created with minor modifications to the model.

- **Centralized inputs** – Instead of having external input data located throughout the model, inputs have been centralized to three worksheets. This has been done to simplify data entry and to help prevent the user from forgetting to update information in a particular file or worksheet.

- **Automated functionalization, classification, and allocation** – The model automatically changes the allocation percentages whenever the user changes a functionalization, classification, or allocation factor of an account. There is no need to recode the allocation percentages or change cell formulas.

- **Cost tracking** – Costs can be tracked on a functional basis allowing for the calculation of functional revenue requirements and functional unit rates. Additional functional categories can be created with minor modifications to the model.

- **User-friendly buttons for running macros** – Instead of having to remember commands to run the macros to calculate the model and print various pages, the macros run off of clicking buttons in CONTROLS.

Concentric COS: Overview of Important Concepts

A. *Worksheet overview*

The Model contains 14 worksheets as follows:

1. CONTROLS – Contains buttons to run the macros to calculate the model and print various worksheets.

2. INPUTS – Provides for the user to specify customer classes, functional factors and classification factors.

3. CLASSIFIERS – Contains areas for data input of external classifiers based on user specified classifications on the INPUTS worksheet.

4. EXTERNAL – Contains areas for data input of user specified external allocators.

5. INTERNAL – Provides for the specification of internal allocation factors.

6. ACCOUNTS – Contains sections for the user to specify plant and expense information by account for the test year. The user can assign functions, classification,n and allocation factors to the various cost elements in this sheet.

7. CLASS – Takes line item cost data and factor information from ACCOUNTS and spreads them out over classification factors.

8. FUNCALLOC – Takes cost data from CLASS and spreads it out to functional/allocation factor categories.

9. CLASS ALLOC – Takes the functional/allocated plant and expense totals and spreads them to customer classes.

10. ACCT DETAIL – Shows, by account, the allocation factor used and the resulting allocation of costs by rate class and cost classification.

11. ACCTFAC – Calculates the factors needed for ACCT DETAIL.

12. REV REQ – The REV REQ sheet calculates the income tax as needed for the SUMMARY. Taking specific lines of data from CLASSALLOC and INPUTS, it calculates income taxes based on the fully functionalized, classified, and allocated costs.

13. SUMMARY – Summarizes results of functionalization, classification and allocation of data into total cost of service, functional rate base, functional revenue requirements and unit costs at equalized rates of return.

14. ErrorCheck – Produce a report of error conditions by row from four worksheets.

B. *Explanation of functional/allocation factors*

One of the ways the revised model has achieved efficiencies while tracking functionalization is through the use of combined functional/allocation factors for grouping costs before spreading to customer classes.

In ACCOUNTS all cost items that are not assigned an internal factor are assigned a functional factor, classification factor, and allocation factor by which the cost will be distributed to the customer classes. Each cost item is carried into CLASS, which separates each cost into the assigned classification categories (e.g., 100% to DEM) and a macro creates the functional/allocation factor combinations for each cost item. These combinations are the name of the functional factor, an underscore, and the name of the allocation factor (e.g., F_PRODU_CP) assigned to that cost item. At the top of FUNCALLOC there are column headings which contain all of the possible functional/allocation factor combinations. Each cost item is then carried into FUNCALLOC and the portion of the costs associated with each functional/allocation factor is entered into the correct column. The rate base and expense totals in each functional/allocation factor column are pulled into CLASSALLOC, where the grouped costs are split into customer classes based on the allocation factor portion of the combined functional/allocator. The functionalization factor portion of the combined functional/allocation factors allows for subtotaling rate base and expenses by function that will be used throughout the rest of the model. Therefore, tracking grouped costs using the functional/allocators allows for calculating functionalized revenue requirements and unit costs.

All external and internal allocation factors must be assigned a name. In addition, each external allocation factor must be assigned a classification. Use of an unnamed allocation factor will cause an error condition which will be flagged in the orange "Check" column and reported on the ErrorCheck worksheet when the user runs the error check macro. Using an allocation factor in a different classification column on ACCOUNTS than that specified for the allocator on EXTERNAL may cause an error condition. To avoid any potential problems do not use allocator for more than one classification. Instead, create a second allocator with a different name. There are no problems that occur if an allocator on EXTERNAL or INTERNAL is not used. However, creating unnecessary allocation factors expands the size of the model.

Class Cost of Service Study

Summary of Results

Line No.	Description	System Total	Residential	Small C&I	Large C&I	Lighting
	(A)	(B)	(C)	(D)	(E)	(F)
	Rate Base					
1	Plant in Service	$ 7,879,244,521	$ 4,057,635,882	$ 1,174,186,676	$ 2,476,605,411	$ 170,816,552
2	Accumulated Reserve	(3,592,451,224)	(1,809,993,025)	(535,986,884)	(1,118,164,331)	(128,306,984)
3	Other Rate Base Items	1,261,058,191	649,145,261	187,863,794	398,184,678	25,864,458
4	Total Rate Base	$ 5,547,851,488	$ 2,896,788,117	$ 826,063,587	$ 1,756,625,758	$ 68,374,025
	Revenues at Current Rates					
5	Retail Sales	$ 1,865,026,784	$ 839,029,639	$ 297,007,513	$ 709,531,759	$ 19,457,873
6	Other Revenue	18,826,089	14,602,739	1,570,847	2,473,910	178,593
7	Sales for Resale	33,831,400	15,401,876	5,100,673	13,250,730	78,122
8	Total Revenues	$ 1,917,684,273	$ 869,034,254	$ 303,679,032	$ 725,256,398	$ 19,714,588
	Expenses at Current Rates					
9	Operations & Maintenance Expenses	$ 473,668,771	$ 253,107,837	$ 69,216,755	$ 134,881,186	$ 16,462,994
10	Depreciation Expense	326,919,520	165,305,836	48,944,733	108,482,048	4,186,902
11	Amortization Expense	113,274,897	53,354,384	17,026,396	42,039,199	854,918
12	Taxes Other Than Income Taxes	46,750,725	24,084,357	6,974,910	14,376,437	1,315,020
13	Fuel Expenses	597,427,000	243,189,990	82,181,388	268,788,477	3,267,145
14	Non-FAC Trackable Fuel Expenses	57,126,331	23,253,974	7,858,234	25,701,717	312,406
15	Income Taxes	29,432,144	5,915,907	9,243,000	15,819,382	(1,546,145)
16	Total Expenses - Current	$ 1,644,599,388	$ 768,212,285	$ 241,445,417	$ 610,088,445	$ 24,853,240
17	Current Operating Income	273,084,885	100,821,969	62,233,615	115,167,953	(5,138,652)
18	Return at Current Rates	4.92%	3.48%	7.53%	6.56%	-7.52%
19	Relative Rate of Return	1.00	0.71	1.53	1.33	(1.53)
	Revenue Requirement at Equal Rates of Return at Current Rates					
20	Required Return	4.92%	4.92%	4.92%	4.92%	4.92%
21	Required Operating Income	$ 273,084,885	$ 142,590,163	$ 40,661,773	$ 86,467,337	$ 3,365,612

Summary of Results

Line No.	Description	System Total	Residential	Small C&I	Large C&I	Lighting
	(A)	(B)	(C)	(D)	(E)	(F)
	Expenses at Required Return					
22	Operations & Maintenance Expenses	$ 473,668,771	$ 253,107,837	$ 69,216,755	$ 134,881,186	$ 16,462,994
23	Depreciation Expense	326,919,520	165,305,836	48,944,733	108,482,048	4,186,902
24	Amortization Expense	113,274,897	53,354,384	17,026,396	42,039,199	854,918
25	Taxes Other than Income	46,750,725	24,084,357	6,974,910	14,376,437	1,315,020
26	Fuel Expenses	597,427,000	243,189,990	82,181,388	268,788,477	3,267,145
27	Non-FAC Trackable Fuel Expenses	57,126,331	23,253,974	7,858,234	25,701,717	312,406
28	Income Taxes	29,432,144	15,367,874	4,382,385	9,319,150	362,734
29	Total Expense - Required	$ 1,644,599,388	$ 777,664,253	$ 236,584,803	$ 603,588,213	$ 26,762,120
30	Total Revenue Requirement at Equal Return	$ 1,917,684,273	$ 920,254,416	$ 277,246,576	$ 690,055,550	$ 30,127,731
31	Current Subsidy	$ -	$ (51,220,162)	$ 26,432,456	$ 35,200,848	$ (10,413,143)
	Revenue Requirement at Equal Rates of Return at Proposed Rates					
32	Required Return	7.52%	7.52%	7.52%	7.52%	7.52%
33	Required Operating Income	$ 417,198,420	$ 217,838,460	$ 62,119,980	$ 132,098,253	$ 5,141,727
34	Operating Income (Deficiency)/Surplus	$ (144,113,536)	$ (117,016,491)	$ 113,635	$ (16,930,300)	$ (10,280,379)
	Expenses at Equal Rates of Return at Proposed Rates					
35	Operations & Maintenance Expenses	$ 474,777,771	$ 254,008,169	$ 69,309,482	$ 134,987,514	$ 16,472,607
36	Depreciation Expense	326,919,520	165,305,836	48,944,733	108,482,048	4,186,902
37	Amortization Expense	113,274,897	53,354,384	17,026,396	42,039,199	854,918
38	Taxes Other than Income	46,750,725	24,084,357	6,974,910	14,376,437	1,315,020
39	Fuel Expenses	597,427,000	243,189,990	82,181,388	268,788,477	3,267,145
40	Non-FAC Trackable Fuel Expenses	57,126,331	23,253,974	7,858,234	25,701,717	312,406
41	Income Taxes	77,140,144	40,278,413	11,486,008	24,425,016	950,707
42	Total Expense - Required	$ 1,693,416,388	$ 803,475,123	$ 243,781,152	$ 618,800,408	$ 27,359,706

Summary of Results

Line No.	Description	System Total	Residential	Small C&I	Large C&I	Lighting
	(A)	(B)	(C)	(D)	(E)	(F)
43	Total Revenue Requirement at Equal Return	$ 2,110,614,809	$ 1,021,313,583	$ 305,901,132	$ 750,898,661	$ 32,501,432
44	Revenue (Deficiency)/Surplus	$ (192,930,536)	$ (152,279,329)	$ (2,222,100)	$ (25,642,263)	$ (12,786,844)
45	Total Revenues	1,917,684,273	869,034,254	303,679,032	725,256,398	19,714,588
46	Total Revenues as Proposed	$ 2,110,614,809	$ 1,021,313,583	$ 305,901,132	$ 750,898,661	$ 32,501,432
47	Less Total Other Revenues	$ 18,826,089	$ 14,602,739	$ 1,570,847	$ 2,473,910	$ 178,593
48	Sales for Resale	33,831,400	15,401,876	5,100,673	13,250,730	78,122
49	Total Base Rate Revenues as Proposed	$ 2,057,957,320	$ 991,308,968	$ 299,229,613	$ 735,174,022	$ 32,244,717
	Mitigation					
50	Mitigation	$ -	$ -	$ -	$ -	$ -
51	Proposed Increase Post Mitigation	192,930,536	152,279,329	2,222,100	25,642,263	12,786,844
	Revenue Requirement at Proposed Mitigated Rates					
52	Revenue Defficiency/Surplus	$ 192,930,536	$ 152,279,329	$ 2,222,100	$ 25,642,263	$ 12,786,844
53	Total Revenues	1,917,684,273	869,034,254	303,679,032	725,256,398	19,714,588
54	Total Revenues as Proposed	$ 2,110,614,809	$ 1,021,313,583	$ 305,901,132	$ 750,898,661	$ 32,501,432
55	Less Total Other Revenues	$ 18,826,089	$ 14,602,739	$ 1,570,847	$ 2,473,910	$ 178,593
56	Sales for Resale	33,831,400	15,401,876	5,100,673	13,250,730	78,122
57	Total Base Rate Revenues as Proposed	$ 2,057,957,320	$ 991,308,968	$ 299,229,613	$ 735,174,022	$ 32,244,717
58	Total Margin in Base Rates	$ 364,540,931	$ 187,833,845	$ 55,448,461	$ 116,373,614	$ 4,885,011
59	Expenses (excl. Income Taxes)	$ 1,616,276,244	$ 763,196,710	$ 232,295,144	$ 594,375,391	$ 26,408,999
60	Interest Expense	140,915,000	73,578,195	20,981,951	44,618,159	1,736,695
61	Taxable Income	$ 353,423,564	$ 184,538,678	$ 52,624,036	$ 111,905,111	$ 4,355,739
62	Income Taxes	77,140,144	40,278,413	11,486,008	24,425,016	950,707
63	Operating Income as Proposed	$ 417,198,420	$ 217,838,460	$ 62,119,980	$ 132,098,253	$ 5,141,727
64	Return at Proposed Rates	7.52%	7.52%	7.52%	7.52%	7.52%
65	Index Rate of Return	1.00	1.00	1.00	1.00	1.00

Summary of Results

Line No.	Description	System Total	Residential	Small C&I	Large C&I	Lighting
	(A)	(B)	(C)	(D)	(E)	(F)
	Functional Revenue Requirement					
	Demand					
66	Production	$ 734,649,800	$ 334,452,168	$ 110,761,247	$ 287,739,969	$ 1,696,415
67	Transmission	$ 129,805,033	$ 59,094,244	$ 19,570,369	$ 50,840,681	$ 299,739
68	Distribution	$ 113,793,228	$ 53,241,735	$ 18,502,446	$ 41,253,061	$ 795,986
69	Distribution Primary	$ 163,117,411	$ 76,319,603	$ 26,522,414	$ 59,134,384	$ 1,141,009
70	Distribution Secondary	$ 25,560,492	$ 13,846,540	$ 4,811,614	$ 6,695,327	$ 207,011
71	Customer	$ -	$ -	$ -	$ -	$ -
72	Customer Service	$ -	$ -	$ -	$ -	$ -
73	Fuel Expenses	$ -	$ -	$ -	$ -	$ -
74	**Total**	$ 1,166,925,964	$ 536,954,291	$ 180,168,090	$ 445,663,423	$ 4,140,161
75	Zero-Check	-	-	-	-	-
	Customer					
76	Production	$ -	$ -	$ -	$ -	$ -
77	Transmission	$ -	$ -	$ -	$ -	$ -
78	Distribution	$ -	$ -	$ -	$ -	$ -
79	Distribution Primary	$ 126,550,499	$ 112,852,978	$ 12,469,932	$ 1,022,386	$ 205,202
80	Distribution Secondary	$ 38,621,351	$ 34,453,939	$ 3,805,761	$ 299,002	$ 62,648
81	Customer	$ 72,344,999	$ 34,776,872	$ 11,210,684	$ 1,926,237	$ 24,431,205
82	Customer Service	$ 43,861,814	$ 32,674,018	$ 7,140,018	$ 4,007,534	$ 40,244
83	Fuel Expenses	$ -	$ -	$ -	$ -	$ -
84	**Total**	$ 281,378,663	$ 214,757,808	$ 34,626,396	$ 7,255,160	$ 24,739,300
85	Zero-Check	-	-	-	-	-
	Energy					
86	Production	$ 64,883,181	$ 26,411,495	$ 8,925,258	$ 29,191,602	$ 354,826
94	**Total**	$ 64,883,181	$ 26,411,495	$ 8,925,258	$ 29,191,602	$ 354,826
95	Zero-Check	$ -	$ -	$ -	$ -	$ -
	Fuel					
96	Fuel Expenses	$ 597,427,000	$ 243,189,990	$ 82,181,388	$ 268,788,477	$ 3,267,145
97	**Total**	$ 597,427,000	$ 243,189,990	$ 82,181,388	$ 268,788,477	$ 3,267,145
98	Zero-Check	-	-	-	-	-
99	**Total**	2,110,614,809	1,021,313,583	305,901,132	750,898,661	32,501,432

Summary of Results

Line No.	Description	System Total	Residential	Small C&I	Large C&I	Lighting
	(A)	(B)	(C)	(D)	(E)	(F)
	Total Revenue Requirement					
100	Demand	$ 1,166,925,964	$ 536,954,291	$ 180,168,090	$ 445,663,423	$ 4,140,161
101	Customer	$ 281,378,663	$ 214,757,808	$ 34,626,396	$ 7,255,160	$ 24,739,300
102	Energy	$ 64,883,181	$ 26,411,495	$ 8,925,258	$ 29,191,602	$ 354,826
103	Fuel	$ 597,427,000	$ 243,189,990	$ 82,181,388	$ 268,788,477	$ 3,267,145
104	**Total**	$ 2,110,614,809	$ 1,021,313,583	$ 305,901,132	$ 750,898,661	$ 32,501,432
105	Zero-Check	-	-	-	-	-
	Billing Determinants					
106	Demand	14,030,235	0	0	14,030,235	0
107	Customer Bills (Count *12)	6,770,247	6,037,452	667,121	54,696	10,978
108	Energy	13,299,137,254	5,386,147,834	1,820,145,259	6,020,483,747	72,360,414
109	Fuel	13,299,137,254	5,386,147,834	1,820,145,259	6,020,483,747	72,360,414
	Unit Costs					
110	Demand	.	$ -	$ -	$ 31.76	$ -
111	Customer	.	$ 124.51	$ 321.97	$ 132.65	$ 2,630.67
112	Energy	.	$ 0.004904	$ 0.004904	$ 0.004849	$ 0.004904
113	Fuel	.	$ 0.045151	$ 0.045151	$ 0.044646	$ 0.045151
114	Demand Revenue	.	$ -	$ -	$ 445,663,423	$ -
115	Customer Revenue	.	751,712,099	214,794,486	7,255,160	28,879,461
116	Energy Revenue	.	26,411,495	8,925,258	29,191,602	354,826
117	Fuel Revenue	.	243,189,990	82,181,388	268,788,477	3,267,145
118	Total Revenue	.	1,021,313,583	305,901,132	750,898,661	32,501,432
119	Zero-Check	.	$ -	$ -	$ -	$ -

Adjusted Revenue Requirement (Excluding Other Revenue and Off-System Sales Margin)

Line No.	Description	System Total	Residential	Small C&I	Large C&I	Lighting
120	Ratio of Base Revenue to Total Revenue	96.52%	96.14%	97.02%	96.74%	99.12%
	Total Revenue Requirement					
121	Demand	$ 1,126,264,320	516,249,217	174,786,056	431,126,122	4,102,926
122	Customer	$ 271,625,976	206,476,700	33,603,037	7,023,238	24,523,001
123	Energy	$ 62,640,023	25,393,062	8,659,131	28,236,185	351,645
124	Fuel	$ 597,427,000	$ 243,189,990	$ 82,181,388	$ 268,788,477	$ 3,267,145
125	**Total**	$ 2,057,957,320	$ 991,308,968	$ 299,229,613	$ 735,174,022	$ 32,244,717
126	Zero-Check	-	-	-	-	-

Summary of Results

Line No.	Description	System Total	Residential	Small C&I	Large C&I	Lighting
	(A)	(B)	(C)	(D)	(E)	(F)
	Billing Determinants					
127	Demand	14,030,235	0	0	14,030,235	0
128	Customer Bills (Count *12)	6,770,247	6,037,452	667,121	54,696	10,978
129	Energy	13,299,137,254	5,386,147,834	1,820,145,259	6,020,483,747	72,360,414
130	Fuel	13,299,137,254	5,386,147,834	1,820,145,259	6,020,483,747	72,360,414
	Unit Costs					
131	Demand	.	$ -	$ -	$ 30.73	$ -
132	Customer	.	$ 119.71	$ 312.37	$ 128.40	$ 2,607.57
133	Energy	.	$ 0.004715	$ 0.004757	$ 0.004690	$ 0.004860
134	Fuel	.	$ 0.045151	$ 0.045151	$ 0.044646	$ 0.045151
135	Demand Revenue	.	$ -	$ -	$ 431,126,122	$ -
136	Customer Revenue	.	722,725,916	208,389,094	7,023,238	28,625,927
137	Energy Revenue	.	25,393,062	8,659,131	28,236,185	351,645
138	Fuel Revenue	.	243,189,990	82,181,388	268,788,477	3,267,145
139	Total Revenue	.	991,308,968	299,229,613	735,174,022	32,244,717
140	Zero-Check	.	$ -	$ -	$ -	$ -
	Grid Facility					
141	Grid Facility - Revenue Requirement	$ 688,854,177	401,170,297	100,935,452	159,803,554	26,944,875
142	Grid Facility - Unit Costs ($/Bill)	$ 101.75	$ 66.45	$ 151.30	$ 2,921.67	$ 2,454.44
	Mitigated Revenue Requirement (Excluding Other Revenue and Off-System Sales Margin)					
143	Ratio of Base Revenue to Total Revenue	97.51%	97.06%	97.82%	97.91%	99.21%
144	Mitigated Amount	0	0	0	0	0
	Total Revenue Requirement					
145	Demand	$ 1,142,252,170	488,072,448	190,341,445	461,143,252	2,695,025
146	Customer	$ 255,638,127	195,207,247	37,261,340	7,408,778	15,760,762
147	Energy	$ 62,640,023	$ 25,393,062	$ 8,659,131	$ 28,236,185	$ 351,645
148	Fuel	$ 597,427,000	$ 243,189,990	$ 82,181,388	$ 268,788,477	$ 3,267,145
149	**Total**	$ 2,057,957,320	$ 951,862,747	$ 318,443,304	$ 765,576,692	$ 22,074,577
150	Zero-Check	-	(39,446,221)	19,213,691	30,402,670	(10,170,140)
	Billing Determinants					
151	Demand	14,030,235	0	0	14,030,235	0
152	Customer Bills (Count *12)	6,770,247	6,037,452	667,121	54,696	10,978
153	Energy	13,299,137,254	5,386,147,834	1,820,145,259	6,020,483,747	72,360,414
154	Fuel	13,299,137,254	5,386,147,834	1,820,145,259	6,020,483,747	72,360,414

Summary of Results

Line No.	Description	System Total	Residential	Small C&I	Large C&I	Lighting
	(A)	(B)	(C)	(D)	(E)	(F)
	Unit Costs					
155	Demand	.	$ -	$ -	$ 32.87	$ -
156	Customer	.	$ 113.17	$ 341.17	$ 135.45	$ 1,681.16
157	Energy	.	$ 0.004715	$ 0.004757	$ 0.004690	$ 0.004860
158	Fuel	.	$ 0.045151	$ 0.045151	$ 0.044646	$ 0.045151
159	Demand Revenue	.	$ -	$ -	$ 461,143,252	$ -
160	Customer Revenue	.	683,279,695	227,602,785	7,408,778	18,455,787
161	Energy Revenue	.	25,393,062	8,659,131	28,236,185	351,645
162	Fuel Revenue	.	243,189,990	82,181,388	268,788,477	3,267,145
163	Total Revenue	.	951,862,747	318,443,304	765,576,692	22,074,577
164	Zero-Check	.	$ -	$ -	$ -	$ -
	Total Revenue Requirement (Excluding Fuel)					
165	Demand	$ 1,142,252,170	$ 488,072,448	$ 190,341,445	$ 461,143,252	$ 2,695,025
166	Customer	$ 255,638,127	$ 195,207,247	$ 37,261,340	$ 7,408,778	$ 15,760,762
167	Energy	$ 62,640,023	$ 25,393,062	$ 8,659,131	$ 28,236,185	$ 351,645
168	**Total**	$ 1,460,530,320	$ 708,672,757	$ 236,261,915	$ 496,788,215	$ 18,807,432
169	**Percent of Total**	100.00%	48.52%	16.18%	34.01%	1.29%
170	Zero-Check	-	(39,446,221)	19,213,691	30,402,670	(10,170,140)

Class Cost of Service Study
Summary of Results

Line No.	Description	System Total	Residential RS	Secondary Small SS	Municipal Device MD	Space Conditioning SH	Conditioning - Schools SE	Water Heating - Controlled CB	Water Heating - Uncontrolled UW
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Rate Base								
1	Plant in Service	$ 7,879,244,521	$ 4,057,635,882	$ 834,475,731	$ 1,451,792	$ 330,394,231	$ 6,720,117	$ 404,153	$ 740,651
2	Accumulated Reserve	(3,592,451,224)	(1,809,993,025)	(384,227,075)	(643,081)	(147,583,349)	(3,000,691)	(191,969)	(340,719)
3	Other Rate Base Items	1,261,058,191	649,145,261	133,273,059	232,688	53,094,695	1,081,606	63,845	117,901
4	Total Rate Base	$ 5,547,851,488	$ 2,896,788,117	$ 583,521,715	$ 1,041,398	$ 235,905,578	$ 4,801,033	$ 276,030	$ 517,833
	Revenues at Current Rates								
5	Retail Sales	$ 1,865,026,784	$ 839,029,639	$ 217,795,735	$ 388,161	$ 76,497,418	$ 2,095,627	$ 64,048	$ 166,524
6	Other Revenue	18,826,089	14,602,739	1,219,159	5,474	331,821	7,078	6,012	1,303
7	Off-System Slaes Margin	33,831,400	15,401,876	3,483,129	1,670	1,578,683	33,899	932	2,359
8	Total Revenues	$ 1,917,684,273	$ 869,034,254	$ 222,498,023	$ 395,305	$ 78,407,922	$ 2,136,604	$ 70,993	$ 170,186
	Expenses at Current Rates								
9	Operations & Maintenance Expenses	$ 473,668,771	$ 253,107,837	$ 50,924,880	$ 98,793	$ 17,758,046	$ 355,565	$ 30,709	$ 48,762
10	Depreciation Expense	326,919,520	165,305,836	34,582,143	51,827	13,978,535	288,193	15,090	28,945
11	Amortization Expense	113,274,897	53,354,384	11,753,199	9,618	5,142,122	108,987	3,839	8,631
12	Taxes Other Than Income Taxes	46,750,725	24,084,357	5,007,322	8,493	1,913,320	38,686	2,566	4,525
13	Fuel Expenses	597,427,000	243,189,990	58,906,741	40,415	22,542,882	620,011	20,146	51,194
14	Non-FAC Trackable Fuel Expenses	57,126,331	23,253,974	5,632,698	3,864	2,155,564	59,286	1,926	4,895
15	Income Taxes	29,432,144	5,915,907	7,481,184	28,494	1,633,699	99,694	(1,902)	1,832
16	Total Expenses - Current	$ 1,644,599,388	$ 768,212,285	$ 174,288,167	$ 241,503	$ 65,124,167	$ 1,570,421	$ 72,374	$ 148,784
17	Current Operating Income	273,084,885	100,821,969	48,209,856	153,802	13,283,755	566,182	(1,382)	21,402
18	Return at Current Rates	4.92%	3.48%	8.26%	14.77%	5.63%	11.79%	-0.50%	4.13%
19	Relative Rate of Return	1.00	0.71	1.68	3.00	1.14	2.40	(0.10)	0.84
	Revenue Requirement at Equal Rates of Return at Current Rates								
20	Required Return	4.92%	4.92%	4.92%	4.92%	4.92%	4.92%	4.92%	4.92%
21	Required Operating Income	$ 273,084,885	$ 142,590,163	$ 28,723,004	$ 51,261	$ 11,612,107	$ 236,324	$ 13,587	$ 25,490
	Expenses at Required Return								
22	Operations & Maintenance Expenses	$ 473,668,771	$ 253,107,837	$ 50,924,880	$ 98,793	$ 17,758,046	$ 355,565	$ 30,709	$ 48,762
23	Depreciation Expense	326,919,520	165,305,836	34,582,143	51,827	13,978,535	288,193	15,090	28,945
24	Amortization Expense	113,274,897	53,354,384	11,753,199	9,618	5,142,122	108,987	3,839	8,631
25	Taxes Other than Income	46,750,725	24,084,357	5,007,322	8,493	1,913,320	38,686	2,566	4,525
26	Fuel Expenses	597,427,000	243,189,990	58,906,741	40,415	22,542,882	620,011	20,146	51,194
27	Non-FAC Trackable Fuel Expenses	57,126,331	23,253,974	5,632,698	3,864	2,155,564	59,286	1,926	4,895
28	Income Taxes	29,432,144	15,367,874	3,095,666	5,525	1,251,513	25,470	1,464	2,747
29	Total Expense - Required	$ 1,644,599,388	$ 777,664,253	$ 169,902,649	$ 218,535	$ 64,741,981	$ 1,496,198	$ 75,741	$ 149,699
30	Total Revenue Requirement at Equal Return	$ 1,917,684,273	$ 920,254,416	$ 198,625,653	$ 269,796	$ 76,354,088	$ 1,732,522	$ 89,328	$ 175,188
31	Current Subsidy	$ -	$ (51,220,162)	$ 23,872,370	$ 125,509	$ 2,053,834	$ 404,082	$ (18,335)	$ (5,003)

Line No.	Description	System Total	Residential RS	Secondary Small SS	Municipal Device MD	Space Conditioning SH	Conditioning - Schools SE	Water Heating - Controlled CB	Water Heating - Uncontrolled UW
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Revenue Requirement at Equal Rates of Return at Proposed Rates								
32	Required Return	7.52%	7.52%	7.52%	7.52%	7.52%	7.52%	7.52%	7.52%
33	Required Operating Income	$ 417,198,420	$ 217,838,460	$ 43,880,832	$ 78,313	$ 17,740,099	$ 361,038	$ 20,757	$ 38,941
34	Operating Income (Deficiency)/Surplus	$ (144,113,536)	$ (117,016,491)	$ 4,329,024	$ 75,488	$ (4,456,344)	$ 205,145	$ (22,139)	$ (17,539)
	Expenses at Equal Rates of Return at Proposed Rates								
35	Operations & Maintenance Expenses	$ 474,777,771	$ 254,008,169	$ 50,999,731	$ 99,262	$ 17,774,981	$ 355,868	$ 30,786	$ 48,853
36	Depreciation Expense	326,919,520	165,305,836	34,582,143	51,827	13,978,535	288,193	15,090	28,945
37	Amortization Expense	113,274,897	53,354,384	11,753,199	9,618	5,142,122	108,987	3,839	8,631
38	Taxes Other than Income	46,750,725	24,084,357	5,007,322	8,493	1,913,320	38,686	2,566	4,525
39	Fuel Expenses	597,427,000	243,189,990	58,906,741	40,415	22,542,882	620,011	20,146	51,194
40	Non-FAC Trackable Fuel Expenses	57,126,331	23,253,974	5,632,698	3,864	2,155,564	59,286	1,926	4,895
41	Income Taxes	77,140,144	40,278,413	8,113,582	14,480	3,280,151	66,756	3,838	7,200
42	Total Expense - Required	$ 1,693,416,388	$ 803,475,123	$ 174,995,417	$ 227,959	$ 66,787,554	$ 1,537,787	$ 78,192	$ 154,243
43	Total Revenue Requirement at Equal Return	$ 2,110,614,809	$ 1,021,313,583	$ 218,876,249	$ 306,272	$ 84,527,653	$ 1,898,825	$ 98,949	$ 193,184
44	Revenue (Deficiency)/Surplus	$ (192,930,536)	$ (152,279,329)	$ 3,621,774	$ 89,033	$ (6,119,731)	$ 237,779	$ (27,956)	$ (22,999)
45	Total Revenues	1,917,684,273	869,034,254	222,498,023	395,305	78,407,922	2,136,604	70,993	170,186
46	Total Revenues as Proposed	$ 2,110,614,809	$ 1,021,313,583	$ 218,876,249	$ 306,272	$ 84,527,653	$ 1,898,825	$ 98,949	$ 193,184
47	Less Total Other Revenues	$ 18,826,089	$ 14,602,739	$ 1,219,159	$ 5,474	$ 331,821	$ 7,078	$ 6,012	$ 1,303
48	Off-System Slaes Margin	33,831,400	15,401,876	3,483,129	1,670	1,578,683	33,899	932	2,359
49	Total Base Rate Revenues as Proposed	$ 2,057,957,320	$ 991,308,968	$ 214,173,961	$ 299,128	$ 82,617,149	$ 1,857,848	$ 92,005	$ 189,522
	Mitigation								
50	Mitigation	$ (0)	$ (39,446,221)	$ 17,082,766	$ 74,782	$ 1,797,562	$ 279,960	$ (19,343)	$ (2,036)
51	Proposed Increase Post Mitigation	192,930,536	112,833,108	13,460,992	(14,251)	7,917,293	42,181	8,613	20,963
	Revenue Requirement at Proposed Mitigated Rates								
52	Revenue Defficiency/Surplus	$ 192,930,536	$ 112,833,108	$ 13,460,992	$ (14,251)	$ 7,917,293	$ 42,181	$ 8,613	$ 20,963
53	Total Revenues	1,917,684,273	869,034,254	222,498,023	395,305	78,407,922	2,136,604	70,993	170,186
54	Total Revenues as Proposed	$ 2,110,614,809	$ 981,867,362	$ 235,959,015	$ 381,054	$ 86,325,215	$ 2,178,785	$ 79,606	$ 191,148
55	Less Total Other Revenues	$ 18,826,089	$ 14,602,739	$ 1,219,159	$ 5,474	$ 331,821	$ 7,078	$ 6,012	$ 1,303
56	Off-System Slaes Margin	33,831,400	15,401,876	3,483,129	1,670	1,578,683	33,899	932	2,359
57	Total Base Rate Revenues as Proposed	$ 2,057,957,320	$ 951,862,747	$ 231,256,727	$ 373,910	$ 84,414,711	$ 2,137,808	$ 72,661	$ 187,486
58	Total Margin in Base Rates	$ 364,540,931	$ 148,387,624	$ 56,261,310	$ 145,951	$ 17,627,158	$ 600,021	$ (5,531)	$ 33,243
59	Expenses (excl. Income Taxes)	$ 1,616,276,244	$ 763,196,710	$ 166,881,835	$ 213,479	$ 63,507,403	$ 1,471,031	$ 74,354	$ 147,043
60	Interest Expense	140,915,000	73,578,195	14,821,407	26,451	5,991,983	121,946	7,011	13,153
61	Taxable Income	$ 353,423,564	$ 145,092,458	$ 54,255,773	$ 141,124	$ 16,825,829	$ 585,808	$ (1,759)	$ 30,952
62	Income Taxes	77,140,144	31,668,667	11,842,159	30,802	3,672,497	127,862	(384)	6,756
63	Operating Income as Proposed	$ 417,198,420	$ 187,001,986	$ 57,235,021	$ 136,773	$ 19,145,316	$ 579,892	$ 5,636	$ 37,349
64	Return at Proposed Rates	7.52%	6.46%	9.81%	13.13%	8.12%	12.08%	2.04%	7.21%
65	Index Rate of Return	1.00	0.86	1.30	1.75	1.08	1.61	0.27	0.96

Line No.	Description (A)	System Total (B)	Residential RS (C)	Secondary Small SS (D)	Municipal Device MD (E)	Space Conditioning SH (F)	Conditioning - Schools SE (G)	Water Heating - Controlled CB (H)	Water Heating - Uncontrolled UW (I)
	Functional Revenue Requirement								
	Demand								
66	Production	$ 734,649,800	$ 334,452,168	$ 75,636,242	$ 36,271	$ 34,281,143	$ 736,112	$ 20,247	$ 51,231
67	Transmission	$ 129,805,033	$ 59,094,244	$ 13,364,143	$ 6,409	$ 6,057,124	$ 130,063	$ 3,578	$ 9,052
68	Distribution	$ 113,793,228	$ 53,241,735	$ 12,191,095	$ 5,764	$ 6,167,159	$ 122,947	$ 4,014	$ 11,466
69	Distribution Primary	$ 163,117,411	$ 76,319,603	$ 17,475,379	$ 8,262	$ 8,840,342	$ 176,240	$ 5,754	$ 16,437
70	Distribution Secondary	$ 25,560,492	$ 13,846,540	$ 3,170,225	$ 1,499	$ 1,603,889	$ 31,975	$ 1,044	$ 2,982
71	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72	Customer Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	Fuel Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	**Total**	$ 1,166,925,964	$ 536,954,291	$ 121,837,084	$ 58,205	$ 56,949,657	$ 1,197,338	$ 34,638	$ 91,168
75	Zero-Check	-	-	-	-	-	-	-	-
	Customer								
76	Production	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
77	Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79	Distribution Primary	$ 126,550,499	$ 112,852,978	$ 11,489,831	$ 119,779	$ 820,698	$ 4,486	$ 17,623	$ 17,515
80	Distribution Secondary	$ 38,621,351	$ 34,453,939	$ 3,506,537	$ 36,569	$ 250,558	$ 1,370	$ 5,380	$ 5,347
81	Customer	$ 72,344,999	$ 34,776,872	$ 10,105,194	$ 36,911	$ 1,041,796	$ 5,695	$ 8,800	$ 12,288
82	Customer Service	$ 43,861,814	$ 32,674,018	$ 6,633,331	$ 10,004	$ 473,807	$ 2,590	$ 10,174	$ 10,112
83	Fuel Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
84	**Total**	$ 281,378,663	$ 214,757,808	$ 31,734,894	$ 203,263	$ 2,586,859	$ 14,140	$ 41,978	$ 45,262
85	Zero-Check	-	-	-	-	-	-	-	-
	Energy								
86	Production	$ 64,883,181	$ 26,411,495	$ 6,397,529	$ 4,389	$ 2,448,255	$ 67,336	$ 2,188	$ 5,560
94	**Total**	$ 64,883,181	$ 26,411,495	$ 6,397,529	$ 4,389	$ 2,448,255	$ 67,336	$ 2,188	$ 5,560
95	Zero-Check	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Fuel								
96	Fuel Expenses	$ 597,427,000	$ 243,189,990	$ 58,906,741	$ 40,415	$ 22,542,882	$ 620,011	$ 20,146	$ 51,194
97	**Total**	$ 597,427,000	$ 243,189,990	$ 58,906,741	$ 40,415	$ 22,542,882	$ 620,011	$ 20,146	$ 51,194
98	Zero-Check	-	-	-	-	-	-	-	-
99	**Total**	2,110,614,809	1,021,313,583	218,876,249	306,272	84,527,653	1,898,825	98,949	193,184
	Total Revenue Requirement								
100	Demand	$ 1,166,925,964	$ 536,954,291	$ 121,837,084	$ 58,205	$ 56,949,657	$ 1,197,338	$ 34,638	$ 91,168
101	Customer	$ 281,378,663	$ 214,757,808	$ 31,734,894	$ 203,263	$ 2,586,859	$ 14,140	$ 41,978	$ 45,262
102	Energy	$ 64,883,181	$ 26,411,495	$ 6,397,529	$ 4,389	$ 2,448,255	$ 67,336	$ 2,188	$ 5,560
103	Fuel	$ 597,427,000	$ 243,189,990	$ 58,906,741	$ 40,415	$ 22,542,882	$ 620,011	$ 20,146	$ 51,194
104	**Total**	$ 2,110,614,809	$ 1,021,313,583	$ 218,876,249	$ 306,272	$ 84,527,653	$ 1,898,825	$ 98,949	$ 193,184
105	Zero-Check	-	-	-	-	-	-	-	-

Line No.	Description	System Total	Residential RS	Secondary Small SS	Municipal Device MD	Space Conditioning SH	Conditioning - Schools SE	Water Heating - Controlled CB	Water Heating - Uncontrolled UW
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Billing Determinants								
106	Demand	14,030,235	0	0	0	0	0	0	0
107	Customer Bills (Count *12)	6,770,247	6,037,452	614,687	6,408	43,906	240	943	937
108	Energy	13,299,137,254	5,386,147,834	1,304,660,668	895,098	499,277,512	13,731,937	446,196	1,133,848
109	Fuel	13,299,137,254	5,386,147,834	1,304,660,668	895,098	499,277,512	13,731,937	446,196	1,133,848
	Unit Costs								
110	Demand	.	$ -	$ -	$ -	$ -	$ -	$ -	$ -
111	Customer	.	$ 124.51	$ 249.84	$ 40.80	$ 1,356.00	$ 5,047.82	$ 81.26	$ 145.60
112	Energy	.	$ 0.004904	$ 0.004904	$ 0.004904	$ 0.004904	$ 0.004904	$ 0.004904	$ 0.004904
113	Fuel	.	$ 0.045151	$ 0.045151	$ 0.045151	$ 0.045151	$ 0.045151	$ 0.045151	$ 0.045151
114	Demand Revenue	.	$ -	$ -	$ -	$ -	$ -	$ -	$ -
115	Customer Revenue	.	751,712,099	153,571,979	261,468	59,536,516	1,211,478	76,615	136,430
116	Energy Revenue	.	26,411,495	6,397,529	4,389	2,448,255	67,336	2,188	5,560
117	Fuel Revenue	.	243,189,990	58,906,741	40,415	22,542,882	620,011	20,146	51,194
118	Total Revenue	.	1,021,313,583	218,876,249	306,272	84,527,653	1,898,825	98,949	193,184
119	Zero-Check	.	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Adjusted Revenue Requirement (Excluding Other Revenue and Off-System Sales Margin)								
120	Ratio of Base Revenue to Total Revenue	96.52%	96.14%	97.06%	97.31%	96.92%	96.80%	91.19%	97.42%
	Total Revenue Requirement								
121	Demand	$ 1,126,264,320	$ 516,249,217	$ 118,255,695	$ 56,641	$ 55,194,346	$ 1,158,971	$ 31,585	$ 88,817
122	Customer	$ 271,625,976	$ 206,476,700	$ 30,802,050	$ 197,801	$ 2,507,126	$ 13,687	$ 38,278	$ 44,094
123	Energy	$ 62,640,023	$ 25,393,062	$ 6,209,475	$ 4,271	$ 2,372,795	$ 65,178	$ 1,995	$ 5,417
124	Fuel	$ 597,427,000	$ 243,189,990	$ 58,906,741	$ 40,415	$ 22,542,882	$ 620,011	$ 20,146	$ 51,194
125	**Total**	$ 2,057,957,320	$ 991,308,968	$ 214,173,961	$ 299,128	$ 82,617,149	$ 1,857,848	$ 92,005	$ 189,522
126	Zero-Check	-	-	-	-	-	-	-	-
	Billing Determinants								
127	Demand	14,030,235	0	0	0	0	0	0	0
128	Customer Bills (Count *12)	6,770,247	6,037,452	614,687	6,408	43,906	240	943	937
129	Energy	13,299,137,254	5,386,147,834	1,304,660,668	895,098	499,277,512	13,731,937	446,196	1,133,848
130	Fuel	13,299,137,254	5,386,147,834	1,304,660,668	895,098	499,277,512	13,731,937	446,196	1,133,848
	Unit Costs								
131	Demand	.	$ -	$ -	$ -	$ -	$ -	$ -	$ -
132	Customer	.	$ 119.71	$ 242.49	$ 39.71	$ 1,314.20	$ 4,886.08	$ 74.10	$ 141.85
133	Energy	.	$ 0.004715	$ 0.004759	$ 0.004772	$ 0.004752	$ 0.004746	$ 0.004471	$ 0.004777
134	Fuel	.	$ 0.045151	$ 0.045151	$ 0.045151	$ 0.045151	$ 0.045151	$ 0.045151	$ 0.045151
135	Demand Revenue	.	$ -	$ -	$ -	$ -	$ -	$ -	$ -
136	Customer Revenue	.	722,725,916	149,057,746	254,442	57,701,472	1,172,659	69,863	132,911
137	Energy Revenue	.	25,393,062	6,209,475	4,271	2,372,795	65,178	1,995	5,417
138	Fuel Revenue	.	243,189,990	58,906,741	40,415	22,542,882	620,011	20,146	51,194
139	Total Revenue	.	991,308,968	214,173,961	299,128	82,617,149	1,857,848	92,005	189,522
140	Zero-Check	.	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Grid Facility								
141	Grid Facility - Revenue Requirement	$ 688,854,177	$ 401,170,297	$ 75,644,823	$ 219,145	$ 24,476,948	$ 460,134	$ 51,400	$ 83,002
142	Grid Facility - Unit Costs ($/Bill)	$ 101.75	$ 66.45	$ 123.06	$ 34.20	$ 557.49	$ 1,917.22	$ 54.52	$ 88.58

Line No.	Description	System Total	Residential RS	Secondary Small SS	Municipal Device MD	Space Conditioning SH	Conditioning - Schools SE	Water Heating - Controlled CB	Water Heating - Uncontrolled UW
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Mitigated Revenue Requirement (Excluding Other Revenue and Off-System Sales Margin)								
143	Ratio of Unmitigated Revenue to Mitigated Revenue	100.00%	94.54%	111.46%	129.39%	103.12%	123.87%	72.31%	98.47%
144	Mitigated Amount	(0)	(39,446,221)	17,082,766	74,782	1,797,562	279,960	(19,343)	(2,036)
	Total Revenue Requirement								
145	Demand	$ 1,142,252,170	$ 488,072,448	$ 131,808,392	$ 73,288	$ 56,913,804	$ 1,435,664	$ 22,840	$ 87,457
146	Customer	$ 255,638,127	$ 195,207,247	$ 34,332,120	$ 255,936	$ 2,585,230	$ 16,955	$ 27,680	$ 43,419
147	Energy	$ 62,640,023	$ 25,393,062	$ 6,209,475	$ 4,271	$ 2,372,795	$ 65,178	$ 1,995	$ 5,417
148	Fuel	$ 597,427,000	$ 243,189,990	$ 58,906,741	$ 40,415	$ 22,542,882	$ 620,011	$ 20,146	$ 51,194
149	**Total**	$ 2,057,957,320	$ 951,862,747	$ 231,256,727	$ 373,910	$ 84,414,711	$ 2,137,808	$ 72,661	$ 187,486
150	Zero-Check	-	-	-	-	-	-	-	-
	Billing Determinants								
151	Demand	14,030,235	0	0	0	0	0	0	0
152	Customer Bills (Count *12)	6,770,247	6,037,452	614,687	6,408	43,906	240	943	937
153	Energy	13,299,137,254	5,386,147,834	1,304,660,668	895,098	499,277,512	13,731,937	446,196	1,133,848
154	Fuel	13,299,137,254	5,386,147,834	1,304,660,668	895,098	499,277,512	13,731,937	446,196	1,133,848
	Unit Costs								
155	Demand	.	$ -	$ -	$ -	$ -	$ -	$ -	$ -
156	Customer	.	$ 113.17	$ 270.28	$ 51.38	$ 1,355.15	$ 6,052.58	$ 53.58	$ 139.68
157	Energy	.	$ 0.004715	$ 0.004759	$ 0.004772	$ 0.004752	$ 0.004746	$ 0.004471	$ 0.004777
158	Fuel	.	$ 0.045151	$ 0.045151	$ 0.045151	$ 0.045151	$ 0.045151	$ 0.045151	$ 0.045151
159	Demand Revenue	.	$ -	$ -	$ -	$ -	$ -	$ -	$ -
160	Customer Revenue	.	683,279,695	166,140,512	329,224	59,499,035	1,452,619	50,520	130,876
161	Energy Revenue	.	25,393,062	6,209,475	4,271	2,372,795	65,178	1,995	5,417
162	Fuel Revenue	$ -	243,189,990	58,906,741	40,415	22,542,882	620,011	20,146	51,194
163	Total Revenue	.	951,862,747	231,256,727	373,910	84,414,711	2,137,808	72,661	187,486
164	Zero-Check	.	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total Revenue Requirement (Excluding Fuel)								
165	Demand	$ 1,142,252,170	$ 488,072,448	$ 131,808,392	$ 73,288	$ 56,913,804	$ 1,435,664	$ 22,840	$ 87,457
166	Customer	$ 255,638,127	$ 195,207,247	$ 34,332,120	$ 255,936	$ 2,585,230	$ 16,955	$ 27,680	$ 43,419
167	Energy	$ 62,640,023	$ 25,393,062	$ 6,209,475	$ 4,271	$ 2,372,795	$ 65,178	$ 1,995	$ 5,417
168	**Total**	$ 1,460,530,320	$ 708,672,757	$ 172,349,986	$ 333,495	$ 61,871,830	$ 1,517,797	$ 52,515	$ 136,292
169	**Percent of Total**	100.00%	48.52%	11.80%	0.02%	4.24%	0.10%	0.00%	0.01%
170	Zero-Check	-	-	-	-	-	-	-	-

Class Cost of Service Study
Summary of Results

Line No.	Description	System Total	Industrial SL	Industrial PL-HL	Process Heating PH	Protective Lighting APL	Municipal Lighting MU1
	(A)	(B)	(J)	(K)	(L)	(M)	(N)
	Rate Base						
1	Plant in Service	$ 7,879,244,521	$ 1,507,117,568	$ 959,765,002	$ 9,722,842	$ 75,432,053	$ 95,384,499
2	Accumulated Reserve	(3,592,451,224)	(677,551,471)	(436,338,280)	(4,274,580)	(63,434,296)	(64,872,688)
3	Other Rate Base Items	1,261,058,191	242,126,530	154,493,330	1,564,818	11,410,673	14,453,785
4	Total Rate Base	$ 5,547,851,488	$ 1,071,692,627	$ 677,920,053	$ 7,013,079	$ 23,408,430	$ 44,965,595
	Revenues at Current Rates						
5	Retail Sales	$ 1,865,026,784	$ 406,995,390	$ 299,643,225	$ 2,893,144	$ 9,281,123	$ 10,176,750
6	Other Revenue	18,826,089	1,506,889	957,247	9,774	78,774	99,819
7	Off-System Slaes Margin	33,831,400	7,798,281	5,407,179	45,270	44,781	33,341
8	Total Revenues	$ 1,917,684,273	$ 416,300,561	$ 306,007,650	$ 2,948,187	$ 9,404,678	$ 10,309,910
	Expenses at Current Rates						
9	Operations & Maintenance Expenses	$ 473,668,771	$ 83,079,635	$ 51,278,233	$ 523,317	$ 7,327,030	$ 9,135,964
10	Depreciation Expense	326,919,520	65,320,267	42,755,541	406,241	1,956,239	2,230,663
11	Amortization Expense	113,274,897	24,929,840	16,960,973	148,385	402,992	451,926
12	Taxes Other Than Income Taxes	46,750,725	8,774,398	5,545,947	56,093	583,216	731,805
13	Fuel Expenses	597,427,000	146,028,400	121,722,970	1,037,106	1,718,106	1,549,040
14	Non-FAC Trackable Fuel Expenses	57,126,331	13,963,324	11,639,224	99,169	164,286	148,120
15	Income Taxes	29,432,144	8,604,274	7,123,539	91,570	(613,439)	(932,706)
16	Total Expenses - Current	$ 1,644,599,388	$ 350,700,139	$ 257,026,426	$ 2,361,881	$ 11,538,429	$ 13,314,811
17	Current Operating Income	273,084,885	65,600,422	48,981,225	586,307	(2,133,752)	(3,004,901)
18	Return at Current Rates	4.92%	6.12%	7.23%	8.36%	-9.12%	-6.68%
19	Relative Rate of Return	1.00	1.24	1.47	1.70	(1.85)	(1.36)
	Revenue Requirement at Equal Rates of Return at Current Rates						
20	Required Return	4.92%	4.92%	4.92%	4.92%	4.92%	4.92%
21	Required Operating Income	$ 273,084,885	$ 52,752,504	$ 33,369,624	$ 345,209	$ 1,152,246	$ 2,213,366
	Expenses at Required Return						
22	Operations & Maintenance Expenses	$ 473,668,771	$ 83,079,635	$ 51,278,233	$ 523,317	$ 7,327,030	$ 9,135,964
23	Depreciation Expense	326,919,520	65,320,267	42,755,541	406,241	1,956,239	2,230,663
24	Amortization Expense	113,274,897	24,929,840	16,960,973	148,385	402,992	451,926
25	Taxes Other than Income	46,750,725	8,774,398	5,545,947	56,093	583,216	731,805
26	Fuel Expenses	597,427,000	146,028,400	121,722,970	1,037,106	1,718,106	1,549,040
27	Non-FAC Trackable Fuel Expenses	57,126,331	13,963,324	11,639,224	99,169	164,286	148,120
28	Income Taxes	29,432,144	5,685,482	3,596,463	37,205	124,185	238,549
29	Total Expense - Required	$ 1,644,599,388	$ 347,781,347	$ 253,499,350	$ 2,307,517	$ 12,276,053	$ 14,486,066
30	Total Revenue Requirement at Equal Return	$ 1,917,684,273	$ 400,533,851	$ 286,868,974	$ 2,652,725	$ 13,428,299	$ 16,699,432
31	Current Subsidy	$ -	$ 15,766,710	$ 19,138,676	$ 295,462	$ (4,023,621)	$ (6,389,522)

Line			Industrial	Industrial	Process Heating	Protective Lighting	Municipal Lighting
No.	Description	System Total	SL	PL-HL	PH	APL	MU1
	(A)	(B)	(J)	(K)	(L)	(M)	(N)
	Revenue Requirement at Equal Rates of Return at Proposed Rates						
32	Required Return	7.52%	7.52%	7.52%	7.52%	7.52%	7.52%
33	Required Operating Income	$ 417,198,420	$ 80,591,283	$ 50,979,587	$ 527,384	$ 1,760,314	$ 3,381,413
34	Operating Income (Deficiency)/Surplus	$ (144,113,536)	$ (14,990,861)	$ (1,998,362)	$ 58,923	$ (3,894,065)	$ (6,386,313)
	Expenses at Equal Rates of Return at Proposed Rates						
35	Operations & Maintenance Expenses	$ 474,777,771	$ 83,144,447	$ 51,319,333	$ 523,735	$ 7,330,340	$ 9,142,267
36	Depreciation Expense	326,919,520	65,320,267	42,755,541	406,241	1,956,239	2,230,663
37	Amortization Expense	113,274,897	24,929,840	16,960,973	148,385	402,992	451,926
38	Taxes Other than Income	46,750,725	8,774,398	5,545,947	56,093	583,216	731,805
39	Fuel Expenses	597,427,000	146,028,400	121,722,970	1,037,106	1,718,106	1,549,040
40	Non-FAC Trackable Fuel Expenses	57,126,331	13,963,324	11,639,224	99,169	164,286	148,120
41	Income Taxes	77,140,144	14,901,358	9,426,145	97,513	325,483	625,224
42	Total Expense - Required	$ 1,693,416,388	$ 357,062,035	$ 259,370,131	$ 2,368,242	$ 12,480,661	$ 14,879,045
43	Total Revenue Requirement at Equal Return	$ 2,110,614,809	$ 437,653,318	$ 310,349,718	$ 2,895,626	$ 14,240,975	$ 18,260,458
44	Revenue (Deficiency)/Surplus	$ (192,930,536)	$ (21,352,757)	$ (4,342,068)	$ 52,562	$ (4,836,297)	$ (7,950,547)
45	Total Revenues	1,917,684,273	416,300,561	306,007,650	2,948,187	9,404,678	10,309,910
46	Total Revenues as Proposed	$ 2,110,614,809	$ 437,653,318	$ 310,349,718	$ 2,895,626	$ 14,240,975	$ 18,260,458
47	Less Total Other Revenues	$ 18,826,089	$ 1,506,889	$ 957,247	$ 9,774	$ 78,774	$ 99,819
48	Off-System Slaes Margin	33,831,400	7,798,281	5,407,179	45,270	44,781	33,341
49	Total Base Rate Revenues as Proposed	$ 2,057,957,320	$ 428,348,147	$ 303,985,293	$ 2,840,582	$ 14,117,420	$ 18,127,297
	Mitigation						
50	Mitigation	$ (0)	$ 14,139,484	$ 16,043,340	$ 219,846	$ (3,588,167)	$ (6,581,973)
51	Proposed Increase Post Mitigation	192,930,536	35,492,242	20,385,407	167,284	1,248,130	1,368,574
	Revenue Requirement at Proposed Mitigated Rates						
52	Revenue Defficiency/Surplus	$ 192,930,536	$ 35,492,242	$ 20,385,407	$ 167,284	$ 1,248,130	$ 1,368,574
53	Total Revenues	1,917,684,273	416,300,561	306,007,650	2,948,187	9,404,678	10,309,910
54	Total Revenues as Proposed	$ 2,110,614,809	$ 451,792,802	$ 326,393,058	$ 3,115,471	$ 10,652,808	$ 11,678,484
55	Less Total Other Revenues	$ 18,826,089	$ 1,506,889	$ 957,247	$ 9,774	$ 78,774	$ 99,819
56	Off-System Slaes Margin	33,831,400	7,798,281	5,407,179	45,270	44,781	33,341
57	Total Base Rate Revenues as Proposed	$ 2,057,957,320	$ 442,487,632	$ 320,028,632	$ 3,060,428	$ 10,529,253	$ 11,545,324
58	Total Margin in Base Rates	$ 364,540,931	$ 85,425,597	$ 60,658,501	$ 692,185	$ (1,951,408)	$ (3,333,721)
59	Expenses (excl. Income Taxes)	$ 1,616,276,244	$ 342,160,676	$ 249,943,987	$ 2,270,729	$ 12,155,178	$ 14,253,821
60	Interest Expense	140,915,000	27,220,910	17,219,117	178,132	594,572	1,142,123
61	Taxable Income	$ 353,423,564	$ 82,411,216	$ 59,229,954	$ 666,611	$ (2,096,943)	$ (3,717,459)
62	Income Taxes	77,140,144	17,987,519	12,927,851	145,498	(457,690)	(811,393)
63	Operating Income as Proposed	$ 417,198,420	$ 91,644,607	$ 63,521,220	$ 699,244	$ (1,044,680)	$ (1,763,943)
64	Return at Proposed Rates	7.52%	8.55%	9.37%	9.97%	-4.46%	-3.92%
65	Index Rate of Return	1.00	1.14	1.25	1.33	(0.59)	(0.52)

Functional Revenue Requirement

Line No.	Description	System Total	Industrial SL	Industrial PL-HL	Process Heating PH	Protective Lighting APL	Municipal Lighting MU1
	(A)	(B)	(J)	(K)	(L)	(M)	(N)
	Demand						
66	Production	$ 734,649,800	$ 169,339,890	$ 117,417,039	$ 983,040	$ 972,412	$ 724,003
67	Transmission	$ 129,805,033	$ 29,920,610	$ 20,746,378	$ 173,693	$ 171,815	$ 127,924
68	Distribution	$ 113,793,228	$ 25,854,612	$ 15,192,337	$ 206,112	$ 405,576	$ 390,410
69	Distribution Primary	$ 163,117,411	$ 37,061,410	$ 21,777,523	$ 295,451	$ 581,374	$ 559,635
70	Distribution Secondary	$ 25,560,492	$ 6,641,723	$ -	$ 53,603	$ 105,478	$ 101,534
71	Customer	$ -	$ -	$ -	$ -	$ -	$ -
72	Customer Service	$ -	$ -	$ -	$ -	$ -	$ -
73	Fuel Expenses	$ -	$ -	$ -	$ -	$ -	$ -
74	**Total**	$ 1,166,925,964	$ 268,818,246	$ 175,133,278	$ 1,711,899	$ 2,236,655	$ 1,903,506
75	Zero-Check	-	-	-	-	-	-
	Customer						
76	Production	$ -	$ -	$ -	$ -	$ -	$ -
77	Transmission	$ -	$ -	$ -	$ -	$ -	$ -
78	Distribution	$ -	$ -	$ -	$ -	$ -	$ -
79	Distribution Primary	$ 126,550,499	$ 982,235	$ 35,665	$ 4,486	$ -	$ 205,202
80	Distribution Secondary	$ 38,621,351	$ 297,633	$ -	$ 1,370	$ -	$ 62,648
81	Customer	$ 72,344,999	$ 1,817,330	$ 98,362	$ 10,546	$ 10,099,620	$ 14,331,585
82	Customer Service	$ 43,861,814	$ 3,850,152	$ 139,798	$ 17,585	$ -	$ 40,244
83	Fuel Expenses	$ -	$ -	$ -	$ -	$ -	$ -
84	**Total**	$ 281,378,663	$ 6,947,350	$ 273,824	$ 33,986	$ 10,099,620	$ 14,639,680
85	Zero-Check	-	-	-	-	-	-
	Energy						
86	Production	$ 64,883,181	$ 15,859,322	$ 13,219,646	$ 112,634	$ 186,594	$ 168,232
94	**Total**	$ 64,883,181	$ 15,859,322	$ 13,219,646	$ 112,634	$ 186,594	$ 168,232
95	Zero-Check	$ -	$ -	$ -	$ -	$ -	$ -
	Fuel						
96	Fuel Expenses	$ 597,427,000	$ 146,028,400	$ 121,722,970	$ 1,037,106	$ 1,718,106	$ 1,549,040
97	**Total**	$ 597,427,000	$ 146,028,400	$ 121,722,970	$ 1,037,106	$ 1,718,106	$ 1,549,040
98	Zero-Check	-	-	-	-	-	-
99	**Total**	2,110,614,809	437,653,318	310,349,718	2,895,626	14,240,975	18,260,458
	Total Revenue Requirement						
100	Demand	$ 1,166,925,964	$ 268,818,246	$ 175,133,278	$ 1,711,899	$ 2,236,655	$ 1,903,506
101	Customer	$ 281,378,663	$ 6,947,350	$ 273,824	$ 33,986	$ 10,099,620	$ 14,639,680
102	Energy	$ 64,883,181	$ 15,859,322	$ 13,219,646	$ 112,634	$ 186,594	$ 168,232
103	Fuel	$ 597,427,000	$ 146,028,400	$ 121,722,970	$ 1,037,106	$ 1,718,106	$ 1,549,040
104	**Total**	$ 2,110,614,809	$ 437,653,318	$ 310,349,718	$ 2,895,626	$ 14,240,975	$ 18,260,458
105	Zero-Check	-	-	-	-	-	-

Line No.	Description (A)	System Total (B)	Industrial SL (J)	Industrial PL-HL (K)	Process Heating PH (L)	Protective Lighting APL (M)	Municipal Lighting MU1 (N)
	Billing Determinants						
106	Demand	14,030,235	8,746,002	5,284,233	0	0	0
107	Customer Bills (Count *12)	6,770,247	52,548	1,908	240	0	10,978
108	Energy	13,299,137,254	3,234,222,568	2,763,291,451	22,969,728	38,052,433	34,307,981
109	Fuel	13,299,137,254	3,234,222,568	2,763,291,451	22,969,728	38,052,433	34,307,981
	Unit Costs						
110	Demand	.	$ 30.74	$ 33.14	$ -	$ -	$ -
111	Customer	.	$ 132.21	$ 143.51	$ -	#DIV/0!	$ 1,506.94
112	Energy	.	$ 0.004904	$ 0.004784	$ 0.080912	$ 0.004904	$ 0.004904
113	Fuel	.	$ 0.045151	$ 0.044050	$ 0.045151	$ 0.045151	$ 0.045151
114	Demand Revenue	.	$ 268,818,246	$ 175,133,278	$ -	$ -	$ -
115	Customer Revenue	.	6,947,350	273,824	-	#DIV/0!	16,543,185
116	Energy Revenue	.	15,859,322	13,219,646	1,858,519	186,594	168,232
117	Fuel Revenue	.	146,028,400	121,722,970	1,037,106	1,718,106	1,549,040
118	Total Revenue	.	437,653,318	310,349,718	2,895,626	#DIV/0!	18,260,458
119	Zero-Check	.	$ -	$ -	$ -	#DIV/0!	$ -
	Adjusted Revenue Requirement (Excluding Other Revenue and						
120	Ratio of Base Revenue to Total Revenue	96.52%	96.81%	96.63%	97.04%	99.01%	99.20%
	Total Revenue Requirement						
121	Demand	$ 1,126,264,320	$ 260,240,791	$ 169,224,133	$ 1,661,198	$ 2,214,587	$ 1,888,338
122	Customer	$ 271,625,976	$ 6,725,674	$ 264,585	$ 32,979	$ 9,999,974	$ 14,523,027
123	Energy	$ 62,640,023	$ 15,353,283	$ 12,773,604	$ 109,298	$ 184,753	$ 166,892
124	Fuel	$ 597,427,000	$ 146,028,400	$ 121,722,970	$ 1,037,106	$ 1,718,106	$ 1,549,040
125	**Total**	$ 2,057,957,320	$ 428,348,147	$ 303,985,293	$ 2,840,582	$ 14,117,420	$ 18,127,297
126	Zero-Check	-	-	-	-	-	-
	Billing Determinants						
127	Demand	14,030,235	8,746,002	5,284,233	0	0	0
128	Customer Bills (Count *12)	6,770,247	52,548	1,908	240	0	10,978
129	Energy	13,299,137,254	3,234,222,568	2,763,291,451	22,969,728	38,052,433	34,307,981
130	Fuel	13,299,137,254	3,234,222,568	2,763,291,451	22,969,728	38,052,433	34,307,981
	Unit Costs						
131	Demand	.	$ 29.76	$ 32.02	$ -	$ -	$ -
132	Customer	.	$ 127.99	$ 138.67	$ 7,059.07	#DIV/0!	$ 1,494.93
133	Energy	.	$ 0.004747	$ 0.004623	$ 0.078515	$ 0.004855	$ 0.004865
134	Fuel	.	$ 0.045151	$ 0.044050	$ 0.045151	$ 0.045151	$ 0.045151
135	Demand Revenue	.	$ 260,240,791	$ 169,224,133	$ -	$ -	$ -
136	Customer Revenue	.	6,725,674	264,585	1,694,177	#DIV/0!	16,411,366
137	Energy Revenue	.	15,353,283	12,773,604	1,803,476	184,753	166,892
138	Fuel Revenue	.	146,028,400	121,722,970	1,037,106	1,718,106	1,549,040
139	Total Revenue	.	428,348,147	303,985,293	4,534,759	#DIV/0!	18,127,297
140	Zero-Check	.	$ -	$ -	$ 1,694,177	#DIV/0!	$ -
	Grid Facility						
141	Grid Facility - Revenue Requirement	$ 688,854,177	$ 103,029,873	$ 56,033,429	$ 740,252	$ 11,251,743	$ 15,693,132
142	Grid Facility - Unit Costs ($/Bill)	$ 101.75	$ 1,960.68	$ 29,367.63	$ 3,084.38	#DIV/0!	$ 1,429.51

Line No.	Description	System Total	Industrial SL	Industrial PL-HL	Process Heating PH	Protective Lighting APL	Municipal Lighting MU1
	(A)	(B)	(J)	(K)	(L)	(M)	(N)
	Mitigated Revenue Requirement (Excluding Other Revenue and						
143	Ratio of Unmitigated Revenue to Mitigated Revenue	100.00%	105.30%	109.47%	112.98%	70.62%	59.89%
144	Mitigated Amount	(0)	14,139,484	16,043,340	219,846	(3,588,167)	(6,581,973)
	Total Revenue Requirement						
145	Demand	$ 1,142,252,170	$ 274,024,060	$ 185,242,428	$ 1,876,764	$ 1,564,027	$ 1,130,998
146	Customer	$ 255,638,127	$ 7,081,889	$ 289,630	$ 37,259	$ 7,062,368	$ 8,698,395
147	Energy	$ 62,640,023	$ 15,353,283	$ 12,773,604	$ 109,298	$ 184,753	$ 166,892
148	Fuel	$ 597,427,000	$ 146,028,400	$ 121,722,970	$ 1,037,106	$ 1,718,106	$ 1,549,040
149	**Total**	$ 2,057,957,320	$ 442,487,632	$ 320,028,632	$ 3,060,428	$ 10,529,253	$ 11,545,324
150	Zero-Check	-	-	-	-	-	-
	Billing Determinants						
151	Demand	14,030,235	8,746,002	5,284,233	0	0	0
152	Customer Bills (Count *12)	6,770,247	52,548	1,908	240	0	10,978
153	Energy	13,299,137,254	3,234,222,568	2,763,291,451	22,969,728	38,052,433	34,307,981
154	Fuel	13,299,137,254	3,234,222,568	2,763,291,451	22,969,728	38,052,433	34,307,981
	Unit Costs						
155	Demand	.	$ 31.33	$ 35.06	$ -	$ -	$ -
156	Customer	.	$ 134.77	$ 151.80	$ 7,975.09	#DIV/0!	$ 895.37
157	Energy	.	$ 0.004747	$ 0.004623	$ 0.088086	$ 0.004855	$ 0.004865
158	Fuel	.	$ 0.045151	$ 0.044050	$ 0.045151	$ 0.045151	$ 0.045151
159	Demand Revenue	.	$ 274,024,060	$ 185,242,428	$ -	$ -	$ -
160	Customer Revenue	.	7,081,889	289,630	1,914,023	#DIV/0!	9,829,392
161	Energy Revenue	.	15,353,283	12,773,604	2,023,321	184,753	166,892
162	Fuel Revenue	$ -	146,028,400	121,722,970	1,037,106	1,718,106	1,549,040
163	Total Revenue	.	442,487,632	320,028,632	4,974,450	#DIV/0!	11,545,324
164	Zero-Check	.	$ -	$ -	$ 1,914,023	#DIV/0!	$ -
	Total Revenue Requirement (Excluding Fuel)						
165	Demand	$ 1,142,252,170	$ 274,024,060	$ 185,242,428	$ 1,876,764	$ 1,564,027	$ 1,130,998
166	Customer	$ 255,638,127	$ 7,081,889	$ 289,630	$ 37,259	$ 7,062,368	$ 8,698,395
167	Energy	$ 62,640,023	$ 15,353,283	$ 12,773,604	$ 109,298	$ 184,753	$ 166,892
168	**Total**	$ 1,460,530,320	$ 296,459,231	$ 198,305,662	$ 2,023,321	$ 8,811,147	$ 9,996,284
169	**Percent of Total**	100.00%	20.30%	13.58%	0.14%	0.60%	0.68%
170	Zero-Check	-	-	-	-	-	-

AES INDIANA

Proposed Mitigation of Rate Increases

A	B	C	D	E	F	G	H
		Current Revenue	**Proposed Revenue**	**ACOSS Deficiency at 7.52% ROR**	**ACOSS Rate Increase**	**Current Subsidy at 4.92% ROR**	**Eliminate 50% of Current Subsidy**
System Total		$ 1,865,026,784	$ 2,057,957,320	$ (192,930,536)	10.34%		
Residential	**RS**	$ 839,029,639	$ 991,308,968	$ (152,279,329)	18.15%	$ (51,220,162)	$ (25,610,081)
Secondary Small [1]	**SS**	$ 218,183,896	$ 214,473,089	$ 3,710,807	-1.70%	$ 23,997,879	$ 11,998,939
Space Conditioning	**SH**	$ 76,497,418	$ 82,617,149	$ (6,119,731)	8.00%	$ 2,053,834	$ 1,026,917
Space Conditioning - Schools	**SE**	$ 2,095,627	$ 1,857,848	$ 237,779	-11.35%	$ 404,082	$ 202,041
Water Heating - Controlled	**CB**	$ 64,048	$ 92,005	$ (27,956)	43.65%	$ (18,335)	$ (9,168)
Water Heating - Uncontrolled	**UW**	$ 166,524	$ 189,522	$ (22,999)	13.81%	$ (5,003)	$ (2,501)
Secondary Large	**SL**	$ 406,995,390	$ 428,348,147	$ (21,352,757)	5.25%	$ 15,766,710	$ 7,883,355
Primary Large	**PL-HL**	$ 299,643,225	$ 303,985,293	$ (4,342,068)	1.45%	$ 19,138,676	$ 9,569,338
Process Heating	**PH**	$ 2,893,144	$ 2,840,582	$ 52,562	-1.82%	$ 295,462	$ 147,731
Automatic Protective Lighting	**APL**	$ 9,281,123	$ 14,117,420	$ (4,836,297)	52.11%	$ (4,023,621)	$ (2,011,811)
Municipal Lighting	**MU1**	$ 10,176,750	$ 18,127,297	$ (7,950,547)	78.12%	$ (6,389,522)	$ (3,194,761)
						$ 0	$ 0

Change in Other Revenue

Total Revenue Deficiency

Notes:

[1] Includes new rate code MD (Small Metered Device)

50% Subsidy Reduction

Increase Capped at 1.3 times System Increase

MD limited to cost to revenue ratio of 1.25

	Current Revenue	**Proposed Revenue**	**ACOSS Deficiency at 7.52% ROR**	**ACOSS Rate Increase**	**Current Subsidy at 4.92% ROR**	**Eliminate 50% of Current Subsidy**
System Total	$ 1,865,026,784	$ 2,057,957,320	$ (192,930,536)	10.34%		
Residential	$ 839,029,639	$ 991,308,968	$ (152,279,329)	18.15%	$ (51,220,162)	$ (25,610,081)
Small C&I	$ 297,007,513	$ 299,229,613	$ (2,222,100)	0.75%	$ 26,432,456	$ 13,216,228
Large C&I	$ 709,531,759	$ 735,174,022	$ (25,642,263)	3.61%	$ 35,200,848	$ 17,600,424
Lighting	$ 19,457,873	$ 32,244,717	$ (12,786,844)	65.72%	$ (10,413,143)	$ (5,206,571)
					$ 0	$ 0

Notes:

50% Subsidy Reduction

Increase Capped at 1.3 times System Increase

MD limited to cost to revenue ratio of 1.25

AES INDIANA

Proposed Mitigation of Rate Increases

							13.45%						
							1.3 times System Increase			First Iteration			Second Iteration
A	B	I	J	K	L		M	N	O	P	Q	R	S
		Revised Deficiency	**Revised Rate Incr.**	**Δ %**	**Mitigated Revenue post Subsidy Reduction**	**0**	**Max if Increase capped at 1.3x System Increase**	**Classes Over Cap**	**Classes Under Cap**	**Additional Mitigation**	**Interim Revised Deficiency**	**Classes Under Cap**	**Additional Mitigation**
System Total					$ 2,057,957,320								
Residential	**RS**	$ (126,669,248)	15.10%	3.05%	$ 965,698,887		$ 112,833,108	$ (13,836,140)	$ -	$ 13,836,140	$ (112,833,108)	$ -	$ -
Secondary Small [1]	**SS**	$ (8,288,132)	3.80%	-5.50%	$ 226,472,028		$ 29,289,275	$ -	$ 20,974,864	$ (5,149,874)	$ (13,450,034)	$ 15,824,990	$ (3,293)
Space Conditioning	**SH**	$ (7,146,648)	9.34%	-1.34%	$ 83,644,066		$ 10,287,409	$ -	$ 3,140,762	$ (771,139)	$ (7,917,786)	$ 2,369,623	$ (493)
Space Conditioning - Schools	**SE**	$ 35,738	-1.71%	-9.64%	$ 2,059,889		$ 281,821	$ -	$ 317,559	$ (77,969)	$ (42,231)	$ 239,590	$ (50)
Water Heating - Controlled	**CB**	$ (18,789)	29.34%	14.31%	$ 82,837		$ 8,613	$ (10,176)	$ -	$ 10,176	$ (8,613)	$ -	$ -
Water Heating - Uncontrolled	**UW**	$ (20,497)	12.31%	1.50%	$ 187,021		$ 22,394	$ -	$ 1,897	$ (466)	$ (20,963)	$ 1,431	$ (0)
Secondary Large	**SL**	$ (29,236,112)	7.18%	-1.94%	$ 436,231,502		$ 54,732,935	$ -	$ 25,496,823	$ (6,260,132)	$ (35,496,244)	$ 19,236,691	$ (4,003)
Primary Large	**PL-HL**	$ (13,911,406)	4.64%	-3.19%	$ 313,554,631		$ 40,296,165	$ -	$ 26,384,759	$ (6,478,144)	$ (20,389,549)	$ 19,906,615	$ (4,142)
Process Heating	**PH**	$ (95,169)	3.29%	-5.11%	$ 2,988,313		$ 389,071	$ -	$ 293,902	$ (72,161)	$ (167,330)	$ 221,742	$ (46)
Automatic Protective Lighting	**APL**	$ (2,824,486)	30.43%	21.68%	$ 12,105,609		$ 1,248,130	$ (1,576,356)	$ -	$ 1,576,356	$ (1,248,130)	$ -	$ -
Municipal Lighting	**MU1**	$ (4,755,787)	46.73%	31.39%	$ 14,932,537		$ 1,368,574	$ (3,387,212)	$ -	$ 3,387,212	$ (1,368,574)	$ -	$ -
		$ (192,930,536)						$ (18,809,884)	$ 76,610,567	$ -	$ (192,942,563)	$ 57,800,682	$ (12,027)
		$ -					$ (12,027)		Change in Other Revenue	$ -			
Notes:		$ (192,930,536)							**Total Revenue Deficiency**	**$ (192,930,536)**			

[1] Includes new rate code MD (Small Metered Devic

50% Subsidy Reduction
Increase Capped at 1.3 times System Increase
MD limited to cost to revenue ratio of 1.25

	Revised Deficiency	**Revised Rate Incr.**	**Δ %**	**Mitigated Revenue post Subsidy Reduction**	**0**	**Max if Increase capped at 1.3x System Increase**	**Classes Over Cap**	**Classes Under Cap**	**Additional Mitigation**	**Interim Revised Deficiency**	**Classes Under Cap**	**Additional Mitigation**
System Total				$ 2,057,957,320								
Residential	$ (126,669,248)	15.10%	3.05%	$ 965,698,887		$ 112,833,108	$ (13,836,140)	$ -	$ 13,836,140	$ (112,833,108)	$ -	$ -
Small C&I	$ (15,438,328)	5.20%	-4.45%	$ 312,445,841		$ 39,889,513	$ (10,176)	$ 24,435,082	$ (5,989,272)	$ (21,439,627)	$ 18,435,635	$ (3,836)
Large C&I	$ (43,242,687)	6.09%	-2.48%	$ 752,774,446		$ 95,418,171	$ -	$ 52,175,484	$ (12,810,437)	$ (56,053,124)	$ 39,365,047	$ (8,191)
Lighting	$ (7,580,273)	38.96%	26.76%	$ 27,038,146		$ 2,616,704	$ (4,963,569)	$ -	$ 4,963,569	$ (2,616,704)	$ -	$ -
							$ (18,809,884)	$ 76,610,567	$ -	$ (192,942,563)	$ 57,800,682	$ (12,027)

Notes:
50% Subsidy Reduction
Increase Capped at 1.3 times System Increase
MD limited to cost to revenue ratio of 1.25

AES INDIANA

Proposed Mitigation of Rate Increases

A	B	T	U	V	W	X	Y
		Final Revised Deficiency	**Final Rate Incr.**	**Final Revenue Requirement**	**Total Mitigation**	**Current Subsidy Eliminated (%)**	**Revenue to Cost Ratio**
System Total							
Residential	**RS**	$ (112,833,108)	**13.45%**	$ 951,862,747	$ (39,446,221)	22.99%	0.96
Secondary Small [1]	**SS**	$ (13,446,741)	**6.16%**	$ 231,630,637	$ 17,157,548	28.50%	1.08
Space Conditioning	**SH**	$ (7,917,293)	**10.35%**	$ 84,414,711	$ 1,797,562	12.48%	1.02
Space Conditioning - Schools	**SE**	$ (42,181)	**2.01%**	$ 2,137,808	$ 279,960	30.72%	1.15
Water Heating - Controlled	**CB**	$ (8,613)	**13.45%**	$ 72,661	$ (19,343)	-5.50%	0.79
Water Heating - Uncontrolled	**UW**	$ (20,963)	**12.59%**	$ 187,486	$ (2,036)	59.30%	0.99
Secondary Large	**SL**	$ (35,492,242)	**8.72%**	$ 442,487,632	$ 14,139,484	10.32%	1.03
Primary Large	**PL-HL**	$ (20,385,407)	**6.80%**	$ 320,028,632	$ 16,043,340	16.17%	1.05
Process Heating	**PH**	$ (167,284)	**5.78%**	$ 3,060,428	$ 219,846	25.59%	1.08
Automatic Protective Lighting	**APL**	$ (1,248,130)	**13.45%**	$ 10,529,253	$ (3,588,167)	10.82%	0.75
Municipal Lighting	**MU1**	$ (1,368,574)	**13.45%**	$ 11,545,324	$ (6,581,973)	-3.01%	0.64
		$ (192,930,536)	10.35%	$ 2,057,957,320	$ (0)		1.00

Notes:

[1] Includes new rate code MD (Small Metered Devic

50% Subsidy Reduction

Increase Capped at 1.3 times System Increase

MD limited to cost to revenue ratio of 1.25

	Final Revised Deficiency	Final Rate Incr.	Final Revenue Requirement	Total Mitigation	Current Subsidy Eliminated (%)	Revenue to Cost Ratio
System Total						
Residential	$ (112,833,108)	**13.45%**	$ 951,862,747	$ (39,446,221)	22.99%	0.96
Small C&I	$ (21,435,791)	**7.22%**	$ 318,443,304	$ 19,213,691	27.31%	1.06
Large C&I	$ (56,044,933)	**7.90%**	$ 765,576,692	$ 30,402,670	13.63%	1.04
Lighting	$ (2,616,704)	**13.45%**	$ 22,074,577	$ (10,170,140)	2.33%	0.68
	$ (192,930,536)	10.35%	$ 2,057,957,320	$ (0)		1.00

Notes:

50% Subsidy Reduction

Increase Capped at 1.3 times System Increase

MD limited to cost to revenue ratio of 1.25

AES Indiana
Class Cost of Service - Industrial Rate Classes
Test Year Ended December 31, 2026

Line No.	Description (A)	Industrial Total (B)	Primary Service (Large) PL (C)	High Load Factor (Primary Distribution) HL1 (D)	High Load Factor (Sub transmission) HL2 (E)	High Load Factor (Transmission) HL3 (F)
	Functional Revenue Requirement					
	Allocation of the Revenue Requirement - Demand Component					
1	**Production**					
2	Allocated Production Demand Cost	$ 117,417,039	$ 50,798,548	$ 50,310,192	$ 7,975,244	$ 8,333,055
3	Demand Billing Determinants	5,284,233	2,276,912	2,255,022	367,588	384,710
4	Loss Factor Adjustment		1.058	1.058	1.029	1.027
5	Adjusted Demand Billing Determinants	5,567,582	2,408,723	2,385,566	378,163	395,130
6	Cost Allocation Factors	100.00%	43.26%	42.85%	6.79%	7.10%
7	**Production Demand Charge**	**$ 22.22**	**$ 22.31**	**$ 22.31**	**$ 21.70**	**$ 21.66**
8	**Transmission**					
9	Allocated Transmission Demand Cost	20,746,378	$ 8,857,735	$ 8,772,581	$ 1,663,029	$ 1,453,034
10	Demand Billing Determinants	5,356,233	2,276,912	2,255,022	439,588	384,710
11	Loss Factor Adjustment		1.058	1.058	1.029	1.027
12	Adjusted Demand Billing Determinants	5,641,653	2,408,723	2,385,566	452,235	395,130
13	Cost Allocation Factors	100.00%	42.70%	42.28%	8.02%	7.00%
14	**Transmission Demand Charge**	**$ 3.87**	**$ 3.89**	**$ 3.89**	**$ 3.78**	**$ 3.78**
15	Total Production and Transmission	$ 138,163,418	$ 59,656,284	$ 59,082,773	$ 9,638,272	$ 9,786,089
16	Demand Billing Determinants	5,284,233	2,276,912	2,255,022	367,588	384,710
17	**Production and Transmission Demand Charge**	**$ 26.15**	**$ 26.20**	**$ 26.20**	**$ 26.22**	**$ 25.44**
18	**Distribution and Distribution Primary**					
19	Allocated Station Equipment	$ 15,192,337				
20	Allocated Primary Distribution Demand Cost	21,777,523				
21	Total Distribution	$ 36,969,860				
22	Demand Billing Determinants	5,356,233	2,276,912	2,255,022	439,588	384,710
23	Loss Factor Adjustment		1.058	1.058	-	-
24	Adjusted Demand Billing Determinants	4,794,289	2,408,723	2,385,566	-	-
25	Cost Allocation Factors	100.00%	50.24%	49.76%	0.00%	0.00%
26	Total Distribution and Distribution Primary	$ 36,969,860	$ 18,574,212	$ 18,395,648	$ -	$ -
27	Demand Billing Determinants	5,356,233	2,276,912	2,255,022	439,588	384,710
28	**Distribution Demand Charge**	**$ 6.90**	**$ 8.16**	**$ 8.16**	**$ -**	**$ -**
29	Total Revenue Requirement - Demand Component	$ 175,133,278	$ 78,230,496	$ 77,478,420	$ 9,638,272	$ 9,786,089
30	Demand Billing Determinants	5,284,233	2,276,912	2,255,022	367,588	384,710
31	**Total Demand Charge**	**$ 33.14**	**$ 34.36**	**$ 34.36**	**$ 26.22**	**$ 25.44**
32	**Allocation of the Revenue Requirement - Customer Component**					
33	**Distribution Primary**					
34	Allocated Distribution Primary Cost	$ 35,665				
35	Number of Customers	153				
36	Distribution Primary Cost Per Customer	$ 233				
37	Number of Customers by Rate Class	153	126	27	-	-
38	Total Distribution Primary Cost	$ 35,665	$ 29,371	$ 6,294	$ -	$ -
39	**Meter Costs**					
40	Allocated Meter Costs	$ 90,506				
41	Total Meter Embedded Cost	$ 335,780	$ 233,127	$ 81,951	$ 12,515	$ 8,187
42	Cost Allocation Factors	100%	69.43%	24.41%	3.73%	2.44%
43	Meter Costs - Allocated	$ 90,506	$ 62,837	$ 22,089	$ 3,373	$ 2,207

AES Indiana

Class Cost of Service - Industrial Rate Classes

Test Year Ended December 31, 2026

			Primary Service (Large)	High Load Factor (Primary Distribution)	High Load Factor (Sub transmission)	High Load Factor (Transmission)
Line No.	Description	Industrial Total	PL	HL1	HL2	HL3
	(A)	(B)	(C)	(D)	(E)	(F)
44	Ratio Check					
45	Number of Customers by Rate Class	160	126	27	5	2
46	Per Customer Meter Cost - Actual	2,099	1,850	3,035	2,503	4,093
47	Scaling of Meter Cost - Actual		1.00	1.64	1.35	2.21
48	Per Customer Meter Cost - Allocated	566	499	818	675	1,103
49	Scaling of Meter Cost - Allocated		1.00	1.64	1.35	2.21
50	Check		TRUE	TRUE	TRUE	TRUE
51	**Additional Customer Costs**					
52	Allocated Additional Customer Costs	$ 147,654				
53	Number of Customers	160				
54	Additional Customer Costs Per Customer	$ 923				
55	Number of Customers by Rate Class	160	126	27	5	2
56	Total Additional Customer Costs Allocated	$ 147,654	$ 116,277	$ 24,917	$ 4,614	$ 1,846
57	Total Revenue Requirement - Customer Component	$ 273,824	$ 208,485	$ 53,299	$ 7,987	$ 4,052
58	Customer Bills by Rate Class	1,920	1,512	324	60	24
59	**Total Customer Charge**	**$ 142.62**	**$ 137.89**	**$ 164.50**	**$ 133.12**	**$ 168.85**
60	**Allocation of the Revenue Requirement - Energy Component**					
61	**Total Revenue Requirement - Energy Component**					
62	Allocated Energy Costs	$ 13,219,646				
63	Energy at the Meter	2,691,778,747	1,024,030,101	1,262,126,058	178,648,530	226,974,058
64	Line Loss Factor		1.047	1.047	1.026	1.024
65	Energy at Source	2,809,172,667	1,072,050,174	1,321,311,218	183,359,745	232,451,530
66	Cost Allocation Factors	100.00%	38.16%	47.04%	6.53%	8.27%
67	Total Revenue Requirement - Energy Component	$ 13,219,646	$ 5,044,946	$ 6,217,940	$ 862,870	$ 1,093,890
68	Energy at the Meter	2,691,778,747	1,024,030,101	1,262,126,058	178,648,530	226,974,058
69	**Total Energy Charge**	**$ 0.004911**	**$ 0.004927**	**$ 0.004927**	**$ 0.004830**	**$ 0.004819**
70	**Allocation of the Revenue Requirement - Fuel Component**					
71	Allocated Fuel Costs	$ 121,722,970				
72	Energy at the Meter	2,691,778,747	1,024,030,101	1,262,126,058	178,648,530	226,974,058
73	Line Loss Factor		1.047	1.047	1.026	1.024
74	Energy at Source	2,809,172,667	1,072,050,174	1,321,311,218	183,359,745	232,451,530
75	Cost Allocation Factors	100.00%	38.16%	47.04%	6.53%	8.27%
76	Total Revenue Requirement - Fuel Component	$ 121,722,970	$ 46,452,513	$ 57,253,129	$ 7,945,077	$ 10,072,250
77	Energy at the Meter	2,691,778,747	1,024,030,101	1,262,126,058	178,648,530	226,974,058
78	**Total Fuel Charge**	**$ 0.045220**	**$ 0.045362**	**$ 0.045362**	**$ 0.044473**	**$ 0.044376**
79	**Total Functional Revenue Requirement**					
80	Demand	$ 175,133,278	$ 78,230,496	$ 77,478,420	$ 9,638,272	$ 9,786,089
81	Customer	273,824	208,485	53,299	7,987	4,052
82	Energy	13,219,646	5,044,946	6,217,940	862,870	1,093,890
83	Fuel	121,722,970	46,452,513	57,253,129	7,945,077	10,072,250
84	**Total Revenue Requirement (incl. Other Revenues)**	**$ 310,349,718**	**$ 129,936,440**	**$ 141,002,789**	**$ 18,454,207**	**$ 20,956,282**
85	Check	TRUE				

AES Indiana
Class Cost of Service - Industrial Rate Classes
Test Year Ended December 31, 2026

Line No.	Description	Industrial Total	Primary Service (Large) PL	High Load Factor (Primary Distribution) HL1	High Load Factor (Sub transmission) HL2	High Load Factor (Transmission) HL3
	(A)	(B)	(C)	(D)	(E)	(F)
86	**Adjusted Revenue Requirement (Excluding Other Revenue and Sale for Resale Revenues)**					
87	**Other Revenue & Sales for Resale**					
88	Total Base Revenue Excl. Fuel	$ 182,262,323				
89	Total Revenue Excl. Fuel	188,626,748				
90	Ratio of Base Revenue to Total Revenue	96.63%				
91	**Total Functional Revenue Requirement (Excluding Other Revenue and Sale for Resale Revenues)**					
92	Demand	$ 169,224,133	$ 75,590,933	$ 74,864,233	$ 9,313,069	$ 9,455,898
93	Customer	264,585	201,451	51,501	7,718	3,916
94	Energy	12,773,604	4,874,725	6,008,141	833,756	1,056,982
95	Fuel	121,722,970	46,452,513	57,253,129	7,945,077	10,072,250
96	**Total Revenue Requirement Excl. Other Revenue**	**$ 303,985,293**	**$ 127,119,622**	**$ 138,177,005**	**$ 18,099,620**	**$ 20,589,046**
97	Check	TRUE				
			41.82%	45.46%	5.95%	6.77%
98	**Billing Determinants**					
99	Demand	5,284,233	2,276,912	2,255,022	367,588	384,710
100	Customer Bills	1,920	1,512	324	60	24
101	Energy	2,691,778,747	1,024,030,101	1,262,126,058	178,648,530	226,974,058
102	Fuel	2,691,778,747	1,024,030,101	1,262,126,058	178,648,530	226,974,058
103	**Unit Costs**					
104	Demand	$ 32.02	$ 33.20	$ 33.20	$ 25.34	$ 24.58
105	Customer	$ 137.80	$ 133.23	$ 158.95	$ 128.63	$ 163.15
106	Energy	$ 0.004745	$ 0.004760	$ 0.004760	$ 0.004667	$ 0.004657
107	Fuel	$ 0.045220	$ 0.045362	$ 0.045362	$ 0.044473	$ 0.044376
108	**Mitigated Revenue Requirement (Excluding Other Revenue and Sale for Resale Revenues)**					
109	**Mitigation**					
110	Mitigated Amount - Demand	$ 16,018,295				
111	Cost Allocation Factors	100.00%	44.67%	44.24%	5.50%	5.59%
112	Mitigation Amount Allocated - Demand	$ 16,018,295	$ 7,155,231	$ 7,086,444	$ 881,550	$ 895,070
113	Mitigated Amount - Customer	$ 25,045				
114	Cost Allocation Factors	100.00%	76.14%	19.46%	2.92%	1.48%
115	Mitigation Amount Allocated - Customer	$ 25,045	$ 19,069	$ 4,875	$ 731	$ 371
116	Check	TRUE				
117	**Total Mitigated Functional Revenue Requirement (Excluding Other Revenue and Sale for Resale Revenues)**					
118	Demand	$ 185,242,428	$ 82,746,165	$ 81,950,677	$ 10,194,619	$ 10,350,968
119	Customer	289,630	220,519	56,376	8,448	4,286
120	Energy	12,773,604	4,874,725	6,008,141	833,756	1,056,982
121	Fuel	121,722,970	46,452,513	57,253,129	7,945,077	10,072,250
122	**Total Mitigated Revenue Requirement Excl. Other Revenue**	$ 320,028,632	$ 134,293,923	$ 145,268,324	$ 18,981,900	$ 21,484,486
123	Check	TRUE				
			41.96%	45.39%	5.93%	6.71%
124	**Billing Determinants**					
125	Demand	5,284,233	2,276,912	2,255,022	367,588	384,710
126	Customer Bills	1,920	1,512	324	60	24
127	Energy	2,691,778,747	1,024,030,101	1,262,126,058	178,648,530	226,974,058
128	Fuel	2,691,778,747	1,024,030,101	1,262,126,058	178,648,530	226,974,058
129	**Unit Costs**					
130	Demand	$ 35.06	$ 36.34	$ 36.34	$ 27.73	$ 26.91
131	Customer	$ 150.85	$ 145.85	$ 174.00	$ 140.81	$ 178.59
132	Energy	$ 0.004745	$ 0.004760	$ 0.004760	$ 0.004667	$ 0.004657
133	Fuel	$ 0.045220	$ 0.045362	$ 0.045362	$ 0.044473	$ 0.044376

AES Indiana
Class Cost of Service - Industrial Rate Classes
Test Year Ended December 31, 2026

Line No.	Description	Industrial Total	Primary Service (Large) PL	High Load Factor (Primary Distribution) HL1	High Load Factor (Sub transmission) HL2	High Load Factor (Transmission) HL3
	(A)	(B)	(C)	(D)	(E)	(F)
134	**Comparison of Current and Proposed Pro Forma Revenues**					
135	Total Current Revenue	$ 299,643,225				
136	Large Commercial Sales Revenue	$ 298,847,192	$ 117,736,451	$ 141,111,098	$ 18,804,136	$ 21,195,508
137	Cost Allocation Factors	100.00%	39.40%	47.22%	6.29%	7.09%
138	Total Current Revenue Allocated	$ 299,643,225	$ 118,050,063	$ 141,486,972	$ 18,854,224	$ 21,251,966
139	Unmitigated Proposed Revenue	$ 303,985,293	$ 127,119,622	$ 138,177,005	$ 18,099,620	$ 20,589,046
140	Mitigated Proposed Revenue	$ 320,028,632	$ 134,293,923	$ 145,268,324	$ 18,981,900	$ 21,484,486
141	Increase: Unmitigated - Current ($)	$ 4,342,068	$ 9,069,560	$ (3,309,968)	$ (754,605)	$ (662,920)
142	Increase: Mitigated - Current ($)	$ 20,385,407	$ 16,243,860	$ 3,781,351	$ 127,676	$ 232,520
143	Increase: Unmitigated - Current (%)	1.45%	7.68%	-2.34%	-4.00%	-3.12%
144	Increase: Mitigated - Current (%)	6.80%	13.76%	2.67%	0.68%	1.09%
145	**Industrial Rates Additional Mitigation**					
146	Cap Increase	1.70				
147	Capped Increase	11.57%	11.57%	11.57%	11.57%	11.57%
148	Allowed Increase at Cap		$ 13,653,062	$ 16,363,655	$ 2,180,582	$ 2,457,893
149	Increase Over Cap		$ (2,590,798)	$ -	$ -	$ -
150	Adidtional Mitigation Needed	$ 2,590,798	$ 2,590,798	$ -	$ -	$ -
151	Mitigation	$ -	$ (2,590,798)	$ 2,026,335	$ 264,777	$ 299,685
152	Final Mitigated Proposed Revenues	$ 320,028,632	$ 131,703,125	$ 147,294,659	$ 19,246,677	$ 21,784,171
153	Increase: Mitigated - Current (%)	6.80%	11.57%	4.10%	2.08%	2.50%
154	**Total Mitigated Functional Revenue Requirement (Excluding Other Revenue and Sale for Resale Revenues)**					
155	Demand	$ 185,247,578	$ 80,162,253	$ 83,975,619	$ 10,459,176	$ 10,650,529
156	Customer	284,480	213,633	57,769	8,668	4,410
157	Energy	12,773,604	4,874,725	6,008,141	833,756	1,056,982
158	Fuel	121,722,970	46,452,513	57,253,129	7,945,077	10,072,250
159	**Total Mitigated Revenue Requirement Excl. Other Revenue**	$ 320,028,632	$ 131,703,125	$ 147,294,659	$ 19,246,677	$ 21,784,171
160	Check	TRUE				
161	**Billing Determinants**					
162	Demand	5,284,233	2,276,912	2,255,022	367,588	384,710
163	Customer Bills	1,920	1,512	324	60	24
164	Energy	2,691,778,747	1,024,030,101	1,262,126,058	178,648,530	226,974,058
165	Fuel	2,691,778,747	1,024,030,101	1,262,126,058	178,648,530	226,974,058
166	**Unit Costs**					
167	Demand	$ 35.06	$ 35.21	$ 37.24	$ 28.45	$ 27.68
168	Customer	$ 148.17	$ 141.29	$ 178.30	$ 144.46	$ 183.76
169	Energy	$ 0.004745	$ 0.004760	$ 0.004760	$ 0.004667	$ 0.004657
170	Fuel	$ 0.045220	$ 0.045362	$ 0.045362	$ 0.044473	$ 0.044376

AES Indiana
Comparison of Current and Proposed Pro Forma Revenues

Line No.	Rate Class	Rate Code	Current Revenue [1]	Unmitigated Proposed Revenue [1]	Mitigated Proposed Revenue [1]	Increase: Unmitigated - Current	Increase: Mitigated [2]	**Increase: Mitigated [3]**
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Residential Service (Rate RS) - Codes RS, RC, RH	RS	$ 839,029,639	$ 991,308,968	$ 951,862,747	$ 152,279,329	$ 112,833,108	**13.45%**
2	Secondary Service (Small) (Rate SS)	SS	217,795,735	214,173,961	231,256,727	(3,621,774)	13,460,992	**6.18%**
3	Municipal Device (Rate MD)	MD	388,161	299,128	373,910	(89,033)	(14,251)	**-3.67%**
4	Electric Space Conditioning-Secondary Service (Rate SH)	SH	76,497,418	82,617,149	84,414,711	6,119,731	7,917,293	**10.35%**
5	Electric Space Conditioning-Schools (Rate SE)	SE	2,095,627	1,857,848	2,137,808	(237,779)	42,181	**2.01%**
6	Water Heating-Controlled Service (Rate CB/CW)	CB	64,048	92,005	72,661	27,956	8,613	**13.45%**
7	Water Heating-Uncontrolled Service (Rate UW)	UW	166,524	189,522	187,486	22,999	20,963	**12.59%**
8	Secondary Service (Large) - (Rate SL)	SL	406,995,390	428,348,147	442,487,632	21,352,757	35,492,242	**8.72%**
9	Primary Service (Large) - (Rate PL)	PL	118,050,063	127,119,622	131,703,125	9,069,560	13,653,062	**11.57%**
10	Process Heating (Rate PH)	PH	2,893,144	2,840,582	3,060,428	(52,562)	167,284	**5.78%**
11	High Load Factor (Rate HL-1) (Primary Distribution)	HL1	141,486,972	138,177,005	147,294,659	(3,309,968)	5,807,687	**4.10%**
12	High Load Factor (Rate HL-2) (Sub transmission)	HL2	18,854,224	18,099,620	19,246,677	(754,605)	392,453	**2.08%**
13	High Load Factor (Rate HL-3) (Transmission)	HL3	21,251,966	20,589,046	21,784,171	(662,920)	532,206	**2.50%**
1	Automatic Protective Lighting (APL)	APL	9,281,123	14,117,420	10,529,253	4,836,297	1,248,130	**13.45%**
2	Municipal Lighting (MU)	MU1	$ 10,176,750	$ 18,127,297	$ 11,545,324	$ 7,950,547	$ 1,368,574	**13.45%**
3	**TOTAL SYSTEM**		**$ 1,865,026,784**	**$ 2,057,957,320**	**$ 2,057,957,320**	**$ 192,930,536**	**$ 192,930,536**	**10.34%**

[1] From ACOSS.
[2] Col. (E) - (C) + (G)

AES Indiana
Comparison of Current and Proposed Pro Forma Revenues

Line No.	Rate Class		Current Revenue [1]	Unmitigated Proposed Revenue [1]	Mitigated Proposed Revenue [1]	Increase: Unmitigated - Current	Increase: Mitigated [2]
	(A)	(B)	(C)	(D)	(E)	(F)	(H)
1	Residential		839,029,639	991,308,968	951,862,747	$ 152,279,329	$ 112,833,108
2	Small C&I		297,007,513	299,229,613	318,443,304	$ 2,222,100	$ 21,435,791
3	Large C&I		709,531,759	735,174,022	765,576,692	$ 25,642,263	$ 56,044,933
4	Lighting		19,457,873	32,244,717	22,074,577	$ 12,786,844	$ 2,616,704
5	**TOTAL SYSTEM**		**$ 1,865,026,784**	**$ 2,057,957,320**	**$ 2,057,957,320**	**$ 192,930,536**	**$ 192,930,536**

AES Indiana
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2026
Residential Service (RS, RC,RH, CR/CW)

Line No.	Description	Annualized Volumes	Current Rate	Annualized Revenue	Adjustment	Adjustment	Total Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
	Billed kwh						
1	First 500 kWh	2,598,027,470	$ 0.125421	$ 325,847,203	$ -	$ -	$ 325,847,203
2	Over 500 kWh	1,903,156,158	$ 0.113822	$ 216,621,040	$ -	$ -	$ 216,621,040
3	Over 1,000	884,964,205	$ 0.101408	$ 89,742,450	$ -	$ -	$ 89,742,450
4	Resid (CR/CW)	44,959	$ 0.076943	$ 3,459	$ -	$ -	$ 3,459
5	Total kWh	5,386,192,793	$ 0.117377	$ 632,214,153	$ -	$ -	$ 632,214,153
	Customer Charge						
6	0 to 325 kWh	1,085,978	$ 12.50	$ 13,574,727	$ -	$ -	$ 13,574,727
7	Over 325 kWh	4,951,474	$ 17.00	$ 84,175,053	$ -	$ -	$ 84,175,053
8	Resid (CR/CW)	158	$ 20.00	$ 3,167	$ -	$ -	$ 3,167
9		6,037,610	$ 16.19	$ 97,752,946	$ -	$ -	$ 97,752,946
10	Residential Service (RS, RC,RH)			$ 729,967,099	$ -	$ -	$ 729,967,099
	Contract Riders						
11	Electric Vehicle Revenue			$ -	$ -	$ -	$ -
12	No. 3 TDSIC			$ 39,680,977	$ -	$ -	$ 39,680,977
13	No. 6 Fuel Cost Adjustment			$ 31,848,558	$ -	$ -	$ 31,848,558
14	No. 7 Employee Discount			$ (146,848)	$ -	$ -	$ (146,848)
15	No. 9 Net Metering			$ -	$ -	$ -	$ -
16	No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
17	No. 20 Environmental Compliance Cost Recovery			$ 42,177,842	$ -	$ -	$ 42,177,842
18	No. 21 Green Power			$ -	$ -	$ -	$ -
19	No. 22 Demand-Side Management Adjustment			$ 6,865,994	$ -	$ -	$ 6,865,994
20	No. 24 Capacity Adjustment			$ (11,929,990)	$ -	$ -	$ (11,929,990)
21	No. 26 Regional Transmission Organization Rider			$ (1,133,999)	$ -	$ -	$ (1,133,999)
22	Total Rider			$ 107,362,533	$ -	$ -	$ 107,362,533
23	Grand Total			$ 837,329,632	$ -	$ -	$ 837,329,632
24						*Balancing Adjustment*	*1.00203*
25						**Total Revenue**	**$ 839,029,639**
						Check	TRUE

AES Indiana
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2026
Residential Service (RS, RC,RH, CR/CW)

🟨 Solved for Yellow Highlighted Cells
🟦 Targeted Difference at Zero

Description	Annualized Volumes	Proposed Rate	Revenue	Adjustment	Adjustment	Total Revenue
(H)	(I)	(J)	(K)	(L)	(M)	(N)
Billed kwh						
First 500 kWh	2,598,027,470	$ 0.160074	$ 415,875,956	$ -	$ -	$ 415,875,956
Over 500 kWh	1,903,156,158	$ 0.148475	$ 282,570,603	$ -	$ -	$ 282,570,603
Over 1,000	884,964,205	$ 0.136061	$ 120,408,879	$ -	$ -	$ 120,408,879
Resid (CR/CW)	44,959	$ 0.113150	$ 5,087	$ -	$ -	$ 5,087
Total kWh	5,386,192,793	$ 0.152030	$ 818,860,524	$ -	$ -	$ 818,860,524
		Target	$ 818,860,524			
		Difference	$ -			
Customer Charge						
0 to 325 kWh	1,085,978	$ 15.00	$ 16,289,673	$ -	$ -	$ 16,289,673
Over 325 kWh	4,951,474	$ 20.00	$ 99,029,474	$ -	$ -	$ 99,029,474
Resid (CR/CW)	158	$ 22.00	$ 3,483	$ -	$ -	$ 3,483
	6,037,610	$ 19.10	$ 115,322,629	$ -	$ -	$ 115,322,629
		Target	$ 115,322,629			
		Difference	$ -			
Residential Service (RS, RC,RH)			$ 934,183,153	$ -	$ -	$ 934,183,153
		Target	$ 934,183,153			
		Difference	$ -			
Contract Riders			.			
Electric Vehicle Revenue			$ -	$ -	$ -	$ -
No. 3 TDSIC			$ -	$ -	$ -	$ -
No. 6 Fuel Cost Adjustment			$ -	$ -	$ -	$ -
No. 7 Employee Discount			$ (186,354)	$ -	$ -	$ (186,354)
No. 9 Net Metering			$ -	$ -	$ -	$ -
No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
No. 20 Environmental Compliance Cost Recovery			$ -	$ -	$ -	$ -
No. 21 Green Power			$ -	$ -	$ -	$ -
No. 22 Demand-Side Management Adjustment			$ 17,865,948	$ -	$ -	$ 17,865,948
No. 24 Capacity Adjustment			$ -	$ -	$ -	$ -
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 17,679,594	$ -	$ -	$ 17,679,594
Grand Total			$ 951,862,747	$ -	$ -	$ 951,862,747
		Check	TRUE			

AES Indiana
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2026
Secondary Service (SS)

Line No.	Description (A)	Annualized Volumes (B)	Current Rate (C)	Annualized Revenue (D)	Adjustment (E)	Adjustment (F)	Total Revenue (G)
	Billed kwh						
1	First 5,000 kWh	884,908,725	$ 0.122952	$ 108,801,298	$ -	$ -	$ 108,801,298
2	Over 5,000	419,751,944	$ 0.108472	$ 45,531,333	$ -	$ -	$ 45,531,333
3	Total kWh	1,304,660,668		$ 154,332,630	$ -	$ -	$ 154,332,630
	Customer Charge						
4	0 to 5,000 kWh	539,148	$ 40.00	$ 21,565,938	$ -	$ -	$ 21,565,938
5	Over 5,000 kWh	75,539	$ 55.00	$ 4,154,642	$ -	$ -	$ 4,154,642
		614,687		$ 25,720,581	$ -	$ -	$ 25,720,581
6	Secondary Service (SS)			$ 180,053,211	$ -	$ -	$ 180,053,211
	Contract Riders						
7	Special Contract Revenue			$ 3,018,593	$ -	$ -	$ 3,018,593
8	Electric Vehicle Revenue			$ -	$ -	$ -	$ -
9	No. 3 TDSIC			$ 8,651,146	$ -	$ -	$ 8,651,146
10	No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
11	No. 6 Fuel Cost Adjustment			$ 7,714,458	$ -	$ -	$ 7,714,458
12	No. 9 Net Metering			$ -	$ -	$ -	$ -
13	No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
14	No. 20 Environmental Compliance Cost Recovery			$ 9,887,451	$ -	$ -	$ 9,887,451
15	No. 21 Green Power			$ -	$ -	$ -	$ -
16	No. 22 Demand-Side Management Adjustment			$ 8,564,199	$ -	$ -	$ 8,564,199
17	No. 24 Capacity Adjustment			$ (2,796,912)	$ -	$ -	$ (2,796,912)
18	No. 26 Regional Transmission Organization Rider			$ (265,929)	$ -	$ -	$ (265,929)
19	Total Rider			$ 34,773,007	$ -	$ -	$ 34,773,007
20	Grand Total			$ 214,826,218	$ -	$ -	$ 214,826,218
21						*Balancing Adjustment*	*1.013823*
22						**Total Revenue**	**$ 217,795,735**
						Check	TRUE

AES Indiana
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2026
Secondary Service (SS)

🟨 Solved for Yellow Highlighted Cells
🟦 Targeted Difference at Zero

Description (H)	Annualized Volumes (I)	Proposed Rate (J)	Revenue (K)	Adjustment (L)	Adjustment (M)	Total Revenue (N)
Billed kwh						
First 5,000 kWh	884,908,725	$ 0.154732	$ 136,923,922	$ -	$ -	$ 136,923,922
Over 5,000	419,751,944	$ 0.140252	$ 58,871,156	$ -	$ -	$ 58,871,156
Total kWh	1,304,660,668		$ 195,795,078	$ -	$ -	$ 195,795,078
		Target	$ 195,795,078			
		Difference	$ -			
Customer Charge						
0 to 5,000 kWh	539,148	$ 44.00	$ 23,722,532	$ -	$ -	$ 23,722,532
Over 5,000 kWh	75,539	$ 60.00	$ 4,532,337	$ -	$ -	$ 4,532,337
	614,687		$ 28,254,869	$ -	$ -	$ 28,254,869
		Target	$ 28,254,869			
		Difference	$ -			
Secondary Service (SS)			$ 224,049,947	$ -	$ -	$ 224,049,947
		Target	$ 224,049,947			
		Difference	$ -			
Contract Riders						
Special Contract Revenue			$ 3,018,593	$ -	$ -	$ 3,018,593
Electric Vehicle Revenue			$ -	$ -	$ -	$ -
No. 3 TDSIC			$ -	$ -	$ -	$ -
No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
No. 6 Fuel Cost Adjustment			$ -	$ -	$ -	$ -
No. 9 Net Metering			$ -	$ -	$ -	$ -
No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
No. 20 Environmental Compliance Cost Recovery			$ -	$ -	$ -	$ -
No. 21 Green Power			$ -	$ -	$ -	$ -
No. 22 Demand-Side Management Adjustment			$ 4,188,187	$ -	$ -	$ 4,188,187
No. 24 Capacity Adjustment			$ -	$ -	$ -	$ -
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 7,206,780	$ -	$ -	$ 7,206,780
Grand Total			$ 231,256,727	$ -	$ -	$ 231,256,727
		Check	TRUE			

AES Indiana
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2026
Municipal Device (Small) (MD)

Line No.	Description	Annualized Volumes	Current Rate	Annualized Revenue	Adjustment	Adjustment	Total Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
	Billed kwh						
1	First 5,000 kWh	895,098	$ 0.122952	$ 110,054	$ -	$ -	$ 110,054
2	Over 5,000	-	$ 0.108472	$ -	$ -	$ -	$ -
3	Total kWh	895,098		$ 110,054	$ -	$ -	$ 110,054
	Customer Charge						
4	0 to 5,000 kWh	6,408	$ 40.00	$ 256,320	$ -	$ -	$ 256,320
5	Over 5,000 kWh	-	$ 55.00	$ -	$ -	$ -	$ -
		6,408		$ 256,320	$ -	$ -	$ 256,320
6	Municipal Device (MD)			$ 366,374	$ -	$ -	$ 366,374
	Contract Riders						
7	Special Contract Revenue			$ -	$ -	$ -	$ -
8	Electric Vehicle Revenue			$ -	$ -	$ -	$ -
9	No. 3 TDSIC			$ 5,935	$ -	$ -	$ 5,935
10	No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
11	No. 6 Fuel Cost Adjustment			$ 5,293	$ -	$ -	$ 5,293
12	No. 9 Net Metering			$ -	$ -	$ -	$ -
13	No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
14	No. 20 Environmental Compliance Cost Recovery			$ 6,784	$ -	$ -	$ 6,784
15	No. 21 Green Power			$ -	$ -	$ -	$ -
16	No. 22 Demand-Side Management Adjustment			$ 5,876	$ -	$ -	$ 5,876
17	No. 24 Capacity Adjustment			$ (1,919)	$ -	$ -	$ (1,919)
18	No. 26 Regional Transmission Organization Rider			$ (182)	$ -	$ -	$ (182)
19	Total Rider			$ 21,786	$ -	$ -	$ 21,786
20	Grand Total			$ 388,160	$ -	$ -	$ 388,160
21						*Balancing Adjustment*	*1.000002*
22						**Total Revenue**	**$ 388,161**
						Check	TRUE

AES Indiana
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2026
Municipal Device (Small) (MD)

🟨 Solved for Yellow Highlighted Cells
🟦 Targeted Difference at Zero

Description	Annualized Volumes	Proposed Rate	Revenue	Adjustment	Adjustment	Total Revenue
(H)	(I)	(J)	(K)	(L)	(M)	(N)
Billed kwh						
First 5,000 kWh	895,098	$ 0.163956	$ 146,756	$ -	$ -	$ 146,756
Over 5,000	-	$ 0.163956	$ -	$ -	$ -	$ -
Total kWh	895,098		$ 146,756	$ -	$ -	$ 146,756
		Target	$ 146,756			
		Difference	$ 0			
Customer Charge						
0 to 5,000 kWh	6,408	$ 35.00	$ 224,280	$ -	$ -	$ 224,280
Over 5,000 kWh	-	$ 35.00	$ -	$ -	$ -	$ -
	6,408		$ 224,280	$ -	$ -	$ 224,280
		Target	$ 224,280			
		Difference	$ -			
Municipal Device (MD)			$ 371,036	$ -	$ -	$ 371,036
		Target	$ 371,036			
		Difference	$ 0			
Contract Riders						
Special Contract Revenue			$ -	$ -	$ -	$ -
Electric Vehicle Revenue			$ -	$ -	$ -	$ -
No. 3 TDSIC			$ -	$ -	$ -	$ -
No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
No. 6 Fuel Cost Adjustment			$ -	$ -	$ -	$ -
No. 9 Net Metering			$ -	$ -	$ -	$ -
No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
No. 20 Environmental Compliance Cost Recovery			$ -	$ -	$ -	$ -
No. 21 Green Power			$ -	$ -	$ -	$ -
No. 22 Demand-Side Management Adjustment			$ 2,873	$ -	$ -	$ 2,873
No. 24 Capacity Adjustment			$ -	$ -	$ -	$ -
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 2,873	$ -	$ -	$ 2,873
Grand Total			$ 373,910	$ -	$ -	$ 373,910
		Check	TRUE			

AES Indiana
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2026
Secondary Service - Electric Space Conditioning Separately Metered (SH)
Net 2022 SE

Line No.	Description	Annualized Volumes	Current Rate	Annualized Revenue	Adjustment	Adjustment	Total Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
	Billed kwh						
1	All kWh	499,277,512	$ 0.123516	$ 61,668,761	$ -	$ -	$ 61,668,761
	Customer Charge						
2	All Customers	43,906	$ 55.00	$ 2,414,830	$ -	$ -	$ 2,414,830
3	Secondary Service (SH)			$ 64,083,591	$ -	$ -	$ 64,083,591
	Contract Riders						
4	No. 3 TDSIC			$ 3,310,687	$ -	$ -	$ 3,310,687
5	No. 6 Fuel Cost Adjustment			$ 2,952,228	$ -	$ -	$ 2,952,228
6	No. 9 Net Metering			$ -	$ -	$ -	$ -
7	No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
8	No. 15 Load Displacement			$ -	$ -	$ -	$ -
9	No. 20 Environmental Compliance Cost Recovery			$ 3,783,805	$ -	$ -	$ 3,783,805
10	No. 21 Green Power			$ -	$ -	$ -	$ -
11	No. 22 Demand-Side Management Adjustment			$ 3,277,413	$ -	$ -	$ 3,277,413
12	No. 24 Capacity Adjustment			$ (1,070,344)	$ -	$ -	$ (1,070,344)
13	No. 26 Regional Transmission Organization Rider			$ (101,768)	$ -	$ -	$ (101,768)
14	Total Rider			$ 12,152,022	$ -	$ -	$ 12,152,022
15	Grand Total			$ 76,235,613	$ -	$ -	$ 76,235,613
16					*Balancing Adjustment*		*1.003434*
17						**Total Revenue**	**$ 76,497,418**
						Check	TRUE

AES Indiana
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2026
Secondary Service - Electric Space Conditioning Separately Metered (SH)

🟨 Solved for Yellow Highlighted Cells
🟦 Targeted Difference at Zero

Description	Annualized Volumes	Proposed Rate	Revenue	Adjustment	Adjustment	Total Revenue
(H)	(I)	(J)	(K)	(L)	(M)	(N)
Billed kwh						
All kWh	499,277,512	$ 0.160587	$ 80,177,584	$ -	$ -	$ 80,177,584
		Target	$ 80,177,584			
		Difference	$ -			
Customer Charge						
All Customers	43,906	$ 60.00	$ 2,634,360	$ -	$ -	$ 2,634,360
		Target	$ 2,634,360			
		Difference	$ -			
Secondary Service (SH)			$ 82,811,944	$ -	$ -	$ 82,811,944
		Target	$ 82,811,944			
		Difference	$ -			
Contract Riders						
No. 3 TDSIC			$ -	$ -	$ -	$ -
No. 6 Fuel Cost Adjustment			$ -	$ -	$ -	$ -
No. 9 Net Metering			$ -	$ -	$ -	$ -
No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
No. 15 Load Displacement			$ -	$ -	$ -	$ -
No. 20 Environmental Compliance Cost Recovery			$ -	$ -	$ -	$ -
No. 21 Green Power			$ -	$ -	$ -	$ -
No. 22 Demand-Side Management Adjustment			$ 1,602,767	$ -	$ -	$ 1,602,767
No. 24 Capacity Adjustment			$ -	$ -	$ -	$ -
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 1,602,767	$ -	$ -	$ 1,602,767
Grand Total			$ 84,414,711	$ -	$ -	$ 84,414,711
		Check	TRUE			

AES Indiana
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2026
Secondary Service - Electric Space Conditioning Separately Metered Schools (SE)

Line No.	Description	Annualized Volumes	Current Rate	Annualized Revenue	Adjustment	Adjustment	Total Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
	Billed kwh						
1	First 5,000 kWh	948,097	$ 0.133318	$ 126,398	$ -	$ -	$ 126,398
2	Over 5,000 kWh	1,166,125	$ 0.118838	$ 138,580	$ -	$ -	$ 138,580
3	Excess of 155 x Connected load	11,617,715	$ 0.105146	$ 1,221,556	$ -	$ -	$1,221,556
	Total kWh	13,731,937		$ 1,486,535	$ -	$ -	$1,486,535
	Customer Charge						
4	All Customers	240	$ 55.00	$ 13,200	$ -	$ -	$ 13,200
5	Secondary Service (SE)			$ 1,499,735	$ -	$ -	$1,499,735
	Contract Riders						
6	No. 3 TDSIC			$ 91,056	$ -	$ -	$ 91,056
7	No. 6 Fuel Cost Adjustment			$ 81,197	$ -	$ -	$ 81,197
8	No. 9 Net Metering			$ -	$ -	$ -	$ -
9	No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
10	No. 15 Load Displacement			$ -	$ -	$ -	$ -
11	No. 20 Environmental Compliance Cost Recovery			$ 104,068	$ -	$ -	$ 104,068
12	No. 21 Green Power			$ -	$ -	$ -	$ -
13	No. 22 Demand-Side Management Adjustment			$ 90,141	$ -	$ -	$ 90,141
14	No. 24 Capacity Adjustment			$ (29,438)	$ -	$ -	$ (29,438)
15	No. 26 Regional Transmission Organization Rider			$ (2,799)	$ -	$ -	$ (2,799)
16	Total Rider			$ 334,225	$ -	$ -	$ 334,225
17	Grand Total			$ 1,833,959	$ -	$ -	$1,833,959
18						*Balancing Adjustment*	*1.1427*
19						**Total Revenue**	**$2,095,627**
						Check	TRUE

AES Indiana
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2026
Secondary Service - Electric Space Conditioning Separately Metered Schools (SE)

🟨 Solved for Yellow Highlighted Cells
🟦 Targeted Difference at Zero

Description	Annualized Volumes	Proposed Rate	Revenue	Adjustment	Adjustment	Total Revenue
(H)	(I)	(J)	(K)	(L)	(M)	(N)
Billed kwh						
First 5,000 kWh	948,097	$ 0.176487	$ 167,327	$ -	$ -	$ 167,327
Over 5,000 kWh	1,166,125	$ 0.162007	$ 188,920	$ -	$ -	$ 188,920
Excess of 155 x Connected load	11,617,715	$ 0.148315	$ 1,723,079	$ -	$ -	$ 1,723,079
Total kWh	13,731,937		$ 2,079,326	$ -	$ -	$ 2,079,326
		Target	$ 2,079,326			
		Difference	$ (0)			
Customer Charge						
All Customers	240	$ 60.00	$ 14,400	$ -	$ -	$ 14,400
		Target	$ 14,400			
		Difference	$ -			
Secondary Service (SE)			$ 2,093,726	$ -	$ -	$ 2,093,726
		Target	$ 2,093,726			
		Difference	$ (0)			
Contract Riders						
No. 3 TDSIC			$ -	$ -	$ -	$ -
No. 6 Fuel Cost Adjustment			$ -	$ -	$ -	$ -
No. 9 Net Metering			$ -	$ -	$ -	$ -
No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
No. 15 Load Displacement			$ -	$ -	$ -	$ -
No. 20 Environmental Compliance Cost Recovery			$ -	$ -	$ -	$ -
No. 21 Green Power			$ -	$ -	$ -	$ -
No. 22 Demand-Side Management Adjustment			$ 44,082	$ -	$ -	$ 44,082
No. 24 Capacity Adjustment			$ -	$ -	$ -	$ -
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 44,082	$ -	$ -	$ 44,082
Grand Total			$ 2,137,808	$ -	$ -	$ 2,137,808
		Check	TRUE			

AES Indiana
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2026
Water Heating-Controlled Service (Rate CB)

Line No.	Description (A)	Annualized Volumes (B)	Current Rate (C)	Annualized Revenue (D)	Adjustment (E)	Adjustment (F)	Total Revenue (G)
	Billed kwh						
1	All kWh	446,196	$ 0.076943	$ 34,332	$ -	$ -	$ 34,332
	Customer Charge						
2	All Customers	943	$ 20.00	$ 18,856	$ -	$ -	$ 18,856
3	Water Heating - Controlled (CB)			$ 53,188	$ -	$ -	$ 53,188
	Contract Riders						
4	No. 3 TDSIC			$ 2,959	$ -	$ -	$ 2,959
5	No. 6 Fuel Cost Adjustment			$ 2,638	$ -	$ -	$ 2,638
6	No. 9 Net Metering			$ -	$ -	$ -	$ -
7	No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
8	No. 20 Environmental Compliance Cost Recovery			$ 3,382	$ -	$ -	$ 3,382
9	No. 21 Green Power			$ -	$ -	$ -	$ -
10	No. 22 Demand-Side Management Adjustment			$ 2,929	$ -	$ -	$ 2,929
11	No. 24 Capacity Adjustment			$ (957)	$ -	$ -	$ (957)
12	No. 26 Regional Transmission Organization Rider			$ (91)	$ -	$ -	$ (91)
13	Total Rider			$ 10,860	$ -	$ -	$ 10,860
14	Grand Total			$ 64,048	$ -	$ -	$ 64,048
15						*Balancing Adjustment*	*1.0000*
16						**Total Revenue**	**$ 64,048**
						Check	TRUE

AES Indiana
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2026
Water Heating-Controlled Service (Rate CB)

🟨	Solved for Yellow Highlighted Cells
🟦	Targeted Difference at Zero

Description (H)	Annualized Volumes (I)	Proposed Rate (J)	Revenue (K)	Adjustment (L)	Adjustment (M)	Total Revenue (N)
Billed kwh						
All kWh	446,196	$ 0.113150	$ 50,487	$ -	$ -	$ 50,487
		Target	$ 50,487			
		Difference	$ -			
Customer Charge						
All Customers	943	$ 22.00	$ 20,742	$ -	$ -	$ 20,742
		Target	$ 20,742			
		Difference	$ -			
Water Heating - Controlled (CB)			$ 71,229	$ -	$ -	$ 71,229
		Target	$ 71,229			
		Difference	$ -			
Contract Riders						
No. 3 TDSIC			$ -	$ -	$ -	$ -
No. 6 Fuel Cost Adjustment			$ -	$ -	$ -	$ -
No. 9 Net Metering			$ -	$ -	$ -	$ -
No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
No. 20 Environmental Compliance Cost Recovery			$ -	$ -	$ -	$ -
No. 21 Green Power			$ -	$ -	$ -	$ -
No. 22 Demand-Side Management Adjustment			$ 1,432	$ -	$ -	$ 1,432
No. 24 Capacity Adjustment			$ -	$ -	$ -	$ -
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 1,432	$ -	$ -	$ 1,432
Grand Total			$ 72,661	$ -	$ -	$ 72,661
		Check	TRUE			

AES Indiana
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2026
Water Heating - Uncontrolled Service (UW)

Line No.	Description	Annualized Volumes	Current Rate	Annualized Revenue	Adjustment	Adjustment	Total Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
	Billed kwh						
1	All kWh	1,133,848	$ 0.089471	$ 101,447	$ -	$ -	$ 101,447
	Customer Charge						
2	All Customers	937	$ 40.00	$ 37,480	$ -	$ -	$ 37,480
3	Water Heating - Uncontrolled (UW)			$ 138,927	$ -	$ -	$ 138,927
	Contract Riders						
4	No. 3 TDSIC			$ 7,518	$ -	$ -	$ 7,518
5	No. 6 Fuel Cost Adjustment			$ 6,704	$ -	$ -	$ 6,704
6	No. 9 Net Metering			$ -	$ -	$ -	$ -
7	No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
8	No. 20 Environmental Compliance Cost Recovery			$ 8,593	$ -	$ -	$ 8,593
9	No. 21 Green Power			$ -	$ -	$ -	$ -
10	No. 22 Demand-Side Management Adjustment			$ 7,443	$ -	$ -	$ 7,443
11	No. 24 Capacity Adjustment			$ (2,431)	$ -	$ -	$ (2,431)
12	No. 26 Regional Transmission Organization Rider			$ (231)	$ -	$ -	$ (231)
13	Total Rider			$ 27,597	$ -	$ -	$ 27,597
14	Grand Total			$ 166,523	$ -	$ -	$ 166,523
15						*Balancing Adjustment*	*1.000002*
16						**Total Revenue**	**$ 166,524**
						Check	TRUE

AES Indiana
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2026
Water Heating - Uncontrolled Service (UW)

🟨 Solved for Yellow Highlighted Cells
🟦 Targeted Difference at Zero

Description	Annualized Volumes	Proposed Rate	Revenue	Adjustment	Adjustment	Total Revenue
(H)	(I)	(J)	(K)	(L)	(M)	(N)
Billed kwh						
All kWh	1,133,848	$ 0.124956	$ 141,682	$ -	$ -	$ 141,682
		Target	$ 141,682			
		Difference	$ -			
Customer Charge						
All Customers	937	$ 45.00	$ 42,165	$ -	$ -	$ 42,165
		Target	$ 42,165			
		Difference	$ -			
Water Heating - Uncontrolled (UW)			$ 183,847	$ -	$ -	$ 183,847
		Target	$ 183,847			
		Difference	$ -			
Contract Riders						
No. 3 TDSIC			$ -	$ -	$ -	$ -
No. 6 Fuel Cost Adjustment			$ -	$ -	$ -	$ -
No. 9 Net Metering			$ -	$ -	$ -	$ -
No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
No. 20 Environmental Compliance Cost Recovery			$ -	$ -	$ -	$ -
No. 21 Green Power			$ -	$ -	$ -	$ -
No. 22 Demand-Side Management Adjustment			$ 3,640	$ -	$ -	$ 3,640
No. 24 Capacity Adjustment			$ -	$ -	$ -	$ -
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 3,640	$ -	$ -	$ 3,640
Grand Total			$ 187,486	$ -	$ -	$ 187,486
		Check	TRUE			

AES Indiana
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2026
Process Heating (PH)

Line No.	Description (A)	Annualized Volumes (B)	Current Rate (C)	Annualized Revenue (D)	Adjustment (E)	Adjustment (F)	Total Revenue (G)
	Billed kwh						
1	First 250 Hrs use	18,009,408	$ 0.097390	$ 1,753,936	$ -	$ -	$ 1,753,936
2	Additional kWh	4,960,320	$ 0.082614	$ 409,792	$ -	$ -	$ 409,792
3	Total kWh	22,969,728		$ 2,163,728	$ -	$ -	$ 2,163,728
4	*Minimum Charge Adj.*			$ 25,681			$ 25,681
5	*Power factor*			$ 13,864			$ 13,864
	Customer Charge						
6	All Customers	240	$ 1,250	$ 300,000	$ -	$ -	$ 300,000
7	Process Heating (PH)			$ 2,503,273	$ -	$ -	$ 2,503,273
	Contract Riders						
8	No. 3 TDSIC			$ 105,669	$ -	$ -	$ 105,669
9	No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
10	No. 6 Fuel Cost Adjustment			$ 135,820	$ -	$ -	$ 135,820
11	No. 8 Off Peak Service			$ -	$ -	$ -	$ -
12	No. 9 Net Metering			$ -	$ -	$ -	$ -
13	No. 17 Curtailment Energy			$ -	$ -	$ -	$ -
14	No. 18 Curtailment Energy II			$ -	$ -	$ -	$ -
15	No. 20 Environmental Compliance Cost Recovery			$ 162,645	$ -	$ -	$ 162,645
16	No. 21 Green Power			$ -	$ -	$ -	$ -
17	No. 22 Demand-Side Management Adjustment			$ 36,111	$ -	$ -	$ 36,111
18	No. 24 Capacity Adjustment			$ (46,000)	$ -	$ -	$ (46,000)
19	No. 26 Regional Transmission Organization Rider			$ (4,372)	$ -	$ -	$ (4,372)
20	Total Rider			$ 389,872	$ -	$ -	$ 389,872
21	Grand Total			$ 2,893,145	$ -	$ -	$ 2,893,145
22						*Balancing Adjustment*	*0.999999*
23						**Total Revenue**	**$ 2,893,144**
						Check	TRUE

AES Indiana
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2026
Process Heating (PH)

🟨	Solved for Yellow Highlighted Cells
🟦	Targeted Difference at Zero

Description (H)	Annualized Volumes (I)	Proposed Rate (J)	Revenue (K)	Adjustment (L)	Adjustment (M)	Total Revenue (N)
Billed kwh						
First 250 Hrs use	18,009,408	$ 0.118372	$ 2,131,807	$ -	$ -	$ 2,131,807
Additional kWh	4,960,320	$ 0.103596	$ 513,869	$ -	$ -	$ 513,869
Total kWh	22,969,728	$ 0.115181	$ 2,645,675	$ -	$ -	$ 2,645,675
		Target	$ 2,645,675			
		Difference	$ -			
Minimum Charge Adj.			$ 27,207			$ 27,207
Power factor			$ 17,456			$ 17,456
Customer Charge						
All Customers	240	$ 1,275	$ 306,000	$ -	$ -	$ 306,000
		Target	$ 306,000			
		Difference	$ -			
Process Heating (PH)			$ 2,996,338	$ -	$ -	$ 2,996,338
		Target	$ 2,996,338			
		Difference	$ -			
Contract Riders						
No. 3 TDSIC			$ -	$ -	$ -	$ -
No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
No. 6 Fuel Cost Adjustment			$ -	$ -	$ -	$ -
No. 8 Off Peak Service			$ -	$ -	$ -	$ -
No. 9 Net Metering			$ -	$ -	$ -	$ -
No. 17 Curtailment Energy			$ -	$ -	$ -	$ -
No. 18 Curtailment Energy II			$ -	$ -	$ -	$ -
No. 20 Environmental Compliance Cost Recovery			$ -	$ -	$ -	$ -
No. 21 Green Power			$ -	$ -	$ -	$ -
No. 22 Demand-Side Management Adjustment			$ 64,089	$ -	$ -	$ 64,089
No. 24 Capacity Adjustment			$ -	$ -	$ -	$ -
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 64,089	$ -	$ -	$ 64,089
Grand Total			$ 3,060,428	$ -	$ -	$ 3,060,428
		Check	TRUE			

AES Indiana
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2026
Secondary Service (Large) (SL)

Line No.	Description	Annualized Volumes	Current Rate	Annualized Revenue	Adjustment	Adjustment	Total Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
	Billed kwh						
1	All kWh	3,234,222,568	$ 0.041430	$ 133,993,841	$ -	$ -	$ 133,993,841
	Billed kW						
2	All kW	8,746,002	$ 24.74	$ 216,376,097	$ -	$ -	$ 216,376,097
3	Power factor			$ (6,894,096)			$ (6,894,096)
	Customer Charge						
4	All Customers	52,548	$ 120.00	$ 6,305,760	$ -	$ -	$ 6,305,760
5	Secondary Service (Large) (SL)			$ 349,781,602	$ -	$ -	$ 349,781,602
	Contract Riders						
6	Electric Vehicle Revenue			$ -	$ -	$ -	$ -
7	No. 3 TDSIC			$ 14,878,522	$ -	$ -	$ 14,878,522
8	No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
9	No. 6 Fuel Cost Adjustment			$ 19,123,958	$ -	$ -	$ 19,123,958
10	No. 8 Off Peak Service			$ (311,398)	$ -	$ -	$ (311,398)
11	No. 9 Net Metering			$ -	$ -	$ -	$ -
12	No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
13	No. 15 Load Displacement			$ -	$ -	$ -	$ -
14	No. 17 Curtailment Energy			$ -	$ -	$ -	$ -
15	No. 18 Curtailment Energy II			$ -	$ -	$ -	$ -
16	No. 20 Environmental Compliance Cost Recovery			$ 22,900,985	$ -	$ -	$ 22,900,985
17	No. 21 Green Power			$ -	$ -	$ -	$ -
18	No. 22 Demand-Side Management Adjustment			$ 5,084,627	$ -	$ -	$ 5,084,627
19	No. 24 Capacity Adjustment			$ (6,477,000)	$ -	$ -	$ (6,477,000)
20	No. 26 Regional Transmission Organization Rider			$ (615,628)	$ -	$ -	$ (615,628)
21	Total Rider			$ 54,584,067	$ -	$ -	$ 54,584,067
22	Grand Total			$ 404,365,669	$ -	$ -	$ 404,365,669
23						*Balancing Adjustment*	*1.006503*
24						**Total Revenue**	**$ 406,995,390**
						Check	TRUE

AES Indiana
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2026
Secondary Service (Large) (SL)

🟨	Solved for Yellow Highlighted Cells
🟦	Targeted Difference at Zero

Description	Annualized Volumes	Proposed Rate	Revenue	Adjustment	Adjustment	Total Revenue
(H)	(I)	(J)	(K)	(L)	(M)	(N)
Billed kwh						
All kWh	3,234,222,568	$ 0.058648	$ 189,681,983	$ -	$ -	$ 189,681,983
		Target	$ 189,681,983			
		Difference	$ -			
Billed kW						
All kW	8,746,002	$ 28.13	$ 246,025,045	$ -	$ -	$ 246,025,045
		Target	$ 246,025,045			
		Difference	$ -			
Power factor			$ (8,615,446)			$ (8,615,446)
Customer Charge						
All Customers	52,548	$ 128.00	$ 6,726,144	$ -	$ -	$ 6,726,144
		Target	$ 6,726,144			
		Difference	$ -			
Secondary Service (Large) (SL)			$ 433,817,727	$ -	$ -	$ 433,817,727
		Target	$ 433,817,727			
		Difference	$ -			
Contract Riders						
Electric Vehicle Revenue			$ -	$ -	$ -	$ -
No. 3 TDSIC			$ -	$ -	$ -	$ -
No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
No. 6 Fuel Cost Adjustment			$ -	$ -	$ -	$ -
No. 8 Off Peak Service			$ (354,068)	$ -	$ -	$ (354,068)
No. 9 Net Metering			$ -	$ -	$ -	$ -
No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
No. 15 Load Displacement			$ -	$ -	$ -	$ -
No. 17 Curtailment Energy			$ -	$ -	$ -	$ -
No. 18 Curtailment Energy II			$ -	$ -	$ -	$ -
No. 20 Environmental Compliance Cost Recovery			$ -	$ -	$ -	$ -
No. 21 Green Power			$ -	$ -	$ -	$ -
No. 22 Demand-Side Management Adjustment			$ 9,023,973	$ -	$ -	$ 9,023,973
No. 24 Capacity Adjustment			$ -	$ -	$ -	$ -
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 8,669,905	$ -	$ -	$ 8,669,905
Grand Total			$ 442,487,632	$ -	$ -	$ 442,487,632
		Check	TRUE			

AES Indiana
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2026
Primary Service (Large) (PL)

Line No.	Description (A)	Annualized Volumes (B)	Current Rate (C)	Annualized Revenue (D)	Adjustment (E)	Adjustment (F)	Total Revenue (G)
	Billed kwh						
1	All kWh	1,024,030,101	$ 0.040836	$ 41,817,293	$ -	$ -	$ 41,817,293
	Billed kW						
2	All kW	2,276,912	$ 28.30	$ 64,436,597	$ -	$ -	$ 64,436,597
3	Power factor			$ (4,198,069)			$ (4,198,069)
	Customer Charge						
4	All Customers	1,512	$ 130.00	$ 196,560	$ -	$ -	$ 196,560
5	Primary Service (Large) (PL)			$ 102,252,381	$ -	$ -	$ 102,252,381
	Contract Riders						
6	Special Contract Revenue			$ -	$ -	$ -	$ -
7	Allocated CSC Revenues + DSM			$ -	$ -	$ -	$ -
8	No. 3 TDSIC			$ 3,723,176	$ -	$ -	$ 3,723,176
9	No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
10	No. 6 Fuel Cost Adjustment			$ 6,055,090	$ -	$ -	$ 6,055,090
11	No. 8 Off Peak Service			$ (53,436)	$ -	$ -	$ (53,436)
12	No. 9 Net Metering			$ -	$ -	$ -	$ -
13	No. 14 Interruptible Power			$ -	$ -	$ -	$ -
14	No. 15 Load Displacement			$ -	$ -	$ -	$ -
15	No. 17 Curtailment Energy			$ -	$ -	$ -	$ -
16	No. 18 Curtailment Energy II			$ -	$ -	$ -	$ -
17	No. 20 Environmental Compliance Cost Recovery			$ 6,149,151	$ -	$ -	$ 6,149,151
18	No. 21 Green Power			$ -	$ -	$ -	$ -
19	No. 22 Demand-Side Management Adjustment			$ 1,609,911	$ -	$ -	$ 1,609,911
20	No. 24 Capacity Adjustment			$ (1,739,148)	$ -	$ -	$ (1,739,148)
21	No. 26 Regional Transmission Organization Rider			$ (165,280)	$ -	$ -	$ (165,280)
22	Total Rider			$ 15,579,463	$ -	$ -	$ 15,579,463
23	Grand Total			$ 117,831,845	$ -	$ -	$ 117,831,845
24						*Balancing Adjustment*	*1.001852*
25						**Total Revenue**	**$ 118,050,063**
						Check	TRUE

AES Indiana
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2026
Primary Service (Large) (PL)

🟨 Solved for Yellow Highlighted Cells
🟦 Targeted Difference at Zero

Description (H)	Annualized Volumes (I)	Proposed Rate (J)	Revenue (K)	Adjustment (L)	Adjustment (M)	Total Revenue (N)
Billed kwh						
All kWh	1,024,030,101	$ 0.055746	$ 57,085,606	$ -	$ -	$ 57,085,606
		Target	$ 57,085,606			
		Difference	$ -			
Billed kW						
All kW	2,276,912	$ 33.10	$ 75,365,773	$ -	$ -	$ 75,365,773
		Target	$ 75,365,773			
		Difference	$ -			
Power factor			$ (5,189,892)			$ (5,189,892)
Customer Charge						
All Customers	1,512	$ 133.00	$ 201,096	$ -	$ -	$ 201,096
		Target	$ 201,096			
		Difference	$ -			
Primary Service (Large) (PL)			$ 127,462,583	$ -	$ -	$ 127,462,583
		Target	$ 127,462,583			
		Difference	$ -			
Contract Riders						
Special Contract Revenue			$ -	$ -	$ -	$ -
Allocated CSC Revenues + DSM			$ 1,445,842	$ -	$ -	$ 1,445,842
No. 3 TDSIC			$ -	$ -	$ -	$ -
No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
No. 6 Fuel Cost Adjustment			$ -	$ -	$ -	$ -
No. 8 Off Peak Service			$ (62,500)	$ -	$ -	$ (62,500)
No. 9 Net Metering			$ -	$ -	$ -	$ -
No. 14 Interruptible Power			$ -	$ -	$ -	$ -
No. 15 Load Displacement			$ -	$ -	$ -	$ -
No. 17 Curtailment Energy			$ -	$ -	$ -	$ -
No. 18 Curtailment Energy II			$ -	$ -	$ -	$ -
No. 20 Environmental Compliance Cost Recovery			$ -	$ -	$ -	$ -
No. 21 Green Power			$ -	$ -	$ -	$ -
No. 22 Demand-Side Management Adjustment			$ 2,857,200	$ -	$ -	$ 2,857,200
No. 24 Capacity Adjustment			$ -	$ -	$ -	$ -
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 4,240,542	$ -	$ -	$ 4,240,542
Grand Total			$ 131,703,125	$ -	$ -	$ 131,703,125
		Check	TRUE			

AES Indiana
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2026
High Load Factor Service - Primary (HL1)

Line No.	Description (A)	Annualized Volumes (B)	Current Rate (C)	Annualized Revenue (D)	Adjustment (E)	Adjustment (F)	Total Revenue (G)
	Billed kwh						
1	All kWh	1,262,126,058	$ 0.046060	$ 58,133,526	$ -	$ -	$ 58,133,526
	Billed kW						
2	All kW	2,255,022	$ 27.95	$ 63,027,872	$ -	$ -	$ 63,027,872
3	Power factor			$ (2,983,966)			$ (2,983,966)
	Customer Charge						
4	All Customers	324	$ 130.00	$ 42,120	$ -	$ -	$ 42,120
5	High Load Factor Service (HL1)			$ 118,219,552	$ -	$ -	$ 118,219,552
	Contract Riders						
6	CSC Revenues			$ 3,589,116	$ -	$ -	$ 3,589,116
7	No. 3 TDSIC			$ 4,604,772	$ -	$ -	$ 4,604,772
8	No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
9	No. 6 Fuel Cost Adjustment			$ 7,885,806	$ -	$ -	$ 7,885,806
10	No. 8 Off Peak Service			$ (260,722)	$ -	$ -	$ (260,722)
11	No. 9 Net Metering			$ -	$ -	$ -	$ -
12	No. 14 Interruptible Power			$ (549,002)	$ -	$ -	$ (549,002)
13	No. 15 Load Displacement			$ -	$ -	$ -	$ -
14	No. 17 Curtailment Energy			$ -	$ -	$ -	$ -
15	No. 18 Curtailment Energy II			$ -	$ -	$ -	$ -
16	No. 20 Environmental Compliance Cost Recovery			$ 8,008,305	$ -	$ -	$ 8,008,305
17	No. 21 Green Power			$ -	$ -	$ -	$ -
18	No. 22 Demand-Side Management Adjustment			$ 2,096,657	$ -	$ -	$ 2,096,657
19	No. 24 Capacity Adjustment			$ (2,264,968)	$ -	$ -	$ (2,264,968)
20	No. 26 Regional Transmission Organization Rider			$ (215,252)	$ -	$ -	$ (215,252)
21	Total Rider			$ 22,894,712	$ -	$ -	$ 22,894,712
22	Grand Total			$ 141,114,265	$ -	$ -	$ 141,114,265
23						*Balancing Adjustment*	*1.002641*
24						**Total Revenue**	**$ 141,486,972**
						Check	TRUE

AES Indiana
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2026
High Load Factor Service - Primary (HL1)

🟨	Solved for Yellow Highlighted Cells
🟦	Targeted Difference at Zero

Description (H)	Annualized Volumes (I)	Proposed Rate (J)	Revenue (K)	Adjustment (L)	Adjustment (M)	Total Revenue (N)
Billed kwh						
All kWh	1,262,126,058	$ 0.054775	$ 69,133,464	$ -	$ -	$ 69,133,464
		Target	$ 69,133,464			
		Difference	$ -			
Billed kW						
All kW	2,255,022	$ 34.30	$ 77,347,264	$ -	$ -	$ 77,347,264
		Target	$ 77,347,264			
		Difference	$ -			
Power factor			$ (3,669,247)			$ (3,669,247)
Customer Charge						
All Customers	324	$ 150.00	$ 48,600	$ -	$ -	$ 48,600
		Target	$ 48,600			
		Difference	$ -			
High Load Factor Service (HL1)			$ 142,860,081	$ -	$ -	$ 142,860,081
		Target	$ 142,860,081			
		Difference	$ -			
Contract Riders						
Allocated CSC Revenues + DSM			$ 1,782,013	$ -	$ -	$ 1,782,013
No. 3 TDSIC			$ -	$ -	$ -	$ -
No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
No. 6 Fuel Cost Adjustment			$ -	$ -	$ -	$ -
No. 8 Off Peak Service			$ (319,956)	$ -	$ -	$ (319,956)
No. 9 Net Metering			$ -	$ -	$ -	$ -
No. 14 Interruptible Power			$ (549,002)	$ -	$ -	$ (549,002)
No. 15 Load Displacement			$ -	$ -	$ -	$ -
No. 17 Curtailment Energy			$ -	$ -	$ -	$ -
No. 18 Curtailment Energy II			$ -	$ -	$ -	$ -
No. 20 Environmental Compliance Cost Recovery			$ -	$ -	$ -	$ -
No. 21 Green Power			$ -	$ -	$ -	$ -
No. 22 Demand-Side Management Adjustment			$ 3,521,524	$ -	$ -	$ 3,521,524
No. 24 Capacity Adjustment			$ -	$ -	$ -	$ -
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 4,434,578	$ -	$ -	$ 4,434,578
Grand Total			$ 147,294,659	$ -	$ -	$ 147,294,659
		Check	TRUE			

AES Indiana
Pro Forma Revenue at Current Rates
Test Year Ended December 31, 2026
High Load Factor Service - Sub transmission (HL2)

Line No.	Description (A)	Annualized Volumes (B)	Current Rate (C)	Annualized Revenue (D)	Adjustment (E)	Adjustment (F)	Total Revenue (G)
	Billed kwh						
1	All kWh	178,648,530	$ 0.040410	$ 7,219,187	$ -	$ -	$ 7,219,187
	Billed kW						
2	All kW	367,588	$ 25.00	$ 9,189,712	$ -	$ -	$ 9,189,712
3	Power factor			$ (650,411)			$ (650,411)
	Customer Charge						
4	Rate HL2	48	$ 215.00	$ 10,320	$ -	$ -	$ 10,320
5	Rate CGS	12	$ 215.00	$ 2,580	$ -	$ -	$ 2,580
6	High Load Factor Service (HL2)			$ 15,771,388	$ -	$ -	$ 15,771,388
	CGS Demand Charge						
7	BUM	314,106	$ 0.6923	$ 217,456	$ -	$ -	$ 217,456
8	T&D	72,000	$ 3.09	$ 222,480	$ -	$ -	$ 222,480
9	CGS Credits			$ (134,446)	$ -	$ -	$ (134,446)
	Contract Riders						
10	Allocated CSC Revenues + DSM			$ -	$ -	$ -	$ -
11	No. 3 TDSIC			$ 649,532	$ -	$ -	$ 649,532
12	No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
13	No. 6 Fuel Cost Adjustment			$ 1,056,349	$ -	$ -	$ 1,056,349
14	No. 8 Off Peak Service			$ -	$ -	$ -	$ -
15	No. 9 Net Metering			$ -	$ -	$ -	$ -
16	No. 14 Interruptible Power			$ -	$ -	$ -	$ -
17	No. 15 Load Displacement			$ -	$ -	$ -	$ -
18	No. 17 Curtailment Energy			$ -	$ -	$ -	$ -
19	No. 18 Curtailment Energy II			$ -	$ -	$ -	$ -
20	No. 20 Environmental Compliance Cost Recovery			$ 1,072,758	$ -	$ -	$ 1,072,758
21	No. 21 Green Power			$ -	$ -	$ -	$ -
22	No. 22 Demand-Side Management Adjustment			$ 280,859	$ -	$ -	$ 280,859
23	No. 24 Capacity Adjustment			$ (303,405)	$ -	$ -	$ (303,405)
24	No. 26 Regional Transmission Organization Rider			$ (28,834)	$ -	$ -	$ (28,834)
25	Total Rider			$ 2,727,258	$ -	$ -	$ 2,727,258
26	Grand Total			$ 18,804,136	$ -	$ -	$ 18,804,136
27						*Balancing Adjustment*	*1.002664*
28						**Total Revenue**	**$ 18,854,224**
						Check	TRUE

AES Indiana
Pro Forma Revenue at Proposed Rates
Test Year Ended December 31, 2026
High Load Factor Service - Sub transmission (HL2)

🟨 Solved for Yellow Highlighted Cells
🟦 Targeted Difference at Zero

Description (H)	Annualized Volumes (I)	Proposed Rate (J)	Revenue (K)	Adjustment (L)	Adjustment (M)	Total Revenue (N)
Billed kwh						
All kWh	178,648,530	$ 0.053437	$ 9,546,514	$ -	$ -	$ 9,546,514
		Target	$ 9,546,514			
		Difference	$ -			
Billed kW						
All kW	367,588	$ 25.20	$ 9,263,230	$ -	$ -	$ 9,263,230
		Target	$ 9,263,230			
		Difference	$ -			
Power factor			$ (737,060)			$ (737,060)
Customer Charge						
All Customers	60	$ 215.00	$ 12,900	$ -	$ -	$ 12,900
		Target	$ 12,900			
		Difference	$ -			
High Load Factor Service (HL2)			$ 18,085,584	$ -	$ -	$ 18,085,584
		Target	$ 18,085,584			
		Difference	$ -			
CGS Demand Charge						
BUM	314,106	$ 0.7133	$ 224,051	$ -	$ -	$ 224,051
T&D	72,000	$ 4.52	$ 325,739	$ -	$ -	$ 325,739
CGS Credits			$ (134,446)	$ -	$ -	$ (134,446)
Contract Riders						
Allocated CSC Revenues + DSM			$ 247,292	$ -	$ -	$ 247,292
No. 3 TDSIC			$ -	$ -	$ -	$ -
No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
No. 6 Fuel Cost Adjustment			$ -	$ -	$ -	$ -
No. 8 Off Peak Service			$ -	$ -	$ -	$ -
No. 9 Net Metering			$ -	$ -	$ -	$ -
No. 14 Interruptible Power			$ -	$ -	$ -	$ -
No. 15 Load Displacement			$ -	$ -	$ -	$ -
No. 17 Curtailment Energy			$ -	$ -	$ -	$ -
No. 18 Curtailment Energy II			$ -	$ -	$ -	$ -
No. 20 Environmental Compliance Cost Recovery			$ -	$ -	$ -	$ -
No. 21 Green Power			$ -	$ -	$ -	$ -
No. 22 Demand-Side Management Adjustment			$ 498,457	$ -	$ -	$ 498,457
No. 24 Capacity Adjustment			$ -	$ -	$ -	$ -
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 745,748	$ -	$ -	$ 745,748
Grand Total			$ 19,246,677	$ -	$ -	$ 19,246,677
		Check	TRUE			

AES Indiana
Lighting Revenue Proof and Proposed Rates

	Code	Description	Inventory (Light Count)	kWh per Light	Total kWh	Separately Metered	Current Annual Base Rate	Current Base Revenue	ProForma Adjustments	Current Revenue Proforma @ Present Rates	Current Rate with ECCR, RTO, DSM, CAP, TDSIC, and Fuel (Base Fuel and FCA)	Proposed Annual Rate	Proposed Revenue	Change (%)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
	APL													**13.35%**
		Company Installed, Owned, and Maintained (APL)												
APL	68	175 WATT LIGHT	7,429	832	6,180,928		$119.40	$887,023	$76,721	$963,744	$129.73	$147.00	$1,092,063	13%
APL	69	400 WATT MV REDDY SENT.	1,049	1,880	1,972,120		$228.96	$240,179	$24,479	$264,658	$252.30	$285.96	$299,972	13%
APL	70	1000 WATT MV REDDY SENT.	64	4,315	276,160		$416.28	$26,642	$3,428	$30,070	$469.84	$532.56	$34,084	13%
APL	71	100 WATT LIGHT	5,332	485	2,586,020		$102.60	$547,063	$32,099	$579,162	$108.62	$123.12	$656,476	13%
APL	72	150 WATT HPS REDDY SENT.	894	733	655,302		$213.24	$190,637	$8,134	$198,771	$222.34	$252.00	$225,288	13%
APL	73	250 WATT HPS REDDY SENT.	925	1,194	1,104,450		$285.72	$264,291	$13,709	$278,000	$300.54	$340.68	$315,129	13%
APL	74	400 WATT HPS REDDY SENT.	1,011	1,848	1,868,328		$336.60	$340,303	$23,191	$363,493	$359.54	$407.52	$412,003	13%
APL	78	175 WATT MV - SEC. METERED - OVERHEAD	59	832	49,088	Yes	$79.20	$4,673	$0	$4,673	$79.20	$89.76	$5,296	13%
APL	79	400 WATT MV - SEC. METERED OVERHEAD	16	1,880	30,080	Yes	$153.48	$2,456	$0	$2,456	$153.48	$174.00	$2,784	13%
APL	80	1000 WATT MV - SEC. METERED - OVERHEAD	1	4,315	4,315	Yes	$237.84	$238	$0	$238	$237.84	$269.64	$270	13%
APL	81	100 WATT HPS - SEC. METERED - OVERHEAD	18	485	8,730	Yes	$82.08	$1,477	$0	$1,477	$82.08	$93.00	$1,674	13%
APL	82	150 WATT HPS - SEC. METERED - OVERHEAD	1	733	733	Yes	$187.56	$188	$0	$188	$187.56	$212.64	$213	13%
APL	83	250 WATT HPS - SEC. METERED - OVERHEAD	2	1,194	2,388	Yes	$237.12	$474	$0	$474	$237.12	$268.80	$538	13%
APL	84	400 WATT HPS - SEC. METERED - OVERHEAD	11	1,848	20,328	Yes	$261.48	$2,876	$0	$2,876	$261.48	$296.40	$3,260	13%
APL	85	ENERGY AND CONTROL ONLY	1	0	0		$46.32	$46	$0	$46	$46.32	$52.56	$53	13%
APL	86	400 WATT MV FLOOD - OVERHEAD	435	1,880	817,800		$229.20	$99,702	$10,151	$109,853	$252.54	$286.20	$124,497	13%
APL	87	150 WATT HPS FLOOD - OVERHEAD	438	733	321,054		$213.84	$93,662	$3,985	$97,647	$222.94	$252.72	$110,691	13%
APL	88	250 WATT HPS FLOOD - OVERHEAD	639	1,194	762,966		$285.84	$182,652	$9,470	$192,122	$300.66	$340.80	$217,771	13%
APL	89	400 WATT HPS FLOOD - OVERHEAD	5,090	1,848	9,406,320		$336.54	$1,712,989	$116,756	$1,829,745	$359.48	$407.40	$2,073,666	13%
APL	90	400 WATT METAL HALIDE FLOOD - OVERHEAD	811	1,774	1,438,714		$335.40	$272,009	$17,858	$289,868	$357.42	$405.12	$328,552	13%
APL	91	400 WATT MV FLOOD - SEC. METERED	6	1,880	11,280	Yes	$153.48	$921	$0	$921	$153.48	$174.00	$1,044	13%
APL	92	150 WATT HPS FLOOD - SEC. METERED	1	733	733	Yes	$187.56	$188	$0	$188	$187.56	$212.64	$213	13%
APL	93	250 WATT HPS FLOOD - SEC. METERED	6	1,194	7,164	Yes	$237.12	$1,423	$0	$1,423	$237.12	$268.80	$1,613	13%
APL	94	400 WATT HPS FLOOD - SEC. METERED	36	1,848	66,528	Yes	$261.48	$9,413	$0	$9,413	$261.48	$296.40	$10,670	13%
APL	95	400 WATT METAL HALIDE FLOOD-SEC. METERED	2	1,774	3,548	Yes	$261.48	$523	$0	$523	$261.48	$296.40	$593	13%
APL	96	- WOOD POLE WITH OVERHEAD FEED -	6,380	0	0		$53.40	$340,692	$0	$340,692	$53.40	$60.48	$385,862	13%
APL	97	- WOOD POLE WITH UNDERGROUND FEED -	739	0	0		$131.88	$97,459	$0	$97,459	$131.88	$149.52	$110,495	13%
APL	126	1000 WATT MV - 1ST FIXTURE	0	4,315	0		$52.08	$0	$0	$0	$105.64	$119.76	$0	13%
APL	127	400 WATT MV-1ST FIXTURE	13	1,880	24,440		$327.36	$4,256	$303	$4,559	$350.70	$397.56	$5,168	13%
APL	128	175 WATT MV-1ST FIXTURE	3	832	2,496		$256.92	$771	$31	$802	$267.25	$302.88	$909	13%
APL	129	400 WATT HPS-1ST FIXTURE	49	1,848	90,552		$464.64	$22,767	$1,124	$23,891	$487.58	$552.60	$27,077	13%
APL	130	250 WATT HPS-1ST FIXTURE	198	1,194	236,412		$312.12	$61,800	$2,934	$64,734	$326.94	$370.56	$73,371	13%
APL	131	150 WATT HPS-1ST FIXTURE	178	733	130,474		$265.20	$47,206	$1,620	$48,825	$274.30	$310.92	$55,344	13%
APL	132	100 WATT HPS-1ST FIXTURE	32	485	15,520		$241.32	$7,722	$193	$7,915	$247.34	$280.32	$8,970	13%
APL	135	400 WATT HPS-1ST FIXTURE-SHOEBOX	85	1,848	157,080		$390.00	$33,150	$1,950	$35,100	$412.94	$468.00	$39,780	13%
APL	136	250 WATT HPS-1ST FIXTURE-SHOEBOX	90	1,194	107,460		$314.04	$28,264	$1,334	$29,597	$328.86	$372.72	$33,545	13%

AES Indiana
Lighting Revenue Proof and Proposed Rates

	Code	Description	Inventory (Light Count)	kWh per Light	Total kWh	Separately Metered	Current Annual Base Rate	Current Base Revenue	ProForma Adjustments	Current Revenue Proforma @ Present Rates	Current Rate with ECCR, RTO, DSM, CAP, TDSIC, and Fuel (Base Fuel and FCA)	Proposed Annual Rate	Proposed Revenue	Change (%)
APL	137	400 WATT METAL HALIDE-1ST FIX-SHOEBOX	301	1,774	533,974		$388.68	$116,993	$6,628	$123,621	$410.70	$465.48	$140,109	13%
APL	138	400 WATT MV-1ST FIXTURE-FLOOD	1	1,880	1,880		$327.36	$327	$23	$351	$350.70	$397.56	$398	13%
APL	139	150 WATT HPS-1ST FIXTURE-FLOOD	12	733	8,796		$265.20	$3,182	$109	$3,292	$274.30	$310.92	$3,731	13%
APL	140	250 WATT HPS-1ST FIXTURE-FLOOD	59	1,194	70,446		$312.12	$18,415	$874	$19,289	$326.94	$370.56	$21,863	13%
APL	141	400 WATT HPS-1ST FIXTURE-FLOOD	233	1,848	430,584		$464.64	$108,261	$5,345	$113,606	$487.58	$552.60	$128,756	13%
APL	142	400 WATT METAL HALIDE-1ST FIX-FLOOD	48	1,774	85,152		$388.68	$18,657	$1,057	$19,714	$410.70	$465.48	$22,343	13%
APL	143	1000 WATT MV - ADDITIONAL FIXTURE	0	4,315	0		$52.08	$0	$0	$0	$105.64	$119.76	$0	13%
APL	144	400 WATT MV-ADDIT'L FIXTURE	1	1,880	1,880		$228.96	$229	$23	$252	$252.30	$285.96	$286	13%
APL	145	175 WATT MV-ADDIT'L FIXTURE	2	832	1,664		$119.40	$239	$21	$259	$129.73	$147.00	$294	13%
APL	146	400 WATT HPS-ADDIT'L FIXTURE	15	1,848	27,720		$336.60	$5,049	$344	$5,393	$359.54	$407.52	$6,113	13%
APL	147	250 WATT HPS-ADDIT'L FIXTURE	12	1,194	14,328		$285.72	$3,429	$178	$3,606	$300.54	$340.68	$4,088	13%
APL	148	150 WATT HPS-ADDIT'L FIXTURE	12	733	8,796		$213.24	$2,559	$109	$2,668	$222.34	$252.00	$3,024	13%
APL	149	100 WATT HPS-ADDIT'L FIXTURE	3	485	1,455		$102.60	$308	$18	$326	$108.62	$123.12	$369	13%
APL	152	400 WATT HPS-ADDIT'L FIXTURE-SHOEBOX	16	1,848	29,568		$155.52	$2,488	$367	$2,855	$178.46	$202.32	$3,237	13%
APL	153	250 WATT HPS-ADDIT'L FIXTURE-SHOEBOX	8	1,194	9,552		$118.08	$945	$119	$1,063	$132.90	$150.60	$1,205	13%
APL	154	400 WATT METAL HALIDE-ADDT'L FIX-SHOEBOX	100	1,774	177,400		$154.08	$15,408	$2,202	$17,610	$176.10	$199.56	$19,956	13%
APL	155	400 WATT MV-ADDIT'L FIXTURE-FLOOD	0	1,880	0		$228.96	$0	$0	$0	$252.30	$285.96	$0	13%
APL	156	150 WATT HPS-ADDIT'L FIXTURE-FLOOD	9	733	6,597		$213.24	$1,919	$82	$2,001	$222.34	$252.00	$2,268	13%
APL	157	250 WATT HPS-ADDIT'L FIXTURE-FLOOD	50	1,194	59,700		$285.72	$14,286	$741	$15,027	$300.54	$340.68	$17,034	13%
APL	158	400 WATT HPS-ADDIT'L FIXTURE-FLOOD	254	1,848	469,392		$336.60	$85,496	$5,826	$91,323	$359.54	$407.52	$103,510	13%
APL	159	400 WATT METAL HALIDE-ADDT'L FIX-FLOOD	101	1,774	179,174		$154.08	$15,562	$2,224	$17,786	$176.10	$199.56	$20,156	13%
APL	160	175 W MV POST TOP WASH	39	832	32,448		$384.00	$14,976	$403	$15,379	$394.33	$447.00	$17,433	13%
APL	161	175 W MV POST TOP	28	832	23,296		$250.32	$7,009	$289	$7,298	$260.65	$295.44	$8,272	13%
APL	162	100 W HPS POST TOP WASH	58	485	28,130		$370.56	$21,492	$349	$21,842	$376.58	$426.84	$24,757	13%
APL	163	100 W HPS POST TOP	335	485	162,475		$240.36	$80,521	$2,017	$82,537	$246.38	$279.24	$93,545	13%
APL	164	150 W HPS POST TOP WASH	105	733	76,965		$427.68	$44,906	$955	$45,862	$436.78	$495.12	$51,988	13%
APL	165	150 W HPS POST TOP BALL	60	733	43,980		$297.48	$17,849	$546	$18,395	$306.58	$347.52	$20,851	13%
APL	180	250 WATT MET HAL 18 FT DIR EMBEDDED	3	1,159	3,477		$701.40	$2,104	$43	$2,147	$715.79	$811.32	$2,434	13%
APL	181	250 WATT MET HAL 12 FT ANCHOR BASED	11	1,159	12,749		$768.12	$8,449	$158	$8,608	$782.51	$886.92	$9,756	13%
APL	182	2-250 WATT MET HAL 18 FT DIR EMBEDDED	7	2,317	16,219		$978.60	$6,850	$201	$7,052	$1,007.36	$1,141.80	$7,993	13%
APL	183	2-250 WATT MET HAL 12 FT ANCHOR BASED	0	2,317	0		$1,044.96	$0	$0	$0	$1,073.72	$1,217.04	$0	13%
APL	188	250 WATT MET HAL 18 FT DIR EMBED PRI METER	0	1,159	0		$638.88	$0	$0	$0	$653.27	$740.40	$0	13%
APL	189	250 WATT MET HAL 12 FT ANCHOR BASE PRI METER	0	1,159	0		$705.36	$0	$0	$0	$719.75	$815.76	$0	13%
APL	190	2-250 WATT MET HAL 18 FT DIR EMBED PRI METER	0	2,317	0		$861.00	$0	$0	$0	$889.76	$1,008.48	$0	13%
APL	191	2-250 WATT MET HAL 12 FT ANCHOR BASE PRI METER	0	2,317	0		$927.72	$0	$0	$0	$956.48	$1,084.20	$0	13%
APL	271	100 WATT LIGHT	1,588	485	770,180		$203.40	$322,999	$9,560	$332,559	$209.42	$237.36	$376,928	13%
APL	272	150 WATT HPS REDDY SENT.	134	733	98,222		$232.92	$31,211	$1,219	$32,430	$242.02	$274.32	$36,759	13%
APL	273	250 WATT HPS REDDY SENT.	278	1,194	331,932		$281.64	$78,296	$4,120	$82,416	$296.46	$336.00	$93,408	13%
APL	274	400 WATT HPS REDDY SENT.	190	1,848	351,120		$345.60	$65,664	$4,358	$70,022	$368.54	$417.72	$79,367	13%
APL	287	150 WATT HPS FLOOD - OVERHEAD	61	733	44,713		$239.52	$14,611	$555	$15,166	$248.62	$281.76	$17,187	13%
APL	288	250 WATT HPS FLOOD - OVERHEAD	105	1,194	125,370		$286.92	$30,127	$1,556	$31,683	$301.74	$342.00	$35,910	13%
APL	289	400 WATT HPS FLOOD - OVERHEAD	1,391	1,848	2,570,568		$349.68	$486,405	$31,907	$518,312	$372.62	$422.40	$587,558	13%
APL	296	- WOOD POLE WITH OVERHEAD FEED -	1,440	0	0		$91.32	$131,501	$0	$131,501	$91.32	$103.56	$149,126	13%
APL	297	- WOOD POLE WITH UNDERGROUND FEED -	120	0	0		$115.56	$13,867	$0	$13,867	$115.56	$131.04	$15,725	13%
APL	300	LED COBRA HEAD 5000-6000 LUMENS	818	185	151,330		$219.84	$179,829	$1,878	$181,708	$222.14	$251.76	$205,940	13%
APL	301	LED COBRA HEAD 6500-7500 LUMENS	96	229	21,984		$226.08	$21,704	$273	$21,977	$228.92	$259.44	$24,906	13%
APL	302	LED COBRA HEAD 12500-13500 LUMENS	108	437	47,196		$278.52	$30,080	$586	$30,666	$283.94	$321.84	$34,759	13%
APL	303	LED COBRA HEAD 20000-21500 LUMENS	367	686	251,762		$324.96	$119,260	$3,125	$122,385	$333.48	$378.00	$138,726	13%

AES Indiana
Lighting Revenue Proof and Proposed Rates

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APL	304	LED AREA LIGHT 11500-16500 LUMENS	3	536	1,608		$304.92	$915	$20	$935	$311.57	$353.16	$1,059	13%
APL	305	LED AREA LIGHT 21000-26000 LUMENS	191	867	165,597		$342.00	$65,322	$2,055	$67,377	$352.76	$399.84	$76,369	13%
APL	306	LED TRAD. POST TOP 6000-7500 LUMENS	115	260	29,900		$276.48	$31,795	$371	$32,166	$279.71	$317.04	$36,460	13%
APL	307	LED TWIN WASH POST TOP 2 @ 6000-7500-LT	0	552	0		$683.88	$0	$0	$0	$690.73	$782.88	$0	13%
APL	308	LED WASH POST TOP 6000-7500 LUMENS	37	276	10,212		$373.08	$13,804	$127	$13,931	$376.51	$426.72	$15,789	13%
APL	313	LED FLOOD 11,500 - 16,500 LUMENS	60	378	22,680		$297.96	$17,878	$282	$18,159	$302.65	$343.08	$20,585	13%
APL	314	LED FLOOD 21,000 - 26,000 LUMENS	1,734	690	1,196,460		$332.28	$576,174	$14,851	$591,025	$340.84	$386.28	$669,810	13%
APL	328	12' FG TRAD COL PAIRED W/LT	115	0	0		$84.60	$9,729	$0	$9,729	$84.60	$95.88	$11,026	13%
APL	329	400 WATT HPS-1ST FIXTURE	13	1,848	24,024		$480.24	$6,243	$298	$6,541	$503.18	$570.36	$7,415	13%
APL	330	250 WATT HPS-1ST FIXTURE	16	1,194	19,104		$416.40	$6,662	$237	$6,900	$431.22	$488.76	$7,820	13%
APL	331	150 WATT HPS-1ST FIXTURE	11	733	8,063		$373.32	$4,107	$100	$4,207	$382.42	$433.44	$4,768	13%
APL	332	100 WATT HPS-1ST FIXTURE	0	485	0		$339.72	$0	$0	$0	$345.74	$391.92	$0	13%
APL	333	400 WATT HPS - 1ST FIXTURE PAINTED BRONZ	0	1,848	0		$582.36	$0	$0	$0	$605.30	$686.04	$0	13%
APL	334	250 WATT HPS - 1ST FIXTURE PAINTED BRONZ	0	1,194	0		$528.00	$0	$0	$0	$542.82	$615.24	$0	13%
APL	335	400 WATT HPS-1ST FIXTURE-SHOEBOX	13	1,848	24,024		$477.00	$6,201	$298	$6,499	$499.94	$566.64	$7,366	13%
APL	336	250 WATT HPS-1ST FIXTURE-SHOEBOX	10	1,194	11,940		$412.32	$4,123	$148	$4,271	$427.14	$484.20	$4,842	13%
APL	337	12' FG FLUTED COL CUST BASE PAIRED W/LT	0	0	0		$171.36	$0	$0	$0	$171.36	$194.28	$0	13%
APL	339	150 WATT HPS-1ST FIXTURE-FLOOD	4	733	2,932		$482.04	$1,928	$36	$1,965	$491.14	$556.68	$2,227	13%
APL	340	250 WATT HPS-1ST FIXTURE-FLOOD	2	1,194	2,388		$517.20	$1,034	$30	$1,064	$532.02	$603.00	$1,206	13%
APL	341	400 WATT HPS-1ST FIXTURE-FLOOD	79	1,848	145,992		$561.60	$44,366	$1,812	$46,179	$584.54	$662.52	$52,339	13%
APL	342	14' AL FLUTED COL CUST BASE PAIRED W/LT	0	0	0		$16.56	$0	$0	$0	$16.56	$18.72	$0	13%
APL	343	14 FG FLUTED COL DIRECT BURY PAIRED W/LT	0	0	0		$174.00	$0	$0	$0	$174.00	$197.28	$0	13%
APL	344	14 FG SMOOTH COL DIRECT BURY PAIRED W/LT	0	0	0		$149.76	$0	$0	$0	$149.76	$169.80	$0	13%
APL	346	400 WATT HPS-ADDIT'L FIXTURE	35	1,848	64,680		$354.60	$12,411	$803	$13,214	$377.54	$427.92	$14,977	13%
APL	347	250 WATT HPS-ADDIT'L FIXTURE	9	1,194	10,746		$290.76	$2,617	$133	$2,750	$305.58	$346.32	$3,117	13%
APL	348	150 WATT HPS-ADDIT'L FIXTURE	1	733	733		$247.80	$248	$9	$257	$256.90	$291.24	$291	13%
APL	349	100 WATT HPS-ADDIT'L FIXTURE	0	485	0		$218.16	$0	$0	$0	$224.18	$254.16	$0	13%
APL	350	400 WATT HPS -ADDITIONAL FIXTURE-PAINTED	0	1,848	0		$345.12	$0	$0	$0	$368.06	$417.24	$0	13%
APL	351	250 WATT HPS -ADDITIONAL FIXTURE-PAINTED	0	1,194	0		$290.76	$0	$0	$0	$305.58	$346.32	$0	13%
APL	352	400 WATT HPS-ADDIT'L FIXTURE-SHOEBOX	0	1,848	0		$348.12	$0	$0	$0	$371.06	$420.60	$0	13%
APL	353	250 WATT HPS-ADDIT'L FIXTURE-SHOEBOX	0	1,194	0		$283.44	$0	$0	$0	$298.26	$338.04	$0	13%
APL	354	AL COL W/BASE PAIRED W/LT	52	0	0		$211.80	$11,014	$0	$11,014	$211.80	$240.12	$12,486	13%
APL	355	AL COL ON CUST OWNED BASE PAIRED W/LT	90	0	0		$118.08	$10,627	$0	$10,627	$118.08	$133.80	$12,042	13%
APL	356	150 WATT HPS-ADDIT'L FIXTURE-FLOOD	0	733	0		$254.88	$0	$0	$0	$263.98	$299.16	$0	13%
APL	357	250 WATT HPS-ADDIT'L FIXTURE-FLOOD	2	1,194	2,388		$302.40	$605	$30	$634	$317.22	$359.52	$719	13%
APL	358	400 WATT HPS-ADDIT'L FIXTURE-FLOOD	132	1,848	243,936		$365.16	$48,201	$3,028	$51,229	$388.10	$439.92	$58,069	13%
APL	362	100 W HPS POST TOP WASH	20	485	9,700		$384.00	$7,680	$120	$7,800	$390.02	$442.08	$8,842	13%
APL	363	100 W HPS POST TOP	5	485	2,425		$286.92	$1,435	$30	$1,465	$292.94	$332.04	$1,660	13%
APL	364	150 W HPS POST TOP WASH	28	733	20,524		$407.28	$11,404	$255	$11,659	$416.38	$471.96	$13,215	13%
APL	365	150 W HPS POST TOP BALL	0	733	0		$365.16	$0	$0	$0	$374.26	$424.20	$0	13%
APL	369	AL COL BZ W/BASE PAIRED W/LT	29	0	0		$231.00	$6,699	$0	$6,699	$231.00	$261.84	$7,593	13%
APL	370	AL COL BZ ON CUST BASE PAIRED W/LT	15	0	0		$137.28	$2,059	$0	$2,059	$137.28	$155.64	$2,335	13%
APL	378	FG COL DIRECT BURY PAIRED W/LT	263	0	0		$126.60	$33,296	$0	$33,296	$126.60	$143.52	$37,746	13%
APL	380	250 WATT MET HAL 18 FT DIR EMBEDDED	88	1,159	101,992		$486.48	$42,810	$1,266	$44,076	$500.87	$567.72	$49,959	13%
APL	381	250 WATT MET HAL 12 FT ANCHOR BASED	140	1,159	162,260		$483.72	$67,721	$2,014	$69,735	$498.11	$564.60	$79,044	13%
APL	382	2-250 WATT MET HAL 18 FT DIR EMBEDDED	80	2,317	185,360		$717.72	$57,418	$2,301	$59,718	$746.48	$846.12	$67,690	13%
APL	383	2-250 WATT MET HAL 12 FT ANCHOR BASED	13	2,317	30,121		$714.96	$9,294	$374	$9,668	$743.72	$843.00	$10,959	13%
APL	388	250 WATT MH 18 FT DIR EMBED PRI METER	32	1,159	37,088		$389.52	$12,465	$460	$12,925	$403.91	$457.80	$14,650	13%
APL	389	250 WATT MH 12 FT ANCHOR BASE PRI METER	16	1,159	18,544		$386.76	$6,188	$230	$6,418	$401.15	$454.68	$7,275	13%
APL	390	2-250 WATT MH 18 FT DIR EMBED PRI METER	17	2,317	39,389		$523.80	$8,905	$489	$9,394	$552.56	$626.28	$10,647	13%
APL	391	2-250 WATT MH 12 FT ANCHOR BASE PRI MTR	9	2,317	20,853		$521.04	$4,689	$259	$4,948	$549.80	$623.16	$5,608	13%
		Total APL	**44,102**		**38,052,433**			**$8,817,661**	**$472,328**	**$9,289,989**			**$10,529,006**	
												Target	**$10,529,253**	
												Over (Under) Recovery	($247)	

AES Indiana
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	MU													
		Company Installed, Owned, and Maintained (MU-1)												**13.54%**
MU1	1	1000 WATT MV - OVERHEAD	1	4,315	4,315		$370.92	$371	$53.56	$424	$424.48	$481.92	$482	14%
MU1	2	1000 WATT MV - TRAFFIC COLUMN	0	4,315	0		$333.60	$0	$0.00	$0	$387.16	$439.56	$0	14%
MU1	3	1000 WATT MV - METAL COLUMN	3	4,315	12,945		$516.60	$1,550	$160.68	$1,710	$570.16	$647.40	$1,942	14%
MU1	4	400 WATT MV - OVERHEAD	16	1,880	30,080		$196.80	$3,149	$373.37	$3,522	$220.14	$249.96	$3,999	14%
MU1	5	400 WATT MV - TRAFFIC COLUMN	0	1,880	0		$179.16	$0	$0.00	$0	$202.50	$229.92	$0	14%
MU1	6	400 WATT MV - METAL COLUMN	143	1,880	268,840		$264.96	$37,889	$3,336.99	$41,226	$288.30	$327.36	$46,812	14%
MU1	7	175 WATT MV - OVERHEAD	409	832	340,288		$130.92	$53,546	$4,223.84	$57,770	$141.25	$160.32	$65,571	14%
MU1	8	175 WATT MV - TRAFFIC COLUMN	0	832	0		$121.32	$0	$0.00	$0	$131.65	$149.52	$0	14%
MU1	9	175 WATT MV - METAL COLUMN	613	832	510,016		$205.68	$126,082	$6,330.60	$132,412	$216.01	$245.28	$150,357	14%
MU1	10	175 W MV - POST TOP	463	832	385,216		$200.52	$92,841	$4,781.51	$97,622	$210.85	$239.40	$110,842	14%
MU1	11	175 W MV - POST TOP WASH	187	832	155,584		$306.00	$57,222	$1,931.19	$59,153	$316.33	$359.16	$67,163	14%
MU1	12	400 WATT HPS - OVERHEAD	236	1,848	436,128		$227.40	$53,666	$5,413.46	$59,080	$250.34	$284.28	$67,090	14%
MU1	13	400 WATT HPS - TRAFFIC COLUMN	65	1,848	120,120		$227.40	$14,781	$1,491.00	$16,272	$250.34	$284.28	$18,478	14%
MU1	14	400 WATT HPS - METAL COLUMN	478	1,848	883,344		$373.08	$178,332	$10,964.55	$189,297	$396.02	$449.64	$214,928	14%
MU1	15	250 WATT HPS - OVERHEAD	505	1,194	602,970		$180.96	$91,385	$7,484.39	$98,869	$195.78	$222.24	$112,231	14%
MU1	16	250 WATT HPS - TRAFFIC COLUMN	36	1,194	42,984		$180.96	$6,515	$533.54	$7,048	$195.78	$222.24	$8,001	14%
MU1	17	250 WATT HPS - METAL COLUMN	607	1,194	724,758		$250.44	$152,017	$8,996.09	$161,013	$265.26	$301.20	$182,828	14%
MU1	18	150 WATT HPS - OVERHEAD	467	733	342,311		$140.04	$65,399	$4,248.95	$69,648	$149.14	$169.32	$79,072	14%
MU1	19	150 WATT HPS - TRAFFIC COLUMN	7	733	5,131		$140.04	$980	$63.69	$1,044	$149.14	$169.32	$1,185	14%
MU1	20	150 WATT HPS - METAL COLUMN	472	733	345,976		$211.80	$99,970	$4,294.44	$104,264	$220.90	$250.80	$118,378	14%
MU1	21	100 WATT HPS - OVERHEAD	828	485	401,580		$117.48	$97,273	$4,984.63	$102,258	$123.50	$140.28	$116,152	14%
MU1	22	100 WATT HPS - TRAFFIC COLUMN	1	485	485		$117.48	$117	$6.02	$124	$123.50	$140.28	$140	14%
MU1	23	100 WATT HPS - METAL COLUMN	567	485	274,995		$192.24	$109,000	$3,413.39	$112,413	$198.26	$225.12	$127,643	14%
MU1	24	100 W HPS - POST TOP	5,604	485	2,717,940		$191.28	$1,071,933	$33,736.56	$1,105,670	$197.30	$224.04	$1,255,520	14%
MU1	25	100 W HPS - POST TOP WASH	1,620	485	785,700		$293.88	$476,086	$9,752.54	$485,838	$299.90	$340.56	$551,707	14%
MU1	26	150 W HPS- POST TOP BALL	21	733	15,393		$232.92	$4,891	$191.07	$5,082	$242.02	$274.80	$5,771	14%
MU1	27	150 W HPS - POST TOP WASH	2,927	733	2,145,491		$339.84	$994,712	$26,631.01	$1,021,343	$348.94	$396.24	$1,159,794	14%
MU1	28	3-150 WATT HPS-1 COLUMN CLUSTER W/BALAST	0	2,496	0		$561.00	$0	$0.00	$0	$591.98	$672.12	$0	14%
MU1	29	3-150 WATT HPS-2 COLUMN CLUSTER N/BALAST	0	2,496	0		$561.00	$0	$0.00	$0	$591.98	$672.12	$0	14%
MU1	30	3-150 WATT HPS-2 COLUMN CLUSTER W/BALAST	0	2,496	0		$561.00	$0	$0.00	$0	$591.98	$672.12	$0	14%
MU1	32	1-150 & 4-100 WATT HPS - CLUSTER	1	2,672	2,672		$781.56	$782	$33.17	$815	$814.73	$925.08	$925	14%
MU1	33	400 WATT HPS-METAL COLUMN-PAINTED BRONZE	74	1,848	136,752		$404.28	$29,917	$1,697.44	$31,614	$427.22	$485.04	$35,893	14%
MU1	34	400 WATT HPS-TRAFFIC COLUMN-PAINT BRONZE	8	1,848	14,784		$232.56	$1,860	$183.51	$2,044	$255.50	$290.04	$2,320	14%
MU1	35	250 WATT HPS-METAL COLUMN-PAINTED BRONZE	1	1,194	1,194		$281.64	$282	$14.82	$296	$296.46	$336.60	$337	14%
MU1	37	175 WATT MV - FIBERGLASS COLUMN	6	832	4,992		$196.32	$1,178	$61.96	$1,240	$206.65	$234.60	$1,408	14%
MU1	38	100 WATT HPS - FIBERGLASS COLUMN	103	485	49,955		$182.88	$18,837	$620.07	$19,457	$188.90	$214.44	$22,087	14%
MU1	39	150 WATT HPS - FIBERGLASS COLUMN	155	733	113,615		$202.32	$31,360	$1,410.25	$32,770	$211.42	$240.00	$37,200	14%
MU1	40	250 WATT HPS - FIBERGLASS COLUMN	124	1,194	148,056		$241.20	$29,909	$1,837.75	$31,747	$256.02	$290.64	$36,039	14%
MU1	41	400 WATT HPS - FIBERGLASS COLUMN	159	1,848	293,832		$348.36	$55,389	$3,647.20	$59,036	$371.30	$421.56	$67,028	14%
MU1	42	400 WATT MH SHOEBOX - FIBERGLASS COLUMN	55	1,774	97,570		$319.80	$17,589	$1,211.09	$18,800	$341.82	$388.08	$21,344	14%
MU1	43	2-400 WATT MH SHOEBOX-FIBERGLASS COLUMN	48	3,547	170,256		$454.20	$21,802	$2,113.31	$23,915	$498.23	$565.68	$27,153	14%
MU1	44	175 WATT MV UPASS 4100HRS - WALL MOUNTED	0	832	0		$156.60	$0	$0.00	$0	$166.93	$189.48	$0	14%
MU1	45	150 WATT HPS UPASS 4100HRS -WALL MOUNTED	192	733	140,736		$180.48	$34,652	$1,746.89	$36,399	$189.58	$215.28	$41,334	14%
MU1	46	250 W HPS - SHOEBOX	10	1,194	11,940		$252.00	$2,520	$148.21	$2,668	$266.82	$303.00	$3,030	14%
MU1	48	2-250 W HPS-SHOEBOX	0	2,388	0		$323.16	$0	$0.00	$0	$352.80	$400.56	$0	14%
MU1	50	400 WATT HPS UPASS 8760HRS WALL MOUNTED	85	4,108	349,180		$421.92	$35,863	$4,334.21	$40,197	$472.91	$537.00	$45,645	14%
MU1	51	150 WATT HPS UPASS 8760HRS WALL MOUNTED	101	1,629	164,529		$242.40	$24,482	$2,042.22	$26,525	$262.62	$298.20	$30,118	14%
MU1	65	400 W HPS - SHOEBOX	43	1,848	79,464		$314.28	$13,514	$986.35	$14,500	$337.22	$382.92	$16,466	14%
MU1	66	2-400 W HPS-SHOEBOX	15	3,697	55,455		$443.52	$6,653	$688.34	$7,341	$489.41	$555.72	$8,336	14%
MU1	101	400 WATT METAL HALIDE - METAL COLUMN	0	1,774	0		$371.88	$0	$0.00	$0	$393.90	$447.24	$0	14%
MU1	184	EXCESS MATERIAL FOR CIRCLE CENTRE MALL	1	0	0		$6,291.12	$6,291	$0.00	$6,291	$6,291.12	$7,142.88	$7,143	14%
MU1	185	PEDESTRIAN LIGHT FOR CIRCLE CENTRE MALL	47	1,880	88,360		$810.48	$38,093	$1,096.77	$39,189	$833.82	$946.68	$44,494	14%
MU1	187	TWIN 80W LED POST TOP	54	640	34,560		$791.28	$42,729	$428.98	$43,158	$799.22	$907.44	$49,002	14%
MU1	200	LED COBRA HEAD 5000-6000 LUMENS	1,581	185	292,485		$213.63	$337,743	$3,630.48	$341,373	$215.92	$245.16	$387,598	14%
MU1	201	LED COBRA HEAD 6500-7500 LUMENS	507	229	116,103		$219.31	$111,190	$1,441.13	$112,631	$222.15	$252.24	$127,886	14%
MU1	202	LED COBRA HEAD 12500-13500 LUMENS	505	437	220,685		$266.64	$134,653	$2,739.26	$137,392	$272.06	$308.88	$155,984	14%

AES Indiana
Lighting Revenue Proof and Proposed Rates

	Code	Description	Inventory (Light Count)	kWh per Light	Total kWh	Separately Metered	Current Annual Base Rate	Current Base Revenue	ProForma Adjustments	Current Revenue Proforma @ Present Rates	Current Rate with ECCR, RTO, DSM, CAP, TDSIC, and Fuel (Base Fuel and FCA)	Proposed Annual Rate	Proposed Revenue	Change (%)
MU1	203	LED COBRA HEAD 20000-21500 LUMENS	276	686	189,336		$308.63	$85,182	$2,350.14	$87,532	$317.14	$360.12	$99,393	14%
MU1	204	LED AREA LIGHT 11500-16500 LUMENS	0	536	0		$287.71	$0	$0.00	$0	$294.36	$334.20	$0	14%
MU1	205	LED AREA LIGHT 21000-26000 LUMENS	31	867	26,877		$321.02	$9,952	$333.61	$10,285	$331.78	$376.68	$11,677	14%
MU1	206	LED TRAD. POST TOP 6000-7500 LUMENS	943	260	245,180		$262.09	$247,152	$3,043.31	$250,195	$265.32	$301.20	$284,032	14%
MU1	207	LED TWIN WASH POST TOP 2 @ 6000-7500-LT	47	552	25,944		$632.93	$29,748	$322.03	$30,070	$639.79	$726.36	$34,139	14%
MU1	208	LED WASH POST TOP 6000-7500 LUMENS	348	276	96,048		$350.10	$121,834	$1,192.20	$123,026	$353.52	$401.40	$139,687	14%
MU1	212	400 WATT HPS - OVERHEAD	4	1,848	7,392		$450.72	$1,803	$91.75	$1,895	$473.66	$537.84	$2,151	14%
MU1	213	400 WATT HPS - TRAFFIC COLUMN	0	1,848	0		$409.32	$0	$0.00	$0	$432.26	$490.80	$0	14%
MU1	214	400 WATT HPS - METAL COLUMN	32	1,848	59,136		$577.92	$18,493	$734.03	$19,227	$600.86	$682.20	$21,830	14%
MU1	215	250 WATT HPS - OVERHEAD	25	1,194	29,850		$388.20	$9,705	$370.51	$10,076	$403.02	$457.56	$11,439	14%
MU1	216	250 WATT HPS - TRAFFIC COLUMN	0	1,194	0		$346.68	$0	$0.00	$0	$361.50	$410.40	$0	14%
MU1	217	250 WATT HPS - METAL COLUMN	41	1,194	48,954		$515.40	$21,131	$607.64	$21,739	$530.22	$602.04	$24,684	14%
MU1	218	150 WATT HPS - OVERHEAD	12	733	8,796		$346.08	$4,153	$109.18	$4,262	$355.18	$403.32	$4,840	14%
MU1	219	150 WATT HPS - TRAFFIC COLUMN	0	733	0		$304.68	$0	$0.00	$0	$313.78	$356.28	$0	14%
MU1	220	150 WATT HPS - METAL COLUMN	1	733	733		$473.28	$473	$9.10	$482	$482.38	$547.68	$548	14%
MU1	221	100 WATT HPS - OVERHEAD	25	485	12,125		$316.92	$7,923	$150.50	$8,074	$322.94	$366.72	$9,168	14%
MU1	222	100 WATT HPS - TRAFFIC COLUMN	0	485	0		$275.40	$0	$0.00	$0	$281.42	$319.56	$0	14%
MU1	223	100 WATT HPS - METAL COLUMN	30	485	14,550		$444.00	$13,320	$180.60	$13,501	$450.02	$510.96	$15,329	14%
MU1	224	100 W HPS - POST TOP	194	485	94,090		$304.20	$59,015	$1,167.90	$60,183	$310.22	$352.20	$68,327	14%
MU1	225	100 W HPS - POST TOP WASH	166	485	80,510		$405.36	$67,290	$999.33	$68,289	$411.38	$467.04	$77,529	14%
MU1	226	150 W HPS- POST TOP BALL	0	733	0		$384.24	$0	$0.00	$0	$393.34	$446.64	$0	14%
MU1	227	150 W HPS - POST TOP WASH	237	733	173,721		$428.04	$101,445	$2,156.32	$103,602	$437.14	$496.32	$117,628	14%
MU1	228	12' FG TRAD COL PAIRED W/LT	920	0	0		$88.08	$81,034	$0.00	$81,034	$88.08	$99.96	$91,963	13%
MU1	232	1-150 & 4-100 WATT HPS - CLUSTER	0	2,672	0		$960.12	$0	$0.00	$0	$993.29	$1,127.76	$0	14%
MU1	233	400 WATT HPS-METAL COLUMN-PAINTED BRONZE	0	1,848	0		$603.60	$0	$0.00	$0	$626.54	$711.36	$0	14%
MU1	234	400 WATT HPS-TRAFFIC COLUMN-PAINT BRONZE	0	1,848	0		$347.04	$0	$0.00	$0	$369.98	$420.12	$0	14%
MU1	235	250 WATT HPS-METAL COLUMN-PAINTED BRONZE	0	1,194	0		$550.92	$0	$0.00	$0	$565.74	$642.36	$0	14%
MU1	236	250 WATT HPS-TRAFFIC COLUMN-PAINT BRONZE	0	1,194	0		$284.52	$0	$0.00	$0	$299.34	$339.84	$0	14%
MU1	237	12' FG FLUTED COL CUST BASE PAIRED W/LT	5	0	0		$178.32	$892	$0.00	$892	$178.32	$202.44	$1,012	14%
MU1	238	100 WATT HPS - FIBERGLASS COLUMN	2	485	970		$359.04	$718	$12.04	$730	$365.06	$414.48	$829	14%
MU1	239	150 WATT HPS - FIBERGLASS COLUMN	13	733	9,529		$392.64	$5,104	$118.28	$5,223	$401.74	$456.12	$5,930	14%
MU1	240	250 WATT HPS - FIBERGLASS COLUMN	0	1,194	0		$434.76	$0	$0.00	$0	$449.58	$510.48	$0	14%
MU1	241	400 WATT HPS - FIBERGLASS COLUMN	1	1,848	1,848		$497.28	$497	$22.94	$520	$520.22	$590.64	$591	14%
MU1	242	14' AL FLUTED COL CUST BASE PAIRED W/LT	59	0	0		$206.40	$12,178	$0.00	$12,178	$206.40	$234.36	$13,827	14%
MU1	243	14 FG FLUTED COL DIRECT BURY PAIRED W/LT	195	0	0		$181.20	$35,334	$0.00	$35,334	$181.20	$205.68	$40,108	14%
MU1	244	14 FG SMOOTH COL DIRECT BURY PAIRED W/LT	115	0	0		$155.76	$17,912	$0.00	$17,912	$155.76	$176.88	$20,341	14%
MU1	245	150 WATT HPS UPASS 4100HRS -WALL MOUNTED	0	733	0		$285.00	$0	$0.00	$0	$294.10	$333.96	$0	14%
MU1	246	250 W HPS - SHOEBOX	0	1,194	0		$430.56	$0	$0.00	$0	$445.38	$505.68	$0	14%
MU1	248	2-250 W HPS-SHOEBOX	0	2,388	0		$493.20	$0	$0.00	$0	$522.84	$593.64	$0	14%
MU1	250	400 WATT HPS UPASS 8760HRS WALL MOUNTED	0	4,108	0		$538.68	$0	$0.00	$0	$589.67	$669.48	$0	14%
MU1	251	150 WATT HPS UPASS 8760HRS WALL MOUNTED	0	1,629	0		$330.12	$0	$0.00	$0	$350.34	$397.80	$0	14%
MU1	254	AL COL W/BASE PAIRED W/LT	195	0	0		$220.56	$43,009	$0.00	$43,009	$220.56	$250.44	$48,836	14%
MU1	255	AL COL ON CUST OWNED BASE PAIRED W/LT	7	0	0		$122.88	$860	$0.00	$860	$122.88	$139.56	$977	14%
MU1	265	400 W HPS - SHOEBOX	1	1,848	1,848		$493.92	$494	$22.94	$517	$516.86	$586.80	$587	14%
MU1	266	2-400 W HPS-SHOEBOX	0	3,697	0		$709.44	$0	$0.00	$0	$755.33	$857.64	$0	14%
MU1	269	AL COL BZ W/BASE PAIRED W/LT	1	0	0		$240.48	$240	$0.00	$240	$240.48	$273.00	$273	14%
MU1	270	AL COL BZ ON CUST BASE PAIRED W/LT	0	0	0		$142.92	$0	$0.00	$0	$142.92	$162.24	$0	14%
MU1	278	FG COL DIRECT BURY PAIRED W/LT	114	0	0		$131.88	$15,034	$0.00	$15,034	$131.88	$149.76	$17,073	14%
MU1	385	PEDESTRIAN LIGHT FOR CIRCLE CENTRE MALL	0	1,880	0		$460.68	$0	$0.00	$0	$484.02	$549.60	$0	14%
MU1	386	80W LED POST TOP	0	320	0		$682.44	$0	$0.00	$0	$686.41	$779.40	$0	14%
MU1	396	WD POLE W/OH FEED-W/OR W/O LT	1,074	0	0		$94.80	$101,815	$0.00	$101,815	$94.80	$107.64	$115,605	14%
MU1	397	WD POLE W/UG FEED-PAIRED W/LT	221	0	0		$120.12	$26,547	$0.00	$26,547	$120.12	$136.44	$30,153	14%

AES Indiana
Lighting Revenue Proof and Proposed Rates

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		Streetlighting with CIAC[1]												
MU1	600	LED COBRA HEAD 5000-6000 LUMENS	14,355	185	2,655,675		$91.68	$1,316,007	$32,963.69	$1,348,971	$93.97	$106.68	$1,531,391	14%
MU1	601	LED COBRA HEAD 6500-7500 LUMENS	1,980	229	453,420		$95.64	$189,367	$5,628.10	$194,995	$98.48	$111.84	$221,443	14%
MU1	602	LED COBRA HEAD 12500-13500 LUMENS	6,850	437	2,993,450		$112.09	$767,810	$37,156.34	$804,967	$117.51	$133.44	$914,064	14%
MU1	603	LED COBRA HEAD 20000-21500 LUMENS	3,932	686	2,697,352		$131.51	$517,094	$33,481.01	$550,575	$140.02	$159.00	$625,188	14%
MU1	604	LED AREA LIGHT 11500-16500 LUMENS	3	536	1,608		$111.74	$335	$19.96	$355	$118.39	$134.40	$403	14%
MU1	605	LED AREA LIGHT 21000-26000 LUMENS	6	867	5,202		$135.06	$810	$64.57	$875	$145.82	$165.60	$994	14%
MU1	606	LED TRAD. POST TOP 6000-7500 LUMENS	40	260	10,400		$99.94	$3,998	$129.09	$4,127	$103.17	$117.12	$4,685	14%
MU1	607	LED TWIN WASH POST TOP 2 @ 6000-7500 L	0	552	0		$116.11	$0	$0.00	$0	$122.97	$139.56	$0	13%
MU1	608	LED WASH POST TOP 6000-7500 LUMENS	162	276	44,712		$96.40	$15,616	$554.99	$16,171	$99.82	$113.28	$18,351	13%
MU1	609	LED COBRA 12500-13500 L-OH FROM 215	12	437	5,244		$218.17	$2,618	$65.09	$2,683	$223.59	$253.92	$3,047	14%
MU1	610	LED COBRA 12500-13500L-METAL COL FRM 217	2	437	874		$344.65	$689	$10.85	$700	$350.07	$397.44	$795	14%
MU1	611	LED COBRA 6500-7500 L-OH FROM 218	12	229	2,748		$201.60	$2,419	$34.11	$2,453	$204.44	$232.08	$2,785	14%
MU1	612	LED COBRA 5000-6000 L-OH FROM 221	12	185	2,220		$197.76	$2,373	$27.56	$2,401	$200.05	$227.16	$2,726	14%
		Streetlighting with CIAC [2]												
MU1	400	LED COBRA HEAD 5000-6000 LUMENS	1,458	185	269,730		$106.68	$155,533	$3,348.04	$158,881	$108.97	$123.72	$180,384	14%
MU1	401	LED COBRA HEAD 6500-7500 LUMENS	405	229	92,745		$110.64	$44,809	$1,151.20	$45,960	$113.48	$128.88	$52,196	14%
MU1	402	LED COBRA HEAD 12500-13500 LUMENS	337	437	147,269		$127.09	$42,829	$1,827.98	$44,657	$132.51	$150.48	$50,712	14%
MU1	403	LED COBRA HEAD 20000-21500 LUMENS	129	686	88,494		$146.51	$18,900	$1,098.44	$19,998	$155.02	$176.04	$22,709	14%
MU1	404	LED AREA LIGHT 11500-16500 LUMENS	0	536	0		$126.74	$0	$0.00	$0	$133.39	$151.44	$0	14%
MU1	405	LED AREA LIGHT 21000-26000 LUMENS	0	867	0		$150.06	$0	$0.00	$0	$160.82	$182.64	$0	14%
MU1	406	LED TRAD. POST TOP 6000-7500 LUMENS	0	260	0		$114.94	$0	$0.00	$0	$118.17	$134.16	$0	14%
MU1	407	LED TWIN WASH POST TOP 2 @ 6000-7500 L	0	552	0		$131.11	$0	$0.00	$0	$137.97	$156.60	$0	14%
MU1	408	LED WASH POST TOP 6000-7500 LUMENS	10	276	2,760		$111.40	$1,114	$34.26	$1,148	$114.82	$130.32	$1,303	13%
MU1	409	LED COBRA 12500-13500 L-OH FROM 215	0	437	0		$233.17	$0	$0.00	$0	$238.59	$270.84	$0	14%
MU1	410	LED COBRA 12500-13500L-METAL COL FRM 217	0	437	0		$359.65	$0	$0.00	$0	$365.07	$414.48	$0	14%
MU1	411	LED COBRA 6500-7500 L-OH FROM 218	0	229	0		$216.60	$0	$0.00	$0	$219.44	$249.12	$0	14%
MU1	412	LED COBRA 5000-6000 L-OH FROM 221	0	185	0		$212.76	$0	$0.00	$0	$215.05	$244.20	$0	14%

AES Indiana
Lighting Revenue Proof and Proposed Rates

	Code	Description	Inventory (Light Count)	kWh per Light	Total kWh	Separately Metered	Current Annual Base Rate	Current Base Revenue	ProForma Adjustments	Current Revenue Proforma @ Present Rates	Current Rate with ECCR, RTO, DSM, CAP, TDSIC, and Fuel (Base Fuel and FCA)	Proposed Annual Rate	Proposed Revenue	Change (%)
		Customer Installed, Owned, and Maintained (MU-1)	**Counts**											
MU1	55	250 WATT MV - CUSTOMER OWNED	2	1,210	2,420		$166.68	$333	$30.04	$363	$181.70	$206.28	$413	14%
MU1	56	175 WATT MV - CUSTOMER OWNED	26	832	21,632		$105.50	$2,743	$268.51	$3,012	$115.83	$131.52	$3,420	14%
MU1	59	400 WATT HPS - CUSTOMER OWNED	410	1,848	757,680		$168.24	$68,978	$9,404.74	$78,383	$191.18	$217.08	$89,003	14%
MU1	60	250 WATT HPS - CUSTOMER OWNED	201	1,194	239,994		$130.68	$26,267	$2,978.94	$29,246	$145.50	$165.24	$33,213	14%
MU1	61	150 WATT HPS - CUSTOMER OWNED	203	733	148,799		$97.56	$19,805	$1,846.97	$21,652	$106.66	$121.08	$24,579	14%
MU1	63	1000 WATT HPS - CUSTOMER OWNED	228	4,355	992,940		$354.12	$80,739	$12,324.91	$93,064	$408.18	$463.44	$105,664	14%
MU1	64	175 WATT MV ORNIMENTAL - CUSTOMER OWNED	2	832	1,664		$156.96	$314	$20.65	$335	$167.29	$189.96	$380	14%
MU1	109	400 WATT HPS-CUSTOMER OWNED WO/MAINT	0	1,848	0		$147.72	$0	$0.00	$0	$170.66	$193.80	$0	14%
MU1	111	150 WATT HPS - CUSTOMER OWNED WO/MAINT	0	733	0		$77.28	$0	$0.00	$0	$86.38	$98.04	$0	14%
MU1	112	1000 WATT HPS - CUSTOMER OWNED WO/MAINT	0	4,355	0		$297.72	$0	$0.00	$0	$351.78	$399.36	$0	14%
		Customer Installed, Owned, but Company Maintained (MU-1)												
MU1	120	400 WATT HPS - CUSTOMER OWNED W/MAINT	13	1,848	24,024		$168.24	$2,187	$298.20	$2,485	$191.18	$217.08	$2,822	14%
		Total MU-1	**56,276**		**26,930,258**			**$9,210,971**	**$334,273**	**$9,545,245**			**$10,838,032**	
		Customer Installed, Owned, and Maintained (MU-4)												
						Watts Adjusted for Min. Bill						**Proposed Price Per Watt**		
MU4		**Total MU-4**	**1,828**		**7,377,723**	**842,187**		**$530,575**	**$91,576**	**$622,151**	**$340.35**	**$ 0.84**	**$707,437**	14%
		Total MU	**58,104**		**34,307,981**			**$9,741,546**	**$425,849**	**$10,167,396**			**$11,545,469**	
												Target	$11,545,324	
												Under (Over) Recovery	$145	
		Grand Total Lighting (APL and MU)	**102,206**		**72,360,414**			**$18,559,207**	**$898,177**	**$19,457,384**			**$22,074,475**	
									Balancing Adjustment	*1.000*				
									Total Lighting Revenue (APL and MU) @ Pro Forma Current Rates	**$19,457,466**				

[1] Streetlighting with CIAC - City of Indianapolis
[2] Streetlighting with CIAC - All Other

AES Indiana
Rate Design Summary

Test Year Ended December 31, 2026

	(A)	(B)	(C)	(D)
Line No.	**Rate RS**		**Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)**	**Proposed Rates**
	Billed kwh			
1		First 500 kWh	$ 0.145381	$ 0.160074
2		Over 500 kWh	$ 0.133782	$ 0.148475
3		Over 1,000	$ 0.121368	$ 0.136061
		Resid (CR/CW)	$ 0.096903	$ 0.113150
	Customer Charge			
4		0 to 325 kWh	$ 12.50	$ 15.00
5		Over 325 kWh	$ 17.00	$ 20.00
		Resid (CR/CW)	$ 20.00	$ 22.00

	(A)	(B)	(C)	(D)
Line No.	**Rate SS**		**Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)**	**Proposed Rates**
	Billed kwh			
1		First 5,000 kWh	$ 0.147291	$ 0.154732
2		Over 5,000 kWh	$ 0.132811	$ 0.140252
	Customer Charge			
3		0 to 5,000 kWh	$ 40.00	$ 44.00
4		Over 5,000 kWh	$ 55.00	$ 60.00

	(A)	(B)	(C)	(D)
Line No.	**Rate MD**		**Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)**	**Proposed Rates**
	Billed kwh			
1		First 5,000 kWh	$ 0.147291	$ 0.163956
2		Over 5,000 kWh	$ 0.132811	$ 0.163956
	Customer Charge			
3		0 to 5,000 kWh	$ 40.00	$ 35.00
4		Over 5,000 kWh	$ 55.00	$ 35.00

	(A)	(B)	(C)	(D)
Line No.	**Rate SH**		**Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)**	**Proposed Rates**
	Billed kwh			
1		All kWh	$ 0.147855	$ 0.160587
	Customer Charge			
2		All Customers	$ 55.00	$ 60.00

AES Indiana
Rate Design Summary

Test Year Ended December 31, 2026

	(A)	(B)		(C)		(D)
Line No.	**Rate SE**			**Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)**		**Proposed Rates**
	Billed kwh					
1		First 5,000 kWh	$	0.157657	$	0.176487
2		Over 5,000 kWh	$	0.143177	$	0.162007
3		Excess of 155 x Cor	$	0.129485	$	0.148315
	Customer Charge					
4		All Customers	$	55.00	$	60.00

	(A)	(B)		(C)		(D)
Line No.	**Rate UW**			**Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)**		**Proposed Rates**
	Billed kwh					
1		All kWh	$	0.113810	$	0.124956
	Customer Charge					
2		All Customers	$	40.00	$	45.00

	(A)	(B)		(C)		(D)
Line No.	**Rate CB**			**Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)**		**Proposed Rates**
	Billed kwh					
1		All kWh	$	0.101282	$	0.113150
	Customer Charge					
2		All Customers	$	20.00	$	22.00

AES Indiana
Rate Design Summary

Test Year Ended December 31, 2026

	(A)	(B)	(C)		(D)	
Line No.	**Rate SL**		**Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)**		**Proposed Rates**	
	Billed kwh					
1		All kWh	$	0.058403	$	0.058648
	Billed kW					
2		All kW	$	24.74	$	28.13
	Customer Charge					
3		All Customers	$	120.00	$	128.00

	(A)	(B)	(C)		(D)	
Line No.	**Rate PL**		**Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)**		**Proposed Rates**	
	Billed kwh					
1		All kWh	$	0.056102	$	0.055746
	Billed kW					
2		All kW	$	28.30	$	33.10
	Customer Charge					
3		All Customers	$	130.00	$	133.00

AES Indiana
Rate Design Summary

Test Year Ended December 31, 2026

	(A)	(B)	(C)	(D)
Line No.	**Rate HL1**		**Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)**	**Proposed Rates**
	Billed kwh			
1		All kWh	$ 0.061326	$ 0.054775
	Billed kW			
2		All kW	$ 27.95	$ 34.30
	Customer Charge			
3		All Customers	$ 130.00	$ 150.00

	(A)	(B)	(C)	(D)
Line No.	**Rate HL2**		**Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)**	**Proposed Rates**
	Billed kwh			
1		All kWh	$ 0.055676	$ 0.053437
	Billed kW			
2		All kW	$ 25.00	$ 25.20
	Customer Charge			
3		All Customers	$ 215.00	$ 215.00

	(A)	(B)	(C)	(D)
Line No.	**Rate HL3 - High Load Factor**		**Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)**	**Proposed Rates**
	Billed kwh			
1		All kWh	$ 0.055139	$ 0.052488
	Billed kW			
2		All kW	$ 24.09	$ 25.00
	Customer Charge			
3		All Customers	$ 500.00	$ 500.00

	(A)	(B)	(C)	(D)
Line No.	**HL4**		**Pro Forma Current Rate with TDSIC, ECCR, DSM, CAP, RTO and Fuel (Base Fuel and FCA)**	**Proposed Rates**

AES Indiana
Rate Design Summary

Test Year Ended December 31, 2026

	Billed kwh					
1		All kWh	$	0.075476	$	0.080611
	Billed kW					
2		All kW	$	15.06	$	16.08
	Customer Charge					
3		All Customers	$	508.21	$	542.78

AES Indiana
Residential Bill Impacts - RS Customers under Phase 2 Rates
Test year Ending December 31, 2026

Proposed Rates

		Including Fuel		Including Fuel & DSM		Excluding Fuel	
Energy Charge		Pro Forma Current Rate [1]	Proposed Rate	Pro Forma Current Rate [1]	Proposed Rate	Pro Forma Current Rate [1]	Proposed Rate
First 500 kWh		$ 0.145381	$ 0.160074	$ 0.145381	$ 0.163391	$ 0.103758	$ 0.118244
Over 500 kWh	500	$ 0.133782	$ 0.148475	$ 0.133782	$ 0.151792	$ 0.092159	$ 0.106645

[1] Includes riders rolled into base rates (TDSIC, ECCR, DSM, CAP, RTO and FAC)

Customer Charge					
0 to 325 kWh		$ 12.50	$ 15.00	$ 12.50	$ 15.00
Over 325 kWh	325	$ 17.00	$ 20.00	$ 17.00	$ 20.00

DSM Charge ($/kWh)	$ 0.003317

- includes DSM Expesne for the Test Year

Bill Impacts for RS Customers

			Including Fuel & DSM					Excluding Fuel				
			Monthly Margin or Base Rate		Increase / <Decrease>			Monthly Total Bill		Increase / <Decrease>		
Line No.	Monthly kWh	% of Customers	Pro Forma Present Rates	Proposed Rates	Amount	Percent	Proposed ¢ / kWh	Pro Forma Present Rates	Proposed Rates	Amount	Percent	Proposed ¢ / kWh
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	100	4.33%	$ 27.04	$ 31.34	$ 4.30	15.90%	0.31340	$ 22.88	$ 26.82	$ 3.94	17.22%	0.26820
2	200	5.17%	41.58	47.68	6.10	14.67%	0.23840	33.25	38.65	5.40	16.24%	0.19325
3	400	16.97%	75.15	85.36	10.21	13.59%	0.21340	58.50	67.30	8.80	15.04%	0.16825
4	600	18.46%	103.07	116.88	13.81	13.40%	0.19480	78.10	89.78	11.68	14.96%	0.14963
5	800	15.24%	129.82	147.24	17.42	13.42%	0.18405	96.53	111.11	14.58	15.10%	0.13889
7	1,000	11.55%	156.58	177.60	21.02	13.42%	0.17760	114.96	132.44	17.48	15.21%	0.13244
8	1,200	8.36%	183.34	207.95	24.61	13.42%	0.17329	133.39	153.77	20.38	15.28%	0.12814
9	1,500	8.19%	223.47	253.49	30.02	13.43%	0.16899	161.04	185.76	24.72	15.35%	0.12384
10	1,800	4.71%	263.61	299.03	35.42	13.44%	0.16613	188.69	217.76	29.07	15.41%	0.12098
11	2,000	1.96%	290.36	329.39	39.03	13.44%	0.16470	207.12	239.09	31.97	15.44%	0.11955
12	2,400	2.31%	343.88	390.10	46.22	13.44%	0.16254	243.98	281.75	37.77	15.48%	0.11740
13	2,700	0.93%	384.01	435.64	51.63	13.44%	0.16135	271.63	313.74	42.11	15.50%	0.11620
14	3,000	0.58%	424.15	481.18	57.03	13.45%	0.16039	299.28	345.73	46.45	15.52%	0.11524
15	4,000	0.82%	557.93	632.97	75.04	13.45%	0.15824	391.44	452.38	60.94	15.57%	0.11310
16	5,000	0.24%	691.71	784.76	93.05	13.45%	0.15695	483.60	559.02	75.42	15.60%	0.11180
17	7,000	0.13%	959.27	1,088.35	129.08	13.46%	0.15548	667.91	772.31	104.40	15.63%	0.11033
18	>7,000	0.05%										
	Average											
19	821		132.60	150.39	17.79	13.42%	0.18324	98.44	113.33	14.89	15.13%	0.13808

AES Indiana
Residential Bill Impacts - RH/RC Customers under Phase 2 Rates
Test year Ending December 31, 2026

Proposed Rates

		Including Fuel		Including Fuel & DSM		Excluding Fuel	
Energy Charge		Pro Forma Current Rate [1]	Proposed Rate	Pro Forma Current Rate [1]	Proposed Rate	Pro Forma Current Rate [1]	Proposed Rate
First 500 kWh		$ 0.145381	$ 0.160074	$ 0.145381	$ 0.163391	$ 0.103758	$ 0.118244
Over 500 kWh	500	$ 0.133782	$ 0.148475	$ 0.133782	$ 0.151792	$ 0.092159	$ 0.106645
Over 1,000	1000	$ 0.121368	$ 0.136061	$ 0.121368	$ 0.139378	$ 0.079745	$ 0.094231

[1] Includes riders rolled into base rates (TDSIC, ECCR, DSM, CAP, RTO and FAC)

Customer Charge					
0 to 325 kWh		$ 12.50	$ 15.00	$ 12.50	$ 15.00
Over 325 kWh	325	$ 17.00	$ 20.00	$ 17.00	$ 20.00

DSM Charge ($/kWh) $ 0.003317
- includes DSM Expesne for the Test Year

Bill Impacts for RH/RC Customers

			Including Fuel & DSM					Excluding Fuel				
			Monthly Margin or Base Rate		Increase / <Decrease>			Monthly Total Bill		Increase / <Decrease>		
Line No.	Monthly kWh	% of Customers	Pro Forma Present Rates	Proposed Rates	Amount	Percent	Proposed ¢ / kWh	Pro Forma Present Rates	Proposed Rates	Amount	Percent	Proposed ¢ / kWh
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	100	2.75%	$ 27.04	$ 31.34	$ 4.30	15.90%	0.31340	$ 22.88	$ 26.82	$ 3.94	17.22%	0.26820
2	200	3.14%	41.58	47.68	6.10	14.67%	0.23840	33.25	38.65	5.40	16.24%	0.19325
3	400	10.29%	75.15	85.36	10.21	13.59%	0.21340	58.50	67.30	8.80	15.04%	0.16825
4	600	13.60%	103.07	116.88	13.81	13.40%	0.19480	78.10	89.78	11.68	14.96%	0.14963
5	800	13.61%	129.82	147.24	17.42	13.42%	0.18405	96.53	111.11	14.58	15.10%	0.13889
6	1,000	12.07%	156.58	177.60	21.02	13.42%	0.17760	114.96	132.44	17.48	15.21%	0.13244
7	1,200	9.91%	180.85	205.48	24.63	13.62%	0.17123	130.91	151.29	20.38	15.57%	0.12608
8	1,500	10.97%	217.26	247.29	30.03	13.82%	0.16486	154.83	179.56	24.73	15.97%	0.11971
9	1,800	7.26%	253.67	289.10	35.43	13.97%	0.16061	178.76	207.82	29.06	16.26%	0.11546
10	2,000	3.39%	277.95	316.98	39.03	14.04%	0.15849	194.71	226.67	31.96	16.41%	0.11334
11	2,400	4.58%	326.50	372.73	46.23	14.16%	0.15530	226.60	264.36	37.76	16.66%	0.11015
12	2,700	2.24%	362.91	414.54	51.63	14.23%	0.15353	250.53	292.63	42.10	16.80%	0.10838
13	3,000	1.61%	399.32	456.36	57.04	14.28%	0.15212	274.45	320.90	46.45	16.92%	0.10697
14	4,000	2.84%	520.68	595.73	75.05	14.41%	0.14893	354.20	415.13	60.93	17.20%	0.10378
15	5,000	1.03%	642.05	735.11	93.06	14.49%	0.14702	433.94	509.36	75.42	17.38%	0.10187
16	7,000	0.55%	884.79	1,013.87	129.08	14.59%	0.14484	593.43	697.82	104.39	17.59%	0.09969
17	>7,000	0.15%										
	Average											
18	1,138		173.35	196.86	23.51	13.56%	0.17296	125.98	145.46	19.48	15.46%	0.12780

AES Indiana
Residential Bill Impacts - RS Customers with Phase 1 Credit
Test year Ending December 31, 2026

Proposed Rates

		Including Fuel		Including Fuel & DSM		Excluding Fuel	
Energy Charge		Pro Forma Current Rate [1]	Proposed Rate	Pro Forma Current Rate [1]	Proposed Rate	Pro Forma Current Rate [1]	Proposed Rate
First 500 kWh		$ 0.145381	$ 0.160074	$ 0.145381	$ 0.163391	$ 0.103758	$ 0.118244
Over 500 kWh	500	$ 0.133782	$ 0.148475	$ 0.133782	$ 0.151792	$ 0.092159	$ 0.106645

[1] Includes riders rolled into base rates (TDSIC, ECCR, DSM, CAP, RTO and FAC)

Customer Charge					
0 to 325 kWh		$ 12.50	$ 15.00	$ 12.50	$ 15.00
Over 325 kWh	325	$ 17.00	$ 20.00	$ 17.00	$ 20.00

DSM Charge ($/kWh)	$ 0.003317
Phase 1 Credit ($/kwh)	$ 0.009237

Bill Impacts for RS Customers

			Including Fuel & DSM					Excluding Fuel				
			Monthly Margin or Base Rate		Increase / <Decrease>			Monthly Total Bill		Increase / <Decrease>		
Line No.	Monthly kWh	% of Customers	Pro Forma Present Rates	Proposed Rates	Amount	Percent	Proposed ¢ / kWh	Pro Forma Present Rates	Proposed Rates	Amount	Percent	Proposed ¢ / kWh
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	100	4.33%	$ 27.04	$ 30.42	$ 3.38	12.49%	0.30416	$ 22.88	$ 25.90	$ 3.02	13.18%	0.25896
2	200	5.17%	41.58	45.83	4.25	10.23%	0.22916	33.25	36.80	3.55	10.68%	0.18401
3	400	16.97%	75.15	81.67	6.52	8.67%	0.20416	58.50	63.61	5.11	8.73%	0.15901
4	600	18.46%	103.07	111.34	8.27	8.02%	0.18556	78.10	84.24	6.14	7.86%	0.14040
5	800	15.24%	129.82	139.85	10.03	7.73%	0.17481	96.53	103.72	7.19	7.45%	0.12965
7	1,000	11.55%	156.58	168.36	11.78	7.53%	0.16836	114.96	123.20	8.24	7.17%	0.12320
8	1,200	8.36%	183.34	196.87	13.53	7.38%	0.16405	133.39	142.69	9.30	6.97%	0.11890
9	1,500	8.19%	223.47	239.63	16.16	7.23%	0.15976	161.04	171.90	10.86	6.75%	0.11460
10	1,800	4.71%	263.61	282.40	18.79	7.13%	0.15689	188.69	201.13	12.44	6.59%	0.11174
11	2,000	1.96%	290.36	310.92	20.56	7.08%	0.15546	207.12	220.62	13.50	6.52%	0.11031
12	2,400	2.31%	343.88	367.93	24.05	6.99%	0.15330	243.98	259.58	15.60	6.39%	0.10816
13	2,700	0.93%	384.01	410.70	26.69	6.95%	0.15211	271.63	288.80	17.17	6.32%	0.10696
14	3,000	0.58%	424.15	453.47	29.32	6.91%	0.15116	299.28	318.02	18.74	6.26%	0.10601
15	4,000	0.82%	557.93	596.02	38.09	6.83%	0.14901	391.44	415.43	23.99	6.13%	0.10386
16	5,000	0.24%	691.71	738.58	46.87	6.78%	0.14772	483.60	512.84	29.24	6.05%	0.10257
17	7,000	0.13%	959.27	1,023.69	64.42	6.72%	0.14624	667.91	707.65	39.74	5.95%	0.10109
18	>7,000	0.05%										
	Average											
19	821		132.60	142.81	10.21	7.70%	0.17400	98.44	105.75	7.31	7.42%	0.12884

AES Indiana
Residential Bill Impacts - RH/RC Customers with Phase 1 Credit
Test year Ending December 31, 2026

Proposed Rates

		Including Fuel		Including Fuel & DSM		Excluding Fuel	
Energy Charge		Pro Forma Current Rate [1]	Proposed Rate	Pro Forma Current Rate [1]	Proposed Rate	Pro Forma Current Rate [1]	Proposed Rate
First 500 kWh		$ 0.145381	$ 0.160074	$ 0.145381	$ 0.163391	$ 0.103758	$ 0.118244
Over 500 kWh	500	$ 0.133782	$ 0.148475	$ 0.133782	$ 0.151792	$ 0.092159	$ 0.106645
Over 1,000	1000	$ 0.121368	$ 0.136061	$ 0.121368	$ 0.139378	$ 0.079745	$ 0.094231

[1] Includes riders rolled into base rates (TDSIC, ECCR, DSM, CAP, RTO and FAC)

Customer Charge					
0 to 325 kWh		$ 12.50	$ 15.00	$ 12.50	$ 15.00
Over 325 kWh	325	$ 17.00	$ 20.00	$ 17.00	$ 20.00

DSM Charge ($/kWh)	$ 0.003317
Phase 1 Credit ($/kwh)	$ 0.009237

Bill Impacts for RH/RC Customers

			Including Fuel & DSM					Excluding Fuel				
			Monthly Margin or Base Rate		Increase / <Decrease>			Monthly Total Bill		Increase / <Decrease>		
Line No.	Monthly kWh	% of Customers	Pro Forma Present Rates	Proposed Rates	Amount	Percent	Proposed ¢ / kWh	Pro Forma Present Rates	Proposed Rates	Amount	Percent	Proposed ¢ / kWh
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	100	2.75%	$ 27.04	$ 30.42	$ 3.38	12.49%	0.30416	$ 22.88	$ 25.90	$ 3.02	13.18%	0.25896
2	200	3.14%	41.58	45.83	4.25	10.23%	0.22916	33.25	36.80	3.55	10.68%	0.18401
3	400	10.29%	75.15	81.67	6.52	8.67%	0.20416	58.50	63.61	5.11	8.73%	0.15901
4	600	13.60%	103.07	111.34	8.27	8.02%	0.18556	78.10	84.24	6.14	7.86%	0.14040
5	800	13.61%	129.82	139.85	10.03	7.73%	0.17481	96.53	103.72	7.19	7.45%	0.12965
6	1,000	12.07%	156.58	168.36	11.78	7.53%	0.16836	114.96	123.20	8.24	7.17%	0.12320
7	1,200	9.91%	180.85	194.40	13.55	7.49%	0.16200	130.91	140.21	9.30	7.10%	0.11684
8	1,500	10.97%	217.26	233.43	16.17	7.44%	0.15562	154.83	165.70	10.87	7.02%	0.11047
9	1,800	7.26%	253.67	272.47	18.80	7.41%	0.15137	178.76	191.19	12.43	6.96%	0.10622
10	2,000	3.39%	277.95	298.51	20.56	7.40%	0.14925	194.71	208.20	13.49	6.93%	0.10410
11	2,400	4.58%	326.50	350.56	24.06	7.37%	0.14607	226.60	242.19	15.59	6.88%	0.10091
12	2,700	2.24%	362.91	389.60	26.69	7.35%	0.14430	250.53	267.69	17.16	6.85%	0.09914
13	3,000	1.61%	399.32	428.65	29.33	7.34%	0.14288	274.45	293.19	18.74	6.83%	0.09773
14	4,000	2.84%	520.68	558.78	38.10	7.32%	0.13970	354.20	378.18	23.98	6.77%	0.09455
15	5,000	1.03%	642.05	688.93	46.88	7.30%	0.13779	433.94	463.18	29.24	6.74%	0.09264
16	7,000	0.55%	884.79	949.21	64.42	7.28%	0.13560	593.43	633.16	39.73	6.70%	0.09045
17	>7,000	0.15%										
	Average											
18	1,138		173.35	186.35	13.00	7.50%	0.16372	125.98	134.95	8.97	7.12%	0.11856

Residential Multi-Family Rate Evaluation

Customer Profile

Profile - Residential

	RS Unified	RS-NMF	RS-MF	RS-NMF+RS-MF
Customers	467,238	363,785	103,466	467,251
Consumption (MWh)	5,125,131	4,054,006	1,071,125	5,125,131
12CP (MW)	10,787	8,708	2,079	10,787
NCP (MW)	1,257	979	330	1,309

Per Customer

	RS Unified	RS-NMF	RS-MF	RS-NMF+RS-MF
kWh/Customer/Month	914	929	863	914
12CP/Customer	23.1	23.9	20.1	23.1
NCP/Customer	2.7	2.7	3.2	2.8

Per MWh

	RS Unified	RS-NMF	RS-MF	RS-NMF+RS-MF
12CP/MWh	2.10	2.15	1.94	2.10
NCP/MWh	0.25	0.24	0.31	0.26

RS = Residential
NMF = Non-Multi Family
MF = Multi Family

ACOS Results Summary

Revenue Requirement

	Un-Mitigated	Mitigated
RS-NMF	$583,475,322	$558,179,635
RS-MF	$153,744,613	$147,094,877
RS-NMF+RS-MF	$737,219,935	$705,274,511
RS Unified	$735,561,438	$705,274,511

Revenue Requirement per kWh			**% Difference from RS Unified**	
	Un-Mitigated	Mitigated	Un-Mitigated	Mitigated
RS-NMF	$0.143926	$0.137686	0.28%	0.05%
RS-MF	$0.143536	$0.137327	0.01%	-0.21%
RS Unified	$0.143521	$0.137611		

RS = Residential
NMF = Non-Multi Family
MF = Multi Family

Residential Multi-Family Rate Evaluation

Illustrative Rates

Billig Units				**% of Total**		
	RS-NMF	RS-MF	RS-NMF+RS-MF	RS-NMF	RS-MF	RS-NMF+RS-MF
Billed kwh						
First 500 kWh	1,906,996,026	517,887,274	2,424,883,300	47%	48%	47%
Over 500 kWh	1,430,955,644	360,659,065	1,791,614,708	35%	34%	35%
Over 1,000	715,998,930	192,578,658	908,577,588	18%	18%	18%
Total	4,053,950,599	1,071,124,997	5,125,075,596	100%	100%	100%
Bills						
0 to 325 kWh	738,029	242,846	980,875	17%	20%	17%
Over 325 kWh	3,627,232	998,746	4,625,979	83%	80%	83%
Total	4,365,261	1,241,592	5,606,853	100%	100%	100%

Illustrative Rates				**% Difference from Residential (RS Unified)**	
	RS-NMF	RS-MF	RS Unified	RS-NMF	RS-MF
Volumetric Charge ($/kWh)					
First 500 kWh	$0.125768	$0.124108	$0.125421	0.28%	-1.05%
Over 500 kWh	$0.114169	$0.112510	$0.113822	0.30%	-1.15%
Over 1,000	$0.101755	$0.100096	$0.101408	0.34%	-1.29%
Customer Charge					
0 to 325 kWh	$12.5	$12.5	$12.5	0.00%	0.00%
Over 325 kWh	$17.0	$17.0	$17.0	0.00%	0.00%

RS = Residential
NMF = Non Multi Family
MF = Multi Family

Illustrative Bill Impacts

Per Month

	Average Usage (kWh)	Change from RS ($)	Change from RS (%)
RS-NMF	929	$0.32	0.25%
RS-MF	863	-$1.13	-0.93%

Bill under Average Usage

Usage	RS Unified	RS-NMF	R-MF
929	$128.50	$128.82	$127.28
863	$120.99	$121.29	$119.86

Change from RS ($)

Usage	RS-NMF	RS-MF
929	$0.32	-$1.22
863	$0.30	-$1.13

Change from RS (%)

Usage	RS-NMF	R-MF
929	0.25%	-0.95%
863	0.25%	-0.93%

							Phase 2 Revenue Collected		Billing Units		Phase 1 Credit	
1	**Rate Class**	**Rate Code**	**Phase 2 - Mitigated Revenue Requirement**	**% of Total**	**Phase 1 - Allocated Revenue Requirement**	**Phase-1 Credit**	**Volumetric Charge**	**Demand Charge**	**kWh**	**kW**	**Volumetric Charge Credit ($/kWh)**	**Demand Charge Credit ($/kW)**
2	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
3	Residential Service (Rate RS) - Codes RS, RC, RH	RS	$ 951,862,747	46.3%	$ 902,111,985	$ 49,750,762			5,386,192,793		$ 0.00924	
4	Secondary Service (Small) (Rate SS)	SS	231,256,727	11.2%	219,169,692	12,087,035			1,304,660,668		$ 0.00926	
5	Municipal Device (Rate MD)	MD	373,910	0.0%	354,367	19,543			895,098		$ 0.02183	
6	Electric Space Conditioning-Secondary Service (Rate SH)	SH	84,414,711	4.1%	80,002,630	4,412,082			499,277,512		$ 0.00884	
7	Electric Space Conditioning-Schools (Rate SE)	SE	2,137,808	0.1%	2,026,072	111,736			13,731,937		$ 0.00814	
8	Water Heating-Controlled Service (Rate CB/CW)	CB	72,661	0.0%	68,864	3,798			446,196		$ 0.00851	
9	Water Heating-Uncontrolled Service (Rate UW)	UW	187,486	0.0%	177,687	9,799			1,133,848		$ 0.00864	
10	Secondary Service (Large) - (Rate SL)	SL	442,487,632	21.5%	419,360,246	23,127,386	189,681,983	246,025,045	3,234,222,568	8,746,002	$ 0.00311	$ 1.49
11	Primary Service (Large) - (Rate PL)	PL	131,703,125	6.4%	124,819,432	6,883,693	57,085,606	75,365,773	1,024,030,101	2,276,912	$ 0.00290	$ 1.72
12	Process Heating (Rate PH)	PH	3,060,428	0.1%	2,900,469	159,959	2,645,675		22,969,728		$ 0.00696	
13	High Load Factor (Rate HL-1) (Primary Distribution)	HL1	147,294,659	7.2%	139,596,047	7,698,612	69,133,464	77,347,264	1,262,126,058	2,255,022	$ 0.00288	$ 1.80
14	High Load Factor (Rate HL-2) (Sub transmission)	HL2	19,246,677	0.9%	18,240,716	1,005,961	9,546,514	9,263,230	178,648,530	367,588	$ 0.00286	$ 1.35
15	High Load Factor (Rate HL-3) (Transmission)	HL3	21,784,171	1.1%	20,645,584	1,138,588	11,913,519	9,617,756	226,974,058	384,710	$ 0.00278	$ 1.32
16	Automatic Protective Lighting (APL)	APL	10,529,253	0.5%	9,978,923	550,330			38,052,433		$ 0.01446	
17	Municipal Lighting (MU)	MU1	$ 11,545,324	0.6%	$ 10,941,888	$ 603,436			34,307,981		$ 0.01759	
18	**TOTAL SYSTEM**		**$ 2,057,957,320**	100%	**$ 1,950,394,600**	**$ 107,562,720**	**$ 340,006,763**	**$ 417,619,067**				
					TRUE							

19	Phase 1 - Revenue Requirement	$ 2,003,052,000
20	Less Total Other Revenues	18,826,000
21	Off-System Sales Margin	33,831,400
22	**Phase 1 - Base Rate Revenue Requirement**	**$ 1,950,394,600**

Indianapolis Power and Light Company
Illustrative Lighting Rate Design - LED v/s Non-LED
Rate Comparison

			Illustrative Rate - New Install ($/month)			Proposed Rate - Existing Light ($/month)		
	LED	Equivalent Non-LED	LED	Non-LED	Difference (%)	LED	Non-LED	Difference (%)
MU	LED COBRA HEAD 5000-6000 LUMENS	100 W HPS COBRA HEAD	$28.79	$31.84	11%	$20.43	$30.56	50%
MU	LED COBRA HEAD 6500-7500 LUMENS	150 W HPS COBRA HEAD	$29.48	$34.20	16%	$21.02	$33.61	60%
MU	LED COBRA HEAD 12500-13500 LUMENS	250 W HPS COBRA HEAD	$32.02	$40.88	28%	$25.74	$38.13	48%
MU	LED COBRA HEAD 20000-21500 LUMENS	400 W HPS COBRA HEAD	$36.32	$45.99	27%	$30.01	$44.82	49%
MU	LED TWIN WASH POST TOP 2 @ 6000-7500-LT	HPS TWIN WASHINGTON (100 W)	$61.93	$64.97	5%	$60.53	n/a	n/a
MU	LED WASH POST TOP 6000-7500 LUMENS	HPS WASHINGTON (100 W)	$35.97	$37.20	3%	$33.45	$38.92	16%

Indianapolis Power and Light Company
Illustrative Lighting Rate Design - LED v/s Non-LED

Illustrative Rate Build-up - New Installation

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
Line No.	**Rate**	**Rate Code**	**Watts with Ballast**	**Description**	**Installed Cost**	**Return**	**Depreciation, Property Tax, and Insurance**	**Fuel & Energy Expense**	**Demand Expense**	**Customer Expense**	**O&M Expense**	**Total Expenses**	**Proposed Annual Rate**	**Proposed Monthly Rate**
						[**E***(WACC)]* Revenue Conversion Factor	(**E***Depr)+ (**E***Tax Rate*.3)+ Insurance	Operating Hours*Fuel & Energy Component *(**C**/1000)	Demand Component***C**	Customer Component	O&M Component	(**G**+**H**+**I**+**J**+**K**)* Revenue Conversion Factor for Expense	**F+L (Rounded)**	**M/12**
	APL													
1	APL	300	46	LED COBRA HEAD 5000-6000 LUMENS	$657.21	$60.60	$20.54	$9.07	$10.50	$148.27	$58.06	$247.86	$308.52	$25.71
2	APL	301	50	LED COBRA HEAD 6500-7500 LUMENS	$711.04	$65.57	$22.22	$9.85	$11.41	$148.27	$58.06	$251.26	$316.80	$26.40
3	APL	302	102	LED COBRA HEAD 12500-13500 LUMENS	$757.73	$69.87	$23.68	$20.10	$23.28	$148.27	$58.06	$274.97	$344.88	$28.74
4	APL	303	174	LED COBRA HEAD 20000-21500 LUMENS	$901.95	$83.17	$28.18	$34.29	$39.71	$148.27	$58.06	$310.30	$393.48	$32.79
5	APL	304	116	LED AREA LIGHT 11500-16500 LUMENS	$752.72	$69.41	$23.52	$22.86	$26.47	$148.27	$58.06	$280.80	$350.16	$29.18
6	APL	305	186	LED AREA LIGHT 21000-26000 LUMENS	$781.37	$72.05	$24.41	$36.66	$42.45	$148.27	$58.06	$311.64	$383.64	$31.97
7	APL	306	65	LED TRAD. POST TOP 6000-7500 LUMENS	$681.68	$62.86	$21.30	$12.81	$14.83	$148.27	$58.06	$256.75	$319.56	$26.63
8	APL	307	138	LED TWIN WASH POST TOP 2 @ 6000-7500-LT	$3,626.26	$334.40	$113.31	$27.20	$31.49	$148.27	$58.06	$380.51	$714.96	$59.58
9	APL	308	69	LED WASH POST TOP 6000-7500 LUMENS	$1,288.67	$118.84	$40.27	$13.60	$15.75	$148.27	$58.06	$277.54	$396.36	$33.03
10	APL	313	91	LED FLOOD 11,500 - 16,500 LUMENS	$716.32	$66.06	$22.38	$17.93	$20.77	$148.27	$58.06	$268.96	$335.04	$27.92
11	APL	314	162	LED FLOOD 21,000 - 26,000 LUMENS	$814.72	$75.13	$25.46	$31.93	$36.97	$148.27	$58.06	$302.42	$377.52	$31.46
12	APL	132	123	100 W HPS COBRA HEAD	$714.72	$65.91	$19.12	$24.24	$28.07	$148.27	$51.01	$272.27	$338.16	$28.18
13	APL	131	186	150 W HPS COBRA HEAD	$699.81	$64.53	$18.72	$36.66	$42.45	$148.27	$51.01	$298.82	$363.36	$30.28
14	APL	130	303	250 W HPS COBRA HEAD	$903.13	$83.28	$24.16	$59.71	$69.15	$148.27	$51.01	$354.34	$437.64	$36.47
15	APL	129	469	400 W HPS COBRA HEAD	$751.94	$69.34	$20.11	$92.43	$107.03	$148.27	$51.01	$421.27	$490.56	$40.88
16	APL		246	HPS TWIN WASHINGTON (100 W)	$3,558.58	$328.16	$95.18	$48.48	$56.14	$148.27	$51.01	$401.39	$729.60	$60.80
17	APL		372	HPS TWIN WASHINGTON (150 W)	$3,434.03	$316.67	$91.85	$73.31	$84.89	$148.27	$51.01	$451.93	$768.60	$64.05
18	APL	162	123	HPS WASHINGTON (100 W)	$1,254.83	$115.71	$33.56	$24.24	$28.07	$148.27	$51.01	$286.80	$402.48	$33.54
19	APL	164	186	HPS WASHINGTON (150 W)	$1,192.56	$109.97	$31.90	$36.66	$42.45	$148.27	$51.01	$312.08	$422.04	$35.17
20	APL	88	303	250 W HPS FLOOD LIGHT	$559.17	$51.56	$14.96	$59.71	$69.15	$148.27	$51.01	$345.08	$396.60	$33.05
21	APL	89	469	400 W HPS FLOOD LIGHT	$768.77	$70.89	$20.56	$92.43	$107.03	$148.27	$51.01	$421.73	$492.60	$41.05

Indianapolis Power and Light Company
Illustrative Lighting Rate Design - LED v/s Non-LED

Illustrative Rate Build-up - New Installation

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
Line No.	Rate	Rate Code	Watts with Ballast	Description	Installed Cost	Return	Depreciation, Property Tax, and Insurance	Fuel & Energy Expense	Demand Expense	Customer Expense	O&M Expense	Total Expenses	Proposed Annual Rate	Proposed Monthly Rate
						[**E***(WACC)]* Revenue Conversion Factor	(**E***Depr)+ (**E***Tax Rate*.3)+ Insurance	Operating Hours*Fuel & Energy Component *(**C**/1000)	Demand Component***C**	Customer Component	O&M Component	(**G**+**H**+**I**+**J**+**K**)* Revenue Conversion Factor for Expense	**F+L (Rounded)**	**M/12**
	MU-1													
22	MU-1	200	46	LED COBRA HEAD 5000-6000 LUMENS	$657.21	$60.60	$17.58	$9.07	$12.80	$185.71	$58.06	$284.85	$345.48	$28.79
23	MU-1	201	50	LED COBRA HEAD 6500-7500 LUMENS	$711.04	$65.57	$19.02	$9.86	$13.92	$185.71	$58.06	$288.21	$353.76	$29.48
24	MU-1	202	102	LED COBRA HEAD 12500-13500 LUMENS	$757.73	$69.87	$20.27	$20.11	$28.39	$185.71	$58.06	$314.34	$384.24	$32.02
25	MU-1	203	174	LED COBRA HEAD 20000-21500 LUMENS	$901.95	$83.17	$24.12	$34.30	$48.43	$185.71	$58.06	$352.65	$435.84	$36.32
26	MU-1	204	116	LED AREA LIGHT 11500-16500 LUMENS	$752.72	$69.41	$20.13	$22.86	$32.29	$185.71	$58.06	$320.90	$390.36	$32.53
27	MU-1	205	186	LED AREA LIGHT 21000-26000 LUMENS	$781.37	$72.05	$20.90	$36.66	$51.77	$185.71	$58.06	$355.14	$427.20	$35.60
28	MU-1	206	65	LED TRAD. POST TOP 6000-7500 LUMENS	$681.68	$62.86	$18.23	$12.81	$18.09	$185.71	$58.06	$294.60	$357.48	$29.79
29	MU-1	207	138	LED TWIN WASH POST TOP 2 @ 6000-7500-LT	$3,626.26	$334.40	$96.99	$27.20	$38.41	$185.71	$58.06	$408.72	$743.16	$61.93
30	MU-1	208	69	LED WASH POST TOP 6000-7500 LUMENS	$1,288.67	$118.84	$34.47	$13.60	$19.21	$185.71	$58.06	$312.84	$431.64	$35.97
31	MU-1	209	91	LED FLOOD 11,500 - 16,500 LUMENS	$716.32	$66.06	$19.16	$17.94	$25.33	$185.71	$58.06	$307.96	$374.04	$31.17
32	MU-1	210	162	LED FLOOD 21,000 - 26,000 LUMENS	$814.72	$75.13	$21.79	$31.93	$45.09	$185.71	$58.06	$344.56	$419.64	$34.97
33	MU-1	221	123	100 W HPS COBRA HEAD	$714.72	$65.91	$19.12	$24.24	$34.24	$185.71	$51.01	$316.13	$382.08	$31.84
34	MU-1	218	186	150 W HPS COBRA HEAD	$699.81	$64.53	$18.72	$36.66	$51.77	$185.71	$51.01	$345.86	$410.40	$34.20
35	MU-1	215	303	250 W HPS COBRA HEAD	$903.13	$83.28	$24.16	$59.72	$84.34	$185.71	$51.01	$407.28	$490.56	$40.88
36	MU-1	212	469	400 W HPS COBRA HEAD	$751.94	$69.34	$20.11	$92.45	$130.55	$185.71	$51.01	$482.59	$551.88	$45.99
37	MU-1		246	HPS TWIN WASHINGTON (100 W)	$3,558.58	$328.16	$95.18	$48.49	$68.47	$185.71	$51.01	$451.45	$779.64	$64.97
38	MU-1		372	HPS TWIN WASHINGTON (150 W)	$3,434.03	$316.67	$91.85	$73.33	$103.55	$185.71	$51.01	$508.36	$825.00	$68.75
39	MU-1	225	123	HPS WASHINGTON (100 W)	$1,254.83	$115.71	$33.56	$24.24	$34.24	$185.71	$51.01	$330.66	$446.40	$37.20
40	MU-1	227	186	HPS WASHINGTON (150 W)	$1,192.56	$109.97	$31.90	$36.66	$51.77	$185.71	$51.01	$359.11	$469.08	$39.09
41	MU-1		303	250 W HPS FLOOD LIGHT	$559.17	$51.56	$14.96	$59.72	$84.34	$185.71	$51.01	$398.03	$449.64	$37.47
42	MU-1		469	400 W HPS FLOOD LIGHT	$768.77	$70.89	$20.56	$92.45	$130.55	$185.71	$51.01	$483.05	$553.92	$46.16

Indianapolis Power and Light Company
Illustrative Lighting Rate Design - LED v/s Non-LED
O&M Comparison

Type	O&M ($)	# of Fixtures	$ per Fixture
LED	$2,175,593	37,472	$58.06
Non-LED	$3,154,167	61,834	$51.01
Total	**$5,329,760**	**99,306**	**$53.67**

Type	Config	Total	% of Total	O&M
LED	OH	440,455	23.9%	$1,275,999
LED	UG	310,526	16.9%	$899,594
Non-LED	OH	510,025	27.7%	$1,477,544
Non-LED	UG	578,744	31.5%	$1,676,623
		1,839,749		**$5,329,760**

Total O&M	**5,329,760**

AES Indiana

Revenue Percentages

Test Year Ended December 31, 2026

TDSIC Allocation Factors

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Rate Class	**Rate Code(s)**	**Total Revenue Requirement**	**Percent**	**Class Revenue Allocation - Transmission**	**Percent**	**Class Revenue Allocation - Distribution**	**Percent**
Residential	RS, RC, RH	$ 951,862,747	46.25%	$ 53,714,577	42.22%	$ 264,249,462	59.00%
Small C&I	SS, SH, SE, CB, UW	318,443,304	15.47%	20,686,257	16.26%	70,113,672	15.65%
Large C&I - Secondary	SL, PH	445,548,059	21.65%	30,690,460	24.12%	72,824,474	16.26%
Large C&I - Primary	PL, HL	320,028,632	15.55%	21,943,914	17.25%	39,141,580	8.74%
Lighting	APL, MU1	$ 22,074,577	1.07%	$ 196,153	0.15%	$ 1,547,862	0.35%
TOTAL SYSTEM		$ 2,057,957,320	100.00%	$ 127,231,360	100.00%	$ 447,877,050	100.00%

Rate Code Allocations

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Rate Class	**Rate Code**	**Total Revenue Requirement**	**Percent**	**Class Revenue Allocation - Transmission**	**Percent**	**Class Revenue Allocation - Distribution**	**Percent**
Residential Service (Rate RS) - Codes RS, RC, RH	RS	$ 951,862,747	46.25%	$ 53,714,577	42.22%	$ 264,249,462	59.00%
Secondary Service (Small) (Rate SS)	SS	231,256,727	11.24%	14,457,882	11.36%	$ 51,747,789	11.55%
Municipal Device (Rate MD)	MD	373,910	0.02%	8,070	0.01%	$ 216,411	0.05%
Electric Space Conditioning-Secondary Service (Rate SH)	SH	84,414,711	4.10%	6,053,311	4.76%	$ 17,671,514	3.95%
Electric Space Conditioning-Schools (Rate SE)	SE	2,137,808	0.10%	155,952	0.12%	$ 404,100	0.09%
Water Heating-Controlled Service (Rate CB/CW)	CB	72,661	0.00%	2,359	0.00%	$ 22,298	0.00%
Water Heating-Uncontrolled Service (Rate UW)	UW	187,486	0.01%	8,683	0.01%	$ 51,559	0.01%
Secondary Service (Large) - (Rate SL)	SL	442,487,632	21.50%	30,500,039	23.97%	$ 72,209,423	16.12%
Primary Service (Large) - (Rate PL)	PL	131,703,125	6.40%	9,369,027	7.36%	$ 19,665,317	4.39%
Process Heating (Rate PH)	PH	3,060,428	0.15%	190,421	0.15%	$ 615,051	0.14%
High Load Factor (Rate HL-1) (Primary Distribution)	HL1	147,294,659	7.16%	9,278,957	7.29%	$ 19,476,263	4.35%
High Load Factor (Rate HL-2) (Sub transmission)	HL2	19,246,677	0.94%	1,759,023	1.38%	$ -	0.00%
High Load Factor (Rate HL-3) (Transmission)	HL3	21,784,171	1.06%	1,536,907	1.21%	$ -	0.00%
Automatic Protective Lighting - APL	APL	10,529,253	0.51%	120,145	0.09%	$ 763,903	0.17%
Municipal Lighting MU-1	MU1	$ 11,545,324	0.56%	$ 76,008	0.06%	$ 783,960	0.18%
TOTAL SYSTEM		$ 2,057,957,320	100.00%	$ 127,231,360	100.00%	$ 447,877,050	100.00%