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VERIFIED DIRECT TESTIMONY

OF

J. STEPHEN GASKE

SENIOR VICE PRESIDENT

CONCENTRIC ENERGY ADVISORS, INC.

ON BEHALF OF

INDIANAPOLIS POWER AND LIGHT COMPANY

SPONSORING WITNESS JSG ATTACHMENTS 1 THROUGH 10

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I. INTRODUCTION AND QUALIFICATIONS

Q1. Please state your name, business address, and job title.

A1. My name is J. Stephen Gaske and I am a Senior Vice President of Concentric Energy Advisors, Inc., 1300 19th Street, Suite 620, Washington, DC 20036.

Q2. Please describe your professional background and education.

A2. I have more than 30 years of experience as a consultant, researcher and professor in the field of public utility economics and finance. I hold a B.A. degree from the University of Virginia and an M.B.A. degree with a major in finance and investments from George Washington University. I also earned a Ph.D. degree from Indiana University where my major field of study was public utilities and my supporting fields were in finance and economics. A copy of my résumé is provided as IPL Witness JSG Attachment-1.

Q3. Have you presented expert testimony in other proceedings?

A3. Yes. I have testified or submitted expert testimony in more than 100 proceedings. Among these submissions have been testimony on issues such as cost allocation, rate design, pricing and generating plant economics before the Federal Energy Regulatory Commission ("FERC"), the U.S. Postal Rate Commission, the National Energy Board of Canada, and more than a dozen state and provincial public utility Commissions. These submissions include testimony on cost allocation and rate design issues for electric utilities in several Indiana Public Utility Commission proceedings. I also have testified or filed testimony or affidavits on numerous occasions before various regulatory bodies on topics such as rate of return, capital structure, revenue requirements, regulatory principles, competition and market power.

Q4. On whose behalf are you testifying?

A4. I am testifying on behalf of Indianapolis Power and Light Company ("IPL" or the "Company").

Q5. What is your assignment in this proceeding?

A5. IPL retained Concentric to conduct a fully-allocated cost-of-service study to determine the embedded costs of serving its various electric retail 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.

Q6. Please summarize the nature and purpose of your testimony?

A6. First, I will discuss the purpose of an Allocated Cost of Service Study ("ACOSS") and describe the Concentric Cost of Service Model ("Concentric Model") used in conducting IPL's electric cost of service study.

Second, I will 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 studies.

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

Fourth, I will present the class-by-class rate of return results and corresponding revenue surpluses or deficiencies from IPL'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 receive large rate increases if the unmitigated results of the ACOSS were to be used to set 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 customer impacts of the proposed rates.

Q7. Does your testimony include attachments?

A7. Yes. I am sponsoring the following attachments:

Attachment No.	Name
1	Résumé
2	Description of the ACOSS Model
3	Summary of Class Cost Allocation and Unit Costs
4	Proposed Mitigated Revenue Requirement by Class
5	Industrial Rate Design
6	Class Revenue Summary
7	Test Year Revenue Proofs at Current and Proposed Rates
8	Summary of Proposed Rate Design
9	Residential Bill Impacts
10	Analysis of LIHEAP Customer Usage

Q8. Did you submit any workpapers?

A8. Yes. I submitted the following workpapers:

Workpapers	Name
WP-1.0C	CONFIDENTIAL Cost of Service Model [Excel file]
WP-1.1	Cost Functionalization and Classification
WP-1.2	Functional Allocation Factors
WP-1.3	Allocation to Rate Schedules
WP-2.0	Class Allocation Factors – External [Excel file]
WP-2.1	Class Allocation Factors Summary
WP-2.2	Primary Secondary Study
WP-2.3	Minimum System Study
WP-2.4	Peak Demands
WP-2.5	Customer Account Analysis
WP-2.6	Uncollectibles Analysis
WP-2.7	Meters and Services
WP-3.0	Peak Demand Analysis [Excel file]
WP-3.1	FERC Tests for 12CP Allocator
WP-4.0C	CONFIDENTIAL Rate Design and Revenue Proof Calculations [Excel file]
WP-5.0	New Lighting Rate Design Calculations [Excel file]
WP-6.0	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.

II. ALLOCATED COST OF SERVICE STUDY

A. Introduction to ACOSS

Q9. Please describe the general approach used to develop the ACOSS?

A9. In this proceeding the purpose of the ACOSS is to allocate IPL's overall adjusted test year revenues and costs 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 historical 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.

In order to allocate costs to the various classes, Concentric reviewed IPL's expense and plant accounts and worked with various IPL 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.

Q10. Please describe the Concentric Model that was used in conducting the ACOSS filed in this proceeding.

A10. IPL has selected the Concentric Model for purposes of conducting the electric ACOSS in this general rate case. The same model was used in IPL's most recent rate case in Cause No. 44576. The Concentric Model was developed by Concentric on a proprietary basis for use in its consulting engagements. An informational brochure describing the components of Concentric's Model, basic parameters, reporting capabilities and key features accompanies this testimony as <u>IPL Witness JSG Attachment-2</u>.

Q11. Is an electronic copy of the Concentric Model provided to the Commission?

A11. Yes. A CD-Rom containing the Concentric Model in Excel format with formulas intact is included with the workpapers provided to the Commission as Confidential JSG Workpaper WP-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 workpapers WP-1.1, WP-1.2 and WP-1.3.

B. Principles of ACOSS Preparation

Q12. What is the guiding principle that should be followed when performing an ACOSS?

A12. Cost causation is the fundamental principle applicable to all cost studies for purposes of allocating costs to customer groups. Cost causation addresses the question of which customer or group of customers causes the utility to incur particular types of costs. 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.

Q13. What is the general framework of an ACOSS?

A13. As I indicated above, the ACOSS analysis is intended to establish cost responsibility among the various customer classes which the utility serves. The analysis should result in an appropriate allocation of the utility's total revenue requirement among the various customer classes. The most important theoretical principle underlying an ACOSS is that cost responsibility should follow cost causation. In other words, the costs assigned or allocated to particular customers should be those costs that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service.

Q14. What are the steps to performing an ACOSS?

A14. In order to establish the cost responsibility of each customer class, initially a three-step analysis of the utility's total operating costs must be undertaken. The three steps which are the predicate for an ACOSS are: (1) cost functionalization; (2) cost classification; and (3) cost allocation.

Q15. Please describe cost functionalization.

A15. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. IPL's primary functional cost categories associated with distribution electric service include: Production, Transmission, Primary Voltage Distribution, Secondary Voltage 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.

Q16. Please describe cost classification.

A16. The second step, classification of costs, further separates the functionalized plant and expenses according to the primary factors that determine the amount of costs incurred. These factors are: (1) the number of customers; (2) the need to meet the peak demand requirements that customers place on the system; and (3) the amount of electricity consumed by customers. These classification categories have been identified for purposes of the ACOSS as 1) Customer Costs; 2) Demand Costs and 3) Energy Costs, respectively.

Q17. 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?

A17. *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 or not 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, transformers and substations, or more localized distribution facilities which are designed to satisfy individual customer maximum demands.

Energy Costs are those costs that vary with the amount of kilowatt hours ("kWh") sold to customers. For example, included in the instant study are base fuel rates 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 IPL's costs are fixed with respect to energy usage and very little of its remaining delivery service cost structure is energy related.

Q18. What is required to appropriately classify costs as Customer, Demand, and Energy?

A18. Usually a determination on the classification of costs can be made simply by knowing the type of activities or assets that reside in a particular FERC account. In these instances, the entire account can be classified in 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 IPL's ACOSS is provided in the section discussing studies of relative costs below.

Q19. Please describe cost allocation.

A19. The final step, cost allocation, is the allocation of each functionalized and classified cost element to the individual customer or rate class that benefits from the cost. 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 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 that a customer consumes. These costs were allocated based on the amount of energy consumed, adjusted for losses of energy that occur in the transmission and distribution process.

Q20. How does the cost analyst establish the fully-allocated costs related to various utility services?

A20. To establish these relationships, the cost analyst 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.

Q21. Please explain the term "direct assignment."

A21. The term "direct assignment" means the assignment of costs to a specific customer or class of customers based on that customer's or class' 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, the cost analyst seeks to maximize the amount of plant and expense directly assigned to a particular customer or customer classes to avoid the need to rely upon other more generalized allocation methods. An alternative to direct assignment is an allocation methodology based on an analysis of factors that affect the relative costs of serving particular customer classes.

Q22. What prompts the analyst to elect to perform a study of the relative costs?

A22. When direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, then further analysis may 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.

Q23. 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?

A23. 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 must be derived to assign or allocate the remaining costs to the customer classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q24. Please explain the considerations relied upon in determining the cost allocation methodologies that are used to perform an ACOSS.

A24. 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. IPL'S ACOSS

Q25. Have you prepared attachments and workpapers that show the allocation of costs to the various rate classes?

A25. Yes. The results of the ACOSS are summarized in IPL Witness JSG Attachment-3. The functionalization and classification of costs is shown on IPL Witness JSG Workpaper 1.1 and the functional allocators used to assign various overhead costs to functions are shown on IPL Witness JSG Workpaper 1.2. Once the costs are functionalized and classified, they are allocated to rate classes. The details of those allocations are shown on IPL Witness JSG Workpaper 1.3 and the primary class-cost allocation factors are shown on

IPL Witness JSG Workpaper 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

Q26. What is the source of the cost data analyzed in IPL's ACOSS?

A26. All cost of service data have been extracted from the Company's total cost of service (*i.e.*, the basic rate revenue requirement) contained in this general rate case filing for the historical test year ending June 30, 2016. 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 company personnel.

Q27. Did you make any adjustments to the total cost of service as provided by IPL?

A27. I made an adjustment to eliminate a negative rate base that occurs for the APL and MU lighting rate codes. This is the result of negative net plant balances for account 371 – Installations on Customer Premises and account 373 – Street Lighting and Signal Systems. A negative rate base incorrectly suggests a negative cost to providing lamps and equipment to these classes. To remedy this I set the rate base for account 371 and 373 to zero. In doing so I needed to redistribute the negative rate base value to the other distribution accounts to ensure the total rate base was correct.

In addition, in IPL's last rate case,[1] costs were allocated separately to each of the rate codes in the large industrial rate class. In that case, costs were allocated separately to the customers being served at primary ("PL" and "HL1"), sub-transmission ("HL2") and

[1] *Indianapolis Power & Light Company*, Cause No. 44576.

transmission (“HL3”) voltage levels. However, in the ACOSS that I conducted for IPL in this proceeding, rate codes PL and HL have been consolidated. Therefore, costs are being allocated to a combined industrial rate class comprised of customers served under rate codes PL and HL. As noted above, customers generally are divided into customer classes based on the type and character of services that they require. After further examination of rates PL and HL, I determined that the type and character of services are very similar for the customers on the two rate schedules and therefore consolidated the rate codes for cost allocation purposes in the ACOSS. The revenue requirement for the consolidated rate class of PL and HL was then assigned to PL, HL1, HL2 and HL3 rate codes as part of the rate design process. The consolidated functionalized revenue requirement which was appropriately classified as either Customer, Demand or Energy-related in the ACOSS was allocated to the rate codes using either the number of customers, billing demand or energy usage adjusted for line losses at different service voltage levels. This allowed for a more appropriate cost allocation and better price signals as to the relative costs of serving the PL and HL rate codes than otherwise would have been achieved if the costs had been allocated to each rate code using the ACOSS.

B. <u>Functionalization and Classification of Costs</u>

Q28. How did you functionalize and classify IPL’s costs?

A28. The process starts with each of the Company’s FERC accounts and assigns the costs in each of these accounts to a specific function. In some instances, the costs in an account are first split into separate functions or classifications if the costs in the account are incurred to perform more than one function, or the costs in an account can be said to vary significantly with respect to more than one factor. For example, the accounts for distribution system poles, towers and fixtures, and conductors and conduits, have been separated into 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.

Plant and operations and maintenance 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” based on the relative amount of certain costs that are directly associated with each function. The specific functional allocators used to assign overhead costs have been selected to reflect the type of direct costs that each overhead account generally supports.

Q29. Do you have a workpaper that provides details of the functionalization and classification process?

A29. Yes. Details of the functionalization and classification process are shown on IPL Witness JSG Workpaper 1.1. Each account of the revenue requirement, 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, have split classifications to reflect 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.

Q30. Please explain the primary-secondary study.

A30. Because 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 IPL'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 cost of that pole type. Using the total costs of all poles by voltage, the ratio of primary poles to secondary poles was calculated. The results of this analysis is provided on IPL Witness JSG Workpaper 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 IPL's Geographic Information System ("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. Using the total costs of all conductors by voltage, the ratio of primary conductors to secondary conductors was calculated. The results of this analysis also are provided on IPL Witness JSG Workpaper 2.2 - Primary Secondary Study.

Q31. Please explain the Minimum System Study.

A31. 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 represents 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. Similar analysis was conducted for secondary poles. The results of this analysis is provided on IPL Witness JSG Workpaper 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. This total circuit miles of primary conductors was multiplied by the replacement cost of a minimum sized primary conductor to calculate the minimum system replacement cost of primary conductors. This was then compared to the total replacement cost of primary conductors to determine the portion of primary conductors that is customer-related and demand-related. Similar analysis was conducted for secondary conductors. The results of this analysis also are provided on IPL Witness JSG Workpaper 2.3 – Minimum System Study.

Q32. Please explain the functionalization of production O&M into fixed and variable components.

A32. 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 Accounts 502, 505, 506, 512, and 513 were variable. These expenses were calculated for the test year and it was determined that about ten percent of non-fuel production O&M expense was variable.

Q33. How are the costs then assigned to functions?

A33. The next step in the process is to spread the costs listed in the first column of costs on IPL Witness JSG Workpaper 1.1 – Cost Functionalization and Classification to the various columns that designate the classifications and functions. In addition, several categories of revenue are designated on IPL Witness JSG Workpaper 1.1 – Cost Functionalization and Classification so that they ultimately will be credited to the cost of service of the various rate classes.

Q34. How were direct costs functionalized?

A34. The direct costs of distribution plant and O&M expenses are distributed to each column of IPL Witness JSG Workpaper 1.1 – Cost Functionalization and Classification by directly assigning costs according 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.

Q35. How did the ACOSS allocate distribution-related O&M expenses?

A35. In general, these expenses were allocated based on the cost allocation methods used for the Company's corresponding plant accounts. A utility's distribution-related O&M expenses generally are thought to support the utility's corresponding plant in service accounts. Put differently, the existence of particular plant facilities necessitates the incurrence of operating 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.

Direct expenses related to Customer Accounts (Accounts 902-904), and Customer Service and Information Expenses (Accounts 907-910) are assigned to four sub-functions: Meter Reading, Customer Records and Collections, Uncollectible Accounts, and Customer Service and Information. Indirect Customer Accounts expenses (Accounts 901 and 905) are allocated to these customer functions according to the relative amount of direct costs associated with each function.

Q36. How are overhead costs functionalized?

A36. 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, 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.

Q37. How were taxes other than income taxes assigned to functions?

A37. All taxes, except for income taxes, were functionalized in a manner which reflected 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; (2) plant ratios; or (3) a combination of plant and operations and maintenance expenses.

Q38. How were income taxes assigned to functions?

A38. 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

Q39. What was the next step in the ACOSS?

A39. After functionalizing and classifying the costs as shown on IPL Witness JSG Workpaper 1.1 – Cost Functionalization and Classification, the functionalized and classified costs were allocated to the individual rate codes or classes on IPL Witness JSG Workpaper 1.3 – Allocation to Rate Classes.

(1) Allocation of Demand-related Costs

Q40. How were the demand-related costs allocated in the ACOSS?

A40. I utilized a coincident peak demand method to allocate generation and transmission costs, and a non-coincident peak demand method to allocate demand-related distribution system costs. "Coincident Peak" refers to the demand of a class at the time when the overall system demand is at a peak. "Non-coincident Peak" refers to the highest level of demand that an individual class experienced during the year or month. This non-coincident peak for a given class may coincide with the overall system peak, but in some instances it occurs at other times that are off-peak for the system as a whole. The factors used to allocate costs to rate classes are developed in IPL Witness JSG Excel Workpaper 2.0, and the resulting allocation factors are shown on IPL Witness JSG Workpaper 2.1 – Class Allocation Factors Summary. Coincident and Non-Coincident peak demands for each of the classes are also shown on IPL Witness JSG Workpaper 2.4.

Q41. What was the source of the data used to develop the demand-related allocation factors?

A41. These data were provided to Concentric by IPL based on information collected and calculated as part of the Company's ongoing load research program. Concentric then adjusted the data to reflect line losses at different voltage levels and balanced the data estimated from statistical sampling to match the known demand for the entire system. These peak demand calculations are shown on IPL Witness JSG Workpaper 3.0.

Q42. Which coincident peak demand allocation method was utilized?

A42. The coincident peaks during each of the twelve months of the test period ("12CP") were utilized to allocate demand-related costs associated with the production and transmission functions. This is the method that was used in the Company's last case and in addition, I applied the FERC's cost allocation tests to IPL's load characteristics. As shown on IPL Witness JSG Workpaper 3.1, IPL has consistently met two of the three tests in recent years, which indicates that the 12CP method continues to be appropriate.

Q43. Why have you used the non-coincident peak demands of customer classes to allocate the costs of demand-related distribution costs?

A43. Although the production and transmission facilities are designed to meet the coincident peak demands of the entire system, as the system moves further from the generating plants and closer to the ultimate retail consumers, the primary factor affecting the planning and sizing of facilities is the level of peak demands in local areas. To the extent that customer classes have their individual peaks at different times, the Company must plan and install facilities to accommodate those individual peaks. In addition, to the extent that these facilities may be used jointly by different classes, the non-coincident peak method ensures that all classes share in the costs of these facilities. Consequently, 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

Q44. How are the energy-related costs allocated in the ACOSS?

A44. 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, and where appropriate, energy losses that occur in serving customers at different voltage levels.

Q45. How were the energy and demand cost allocation data adjusted for line losses in the distribution system?

A45. Because some energy and power is 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 are 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-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

Q46. How have the customer-related costs been allocated in the ACOSS?

A46. 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 on IPL Witness JSG Workpaper 2.1 – Class Allocation Factors Summary. The general methods used to develop the customer-related allocation factors are discussed below.

Q47. How were metering costs allocated to rate classes?

A47. All non-lighting customers require a meter, but General Service and Industrial meters generally cost considerably more than 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 replacement costs of each type of meter. This provided an estimate of the relative cost of providing meters 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 IPL Witness JSG Workpaper 2.1 – Class Allocation Factors Summary that were used to allocate metering costs to each class. Further backup for the meter allocations is provided as IPL Witness JSG Workpaper 2.7 – Meters and Services Study.

Q48. How were service lines allocated to each class?

A48. For allocating the costs of the service lines IPL 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 IPL Witness JSG Workpaper 2.1 – Class Allocation Factors Summary and the additional backup is provided as IPL Witness JSG Workpaper 2.7 – Meters and Services Study.

Q49. How were customer service costs allocated?

A49. IPL 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 IPL Witness JSG Workpaper 2.1 – Class Allocation Factors Summary with additional information provided as IPL Witness JSG Workpaper 2.5 – Customer Account Analysis.

Q50. Are there any other methods used to assign customer-related costs?

A50. 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 IPL so there is no expectation that meter reading costs vary materially between rate classes. Further uncollectible costs were allocated based on the amount of uncollectibles by rate class category. Details relating to uncollectibles are provided in IPL Witness JSG Workpaper 2.6 – Uncollectibles Analysis.

IV. RESULTS OF IPL'S ACOSS

Q51. Please describe the results of the ACOSS with respect to rate of return under the Company's existing rate classes.

A51. <u>IPL Witness JSG Attachment-3</u> presents the summary results of the ACOSS and the relative rates of return produced by each class for the historical test year ending June 30,

2016. As shown on line 18 of this attachment (on pages 8 and 13), at present rates the ACOSS shows a wide variation in the rates of return by rate schedule.

Q52. 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?

A52. Line 31 of IPL Witness JSG Attachment-3 indicates 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.

V. RATE DESIGN

A. Rate Design Objectives and Principles

Q53. What are the primary objectives of a rate structure for the services that are offered by a regulated company?

A53. As a general matter, the following eight criteria of Professor James C. Bonbright have remained viable and resilient over the four decades since their first publication (*Principles of Public Utility Rates*, 1961, page 291):

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.

Q54. Are these foregoing general rate criteria for rate structures all consistent with one another?

A54. No, they need not be. By illustration, a given rate structure that embodies the ultimate in rate *stability* could soon become unacceptable with respect to other criteria, e.g., achieving a fair rate of return, or relative fairness among customer classes. Thus, there can be tensions and conflict among these rate criteria, based on the specific facts and circumstances of any company.

Q55. Does each of these foregoing general rate criteria carry equal importance and weight?

A55. No. I agree with Professor Bonbright's assessment (page 292) that the rate criteria designated as items (3), (6), and (8) above are the three primary ones. Many rate design and rate structure disputes revolve around the tensions that can arise between items (6) and (8), i.e., the potential conflict between standards of "fairness" and "efficiency" as among the affected customer classes. From these potential conflicts arise many current rate debates, such as the proper nature and form(s) of marginal-cost pricing. However, the importance of the "fair return" criteria for a rate structure is hard to overstate. A set of rates that putatively meet all of the other rate criteria, but that fail to generate an acceptable return on and return of capital, can jeopardize the basic viability of the operation and its ability to render service. Consequently, rates that comport with fair return standards are a predicate for a viable privately-owned operating entity that can seek to satisfy all of these other applicable rate criteria.

Q56. What are the principles and objectives of IPL for designing rates in this proceeding?

A56. IPL had three primary policy objectives in the development of the rates proposed in this proceeding: (1) the charge for any service rendered is reasonable and just; (2) the rates and charges should afford IPL an improved and reasonable opportunity to recover its revenue requirement and provide a fair return on its investment; (3) the rates should provide incentives for efficient usage by reflecting the manner in which costs are incurred as a result of customer usage decisions. Gradualism in the impacts of rate changes on customers was another important objective of the Company. Consequently, the Company decided to mitigate the impact of rate changes on any one rate schedule in this rate case so that the rates would be adjusted only part of the way in the direction of fully-allocated costs. To achieve that goal, I applied an equalized subsidy reduction amount, or percentage, for all of the rate classes which allowed for the largest subsidized class, the residential class, to have an overall rate increase less than ten percent and ensured that no customer class receives a revenue decrease. In addition, the level of customer charges for the residential and small commercial rate classes were not increased to a level that fully recovers fixed costs at this time, and the inclining block structure of their customer charges was retained, so as to mitigate the impacts on smaller customers in the residential and small commercial rate classes.

VI. DESCRIPTION OF PROPOSED CLASS REVENUE REQUIREMENTS

Q57. What total electric revenue requirement is the Company proposing in this proceeding?

A57. The Company has a total revenue requirement of approximately $1,410 million as shown on line 46 of <u>IPL Witness JSG Attachment-3</u>. Because the Company collects miscellaneous other revenue from ancillary charges and off-system sales, the proposed rates are designed to collect Base Rate revenue of approximately $1,376 million from the retail customers, as shown on line 49 of <u>IPL Witness JSG Attachment-3</u>.

Q58. Have you examined the percentage rate increases that would be required for each rate schedule according to the Allocated Cost of Service Study?

A58. Yes. Column C on pages 1 and 2 of <u>IPL Witness JSG Attachment-4</u> presents normalized revenues that IPL 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 ACOSS-based rates were to be applied. Although the overall rate increase that the Company is requesting is slightly more than seven percent, the ACOSS study indicates that the residential class would require a rate increase of more than 17 percent and the controlled water heating rate schedule would require a rate increase of as much as 73 percent. However, it was determined that the percentage rate increases experienced by individual rate schedules should be mitigated.

A. Mitigation of Class Impacts

Q59. How did you go about mitigating the class rate increases?

A59. I primarily used an approach that the IURC has approved in other utility rate cases, including IPL's last rate case. That approach first calculates the subsidy that each rate schedule is currently paying, as measured by 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 eliminate in the current rate case.

I was also guided by certain goals that the Company wanted to achieve. These included: (i) residential class rate increase less than 10 percent; and (ii) no rate schedule to receive a rate decrease. The resulting rate mitigation achieves these goals.

Q60. Please describe the calculations that you performed in mitigating the rate increases.

A60. The subsidy that each class and rate schedule is paying or receiving at current rates is shown in column G of IPL Witness JSG Attachment-4, page 1. That column, which is calculated on line 31 of IPL Witness JSG Attachment-3, shows the difference between (i) the total revenues that each rate schedule paid on a normalized basis during the test year (column C), and (ii) the revenues required if each rate schedule had generated an equal rate of return during the test year (line 20 of IPL Witness JSG Attachment-3). As shown on lines 18 and 19 of IPL Witness JSG Attachment-3, at present rates there is a wide variation in the rates of return generated by each rate schedule. For example, the residential rate of return is below the average rate of return for IPL during the test year, while the Secondary Small and the large commercial and industrial rate schedules generated an above-average rate of return.

In consultation with the Company I determined that reducing the current subsidies by 15 percent would provide nearly all rate schedules a rate increase less than 11 percent. Only the small, closed Controlled Water Heating (CB) rate schedule will experience a rate increase greater than two times the system average rate increase. The proposed rate increases for each rate code are shown in column I of IPL Witness JSG Attachment-4 and the percentage rate increases are shown in column J. The overall effect is to move classes and rate schedules closer to cost-of-service based rates in this proceeding while avoiding extreme rate increases for any single rate schedule.

Q61. What revenue requirement do you propose for each rate schedule in this proceeding?

A61. Column K of IPL Witness JSG Attachment-4 shows the proposed pro forma revenue for each rate class and rate schedule that is produced by the ACOSS analysis and my rate mitigation calculations. Page 2 of IPL Witness JSG Attachment 4 supports IPL Financial Exhibit IPL-OPER, Schedule REV10. A summary comparison of the mitigated and unmitigated revenue and required rate increases, with low load factor rate design costs reallocated among large Commercial and Industrial customers, is also shown on IPL Witness JSG Attachment-6.

Q62. What rate of return would be generated by each rate schedule at the proposed mitigated revenue requirements?

A62. The pro forma rates of return that would be produced by each rate schedule at the proposed mitigated revenue requirements are shown on line 64 of IPL Witness JSG Attachment-3. As discussed in the next section, the revenue requirements of the Large Commercial and Industrial rate codes are adjusted slightly from these levels in order to re-allocate a revenue deficiency that would occur as a result of the proposal to offer a new low-load factor rate design for large transmission voltage customers.

B. Rate Design

Q63. Were there certain general principles that you followed in designing rates for individual rate schedules?

A63. One principle that I applied was to move the components of the rate design closer to a level that reflects the marginal cost associated with usage. To do that, 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. In doing so, the proportion of the fixed costs recovered through variable energy charges was reduced.

For example, I generally 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 there is a customer charge in the rate, I generally set that at a level close to the level of customer-related costs calculated on IPL Witness JSG Attachment-3. For rate schedules without demand meters, I then set the energy charge at a level that would recover the remaining portion of the revenue requirement, generally through a declining block energy charge. For rate schedules that have demand meters, I designed the rates to recover most of the remaining fixed costs in a demand charge.

Energy charges for those rate schedules are designed to recover the fuel and variable energy costs, plus a margin of approximately one mill per kWh.

With respect to the residential customers I also tried to meet several additional criteria. First, a majority of the residential customers should experience a rate increase of less than $10.00 per month. Second, the smallest customers (in terms of least kWh of consumption) should receive increases of less than $8.00 per month. Third, customers who consume more energy generally should receive larger increases in their monthly bill than smaller customers. The result of this third criterion is that larger residential customers will experience a larger dollar increase, but a lower percentage increase, in their monthly bills than smaller customers.

Q64. How were the proposed rates for each rate schedule calculated?

A64. Detailed calculations for each rate component of each rate schedule and a proof of proposed revenues by rate schedule is shown on <u>IPL Witness JSG Attachment-7</u> and in IPL Witness JSG Workpaper 4.0C. As the attachment shows, the proposed total revenue requirement for each rate schedule will be achieved by implementing the proposed rates.

Q65. What levels of monthly customer charges are you proposing for the residential and small commercial rate schedules?

A65. The proposed rates would increase the Residential monthly customer charge for the small customers (< 325 kWh/month) from its current level of $11.25 to the proposed level of $19.00, and the customer charge for the larger customers would be increased from $17.00 to $27.00. Similarly, the Small Secondary service monthly customer charges would be increased from its current level of $30.00 to the proposed level of $40.00 for the smallest customers on that rate schedule, and the largest customers would receive an increase from the current level of $50.00 to the proposed level of $55.00. All of these changes are being made in order to more closely reflect the costs of serving each customer, as indicated by the ACOSS. For example, the unit costs resulting from the ACOSS are shown near the bottom of IPL Witness JSG Attachment-3. For the Residential class the cost-based customer charge would be approximately $83 and for the Small Secondary rate schedule the cost-based customer charge would be approximately $160. Thus, although the increases in customer charges for these rate schedules 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. This increase in customer charges 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."[2]

Q66. How are you proposing to recover fixed costs in the variable energy charge component of the residential and small commercial rate schedules?

A66. The existing declining-block rate structure for these two rate schedules is retained in the proposed rates. For the residential (RS) class the rates per kWh are highest 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

[2] *Indianapolis Power and Light Company*, Cause No. 44576 (IURC 3/16/16), page 72.

kWh consumed each month will be charged at a higher rate, and a somewhat lower rate will be charged for amounts over 5,000 kWh.

Because the residential and small commercial customers generally do not have meters that measure their peak monthly demand and allow fixed, demand-related costs to be recovered through a demand charge, a declining block rate structure is a second-best way to recover the fixed costs that are not recovered in the customer charge. IPL'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 of most customers. This blocking structure provides better price signals for efficient consumption and also reduces the variability of the Company's earnings associated with year-to-year fluctuations in usage.

Q67. How did you design the rates for large industrial customers?

A67. In the cost allocation process, costs were allocated to the PL and HL classes as a single group. I then designed rates by recognizing that the primary driver of differences in their costs of service were related to differences in voltage levels and line losses, usage of different portions of the transmission and distribution system, and different metering costs. The calculation of the cost of service for each of the rate codes in this group are shown on <u>IPL Witness JSG Attachment-5</u> and the "Industrial Cost Allocation" tab of IPL Witness JSG Workpaper 4.0C.

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

Second, the allocated Distribution demand-related costs were assigned to the PL and HL1 customers who take service at a primary distribution voltage. 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.

Finally, credits for Other Revenues and adjustments for rate mitigation adjustment and the low load factor rate recovery (discussed below) were assigned to each rate code.

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 IPL Witness JSG Workpaper 4.0C. These final rate design calculations are also shown in IPL Witness JSG Attachment-7.

Q68. What other changes have you made to the rate design?

A68. One proposed change is to implement a low load factor rate option for customers who take service at transmission voltage. The large rate increase for low load factor customers due to an increase in the demand charge was a concern raised by the IURC in the Company's last rate proceeding and the Commission ordered the Company to present an industrial low load factor rate option in its next base rate proceeding, or discuss why a low load factor rate should not be implemented.[3]

The two primary arguments against implementing a low load factor rate are that it obscures price signals for efficient usage, and that it shifts costs to other customers by reducing the bill of the low load factor customers. Nevertheless, IPL is proposing to implement a low load factor rate in this proceeding. The low load factor rate would be available to transmission voltage customers on rate HL with an annual average billing load factor less than 15 percent during the preceding 12 months. The overall effect of the low load factor rate would be to mitigate the large increase in total bill that a low load factor customer would otherwise experience due to the proposed increase in the rate HL3 demand charge.

The demand charge for the low load factor rate was set equal to 72.50 percent of the proposed demand charge for Rate HL3 (i.e., $15.33 instead of $21.14 per kW). The low load factor energy charge then was set equal to an amount that would recover the total HL3 revenue requirement if all HL3 customers were to be charged the low load factor rate. The Company's goal in developing the low load factor rate design was to ensure that the largest increase to any low load factor customer that is served on the high load

[3] *Indianapolis Power and Light Company*, Cause No. 44576 (IURC 3/16/16), page 72.

factor rate schedule did not exceed approximately 25 percent. Calculation of the low load factor rate and the anticipated revenue shortfall is shown on "Low LF for Rate HL3 (HL4)" tab of Confidential IPL Witness JSG Workpaper 4.0C.

The revenue shortfall associated with the low load factor rate was calculated by first calculating the revenue to be collected from high load factor customers on Rate HL3, plus the revenue to be collected from low load factor customers that are charged the low load factor rate (to be designated as rate code "HL4"). This proposed revenue was then subtracted from the overall revenue requirement for Rate HL3 to determine the amount of the revenue shortfall.

Q69. How do you propose to recover the revenue shortfall associated with the low load factor rate?

A69. The only customer(s) that will be on the low load factor rate are ones that will pay a significantly lower overall bill than they would if they were on the regular rate. The anticipated revenue shortfall associated with the customers who will be moved to the low load factor rate has been allocated to the regular rate large industrial customers on rate codes SL, PL, PH, HL1, HL2 and HL3 on the basis of their pro rata kWh usage. The calculation of the shortfall and allocation of the shortfall costs to other customers is shown on IPL Witness JSG Workpaper 4.0C. On column G of IPL Witness JSG Attachment-6, these shortfall amounts are then added to the revenue requirement for the other customers in the Large Commercial and Industrial rate class to ensure that the Company will have an opportunity to recover the total revenue requirement.

Q70. Is IPL proposing to change the lighting provisions in its tariff?

A70. IPL is proposing to add an option for several LED lights to its tariff and eliminate the option of New customer-owned lights. Other than that, the Company is proposing to continue the service offerings used in the Company's last rate case which included developing a set of rates that would apply to all existing "vintage" lights, and a different set of rates that would apply to new lights installed after March 16, 2016, the date that rates were implemented in IPL's last base rate proceeding. This approach reflects the fact that the costs of providing service for a new light are considerably higher than the costs and rates associated with the existing lights. However, the Company is also proposing that the lights that have been installed after the implementation of the rates approved in the last proceeding ("already-installed New lights") receive the same set of rates as the new lights that will be installed after the conclusion of this proceeding. The already-installed New lights were installed within the last year and have experienced only a small amount of depreciation. Therefore, in this proceeding, the Company is proposing a set of rates that would apply to all "Vintage" lights that were installed prior to the implementation of new base rates in Docket No. 44576, and a different set of rates that would apply to all "New" lights installed after that date.

Q71. How were the rates for "Vintage" lights designed?

A71. Rates for the Vintage Automatic Protective Lights (APL) and Municipal Lights (MU) were designed by applying an across-the-board increase of approximately 2.6 percent to each of the Municipal Lights and 3.4 percent to each of the APL lights so as to recover the total lighting revenue requirement. These percentages differ slightly from the overall percentage increases shown on IPL Witness JSG Attachment-4 because the total revenue requirement for APL and MU included the costs associated with the already-installed

New lights. Because these already-installed lights will be charged the proposed rates for New lights, the revenues associated with these New Lights was credited to the cost of service that must be recovered from the Vintage lights. The remaining revenue shortfalls for the lighting classes were then allocated to the Vintage lights in the APL and MU rate schedules. Calculation of these proposed Vintage rates in hardcopy format is shown toward the end of IPL Witness JSG Attachment-7, and an excel version is provided in IPL Witness JSG Workpaper 4.0C.

Q72. How were the rates for "New" lights designed?

A72. An allocated cost of providing and serving each type of New light was determined using the results of the ACOSS study and the current installation cost of each type of lamp. These calculations are shown in IPL Witness JSG Workpaper 5.0. For example, an annual capital cost recovery factor was applied to the installed cost of a new light of each type in the tariff. The capital cost recovery factor provides for an annual return, plus depreciation and taxes related to a new light. In addition, the cost of maintenance, customer service costs for each lamp, the demand-related costs per watt, and the energy-related costs per kWh were calculated from data in the ACOSS study. These various costs per unit were then applied to the demand and energy characteristics of each light to calculate a cost-based rate for each type of new light offered in the tariff.

Q73. How were the rates for New LED lights designed?

A73. The LED lighting rates were designed in the same manner as the other New lights with one exception. The Operation and Maintenance component of the LED rate calculation was reduced to reflect an assumption that the O&M costs per LED light will be 75 percent of the level of the O&M for other lights.

C. Backup and Maintenance Service -- Rider Nos. 10 and 11

Q74. Is IPL proposing to change the provisions of Backup and Maintenance Service Rider Nos. 10 and 11?

A74. No. Backup Service, Rider No. 10, and Maintenance Service, Rider No. 11, are provided under Rate Schedules CGS and REP. The Company informs me that no service has been, or is currently being provided, pursuant to Rider Nos. 10 or 11. However, while IPL has not proposed any changes to the current Backup and Maintenance Service Rider Nos. 10 and 11, the Company has informed me that it will work with customers in the future, who anticipate the need for backup or maintenance service, to discuss possible rate design alternatives that fit the unique circumstances of that customer need.

D. Rider No. 14 - Interruptible Power Credit

Q75. Are you proposing any changes to the amount of the credit that will be offered to customers who elect to take service under Interruptible Rider No. 14?

A75. No. There are no customers currently taking service under Rider No. 14 and no change is being proposed to the current amount of the credit.

VII. REVENUE PROOF AND TYPICAL BILLS

Q76. Do you have an attachment that shows the rate components and revenue that will be collected from each rate schedule at the proposed rates?

A76. Yes. IPL Witness JSG Attachment-7 demonstrates that the targeted total revenue for each rate schedule will be achieved using the proposed rates and normalized test period volumes. Note that detailed calculations for customers taking service at transmission voltage levels are considered confidential and are omitted from Attachment-7. Those calculations can be found in IPL Witness JSG Workpaper 4.0C. IPL Witness JSG Attachment-8 summarizes the new non-lighting rates that are being proposed in this proceeding.

Q77. Do you have an attachment that shows how the proposed rates will affect various residential customers?

A77. Yes. The typical bill impacts for residential customers are shown on IPL Witness JSG Attachment-9. It can be seen in Col. E of that attachment that the smallest residential customers will experience an increase in their monthly bill of less than $ 8.00 per month and a majority of customers will experience a rate increase of less than $10.00 per month. A typical customer who uses 1,000 kWh per month will experience an increase of $10.18 per month in its bill, which is an increase of approximately 9.3 percent.

Q78. Have you examined how the proposed changes to the residential rate will affect low income customers?

A78. Yes. IPL Witness JSG Attachment-10 shows a comparison of the usage characteristics of customers on the Low Income Heating Energy Assistance Program ("LIHEAP") with the characteristics of non-LIHEAP customers. The average LIHEAP customer uses only five percent less energy than a regular customer (891 v. 940 kWh), and the distribution of their usage levels is remarkably similar. For example, 19 percent of LIHEAP customers use less than 400 kWh per month and 19 percent of regular customers also use less than 400 kWh per month. At the other end of the scale, 10 percent of LIHEAP customers use more than 1,600 kWh per month, while 13 percent of regular customers use more than 1,600 kWh per month. This indicates that low-income customers are <u>not</u> more likely to be low-usage customers, and that many low-income customers have high usage. In other words, an increase in the residential customer charge, with a corresponding reduction in the energy charge, will not have a significantly disproportionate impact on low-income customers. Moreover, the many low-income customers who have above-average usage, and who pay the highest electric bills, will benefit from a rate design that more appropriately reflects the cost of service.

VIII. SUMMARY AND CONCLUSIONS

Q79. Do the proposed rate levels and structure establish rates that are just, reasonable, and not unreasonably preferential or discriminatory?

A79. Yes. In my opinion, the proposed rate structure and rates are just, reasonable, and not unreasonably preferential or discriminatory. Further, the proposed rate structure and rates should provide IPL a reasonable opportunity to earn the required return on its invested capital and recover its necessary and reasonable operating expenses.

Q80. Does this conclude your prepared Direct Testimony?

A80. Yes, it does.

VERIFICATION

I. J. STEPHEN GASKE, SENIOR VICE PRESIDENT, Concentric Energy Advisors, Inc., affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

J. Stephen Gaske

December 22, 2016

J. Stephen Gaske, Ph.D.
Senior Vice President

Steve Gaske has more than 30 years of experience as an economic consultant, researcher, and professor in the fields of public utility economics, finance, and regulation. Dr. Gaske has provided consulting services in more than 300 regulatory, antitrust, tax, and civil proceedings. In addition, he has presented expert testimony in more than 100 state, provincial, and federal regulatory commission hearings in Canada, the U.S. and Mexico.

AREAS OF EXPERTISE

His specialty is the application to regulated industries of inter-related principles from economics, finance and regulatory theory. His areas of expertise include:

- Finance, cost of capital, and risk analysis;
- Rate design, cost allocation, cost of service, and pricing of services;
- Energy markets and the economics of public utilities and energy infrastructure;
- Competition and antitrust principles; and
- Regulatory economics, rules, and policies.

INDUSTRY EXPERTISE

His work has involved:

- Most of the major natural gas pipelines in North America;
- Many electric utilities;
- Many natural gas distribution companies;
- Several major oil pipelines;
- Railroads;
- Postal Service;
- Telephone and satellite telecommunications companies; and
- Sewer and water companies.

REPRESENTATIVE PROJECT EXPERIENCE

Some of the projects on which Dr. Gaske has worked include:

- Advisor to numerous U.S. and Canadian pipelines on economics, pricing strategies and regulatory matters;
- Development of computerized cost of service models for calculating both traditional and levelized rates for gas and oil pipelines, and rates for electric utilities;
- On behalf of a new, greenfield pipeline designed to carry Canadian gas to U.S. New England markets he served as the rate and financial advisor during the development, permitting and financing stages.
- A variety of White Papers on technical aspects of calculating the allowed rate of return for regulated companies, including white papers submitted in proceedings involving FERC generic rate of return for

electric utilities, FERC rate of return for gas and oil pipelines, Canadian rate of return for pipelines and utilities;

- An analysis of the applicability of various finance theories to telephone ratemaking by the U. S. Federal Communications Commission;
- A study of the economic structure, risks and cost of capital of the satellite telecommunications industry;
- Author of several issues of the H. Zinder & Associates Summary of Natural Gas Pipeline Rates;
- Several studies of regional natural gas market competition, market power, pricing and capacity needs;
- An evaluation of Federal Energy Regulatory Commission policies designed to promote liquidity in the natural gas commodity markets;
- Numerous studies of electric rate, regulatory and market issues such as canceled plant treatment, time-differentiated rates, non-utility generation, competitive bidding, and open-access transmission;
- Author of two updates of the Edison Electric Institute Glossary of Electric Utility Terms;
- Several studies of pricing, contract provisions, competitive bidding programs, and transmission practices for independent electric generation; and,
- Several reports and projects on incentive regulation and the application of price cap regulation to both electric and natural gas companies.

LITIGATION SUPPORT AND EXPERT TESTIMONY

Dr. Gaske has testified or filed testimony or affidavits in more than 100 regulatory proceedings on the following topics:

Commission	Topic
Alaska Regulatory Commission	Oil Pipeline Rate of Return/Rate Base
Alberta Energy and Utilities Board	Gas Pipeline Cost Allocation/Rate Design
Alberta Utilities Commission	Utility Cost of Capital; Gas Pipeline Contracts and Market Power
Colorado Board of Assessment Appeals	Property Tax Discount Rate
U.S. Economic Regulatory Administration	Gas Distribution Rate Design
U. S. Federal Energy Regulatory Commission	Electric Transmission Rate of Return; Gas Pipeline Cost Allocation and Rate Design, Rate of Return and Capital Structure, Competition, Revenue Requirements; Oil Pipeline Rate of Return, Pricing and Tariff Provision
Idaho Public Service Commission	Gas Distribution Rate of Return
Indiana Utilities Regulatory Commission	Electric Cost Allocation/Rate Design
Iowa Utilities Board	Electric Avoided Costs/Externalities
Maine Public Utilities Commission	Electric Rate Design/Demand Management

Comision Reguladora de Energia de México	Gas Pipeline Rate of Return
Montana Public Service Commission	Electric/Gas Distribution Rate of Return; Electric Cost Allocation and Rate Design
Minnesota Public Utilities Commission	Gas Distribution Rate of Return
National Energy Board of Canada	Gas Pipeline Cost Allocation and Rate Design; Oil Pipeline Service Structure and Rates
New Mexico Regulatory Commission	Electric Rate of Return
New York Public Service Commission	Gas Pipeline Capital Structure
New Brunswick Energy and Utilities Board	Gas Distribution Ratemaking
North Dakota Public Service Commission	Electric/Gas Distribution Rate of Return; Natural Gas Market Pricing; Electric Cost Allocation and Rate Design
Nova Scotia Utility and Review Board	Cost Allocation and Pricing of Bridge Access
Ontario Energy Board	Rate of Return; Access to and Pricing of Gas Pipeline Expansions; LNG Regulation
U.S. Postal Rate Commission	Postal Pricing/Rate Design
Régie de l'énergie du Québec	Rate of Return/Regulatory Principles
South Dakota Public Utilities Commission	Gas Distribution Rate of Return
Texas Public Utilities Commission	Electric Cost Allocation and Rate Design
Texas Railroad Commission	Gas Pipeline Cost Allocation/Rate Design
Washington Utilities and Transportation Comm.	Gas Distribution Rate of Return
Wisconsin Public Service Commission	Electric Generation Economics
Wyoming Public Service Commission	Electric/Gas Distribution Rate of Return
Wyoming Board of Equalization	Property Tax Discount Rate

TEACHING/SPEAKING ENGAGEMENTS

Dr. Gaske has spoken on utility finance and economic issues before numerous professional groups. From 1983-1986, he served as Coordinator of the Edison Electric Institute Electric Rate Fundamentals Course. He has lectured on marginal cost estimation for electric utilities at the EEI rate course, and on both low-income rates and natural gas pipeline cost allocation and rate design before the American Gas Association Gas Rate Fundamentals Course. In addition, Dr. Gaske has taught college courses in Public Utility Economics, Transportation, Physical Distribution, Financial Management, Investments, Corporate Finance, and Corporate Financial Theory.

PROFESSIONAL HISTORY

CONSULTING

Concentric Energy Advisors, Inc. (2008 – present)
Senior Vice President

H. Zinder & Associates (1988 – 2008)
President/Senior Vice-President/Consultant

Independent Consulting on Public Utility Issues (1982 - 1988)

Olson & Company, Inc. (1980 – 1981)
Public Utility Consultant

H. Zinder & Associates (1977 – 1980)
Research Assistant and Supervisor of Regulatory Research

ACADEMIC/TEACHING

Trinity University (1986 – 1988)
Assistant Professor of Finance

Indiana University School of Business (1982 - 1986)
Associate Instructor of Public Utilities and Transportation

Northern Virginia Community College (1978)
Lecturer in Accounting

EDUCATION

Ph.D., Indiana University School of Business, 1987
M.B.A., George Washington University, 1977
B.A., University of Virginia, 1975

PROFESSIONAL ASSOCIATIONS

American Economic Association
American Finance Association
American Gas Association Rate Committee (1989-2001)
Energy Bar Association
Financial Management Association

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 single 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. Text is shaded blue to indicate an item that is an external user input and black to indicate that a cell is calculated.

- **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. There are currently options for 15 different (external) functional categories built into the model. 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 15 worksheets as follows:

1. CONTROLS – Contains buttons to run the macros to calculate the model and print various worksheets are also on this worksheet.

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 model allows for two cost alternatives but more can be added with minor modifications.

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. MITIGATION – Summarizes the current revenues from each class, the calculated cost of service the amount by which current rates over- or under-recover costs, and calculates an amount of the

current subsidies to keep for each class in order to mitigate the amount of the proposed rate increases for individual classes.

15. 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 <u>may</u> 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. The model can currently handle a maximum of 59 functional/allocation factors.

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	$ 5,594,471,211	$ 2,663,463,768	$ 827,015,107	$ 1,971,871,629	$ 132,120,707
2	Accumulated Reserve	(2,744,382,545)	(1,312,180,511)	(411,145,034)	(900,214,231)	(120,842,768)
3	Other Rate Base Items	191,307,000	87,303,757	27,781,938	72,319,176	3,902,129
4	Total Rate Base	$ 3,041,395,666	$ 1,438,587,013	$ 443,652,012	$ 1,143,976,574	$ 15,180,068
	Revenues at Current Rates					
5	Retail Sales	$ 1,284,926,154	$ 522,771,476	$ 194,258,177	$ 551,386,502	$ 16,510,000
6	Other Revenue	19,490,510	11,050,032	2,493,938	5,312,919	633,621
7	Sales for Resale	14,823,947	6,941,942	2,083,380	5,763,239	35,386
8	Total Revenues	$ 1,319,240,611	$ 540,763,449	$ 198,835,495	$ 562,462,660	$ 17,179,007
	Expenses at Current Rates					
9	Operations & Maintenance Expenses	$ 417,108,323	$ 204,133,443	$ 59,697,164	$ 143,225,806	$ 10,051,910
10	Depreciation Expense	207,193,006	100,616,687	31,254,967	73,715,637	1,605,715
11	Amortization Expense	13,490,249	6,339,070	1,915,489	5,146,156	89,533
12	Taxes Other Than Income Taxes	47,883,249	22,974,738	7,050,186	16,895,255	963,070
13	Fuel Expenses	436,635,496	160,818,949	58,217,508	214,124,577	3,474,462
14	Non-FAC Trackable Fuel Expenses	11,630,446	4,283,698	1,550,714	5,703,488	92,545
15	Income Taxes	29,130,534	1,139,360	7,576,582	20,276,646	137,946
16	Total Expenses - Current	$ 1,163,071,303	$ 500,305,945	$ 167,262,611	$ 479,087,566	$ 16,415,181
17	Current Operating Income	156,169,308	40,457,504	31,572,885	83,375,094	763,826
18	Return at Current Rates	5.13%	2.81%	7.12%	7.29%	5.03%
19	Index Rate of Return	1.00	0.55	1.39	1.42	0.98
	Revenue Requirement at Equal Rates of Return at Current Rates					
20	Required Return	5.13%	5.13%	5.13%	5.13%	5.13%
21	Required Operating Income	$ 156,169,308	$ 73,868,435	$ 22,780,603	$ 58,740,805	$ 779,465

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	$ 417,108,323	$ 204,133,443	$ 59,697,164	$ 143,225,806	$ 10,051,910
23	Depreciation Expense	207,193,006	100,616,687	31,254,967	73,715,637	1,605,715
24	Amortization Expense	13,490,249	6,339,070	1,915,489	5,146,156	89,533
25	Taxes Other than Income	47,883,249	22,974,738	7,050,186	16,895,255	963,070
26	Fuel Expenses	436,635,496	160,818,949	58,217,508	214,124,577	3,474,462
27	Non-FAC Trackable Fuel Expenses	11,630,446	4,283,698	1,550,714	5,703,488	92,545
28	Income Taxes	29,130,534	13,778,808	4,249,306	10,957,025	145,395
29	Total Expense - Required	$ 1,163,071,303	$ 512,945,394	$ 163,935,334	$ 469,767,944	$ 16,422,631
30	Total Revenue Requirement at Equal Return	$ 1,319,240,611	$ 586,813,829	$ 186,715,937	$ 528,508,749	$ 17,202,095
31	Current Subsidy	$ -	$ (46,050,380)	$ 12,119,558	$ 33,953,910	$ (23,088)
	Revenue Requirement at Equal Rates of Return at Proposed Rates					
32	Required Return	7.03%	7.03%	7.03%	7.03%	7.03%
33	Required Operating Income	$ 213,743,000	$ 101,100,921	$ 31,178,946	$ 80,396,309	$ 1,066,824
34	Operating Income (Deficiency)/Surplus	$ (57,573,692)	$ (60,643,417)	$ 393,938	$ 2,978,785	$ (302,998)
	Expenses at Equal Rates of Return at Proposed Rates					
35	Operations & Maintenance Expenses	$ 417,538,323	$ 204,423,692	$ 59,733,792	$ 143,325,626	$ 10,055,214
36	Depreciation Expense	207,193,006	100,616,687	31,254,967	73,715,637	1,605,715
37	Amortization Expense	13,490,249	6,339,070	1,915,489	5,146,156	89,533
38	Taxes Other than Income	49,162,249	23,582,269	7,236,322	17,371,257	972,401
39	Fuel Expenses	436,635,496	160,818,949	58,217,508	214,124,577	3,474,462
40	Non-FAC Trackable Fuel Expenses	11,630,446	4,283,698	1,550,714	5,703,488	92,545
41	Income Taxes	61,511,000	29,094,842	8,972,683	23,136,465	307,011
42	Total Expense - Required	$ 1,197,160,769	$ 529,159,207	$ 168,881,474	$ 482,523,206	$ 16,596,881

Summary of Results

Line No.	Description	System Total	Residential	Small C&I	Large C&I	Lighting
	(A)	(B)	(C)	(D)	(E)	(F)
43a	Interruptble Power Credit	-	-	-	-	-
43	Total Revenue Requirement at Equal Return	$ 1,410,903,769	$ 630,260,129	$ 200,060,420	$ 562,919,515	$ 17,663,705
44	Revenue (Deficiency)/Surplus	$ (91,663,158)	$ (89,496,679)	$ (1,224,925)	$ (456,855)	$ (484,698)
45	Total Revenues	1,319,240,611	540,763,449	198,835,495	562,462,660	17,179,007
46	Total Revenues as Proposed	$ 1,410,903,769	$ 630,260,129	$ 200,060,420	$ 562,919,515	$ 17,663,705
47	Less Total Other Revenues Including Migrations	$ 19,490,510	$ 11,050,032	$ 2,493,938	$ 5,312,919	$ 633,621
48	Sales for Resale	14,823,947	6,941,942	2,083,380	5,763,239	35,386
49	Total Base Rate Revenues as Proposed	$ 1,376,589,312	$ 612,268,155	$ 195,483,102	$ 551,843,357	$ 16,994,698
	Mitigation					
50	Mitigation	$ 0	$ (39,142,823)	$ 10,301,624	$ 28,860,824	$ (19,625)
51	Proposed Increase Post Mitigation	91,663,158	50,353,856	11,526,549	29,317,679	465,073
	Revenue Requirement at Proposed Mitigated Rates					
52	Revenue Defficiency/Surplus	$ 91,663,158	$ 50,353,856	$ 11,526,549	$ 29,317,679	$ 465,073
53	Total Revenues	1,319,240,611	540,763,449	198,835,495	562,462,660	17,179,007
54	Total Revenues as Proposed	$ 1,410,903,769	$ 591,117,306	$ 210,362,045	$ 591,780,339	$ 17,644,080
55	Less Total Other Revenues Including Migrations	$ 19,490,510	$ 11,050,032	$ 2,493,938	$ 5,312,919	$ 633,621
56	Sales for Resale	14,823,947	6,941,942	2,083,380	5,763,239	35,386
57	Total Base Rate Revenues as Proposed	$ 1,376,589,312	$ 573,125,332	$ 205,784,726	$ 580,704,181	$ 16,975,073
58	Total Margin in Base Rates	$ 179,428,543	$ 43,966,125	$ 36,903,252	$ 98,180,974	$ 378,192
59	Expenses (excl. Income Taxes)	$ 1,135,649,769	$ 500,064,365	$ 159,908,791	$ 459,386,742	$ 16,289,870
60	Interest Expense	77,251,000	36,539,897	11,268,695	29,056,836	385,571
61	Taxable Income	$ 198,003,000	$ 54,513,043	$ 39,184,558	$ 103,336,761	$ 968,638
62	Income Taxes	61,511,000	16,934,853	12,172,954	32,102,279	300,914
63	Operating Income as Proposed	$ 213,743,000	$ 74,118,087	$ 38,280,300	$ 100,291,318	$ 1,053,295
64	Return at Proposed Rates	7.03%	5.15%	8.63%	8.77%	6.94%
65	Index Rate of Return	1.00	0.73	1.23	1.25	0.99

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					
189	Production	$ 663,255,242	$ 310,597,381	$ 93,214,917	$ 257,859,689	$ 1,583,254
190	Transmission	$ 88,120,233	$ 41,266,034	$ 12,384,554	$ 34,259,293	$ 210,351
191	Distribution	$ 28,461,615	$ 11,161,777	$ 4,415,452	$ 12,624,262	$ 260,124
192	Distribution Primary	$ 36,533,003	$ 14,327,129	$ 5,667,624	$ 16,204,358	$ 333,892
193	Distribution Secondary	$ 13,907,742	$ 6,446,798	$ 2,573,724	$ 4,735,562	$ 151,658
194	Customer	$ -	$ -	$ -	$ -	$ -
195	Customer Service	$ -	$ -	$ -	$ -	$ -
196	Fuel Expenses	$ -	$ -	$ -	$ -	$ -
197	**Total**	$ 830,277,834	$ 383,799,120	$ 118,256,271	$ 325,683,165	$ 2,539,279
198	Zero-Check	-	-	-	-	-
	Customer					
199	Production	$ -	$ -	$ -	$ -	$ -
200	Transmission	$ -	$ -	$ -	$ -	$ -
201	Distribution	$ -	$ -	$ -	$ -	$ -
202	Distribution Primary	$ 23,184,703	$ 20,476,105	$ 2,442,382	$ 221,950	$ 44,265
203	Distribution Secondary	$ 8,513,342	$ 7,522,164	$ 897,104	$ 77,812	$ 16,261
204	Customer	$ 42,080,614	$ 19,580,862	$ 9,707,799	$ 1,514,316	$ 11,277,636
205	Customer Service	$ 36,828,020	$ 25,767,223	$ 6,088,230	$ 4,926,411	$ 46,155
206	Fuel Expenses	$ -	$ -	$ -	$ -	$ -
207	**Total**	$ 110,606,679	$ 73,346,355	$ 19,135,516	$ 6,740,490	$ 11,384,318
208	Zero-Check	-	-	-	-	-
	Energy					
209	Production	$ 33,383,760	$ 12,295,705	$ 4,451,125	$ 16,371,284	$ 265,646
217	**Total**	$ 33,383,760	$ 12,295,705	$ 4,451,125	$ 16,371,284	$ 265,646
218	Zero-Check	$ -	$ -	$ -	$ -	$ -
	Fuel					
219	Fuel Expenses	$ 436,635,496	$ 160,818,949	$ 58,217,508	$ 214,124,577	$ 3,474,462
220	**Total**	$ 436,635,496	$ 160,818,949	$ 58,217,508	$ 214,124,577	$ 3,474,462
221	Zero-Check	-	-	-	-	-
222	**Total**	1,410,903,769	630,260,129	200,060,420	562,919,515	17,663,705

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					
223	Demand	$ 830,277,834	$ 383,799,120	$ 118,256,271	$ 325,683,165	$ 2,539,279
224	Customer	$ 110,606,679	$ 73,346,355	$ 19,135,516	$ 6,740,490	$ 11,384,318
225	Energy	$ 33,383,760	$ 12,295,705	$ 4,451,125	$ 16,371,284	$ 265,646
226	Fuel	$ 436,635,496	$ 160,818,949	$ 58,217,508	$ 214,124,577	$ 3,474,462
227	**Total**	$ 1,410,903,769	$ 630,260,129	$ 200,060,420	$ 562,919,515	$ 17,663,705
228	Zero-Check	-	-	-	-	-
	Billing Determinants					
229	Demand	15,386,194	0	0	15,386,194	0
230	Customer Bills (Count *12)	5,983,055	5,284,020	630,276	57,336	11,423
231	Energy	13,392,600,834	4,928,558,302	1,772,807,714	6,585,433,220	105,801,598
232	Fuel	13,392,600,834	4,928,558,302	1,772,807,714	6,585,433,220	105,801,598
	Unit Costs					
233	Demand	.	$ -	$ -	$ 21.17	$ -
234	Customer	.	$ 86.51	$ 217.99	$ 117.56	$ 1,218.91
235	Energy	.	$ 0.002495	$ 0.002511	$ 0.002486	$ 0.002511
236	Fuel	.	$ 0.032630	$ 0.032839	$ 0.032515	$ 0.032839
237	Demand Revenue	.	$ -	$ -	$ 325,683,165	$ -
238	Customer Revenue	.	457,145,475	137,391,787	6,740,490	13,923,597
239	Energy Revenue	.	12,295,705	4,451,125	16,371,284	265,646
240	Fuel Revenue	.	160,818,949	58,217,508	214,124,577	3,474,462
241	Total Revenue	.	630,260,129	200,060,420	562,919,515	17,663,705
242	Zero-Check	.	$ -	$ -	$ -	$ -

Adjusted Revenue Requirement (Excluding Other Revenue and Sale for Resale Revenues)

Line No.	Description	System Total	Residential	Small C&I	Large C&I	Lighting
243	Ratio of Base Revenue to Total Revenue	96.48%	96.17%	96.77%	96.82%	95.29%
	Total Revenue Requirement					
244	Demand	$ 801,302,213	369,089,495	114,451,072	315,343,053	2,418,594
245	Customer	$ 106,414,619	70,535,256	18,506,935	6,523,867	10,848,561
246	Energy	$ 32,236,984	11,824,455	4,307,587	15,851,860	253,082
247	Fuel	$ 436,635,496	$ 160,818,949	$ 58,217,508	$ 214,124,577	$ 3,474,462
248	**Total**	$ 1,376,589,312	$ 612,268,155	$ 195,483,102	$ 551,843,357	$ 16,994,698
249	Zero-Check	-	-	-	-	-
	Billing Determinants					
250	Demand	15,386,194	0	0	15,386,194	0
251	Customer Bills (Count *12)	5,983,055	5,284,020	630,276	57,336	11,423
252	Energy	13,392,600,834	4,928,558,302	1,772,807,714	6,585,433,220	105,801,598
253	Fuel	13,392,600,834	4,928,558,302	1,772,807,714	6,585,433,220	105,801,598

Summary of Results

Line No.	Description	System Total	Residential	Small C&I	Large C&I	Lighting
	(A)	(B)	(C)	(D)	(E)	(F)
	Unit Costs					
254	Demand	.	$ -	$ -	$ 20.50	$ -
255	Customer	.	$ 83.20	$ 210.95	$ 113.78	$ 1,161.44
256	Energy	.	$ 0.002399	$ 0.002430	$ 0.002407	$ 0.002392
257	Fuel	.	$ 0.032630	$ 0.032839	$ 0.032515	$ 0.032839
258	Demand Revenue	.	$ -	$ -	$ 315,343,053	$ -
259	Customer Revenue	.	439,624,750	132,958,007	6,523,867	13,267,154
260	Energy Revenue	.	11,824,455	4,307,587	15,851,860	253,082
261	Fuel Revenue	.	160,818,949	58,217,508	214,124,577	3,474,462
262	Total Revenue	.	612,268,155	195,483,102	551,843,357	16,994,698
263	Zero-Check	.	$ -	$ -	$ -	$ -
	Grid Facility					
264	Grid Facility - Revenue Requirement	$ 267,625,812	140,931,438	42,744,931	72,189,999	11,759,444
265	Grid Facility - Unit Costs	$ 44.73	$ 26.67	$ 67.82	$ 1,259.07	$ 1,029.45
	Mitigated Revenue Requirement (Excluding Other Revenue and Sale for Resale Revenues)					
266	Ratio of Base Revenue to Total Revenue	97.57%	96.96%	97.82%	98.13%	96.21%
267	Mitigated Amount	0	(39,142,823)	10,301,624	28,860,824	(19,625)
	Total Revenue Requirement					
268	Demand	$ 804,332,043	336,226,912	122,256,063	343,429,982	2,419,086
269	Customer	$ 103,384,789	64,255,015	21,003,569	7,297,762	10,828,443
270	Energy	$ 32,236,984	$ 11,824,455	$ 4,307,587	$ 15,851,860	$ 253,082
271	Fuel	$ 436,635,496	$ 160,818,949	$ 58,217,508	$ 214,124,577	$ 3,474,462
272	**Total**	$ 1,376,589,312	$ 573,125,332	$ 205,784,726	$ 580,704,181	$ 16,975,073
273	Zero-Check	-	-	-	-	-
	Billing Determinants					
274	Demand	15,386,194	0	0	15,386,194	0
275	Customer Bills (Count *12)	5,983,055	5,284,020	630,276	57,336	11,423
276	Energy	13,392,600,834	4,928,558,302	1,772,807,714	6,585,433,220	105,801,598
277	Fuel	13,392,600,834	4,928,558,302	1,772,807,714	6,585,433,220	105,801,598
	Unit Costs					
278	Demand	.	$ -	$ -	$ 22.32	$ -
279	Customer	.	$ 75.79	$ 227.30	$ 127.28	$ 1,159.72
280	Energy	.	$ 0.002399	$ 0.002430	$ 0.002407	$ 0.002392
281	Fuel	.	$ 0.032630	$ 0.032839	$ 0.032515	$ 0.032839
282	Demand Revenue	.	$ -	$ -	$ 343,429,982	$ -
283	Customer Revenue	.	400,481,928	143,259,631	7,297,762	13,247,529
284	Energy Revenue	.	11,824,455	4,307,587	15,851,860	253,082
285	Fuel Revenue	.	160,818,949	58,217,508	214,124,577	3,474,462
286	Total Revenue	.	573,125,332	205,784,726	580,704,181	16,975,073
287	Zero-Check	.	$ -	$ -	$ -	$ -

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 (Excluding Fuel)					
288	Demand	$ 804,332,043	$ 336,226,912	$ 122,256,063	$ 343,429,982	$ 2,419,086
289	Customer	$ 103,384,789	$ 64,255,015	$ 21,003,569	$ 7,297,762	$ 10,828,443
290	Energy	$ 32,236,984	$ 11,824,455	$ 4,307,587	$ 15,851,860	$ 253,082
291	**Total**	$ 939,953,816	$ 412,306,383	$ 147,567,218	$ 366,579,604	$ 13,500,611
292	**Percent of Total**	100.00%	43.86%	15.70%	39.00%	1.44%
293	Zero-Check	-	-	-	-	-

Class Cost of Service Study
Summary of Results

Line No.	Description	System Total	Residential RS	Secondary Small SS	Space Conditioning SH	Space Conditioning - Schools SE	Water Heating - Controlled CB	Water Heating - Uncontrolled UW
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Rate Base							
1	Plant in Service	$ 5,594,471,211	$ 2,663,463,768	$ 572,194,397	$ 246,771,222	$ 7,107,318	$ 345,492	$ 596,678
2	Accumulated Reserve	(2,744,382,545)	(1,312,180,511)	(288,282,286)	(118,960,917)	(3,353,744)	(220,369)	(327,718)
3	Other Rate Base Items	191,307,000	87,303,757	19,173,161	8,330,134	247,781	10,668	20,195
4	Total Rate Base	$ 3,041,395,666	$ 1,438,587,013	$ 303,085,272	$ 136,140,439	$ 4,001,355	$ 135,791	$ 289,155
	Revenues at Current Rates							
5	Retail Sales	$ 1,284,926,154	$ 522,771,476	$ 144,173,818	$ 48,220,530	$ 1,702,175	$ 39,556	$ 122,097
6	Other Revenue	19,490,510	11,050,032	1,872,798	600,196	18,160	1,041	1,743
7	Sales for Resale	14,823,947	6,941,942	1,401,906	659,848	19,809	519	1,299
8	Total Revenues	$ 1,319,240,611	$ 540,763,449	$ 147,448,522	$ 49,480,575	$ 1,740,144	$ 41,116	$ 125,139
	Expenses at Current Rates							
9	Operations & Maintenance Expenses	$ 417,108,323	$ 204,133,443	$ 42,116,218	$ 17,017,291	$ 491,045	$ 27,411	$ 45,199
10	Depreciation Expense	207,193,006	100,616,687	21,907,968	9,051,784	260,402	12,600	22,212
11	Amortization Expense	13,490,249	6,339,070	1,296,636	599,231	17,844	545	1,233
12	Taxes Other Than Income Taxes	47,883,249	22,974,738	4,908,765	2,073,760	59,734	2,882	5,045
13	Fuel Expenses	436,635,496	160,818,949	40,068,855	17,488,272	601,646	13,809	44,927
14	Non-FAC Trackable Fuel Expenses	11,630,446	4,283,698	1,067,296	465,828	16,026	368	1,197
15	Income Taxes	29,130,534	1,139,360	7,732,373	(201,748)	52,050	(5,493)	(600)
16	Total Expenses - Current	$ 1,163,071,303	$ 500,305,945	$ 119,098,110	$ 46,494,418	$ 1,498,746	$ 52,122	$ 119,214
17	Current Operating Income	156,169,308	40,457,504	28,350,412	2,986,156	241,398	(11,006)	5,924
18	Return at Current Rates	5.13%	2.81%	9.35%	2.19%	6.03%	-8.11%	2.05%
19	Index Rate of Return	1.00	0.55	1.82	0.43	1.17	(1.58)	0.40
	Revenue Requirement at Equal Rates of Return at Current Rates							
20	Required Return	5.13%	5.13%	5.13%	5.13%	5.13%	5.13%	5.13%
21	Required Operating Income	$ 156,169,308	$ 73,868,435	$ 15,562,795	$ 6,990,527	$ 205,461	$ 6,973	$ 14,847
	Expenses at Required Return							
22	Operations & Maintenance Expenses	$ 417,108,323	$ 204,133,443	$ 42,116,218	$ 17,017,291	$ 491,045	$ 27,411	$ 45,199
23	Depreciation Expense	207,193,006	100,616,687	21,907,968	9,051,784	260,402	12,600	22,212
24	Amortization Expense	13,490,249	6,339,070	1,296,636	599,231	17,844	545	1,233
25	Taxes Other than Income	47,883,249	22,974,738	4,908,765	2,073,760	59,734	2,882	5,045
26	Fuel Expenses	436,635,496	160,818,949	40,068,855	17,488,272	601,646	13,809	44,927
27	Non-FAC Trackable Fuel Expenses	11,630,446	4,283,698	1,067,296	465,828	16,026	368	1,197
28	Income Taxes	29,130,534	13,778,808	2,902,955	1,303,955	38,325	1,301	2,770
29	Total Expense - Required	$ 1,163,071,303	$ 512,945,394	$ 114,268,692	$ 48,000,121	$ 1,485,021	$ 58,916	$ 122,583
30	Total Revenue Requirement at Equal Return	$ 1,319,240,611	$ 586,813,829	$ 129,831,487	$ 54,990,648	$ 1,690,482	$ 65,889	$ 137,431
31	Current Subsidy	$ -	$ (46,050,380)	$ 17,617,035	$ (5,510,074)	$ 49,662	$ (24,773)	$ (12,292)

Line No.	Description	System Total	Residential RS	Secondary Small SS	Space Conditioning SH	Space Conditioning - Schools SE	Water Heating - Controlled CB	Water Heating - Uncontrolled UW
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Revenue Requirement at Equal Rates of Return at Proposed Rates							
32	Required Return	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%
33	Required Operating Income	$ 213,743,000	$ 101,100,921	$ 21,300,206	$ 9,567,669	$ 281,207	$ 9,543	$ 20,321
34	Operating Income (Deficiency)/Surplus	$ (57,573,692)	$ (60,643,417)	$ 7,050,206	$ (6,581,512)	$ (39,809)	$ (20,549)	$ (14,397)
	Expenses at Equal Rates of Return at Proposed Rates							
35	Operations & Maintenance Expenses	$ 417,538,323	$ 204,423,692	$ 42,146,310	$ 17,023,590	$ 491,192	$ 27,455	$ 45,245
36	Depreciation Expense	207,193,006	100,616,687	21,907,968	9,051,784	260,402	12,600	22,212
37	Amortization Expense	13,490,249	6,339,070	1,296,636	599,231	17,844	545	1,233
38	Taxes Other than Income	49,162,249	23,582,269	5,036,420	2,130,395	61,395	2,943	5,169
39	Fuel Expenses	436,635,496	160,818,949	40,068,855	17,488,272	601,646	13,809	44,927
40	Non-FAC Trackable Fuel Expenses	11,630,446	4,283,698	1,067,296	465,828	16,026	368	1,197
41	Income Taxes	61,511,000	29,094,842	6,129,777	2,753,385	80,926	2,746	5,848
42	Total Expense - Required	$ 1,197,160,769	$ 529,159,207	$ 117,653,262	$ 49,512,486	$ 1,529,429	$ 60,466	$ 125,831
43a	Interruptble Power Credit	-	-	-	-	-	-	-
43	Total Revenue Requirement at Equal Return	$ 1,410,903,769	$ 630,260,129	$ 138,953,468	$ 59,080,155	$ 1,810,636	$ 70,009	$ 146,152
44	Revenue (Deficiency)/Surplus	$ (91,663,158)	$ (89,496,679)	$ 8,495,054	$ (9,599,580)	$ (70,492)	$ (28,893)	$ (21,014)
45	Total Revenues	1,319,240,611	540,763,449	147,448,522	49,480,575	1,740,144	41,116	125,139
46	Total Revenues as Proposed	$ 1,410,903,769	$ 630,260,129	$ 138,953,468	$ 59,080,155	$ 1,810,636	$ 70,009	$ 146,152
47	Less Total Other Revenues Including Migrations	$ 19,490,510	$ 11,050,032	$ 1,872,798	$ 600,196	$ 18,160	$ 1,041	$ 1,743
48	Sales for Resale	14,823,947	6,941,942	1,401,906	659,848	19,809	519	1,299
49	Total Base Rate Revenues as Proposed	$ 1,376,589,312	$ 612,268,155	$ 135,678,764	$ 57,820,110	$ 1,772,667	$ 68,449	$ 143,111
	Mitigation							
50	Mitigation	$ 0	$ (39,142,823)	$ 14,974,479	$ (4,683,563)	$ 42,213	$ (21,057)	$ (10,448)
51	Proposed Increase Post Mitigation	91,663,158	50,353,856	6,479,426	4,916,017	112,705	7,836	10,565
	Revenue Requirement at Proposed Mitigated Rates							
52	Revenue Defficiency/Surplus	$ 91,663,158	$ 50,353,856	$ 6,479,426	$ 4,916,017	$ 112,705	$ 7,836	$ 10,565
53	Total Revenues	1,319,240,611	540,763,449	147,448,522	49,480,575	1,740,144	41,116	125,139
54	Total Revenues as Proposed	$ 1,410,903,769	$ 591,117,306	$ 153,927,947	$ 54,396,592	$ 1,852,849	$ 48,952	$ 135,704
55	Less Total Other Revenues Including Migrations	$ 19,490,510	$ 11,050,032	$ 1,872,798	$ 600,196	$ 18,160	$ 1,041	$ 1,743
56	Sales for Resale	14,823,947	6,941,942	1,401,906	659,848	19,809	519	1,299
57	Total Base Rate Revenues as Proposed	$ 1,376,589,312	$ 573,125,332	$ 150,653,243	$ 53,136,547	$ 1,814,880	$ 47,393	$ 132,663
58	Total Margin in Base Rates	$ 179,428,543	$ 43,966,125	$ 32,999,982	$ 3,624,062	$ 285,451	$ (13,074)	$ 6,832
59	Expenses (excl. Income Taxes)	$ 1,135,649,769	$ 500,064,365	$ 111,523,484	$ 46,759,100	$ 1,448,504	$ 57,720	$ 119,983
60	Interest Expense	77,251,000	36,539,897	7,698,321	3,457,947	101,634	3,449	7,344
61	Taxable Income	$ 198,003,000	$ 54,513,043	$ 34,706,142	$ 4,179,545	$ 302,712	$ (12,216)	$ 8,376
62	Income Taxes	61,511,000	16,934,853	10,781,703	1,298,404	94,039	(3,795)	2,602
63	Operating Income as Proposed	$ 213,743,000	$ 74,118,087	$ 31,622,760	$ 6,339,087	$ 310,306	$ (4,972)	$ 13,119
64	Return at Proposed Rates	7.03%	5.15%	10.43%	4.66%	7.76%	-3.66%	4.54%
65	Index Rate of Return	1.00	0.73	1.48	0.66	1.10	(0.52)	0.65

Line No.	Description (A)	System Total (B)	Residential RS (C)	Secondary Small SS (D)	Space Conditioning SH (E)	Space Conditioning - Schools SE (F)	Water Heating - Controlled CB (G)	Water Heating - Uncontrolled UW (H)
	Functional Revenue Requirement							
	Demand							
189	Production	$ 663,255,242	$ 310,597,381	$ 62,724,266	$ 29,523,030	$ 886,283	$ 23,227	$ 58,111
190	Transmission	$ 88,120,233	$ 41,266,034	$ 8,333,559	$ 3,922,436	$ 117,752	$ 3,086	$ 7,721
191	Distribution	$ 28,461,615	$ 11,161,777	$ 2,589,167	$ 1,772,414	$ 50,732	$ 800	$ 2,340
192	Distribution Primary	$ 36,533,003	$ 14,327,129	$ 3,323,425	$ 2,275,051	$ 65,118	$ 1,026	$ 3,003
193	Distribution Secondary	$ 13,907,742	$ 6,446,798	$ 1,508,961	$ 1,033,355	$ 29,578	$ 466	$ 1,364
194	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
195	Customer Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -
196	Fuel Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
197	**Total**	$ 830,277,834	$ 383,799,120	$ 78,479,379	$ 38,526,286	$ 1,149,462	$ 28,606	$ 72,539
198	Zero-Check	-	-	-	-	-	-	-
	Customer							
199	Production	$ -	$ -	$ -	$ -	$ -	$ -	$ -
200	Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -
201	Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -
202	Distribution Primary	$ 23,184,703	$ 20,476,105	$ 2,246,473	$ 186,284	$ 1,256	$ 4,371	$ 3,999
203	Distribution Secondary	$ 8,513,342	$ 7,522,164	$ 825,134	$ 68,434	$ 461	$ 1,606	$ 1,469
204	Customer	$ 42,080,614	$ 19,580,862	$ 8,670,212	$ 1,009,424	$ 8,682	$ 9,666	$ 9,815
205	Customer Service	$ 36,828,020	$ 25,767,223	$ 5,599,878	$ 464,358	$ 3,130	$ 10,896	$ 9,969
206	Fuel Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
207	**Total**	$ 110,606,679	$ 73,346,355	$ 17,341,698	$ 1,728,499	$ 13,529	$ 26,539	$ 25,252
208	Zero-Check	-	-	-	-	-	-	-
	Energy							
209	Production	$ 33,383,760	$ 12,295,705	$ 3,063,537	$ 1,337,098	$ 46,000	$ 1,056	$ 3,435
210	Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -
211	Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -
212	Distribution Primary	$ -	$ -	$ -	$ -	$ -	$ -	$ -
213	Distribution Secondary	$ -	$ -	$ -	$ -	$ -	$ -	$ -
214	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -
215	Customer Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -
216	Fuel Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -
217	**Total**	$ 33,383,760	$ 12,295,705	$ 3,063,537	$ 1,337,098	$ 46,000	$ 1,056	$ 3,435
218	Zero-Check	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Fuel							
219	Fuel Expenses	$ 436,635,496	$ 160,818,949	$ 40,068,855	$ 17,488,272	$ 601,646	$ 13,809	$ 44,927
220	**Total**	$ 436,635,496	$ 160,818,949	$ 40,068,855	$ 17,488,272	$ 601,646	$ 13,809	$ 44,927
221	Zero-Check	-	-	-	-	-	-	-
222	**Total**	1,410,903,769	630,260,129	138,953,468	59,080,155	1,810,636	70,009	146,152
	Total Revenue Requirement							
223	Demand	$ 830,277,834	$ 383,799,120	$ 78,479,379	$ 38,526,286	$ 1,149,462	$ 28,606	$ 72,539
224	Customer	$ 110,606,679	$ 73,346,355	$ 17,341,698	$ 1,728,499	$ 13,529	$ 26,539	$ 25,252
225	Energy	$ 33,383,760	$ 12,295,705	$ 3,063,537	$ 1,337,098	$ 46,000	$ 1,056	$ 3,435
226	Fuel	$ 436,635,496	$ 160,818,949	$ 40,068,855	$ 17,488,272	$ 601,646	$ 13,809	$ 44,927
227	**Total**	$ 1,410,903,769	$ 630,260,129	$ 138,953,468	$ 59,080,155	$ 1,810,636	$ 70,009	$ 146,152
228	Zero-Check	-	-	-	-	-	-	-

Line No.	Description	System Total	Residential RS	Secondary Small SS	Space Conditioning SH	Space Conditioning - Schools SE	Water Heating - Controlled CB	Water Heating - Uncontrolled UW
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Billing Determinants							
229	Demand	15,386,194	0	0	0	0	0	0
230	Customer Bills (Count *12)	5,983,055	5,284,020	579,720	48,072	324	1,128	1,032
231	Energy	13,392,600,834	4,928,558,302	1,220,159,122	532,539,165	18,320,841	420,505	1,368,082
232	Fuel	13,392,600,834	4,928,558,302	1,220,159,122	532,539,165	18,320,841	420,505	1,368,082
	Unit Costs							
233	Demand	.	$ -	$ -	$ -	$ -	$ -	$ -
234	Customer	.	$ 86.51	$ 165.29	$ 837.39	$ 3,589.48	$ 48.89	$ 94.76
235	Energy	.	$ 0.002495	$ 0.002511	$ 0.002511	$ 0.002511	$ 0.002511	$ 0.002511
236	Fuel	.	$ 0.032630	$ 0.032839	$ 0.032839	$ 0.032839	$ 0.032839	$ 0.032839
237	Demand Revenue	.	$ -	$ -	$ -	$ -	$ -	$ -
238	Customer Revenue	.	457,145,475	95,821,076	40,254,785	1,162,991	55,144	97,790
239	Energy Revenue	.	12,295,705	3,063,537	1,337,098	46,000	1,056	3,435
240	Fuel Revenue	.	160,818,949	40,068,855	17,488,272	601,646	13,809	44,927
241	Total Revenue	.	630,260,129	138,953,468	59,080,155	1,810,636	70,009	146,152
242	Zero-Check	.	$ -	$ -	$ -	$ -	$ -	$ -
	Adjusted Revenue Requirement (Excluding Other Revenue and Sale for Resale Revenues)							
243	Ratio of Base Revenue to Total Revenue	96.48%	96.17%	96.69%	96.97%	96.86%	97.22%	97.00%
	Total Revenue Requirement							
244	Demand	$ 801,302,213	$ 369,089,495	$ 75,880,423	$ 37,359,115	$ 1,113,363	$ 27,812	$ 70,359
245	Customer	$ 106,414,619	$ 70,535,256	$ 16,767,403	$ 1,676,134	$ 13,104	$ 25,802	$ 24,493
246	Energy	$ 32,236,984	$ 11,824,455	$ 2,962,084	$ 1,296,590	$ 44,555	$ 1,026	$ 3,332
247	Fuel	$ 436,635,496	$ 160,818,949	$ 40,068,855	$ 17,488,272	$ 601,646	$ 13,809	$ 44,927
248	**Total**	$ 1,376,589,312	$ 612,268,155	$ 135,678,764	$ 57,820,110	$ 1,772,667	$ 68,449	$ 143,111
249	Zero-Check	-	-	-	-	-	-	-
	Billing Determinants							
250	Demand	15,386,194	0	0	0	0	0	0
251	Customer Bills (Count *12)	5,983,055	5,284,020	579,720	48,072	324	1,128	1,032
252	Energy	13,392,600,834	4,928,558,302	1,220,159,122	532,539,165	18,320,841	420,505	1,368,082
253	Fuel	13,392,600,834	4,928,558,302	1,220,159,122	532,539,165	18,320,841	420,505	1,368,082
	Unit Costs							
254	Demand	.	$ -	$ -	$ -	$ -	$ -	$ -
255	Customer	.	$ 83.20	$ 159.81	$ 812.02	$ 3,476.75	$ 47.53	$ 91.91
256	Energy	.	$ 0.002399	$ 0.002428	$ 0.002435	$ 0.002432	$ 0.002441	$ 0.002435
257	Fuel	.	$ 0.032630	$ 0.032839	$ 0.032839	$ 0.032839	$ 0.032839	$ 0.032839
258	Demand Revenue	.	$ -	$ -	$ -	$ -	$ -	$ -
259	Customer Revenue	.	439,624,750	92,647,826	39,035,249	1,126,467	53,614	94,852
260	Energy Revenue	.	11,824,455	2,962,084	1,296,590	44,555	1,026	3,332
261	Fuel Revenue	.	160,818,949	40,068,855	17,488,272	601,646	13,809	44,927
262	Total Revenue	.	612,268,155	135,678,764	57,820,110	1,772,667	68,449	143,111
263	Zero-Check	.	$ -	$ -	$ -	$ -	$ -	$ -
	Grid Facility							
264	Grid Facility - Revenue Requirement	$ 267,625,812	$ 140,931,438	$ 32,000,763	$ 10,406,632	$ 268,018	$ 31,031	$ 38,487
265	Grid Facility - Unit Costs	$ 44.73	$ 26.67	$ 55.20	$ 216.48	$ 827.22	$ 27.51	$ 37.29

Mitigated Revenue Requirement (Excluding Other Revenue and Sale for Resale Revenues)

Line No.	Description	System Total	Residential RS	Secondary Small SS	Space Conditioning SH	Space Conditioning - Schools SE	Water Heating - Controlled CB	Water Heating - Uncontrolled UW
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
266	Ratio of Base Revenue to Total Revenue	97.57%	91.10%	116.16%	88.00%	103.75%	60.72%	88.98%
267	Mitigated Amount	0	(39,142,823)	14,974,479	(4,683,563)	42,213	(21,057)	(10,448)
	Total Revenue Requirement							
268	Demand	$ 804,332,043	$ 336,226,912	$ 88,144,821	$ 32,876,660	$ 1,155,084	$ 16,889	$ 62,609
269	Customer	$ 103,384,789	$ 64,255,015	$ 19,477,484	$ 1,475,026	$ 13,595	$ 15,668	$ 21,795
270	Energy	$ 32,236,984	$ 11,824,455	$ 2,962,084	$ 1,296,590	$ 44,555	$ 1,026	$ 3,332
271	Fuel	$ 436,635,496	$ 160,818,949	$ 40,068,855	$ 17,488,272	$ 601,646	$ 13,809	$ 44,927
272	**Total**	$ 1,376,589,312	$ 573,125,332	$ 150,653,243	$ 53,136,547	$ 1,814,880	$ 47,393	$ 132,663
273	Zero-Check	-	-	-	-	-	-	-
	Billing Determinants							
274	Demand	15,386,194	0	0	0	0	0	0
275	Customer Bills (Count *12)	5,983,055	5,284,020	579,720	48,072	324	1,128	1,032
276	Energy	13,392,600,834	4,928,558,302	1,220,159,122	532,539,165	18,320,841	420,505	1,368,082
277	Fuel	13,392,600,834	4,928,558,302	1,220,159,122	532,539,165	18,320,841	420,505	1,368,082
	Unit Costs							
278	Demand	.	$ -	$ -	$ -	$ -	$ -	$ -
279	Customer	.	$ 75.79	$ 185.65	$ 714.59	$ 3,607.03	$ 28.86	$ 81.79
280	Energy	.	$ 0.002399	$ 0.002428	$ 0.002435	$ 0.002432	$ 0.002441	$ 0.002435
281	Fuel	.	$ 0.032630	$ 0.032839	$ 0.032839	$ 0.032839	$ 0.032839	$ 0.032839
282	Demand Revenue	.	$ -	$ -	$ -	$ -	$ -	$ -
283	Customer Revenue	.	400,481,928	107,622,305	34,351,686	1,168,679	32,557	84,404
284	Energy Revenue	.	11,824,455	2,962,084	1,296,590	44,555	1,026	3,332
285	Fuel Revenue	$ -	160,818,949	40,068,855	17,488,272	601,646	13,809	44,927
286	Total Revenue	.	573,125,332	150,653,243	53,136,547	1,814,880	47,393	132,663
287	Zero-Check	.	$ -	$ -	$ -	$ -	$ -	$ -
	Total Revenue Requirement (Excluding Fuel)							
288	Demand	$ 804,332,043	$ 336,226,912	$ 88,144,821	$ 32,876,660	$ 1,155,084	$ 16,889	$ 62,609
289	Customer	$ 103,384,789	$ 64,255,015	$ 19,477,484	$ 1,475,026	$ 13,595	$ 15,668	$ 21,795
290	Energy	$ 32,236,984	$ 11,824,455	$ 2,962,084	$ 1,296,590	$ 44,555	$ 1,026	$ 3,332
291	**Total**	$ 939,953,816	$ 412,306,383	$ 110,584,389	$ 35,648,276	$ 1,213,235	$ 33,583	$ 87,736
292	**Percent of Total**	100.00%	43.86%	11.76%	3.79%	0.13%	0.00%	0.01%
293	Zero-Check	-	-	-	-	-	-	-

Class Cost of Service Study
Summary of Results

Line No.	Description	System Total	Secondary Large SL	Industrial PL-HL	Process Heating PH	Protective Lighting APL	Municipal Lighting MU1
	(A)	(B)	(I)	(J)	(K)	(L)	(M)
	Rate Base						
1	Plant in Service	$ 5,594,471,211	$ 1,136,365,573	$ 821,401,289	$ 14,104,767	$ 51,769,947	$ 80,350,760
2	Accumulated Reserve	(2,744,382,545)	(537,096,979)	(356,676,261)	(6,440,991)	(46,807,204)	(74,035,565)
3	Other Rate Base Items	191,307,000	41,041,307	30,782,599	495,269	1,515,383	2,386,746
4	Total Rate Base	$ 3,041,395,666	$ 640,309,900	$ 495,507,627	$ 8,159,046	$ 6,478,126	$ 8,701,942
	Revenues at Current Rates						
5	Retail Sales	$ 1,284,926,154	$ 314,645,975	$ 233,271,419	$ 3,469,108	$ 7,177,089	$ 9,332,911
6	Other Revenue	19,490,510	3,232,638	2,045,013	35,268	254,066	379,555
7	Sales for Resale	14,823,947	3,148,020	2,574,000	41,219	13,416	21,970
8	Total Revenues	$ 1,319,240,611	$ 321,026,633	$ 237,890,432	$ 3,545,595	$ 7,444,571	$ 9,734,436
	Expenses at Current Rates						
9	Operations & Maintenance Expenses	$ 417,108,323	$ 82,627,117	$ 59,588,122	$ 1,010,566	$ 4,646,693	$ 5,405,217
10	Depreciation Expense	207,193,006	41,690,655	31,497,557	527,425	582,393	1,023,322
11	Amortization Expense	13,490,249	2,839,494	2,269,856	36,806	34,896	54,638
12	Taxes Other Than Income Taxes	47,883,249	9,693,337	7,081,340	120,578	417,444	545,626
13	Fuel Expenses	436,635,496	115,671,188	97,207,315	1,246,074	1,485,564	1,988,898
14	Non-FAC Trackable Fuel Expenses	11,630,446	3,081,054	2,589,243	33,191	39,569	52,976
15	Income Taxes	29,130,534	13,371,320	6,806,804	98,522	18,723	119,222
16	Total Expenses - Current	$ 1,163,071,303	$ 268,974,166	$ 207,040,236	$ 3,073,163	$ 7,225,282	$ 9,189,899
17	Current Operating Income	156,169,308	52,052,467	30,850,195	472,431	219,288	544,537
18	Return at Current Rates	5.13%	8.13%	6.23%	5.79%	3.39%	6.26%
19	Index Rate of Return	1.00	1.58	1.21	1.13	0.66	1.22
	Revenue Requirement at Equal Rates of Return at Current Rates						
20	Required Return	5.13%	5.13%	5.13%	5.13%	5.13%	5.13%
21	Required Operating Income	$ 156,169,308	$ 32,878,575	$ 25,443,281	$ 418,950	$ 332,638	$ 446,827
	Expenses at Required Return						
22	Operations & Maintenance Expenses	$ 417,108,323	$ 82,627,117	$ 59,588,122	$ 1,010,566	$ 4,646,693	$ 5,405,217
23	Depreciation Expense	207,193,006	41,690,655	31,497,557	527,425	582,393	1,023,322
24	Amortization Expense	13,490,249	2,839,494	2,269,856	36,806	34,896	54,638
25	Taxes Other than Income	47,883,249	9,693,337	7,081,340	120,578	417,444	545,626
26	Fuel Expenses	436,635,496	115,671,188	97,207,315	1,246,074	1,485,564	1,988,898
27	Non-FAC Trackable Fuel Expenses	11,630,446	3,081,054	2,589,243	33,191	39,569	52,976
28	Income Taxes	29,130,534	6,132,898	4,745,980	78,147	62,048	83,347
29	Total Expense - Required	$ 1,163,071,303	$ 261,735,744	$ 204,979,412	$ 3,052,789	$ 7,268,607	$ 9,154,024
30	Total Revenue Requirement at Equal Return	$ 1,319,240,611	$ 294,614,318	$ 230,422,693	$ 3,471,738	$ 7,601,245	$ 9,600,850
31	Current Subsidy	$ -	$ 26,412,315	$ 7,467,739	$ 73,856	$ (156,674)	$ 133,586

Line No.	Description	System Total	Secondary Large SL	Industrial PL-HL	Process Heating PH	Protective Lighting APL	Municipal Lighting MU1
	(A)	(B)	(I)	(J)	(K)	(L)	(M)
	Revenue Requirement at Equal Rates of Return at Proposed Rates						
32	Required Return	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%
33	Required Operating Income	$ 213,743,000	$ 44,999,656	$ 34,823,252	$ 573,401	$ 455,269	$ 611,554
34	Operating Income (Deficiency)/Surplus	$ (57,573,692)	$ 7,052,811	$ (3,973,056)	$ (100,969)	$ (235,981)	$ (67,017)
	Expenses at Equal Rates of Return at Proposed Rates						
35	Operations & Maintenance Expenses	$ 417,538,323	$ 82,708,313	$ 59,606,074	$ 1,011,239	$ 4,647,699	$ 5,407,515
36	Depreciation Expense	207,193,006	41,690,655	31,497,557	527,425	582,393	1,023,322
37	Amortization Expense	13,490,249	2,839,494	2,269,856	36,806	34,896	54,638
38	Taxes Other than Income	49,162,249	9,960,685	7,286,603	123,969	421,558	550,843
39	Fuel Expenses	436,635,496	115,671,188	97,207,315	1,246,074	1,485,564	1,988,898
40	Non-FAC Trackable Fuel Expenses	11,630,446	3,081,054	2,589,243	33,191	39,569	52,976
41	Income Taxes	61,511,000	12,950,009	10,021,442	165,013	131,017	175,993
42	Total Expense - Required	$ 1,197,160,769	$ 268,901,400	$ 210,478,089	$ 3,143,718	$ 7,342,696	$ 9,254,185
43a	Interruptble Power Credit	-	-	-	-	-	-
43	Total Revenue Requirement at Equal Return	$ 1,410,903,769	$ 313,901,056	$ 245,301,340	$ 3,717,119	$ 7,797,965	$ 9,865,740
44	Revenue (Deficiency)/Surplus	$ (91,663,158)	$ 7,125,577	$ (7,410,909)	$ (171,524)	$ (353,394)	$ (131,304)
45	Total Revenues	1,319,240,611	321,026,633	237,890,432	3,545,595	7,444,571	9,734,436
46	Total Revenues as Proposed	$ 1,410,903,769	$ 313,901,056	$ 245,301,340	$ 3,717,119	$ 7,797,965	$ 9,865,740
47	Less Total Other Revenues Including Migrations	$ 19,490,510	$ 3,232,638	$ 2,045,013	$ 35,268	$ 254,066	$ 379,555
48	Sales for Resale	14,823,947	3,148,020	2,574,000	41,219	13,416	21,970
49	Total Base Rate Revenues as Proposed	$ 1,376,589,312	$ 307,520,397	$ 240,682,328	$ 3,640,632	$ 7,530,484	$ 9,464,215
	Mitigation						
50	Mitigation	$ 0	$ 22,450,467	$ 6,347,578	$ 62,778	$ (133,173)	$ 113,548
51	Proposed Increase Post Mitigation	91,663,158	15,324,890	13,758,487	234,302	220,221	244,852
	Revenue Requirement at Proposed Mitigated Rates						
52	Revenue Defficiency/Surplus	$ 91,663,158	$ 15,324,890	$ 13,758,487	$ 234,302	$ 220,221	$ 244,852
53	Total Revenues	1,319,240,611	321,026,633	237,890,432	3,545,595	7,444,571	9,734,436
54	Total Revenues as Proposed	$ 1,410,903,769	$ 336,351,523	$ 251,648,919	$ 3,779,897	$ 7,664,792	$ 9,979,288
55	Less Total Other Revenues Including Migrations	$ 19,490,510	$ 3,232,638	$ 2,045,013	$ 35,268	$ 254,066	$ 379,555
56	Sales for Resale	14,823,947	3,148,020	2,574,000	41,219	13,416	21,970
57	Total Base Rate Revenues as Proposed	$ 1,376,589,312	$ 329,970,865	$ 247,029,906	$ 3,703,410	$ 7,397,311	$ 9,577,762
58	Total Margin in Base Rates	$ 179,428,543	$ 61,069,465	$ 36,551,817	$ 559,692	$ 54,615	$ 323,577
59	Expenses (excl. Income Taxes)	$ 1,135,649,769	$ 255,951,390	$ 200,456,647	$ 2,978,705	$ 7,211,678	$ 9,078,192
60	Interest Expense	77,251,000	16,263,777	12,585,820	207,239	164,543	221,028
61	Taxable Income	$ 198,003,000	$ 64,136,356	$ 38,606,451	$ 593,954	$ 288,570	$ 680,068
62	Income Taxes	61,511,000	19,924,402	11,993,361	184,516	89,646	211,268
63	Operating Income as Proposed	$ 213,743,000	$ 60,475,731	$ 39,198,911	$ 616,676	$ 363,467	$ 689,828
64	Return at Proposed Rates	7.03%	9.44%	7.91%	7.56%	5.61%	7.93%
65	Index Rate of Return	1.00	1.34	1.13	1.08	0.80	1.13

Line No.	Description	System Total	Secondary Large SL	Industrial PL-HL	Process Heating PH	Protective Lighting APL	Municipal Lighting MU1
	(A)	(B)	(I)	(J)	(K)	(L)	(M)
	Functional Revenue Requirement						
	Demand						
189	Production	$ 663,255,242	$ 140,849,167	$ 115,166,297	$ 1,844,225	$ 600,248	$ 983,006
190	Transmission	$ 88,120,233	$ 18,713,250	$ 15,301,019	$ 245,024	$ 79,749	$ 130,602
191	Distribution	$ 28,461,615	$ 8,197,089	$ 4,338,508	$ 88,666	$ 117,900	$ 142,224
192	Distribution Primary	$ 36,533,003	$ 10,521,689	$ 5,568,859	$ 113,810	$ 151,335	$ 182,557
193	Distribution Secondary	$ 13,907,742	$ 4,695,608	$ -	$ 39,953	$ 68,738	$ 82,920
194	Customer	$ -	$ -	$ -	$ -	$ -	$ -
195	Customer Service	$ -	$ -	$ -	$ -	$ -	$ -
196	Fuel Expenses	$ -	$ -	$ -	$ -	$ -	$ -
197	**Total**	$ 830,277,834	$ 182,976,803	$ 140,374,683	$ 2,331,679	$ 1,017,969	$ 1,521,309
198	Zero-Check	-	-	-	-	-	-
	Customer						
199	Production	$ -	$ -	$ -	$ -	$ -	$ -
200	Transmission	$ -	$ -	$ -	$ -	$ -	$ -
201	Distribution	$ -	$ -	$ -	$ -	$ -	$ -
202	Distribution Primary	$ 23,184,703	$ 212,603	$ 7,905	$ 1,442	$ -	$ 44,265
203	Distribution Secondary	$ 8,513,342	$ 77,522	$ -	$ 290	$ -	$ 16,261
204	Customer	$ 42,080,614	$ 1,405,076	$ 98,840	$ 10,400	$ 5,180,851	$ 6,096,786
205	Customer Service	$ 36,828,020	$ 4,714,013	$ 180,436	$ 31,963	$ -	$ 46,155
206	Fuel Expenses	$ -	$ -	$ -	$ -	$ -	$ -
207	**Total**	$ 110,606,679	$ 6,409,214	$ 287,181	$ 44,095	$ 5,180,851	$ 6,203,468
208	Zero-Check	-	-	-	-	-	-
	Energy						
209	Production	$ 33,383,760	$ 8,843,851	$ 7,432,162	$ 95,271	$ 113,581	$ 152,065
210	Transmission	$ -	$ -	$ -	$ -	$ -	$ -
211	Distribution	$ -	$ -	$ -	$ -	$ -	$ -
212	Distribution Primary	$ -	$ -	$ -	$ -	$ -	$ -
213	Distribution Secondary	$ -	$ -	$ -	$ -	$ -	$ -
214	Customer	$ -	$ -	$ -	$ -	$ -	$ -
215	Customer Service	$ -	$ -	$ -	$ -	$ -	$ -
216	Fuel Expenses	$ -	$ -	$ -	$ -	$ -	$ -
217	**Total**	$ 33,383,760	$ 8,843,851	$ 7,432,162	$ 95,271	$ 113,581	$ 152,065
218	Zero-Check	$ -	$ -	$ -	$ -	$ -	$ -
	Fuel						
219	Fuel Expenses	$ 436,635,496	$ 115,671,188	$ 97,207,315	$ 1,246,074	$ 1,485,564	$ 1,988,898
220	**Total**	$ 436,635,496	$ 115,671,188	$ 97,207,315	$ 1,246,074	$ 1,485,564	$ 1,988,898
221	Zero-Check	-	-	-	-	-	-
222	**Total**	1,410,903,769	313,901,056	245,301,340	3,717,119	7,797,965	9,865,740
	Total Revenue Requirement						
223	Demand	$ 830,277,834	$ 182,976,803	$ 140,374,683	$ 2,331,679	$ 1,017,969	$ 1,521,309
224	Customer	$ 110,606,679	$ 6,409,214	$ 287,181	$ 44,095	$ 5,180,851	$ 6,203,468
225	Energy	$ 33,383,760	$ 8,843,851	$ 7,432,162	$ 95,271	$ 113,581	$ 152,065
226	Fuel	$ 436,635,496	$ 115,671,188	$ 97,207,315	$ 1,246,074	$ 1,485,564	$ 1,988,898
227	**Total**	$ 1,410,903,769	$ 313,901,056	$ 245,301,340	$ 3,717,119	$ 7,797,965	$ 9,865,740
228	Zero-Check	-	-	-	-	-	-

Line No.	Description	System Total	Secondary Large SL	Industrial PL-HL	Process Heating PH	Protective Lighting APL	Municipal Lighting MU1
	(A)	(B)	(I)	(J)	(K)	(L)	(M)
	Billing Determinants						
229	Demand	15,386,194	9,227,969	6,158,225	0	0	0
230	Customer Bills (Count *12)	5,983,055	54,864	2,100	372	0	11,423
231	Energy	13,392,600,834	3,501,932,620	3,045,661,276	37,839,324	45,237,227	60,564,371
232	Fuel	13,392,600,834	3,501,932,620	3,045,661,276	37,839,324	45,237,227	60,564,371
	Unit Costs						
233	Demand	.	$ 19.83	$ 22.79	$ -	$ -	$ -
234	Customer	.	$ 116.82	$ 136.75	$ 6,386.49	$ -	$ 676.25
235	Energy	.	$ 0.002525	$ 0.002440	$ 0.002518	$ 0.139540	$ 0.002511
236	Fuel	.	$ 0.033031	$ 0.031917	$ 0.032931	$ 0.032839	$ 0.032839
237	Demand Revenue	.	$ 182,976,803	$ 140,374,683	$ -	$ -	$ -
238	Customer Revenue	.	6,409,214	287,181	2,375,774	-	7,724,777
239	Energy Revenue	.	8,843,851	7,432,162	95,271	6,312,401	152,065
240	Fuel Revenue	.	115,671,188	97,207,315	1,246,074	1,485,564	1,988,898
241	Total Revenue	.	313,901,056	245,301,340	3,717,119	7,797,965	9,865,740
242	Zero-Check	.	$ -	$ -	$ -	$ -	$ -
	Adjusted Revenue Requirement (Excluding Other Revenue						
243	Ratio of Base Revenue to Total Revenue	96.48%	96.78%	96.88%	96.90%	95.76%	94.90%
	Total Revenue Requirement						
244	Demand	$ 801,302,213	$ 177,087,113	$ 135,996,434	$ 2,259,506	$ 974,834	$ 1,443,760
245	Customer	$ 106,414,619	$ 6,202,913	$ 278,224	$ 42,730	$ 4,961,318	$ 5,887,243
246	Energy	$ 32,236,984	$ 8,559,183	$ 7,200,355	$ 92,322	$ 108,769	$ 144,313
247	Fuel	$ 436,635,496	$ 115,671,188	$ 97,207,315	$ 1,246,074	$ 1,485,564	$ 1,988,898
248	**Total**	$ 1,376,589,312	$ 307,520,397	$ 240,682,328	$ 3,640,632	$ 7,530,484	$ 9,464,215
249	Zero-Check	-	-	-	-	-	-
	Billing Determinants						
250	Demand	15,386,194	9,227,969	6,158,225	0	0	0
251	Customer Bills (Count *12)	5,983,055	54,864	2,100	372	0	11,423
252	Energy	13,392,600,834	3,501,932,620	3,045,661,276	37,839,324	45,237,227	60,564,371
253	Fuel	13,392,600,834	3,501,932,620	3,045,661,276	37,839,324	45,237,227	60,564,371
	Unit Costs						
254	Demand	.	$ 19.19	$ 22.08	$ -	$ -	$ -
255	Customer	.	$ 113.06	$ 132.49	$ 6,188.81	$ -	$ 641.78
256	Energy	.	$ 0.002444	$ 0.002364	$ 0.002440	$ 0.133627	$ 0.002383
257	Fuel	.	$ 0.033031	$ 0.031917	$ 0.032931	$ 0.032839	$ 0.032839
258	Demand Revenue	.	$ 177,087,113	$ 135,996,434	$ -	$ -	$ -
259	Customer Revenue	.	6,202,913	278,224	2,302,236	-	7,331,003
260	Energy Revenue	.	8,559,183	7,200,355	92,322	6,044,920	144,313
261	Fuel Revenue	.	115,671,188	97,207,315	1,246,074	1,485,564	1,988,898
262	Total Revenue	.	307,520,397	240,682,328	3,640,632	7,530,484	9,464,215
263	Zero-Check	.	$ -	$ -	$ -	$ -	$ -
	Grid Facility						
264	Grid Facility - Revenue Requirement	$ 267,625,812	$ 46,974,537	$ 24,700,367	$ 515,095	$ 5,361,338	$ 6,398,106
265	Grid Facility - Unit Costs	$ 44.73	$ 856.20	$ 11,762.08	$ 1,384.67	#DIV/0!	$ 560.11

Line No.	Description	System Total	Secondary Large SL	Industrial PL-HL	Process Heating PH	Protective Lighting APL	Municipal Lighting MU1
	(A)	(B)	(I)	(J)	(K)	(L)	(M)
	Mitigated Revenue Requirement (Excluding Other Revenue						
266	Ratio of Base Revenue to Total Revenue	97.57%	112.25%	104.66%	102.73%	97.76%	101.55%
267	Mitigated Amount	0	22,450,467	6,347,578	62,778	(133,173)	113,548
	Total Revenue Requirement						
268	Demand	$ 804,332,043	$ 198,777,811	$ 142,331,053	$ 2,321,119	$ 952,964	$ 1,466,122
269	Customer	$ 103,384,789	$ 6,962,683	$ 291,183	$ 43,895	$ 4,850,014	$ 5,978,429
270	Energy	$ 32,236,984	$ 8,559,183	$ 7,200,355	$ 92,322	$ 108,769	$ 144,313
271	Fuel	$ 436,635,496	$ 115,671,188	$ 97,207,315	$ 1,246,074	$ 1,485,564	$ 1,988,898
272	**Total**	$ 1,376,589,312	$ 329,970,865	$ 247,029,906	$ 3,703,410	$ 7,397,311	$ 9,577,762
273	Zero-Check	-	-	-	-	-	-
	Billing Determinants						
274	Demand	15,386,194	9,227,969	6,158,225	0	0	0
275	Customer Bills (Count *12)	5,983,055	54,864	2,100	372	0	11,423
276	Energy	13,392,600,834	3,501,932,620	3,045,661,276	37,839,324	45,237,227	60,564,371
277	Fuel	13,392,600,834	3,501,932,620	3,045,661,276	37,839,324	45,237,227	60,564,371
	Unit Costs						
278	Demand	.	$ 21.54	$ 23.11	$ -	$ -	$ -
279	Customer	.	$ 126.91	$ 138.66	$ 6,357.56	$ -	$ 651.72
280	Energy	.	$ 0.002444	$ 0.002364	$ 0.002440	$ 0.130683	$ 0.002383
281	Fuel	.	$ 0.033031	$ 0.031917	$ 0.032931	$ 0.032839	$ 0.032839
282	Demand Revenue	.	$ 198,777,811	$ 142,331,053	$ -	$ -	$ -
283	Customer Revenue	.	6,962,683	291,183	2,365,014	-	7,444,551
284	Energy Revenue	.	8,559,183	7,200,355	92,322	5,911,747	144,313
285	Fuel Revenue	$ -	115,671,188	97,207,315	1,246,074	1,485,564	1,988,898
286	Total Revenue	.	329,970,865	247,029,906	3,703,410	7,397,311	9,577,762
287	Zero-Check	.	$ -	$ -	$ -	$ -	$ -
	Total Revenue Requirement (Excluding Fuel)						
288	Demand	$ 804,332,043	$ 198,777,811	$ 142,331,053	$ 2,321,119	$ 952,964	$ 1,466,122
289	Customer	$ 103,384,789	$ 6,962,683	$ 291,183	$ 43,895	$ 4,850,014	$ 5,978,429
290	Energy	$ 32,236,984	$ 8,559,183	$ 7,200,355	$ 92,322	$ 108,769	$ 144,313
291	**Total**	$ 939,953,816	$ 214,299,677	$ 149,822,591	$ 2,457,336	$ 5,911,747	$ 7,588,864
292	**Percent of Total**	100.00%	22.80%	15.94%	0.26%	0.63%	0.81%
293	Zero-Check	-	-	-	-	-	-

INDIANAPOLIS POWER AND LIGHT COMPANY
Proposed Mitigation of Rate Increases

A	B	C	D	E	F	G	H	I	J	K
		Current Revenue	Proposed Revenue	ACOSS Deficiency at 7.03% ROR	ACOSS Rate Increase	Current Subsidy at 5.13% ROR	Eliminate % of Current Subsidy	Revised Deficiency	% < Revised Rate Incr. [1]	Proposed Mitigated Revenue [1]
System Total		$ 1,284,926,154	$ 1,376,589,312	$ (91,663,158)	7.13%		G*Factor	E - G + H	F - J	**$ 1,376,589,312**
							15.00%			
Residential	**RS**	$ 522,771,476	$ 612,268,155	$ (89,496,679)	17.12%	$ (46,050,380)	$ (6,907,557)	$ (50,353,856)	**9.63%**	**$ 573,125,332**
Secondary Small	**SS**	$ 144,173,818	$ 135,678,764	$ 8,495,054	-5.89%	$ 17,617,035	$ 2,642,555	$ (6,479,426)	**4.49%**	**$ 150,653,243**
Space Conditioning	**SH**	$ 48,220,530	$ 57,820,110	$ (9,599,580)	19.91%	$ (5,510,074)	$ (826,511)	$ (4,916,017)	**10.19%**	**$ 53,136,547**
Space Conditioning - Schools	**SE**	$ 1,702,175	$ 1,772,667	$ (70,492)	4.14%	$ 49,662	$ 7,449	$ (112,705)	**6.62%**	**$ 1,814,880**
Water Heating - Controlled	**CB**	$ 39,556	$ 68,449	$ (28,893)	73.04%	$ (24,773)	$ (3,716)	$ (7,836)	**19.81%**	**$ 47,393**
Water Heating - Uncontrolled	**UW**	$ 122,097	$ 143,111	$ (21,014)	17.21%	$ (12,292)	$ (1,844)	$ (10,565)	**8.65%**	**$ 132,663**
Secondary Large	**SL**	$ 314,645,975	$ 307,520,397	$ 7,125,577	-2.26%	$ 26,412,315	$ 3,961,847	$ (15,324,890)	**4.87%**	**$ 329,970,865**
Primary Large	**PL-HL**	$ 233,271,419	$ 240,682,328	$ (7,410,909)	3.18%	$ 7,467,739	$ 1,120,161	$ (13,758,487)	**5.90%**	**$ 247,029,906**
Process Heating	**PH**	$ 3,469,108	$ 3,640,632	$ (171,524)	4.94%	$ 73,856	$ 11,078	$ (234,302)	**6.75%**	**$ 3,703,410**
Automatic Protective Lighting	**APL**	$ 7,177,089	$ 7,530,484	$ (353,394)	4.92%	$ (156,674)	$ (23,501)	$ (220,221)	**3.07%**	**$ 7,397,311**
Municipal Lighting	**MU1**	$ 9,332,911	$ 9,464,215	$ (131,304)	1.41%	$ 133,586	$ 20,038	$ (244,852)	**2.62%**	**$ 9,577,762**
						$ 0	$ 0	$ (91,663,158)		
							Change in Other Revenue	$ -		
							Total Revenue Deficiency	**$ (91,663,158)**		

Notes:
[1] Excludes the low load factor rate design adjustment.

INDIANAPOLIS POWER AND LIGHT COMPANY
Proposed Mitigation of Rate Increases

A	B	C	D	E	F	G	H	I	J	K
		Current Revenue	Proposed Revenue	ACOSS Deficiency at 7.03% ROR	ACOSS Rate Increase	Current Subsidy at 5.13% ROR	Eliminate % of Current Subsidy	Revised Deficiency	Revised Rate Incr. [1]	Proposed Mitigated Revenue [1]
System Total		$ 1,284,926,154	$ 1,376,589,312	$ (91,663,158)	7.13%		G*Factor	E - H		**$ 1,376,589,312**
							15.00%			
Residential		$ 522,771,476	$ 612,268,155	$ (89,496,679)	17.12%	$ (46,050,380)	$ (6,907,557)	$ (50,353,856)	**9.63%**	**$ 573,125,332**
Small C&I		$ 194,258,177	$ 195,483,102	$ (1,224,925)	0.63%	$ 12,119,558	$ 1,817,934	$ (11,526,549)	**5.93%**	**$ 205,784,726**
Large C&I		$ 551,386,502	$ 551,843,357	$ (456,855)	0.08%	$ 33,953,910	$ 5,093,087	$ (29,317,679)	**5.32%**	**$ 580,704,181**
Lighting		$ 16,510,000	$ 16,994,698	$ (484,698)	2.94%	$ (23,088)	$ (3,463)	$ (465,073)	**2.82%**	**$ 16,975,073**
						$ 0	$ 0	$ (91,663,158)		
							Change in Other Revenue	$ -		
							Total Revenue Deficiency	**$ (91,663,158)**		

Notes:
[1] Excludes the low load factor rate design adjustment.

INDIANAPOLIS POWER AND LIGHT COMPANY
Class Cost of Service - Industrial Rate Classes
Test Year Ended June 30, 2016

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)
	Functional Revenue Requirement					
	Allocation of the Revenue Requirement - Demand Component					
1	**Production and Transmission**					
2	Allocated Production Demand Cost	$ 115,166,297				
3	Allocated Transmission Demand Cost	15,301,019				
4	Total Production and Transmission	$ 130,467,316				
5	Demand Billing Determinants	6,158,225	2,794,988	2,462,182	429,135	471,920
6	Loss Factor Adjustment		1.043	1.043	1.038	1.025
7	Adjusted Demand Billing Determinants	6,412,379	2,915,235	2,568,009	445,378	483,758
8	Cost Allocation Factors	100.00%	45.46%	40.05%	6.95%	7.54%
9	Total Production and Transmission	$ 130,467,316	$ 59,313,854	$ 52,249,122	$ 9,061,727	$ 9,842,614
10	Demand Billing Determinants	6,158,225	2,794,988	2,462,182	429,135	471,920
11	**Production and Transmission Demand Charge**	**$ 21.19**	**$ 21.22**	**$ 21.22**	**$ 21.12**	**$ 20.86**
12	**Distribution and Distribution Primary**					
13	Allocated Station Equipment	$ 4,338,508				
14	Allocated Primary Distribution Demand Cost	5,568,859				
15	Total Distribution	$ 9,907,367				
16	Demand Billing Determinants	6,158,225	2,794,988	2,462,182	429,135	471,920
17	Loss Factor Adjustment		1.005	1.005	-	-
18	Adjusted Demand Billing Determinants	5,283,263	2,808,920	2,474,344	-	-
19	Cost Allocation Factors	100.00%	53.17%	46.83%	0.00%	0.00%
20	Total Distribution and Distribution Primary	$ 9,907,367	$ 5,267,388	$ 4,639,979	$ -	$ -
21	Demand Billing Determinants	6,158,225	2,794,988	2,462,182	429,135	471,920
22	**Distribution Demand Charge**	**$ 1.61**	**$ 1.88**	**$ 1.88**	**$ -**	**$ -**
23	Total Revenue Requirement - Demand Component	$ 140,374,683	$ 64,581,242	$ 56,889,101	$ 9,061,727	$ 9,842,614
24	Demand Billing Determinants	6,158,225	2,794,988	2,462,182	429,135	471,920
25	**Total Demand Charge**	**$ 22.79**	**$ 23.11**	**$ 23.11**	**$ 21.12**	**$ 20.86**
	Allocation of the Revenue Requirement - Customer Component					
26	**Distribution Primary**					
27	Allocated Distribution Primary Cost	$ 7,905				
28	Number of Customers	168				
29	Distribution Primary Cost Per Customer	$ 47				
30	Number of Customer by Rate Class	168	141	27	-	-
31	Total Distribution Primary Cost	$ 7,905	$ 6,635	$ 1,270	$ -	$ -
32	**Meter Costs**					
33	Allocated Meter Costs	$ 86,560				
34	Total Meter Replacement Cost	$ 137,925	$ 88,520	$ 18,766	$ 12,102	$ 18,536
35	Cost Allocation Factors	100%	64.18%	13.61%	8.77%	13.44%
36	Meter Costs - Allocated	$ 86,560	$ 55,554	$ 11,778	$ 7,595	$ 11,633
37	**Additional Customer Costs**					
38	Allocated Additional Customer Costs	$ 192,716				
39	Number of Customers	175				
40	Additional Customer Costs Per Customer	$ 1,101				
41	Number of Customer by Rate Class	175	141	27	5	2
42	Total Additional Customer Costs Allocated	$ 192,716	$ 155,274	$ 29,733	$ 5,506	$ 2,202
43	Total Revenue Requirement - Customer Component	$ 287,181	$ 217,463	$ 42,781	$ 13,101	$ 13,836
44	Customer Bills by Rate Class	2,100	1,692	324	60	24
45	**Total Customer Charge**	**$ 137**	**$ 129**	**$ 132**	**$ 218**	**$ 576**

INDIANAPOLIS POWER AND LIGHT COMPANY
Class Cost of Service - Industrial Rate Classes
Test Year Ended June 30, 2016

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)
	Allocation of the Revenue Requirement - Energy Component						
46	**Total Revenue Requirement - Energy Component**						
47	Allocated Energy Costs	$	7,432,162				
48	Energy at the Meter		3,045,661,276	1,230,822,724	1,317,040,818	225,993,534	271,804,200
49	Line Loss Factor			1.042	1.042	1.036	1.024
50	Energy at Source		3,166,409,950	1,282,099,374	1,371,917,519	234,190,191	278,202,866
51	Cost Allocation Factors		100.00%	40.49%	43.33%	7.40%	8.79%
52	Total Revenue Requirement - Energy Component	$	7,432,162	$ 3,009,329	$ 3,220,149	$ 549,689	$ 652,995
53	Energy at the Meter		3,045,661,276	1,230,822,724	1,317,040,818	225,993,534	271,804,200
54	**Total Energy Charge**	**$**	**0.002440**	**$ 0.002445**	**$ 0.002445**	**$ 0.002432**	**$ 0.002402**
	Allocation of the Revenue Requirement - Fuel Component						
55	Allocated Fuel Costs	$	97,207,315				
56	Energy at the Meter		3,045,661,276	1,230,822,724	1,317,040,818	225,993,534	271,804,200
57	Line Loss Factor			1.042	1.042	1.036	1.024
58	Energy at Source		3,166,409,950	1,282,099,374	1,371,917,519	234,190,191	278,202,866
59	Cost Allocation Factors		100.00%	40.49%	43.33%	7.40%	8.79%
60	Total Revenue Requirement - Fuel Component	$	97,207,315	$ 39,359,855	$ 42,117,231	$ 7,189,530	$ 8,540,699
61	Energy at the Meter		3,045,661,276	1,230,822,724	1,317,040,818	225,993,534	271,804,200
62	**Total Fuel Charge**	**$**	**0.031917**	**$ 0.031978**	**$ 0.031979**	**$ 0.031813**	**$ 0.031422**
	Total Functional Revenue Requirement						
63	Demand	$	140,374,683	$ 64,581,242	$ 56,889,101	$ 9,061,727	$ 9,842,614
64	Customer		287,181	217,463	42,781	13,101	13,836
65	Energy		7,432,162	3,009,329	3,220,149	549,689	652,995
66	Fuel		97,207,315	39,359,855	42,117,231	7,189,530	8,540,699
67	**Total Revenue Requirement**	**$**	**245,301,340**	**$ 107,167,889**	**$ 102,269,262**	**$ 16,814,046**	**$ 19,050,143**

Adjusted Revenue Requirement (Excluding Other Revenue and Sale for Resale Revenues)

Line No.	Description		Industrial Total	PL	HL1	HL2	HL3
	Other Revenue & Sales for Resale						
68	Total Base Revenue Excl. Fuel	$	143,475,013				
69	Total Revenue Excl. Fuel		148,094,026				
70	Ratio of Base Revenue to Total Revenue		96.88%				
	Total Functional Revenue Requirement (Excluding Other Revenue and Sale for Resale Revenues)						
71	Demand	$	135,996,434	$ 62,566,970	$ 55,114,745	$ 8,779,094	$ 9,535,626
72	Customer		278,224	210,680	41,447	12,692	13,404
73	Energy		7,200,355	2,915,469	3,119,714	532,544	632,628
74	Fuel		97,207,315	39,359,855	42,117,231	7,189,530	8,540,699
75	**Total Revenue Requirement Excl. Other Revenue**	**$**	**240,682,328**	**$ 105,052,975**	**$ 100,393,136**	**$ 16,513,860**	**$ 18,722,356**
76	**Billing Determinants**						
77	Demand		6,158,225	2,794,988	2,462,182	429,135	471,920
78	Customer Bills		2,100	1,692	324	60	24
79	Energy		3,045,661,276	1,230,822,724	1,317,040,818	225,993,534	271,804,200
80	Fuel		3,045,661,276	1,230,822,724	1,317,040,818	225,993,534	271,804,200
81	**Unit Costs**						
82	Demand	$	22.08	$ 22.39	$ 22.38	$ 20.46	$ 20.21
83	Customer	$	132.49	$ 124.52	$ 127.92	$ 211.54	$ 558.51
84	Energy	$	0.002364	$ 0.002369	$ 0.002369	$ 0.002356	$ 0.002328
85	Fuel	$	0.031917	$ 0.031978	$ 0.031979	$ 0.031813	$ 0.031422

INDIANAPOLIS POWER AND LIGHT COMPANY
Class Cost of Service - Industrial Rate Classes
Test Year Ended June 30, 2016

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)
	Mitigated Revenue Requirement (Excluding Other Revenue and Sale for Resale Revenues)					
	Mitigation					
86	Mitigated Amount - Demand	$ 6,334,619				
87	Cost Allocation Factors	100.00%	46.01%	40.53%	6.46%	7.01%
88	Mitigation Amount Allocated - Demand	$ 6,334,619	$ 2,914,326	$ 2,567,206	$ 408,924	$ 444,163
89	Mitigated Amount - Customer	$ 12,959				
90	Cost Allocation Factors	100.00%	75.72%	14.90%	4.56%	4.82%
91	Mitigation Amount Allocated - Customer	$ 12,959	$ 9,813	$ 1,931	$ 591	$ 624
	Total Mitigated Functional Revenue Requirement (Excluding Other Revenue and Sale for Resale Revenues)					
92	Demand	$ 142,331,053	$ 65,481,296	$ 57,681,951	$ 9,188,018	$ 9,979,788
93	Customer	291,183	220,494	43,378	13,284	14,028
94	Energy	7,200,355	2,915,469	3,119,714	532,544	632,628
95	Fuel	97,207,315	39,359,855	42,117,231	7,189,530	8,540,699
96	**Total Mitigated Revenue Requirement Excl. Other Revenue**	$ 247,029,906	$ 107,977,114	$ 102,962,273	$ 16,923,375	$ 19,167,144
97	**Billing Determinants**					
98	Demand	6,158,225	2,794,988	2,462,182	429,135	471,920
99	Customer Bills	2,100	1,692	324	60	24
100	Energy	3,045,661,276	1,230,822,724	1,317,040,818	225,993,534	271,804,200
101	Fuel	3,045,661,276	1,230,822,724	1,317,040,818	225,993,534	271,804,200
102	**Unit Costs**					
103	Demand	$ 23.11	$ 23.43	$ 23.43	$ 21.41	$ 21.15
104	Customer	$ 138.66	$ 130.32	$ 133.88	$ 221.39	$ 584.52
105	Energy	$ 0.002364	$ 0.002369	$ 0.002369	$ 0.002356	$ 0.002328
106	Fuel	$ 0.031917	$ 0.031978	$ 0.031979	$ 0.031813	$ 0.031422
	Comparison of Current and Proposed Pro Forma Revenues					
107	Total Current Revenue	$ 233,271,419				
108	Large Commercial Sales Revenue	$ 233,270,845	$ 100,095,856	$ 97,714,366	$ 16,577,844	$ 18,882,779
109	Cost Allocation Factors	100.00%	42.91%	41.89%	7.11%	8.09%
110	Total Current Revenue Allocated	$ 233,271,419	$ 100,096,102	$ 97,714,606	$ 16,577,885	$ 18,882,826
111	Unmitigated Proposed Revenue	$ 240,682,328	$ 105,052,975	$ 100,393,136	$ 16,513,860	$ 18,722,356
112	Mitigated Proposed Revenue	$ 247,029,906	$ 107,977,114	$ 102,962,273	$ 16,923,375	$ 19,167,144
113	Increase: Unmitigated - Current ($)	$ 7,410,909	$ 4,956,872	$ 2,678,530	$ (64,024)	$ (160,469)
114	Increase: Mitigated - Current ($)	$ 13,758,487	$ 7,881,012	$ 5,247,667	$ 345,491	$ 284,318
115	Increase: Unmitigated - Current (%)	3.18%	4.95%	2.74%	-0.39%	-0.85%
116	Increase: Mitigated - Current (%)	5.90%	7.87%	5.37%	2.08%	1.51%

INDIANAPOLIS POWER AND LIGHT COMPANY
Comparison of Current and Proposed Pro Forma Revenues

Line No.	Rate Class	Rate Code	Current Revenue	Unmitigated Proposed Revenue	Mitigated Proposed Revenue [1]	Increase: Unmitigated - Current	Low Load Factor Rate Recovery	Increase: Mitigated [2]	**Increase: Unmitigated - Current (%)**	**Increase: Mitigated [3]**
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	Residential Service (Rate RS) - Codes RS, RC, RH	RS	$ 522,771,476	$ 612,268,155	$ 573,125,332	$ 89,496,679	$ -	$ 50,353,856	**17.12%**	**9.63%**
2	Secondary Service (Small) (Rate SS)	SS	144,173,818	135,678,764	150,653,243	(8,495,054)	-	6,479,426	**-5.89%**	**4.49%**
3	Electric Space Conditioning-Secondary Service (Rate SH)	SH	48,220,530	57,820,110	53,136,547	9,599,580	-	4,916,017	**19.91%**	**10.19%**
4	Electric Space Conditioning-Schools (Rate SE)	SE	1,702,175	1,772,667	1,814,880	70,492	-	112,705	**4.14%**	**6.62%**
5	Water Heating-Controlled Service (Rate CB/CW)	CB	39,556	68,449	47,393	28,893	-	7,836	**73.04%**	**19.81%**
6	Water Heating-Uncontrolled Service (Rate UW)	UW	122,097	143,111	132,663	21,014	-	10,565	**17.21%**	**8.65%**
7	Secondary Service (Large) - (Rate SL)	SL	314,645,975	307,520,397	329,970,865	(7,125,577)	67,973	15,392,863	**-2.26%**	**4.89%**
8	Primary Service (Large) - (Rate PL)	PL	100,096,102	105,052,975	107,977,114	4,956,872	23,890	7,904,902	**4.95%**	**7.90%**
9	Process Heating (Rate PH)	PH	3,469,108	3,640,632	3,703,410	171,524	734	235,036	**4.94%**	**6.78%**
10	High Load Factor (Rate HL-1) (Primary Distribution)	HL1	97,714,606	100,393,136	102,962,273	2,678,530	25,564	5,273,231	**2.74%**	**5.40%**
11	High Load Factor (Rate HL-2) (Sub transmission)	HL2	16,577,885	16,513,860	16,923,375	(64,024)	4,387	349,878	**-0.39%**	**2.11%**
12	High Load Factor (Rate HL-3) (Transmission)	HL3	18,882,826	18,722,356	19,167,144	(160,469)	(122,549)	161,769	**-0.85%**	**0.86%**
13	Automatic Protective Lighting (APL)	APL	7,177,089	7,530,484	7,397,311	353,394	-	220,221	**4.92%**	**3.07%**
14	Municipal Lighting (MU)	MU1	$ 9,332,911	$ 9,464,215	$ 9,577,762	$ 131,304	$ -	$ 244,852	**1.41%**	**2.62%**
15	**TOTAL SYSTEM**		**$ 1,284,926,154**	**$ 1,376,589,312**	**$ 1,376,589,312**	**$ 91,663,158**	**$ -**	**$ 91,663,158**	**7.13%**	**7.13%**

[1] From ACOSS.
[2] Col. (E) - (C) + (G)
[3] Includes Low Load Factor Rate Recovery.

Indianapolis Power and Light Company
Pro Forma Revenue at Current Rates
Test Year Ended June 30, 2016
Residential Service (RS, RC,RH, CR/CW)

Line No.	Description (A)	Annualized Volumes (B)	Current Rate (C)	Annualized Revenue (D)	Adjustment (E)	Adjustment (F)	Total Revenue (G)
	Billed kwh						
1	First 500 kWh	2,263,769,994	$ 0.090886	$ 205,745,000	$ -	$ -	$ 205,745,000
2	Over 500 kWh	1,717,862,460	$ 0.069951	$ 120,166,197	$ -	$ -	$ 120,166,197
3	Over 1,000	946,853,725	$ 0.057348	$ 54,300,167	$ -	$ -	$ 54,300,167
4	Resid (CR/CW)	72,123	$ 0.064316	$ 4,639	$ -	$ -	$ 4,639
5	Total kWh	4,928,558,302		$ 380,216,003	$ -	$ -	$ 380,216,003
	Customer Charge						
6	0 to 325 kWh	973,096	$ 11.25	$ 10,947,330	$ -	$ -	$ 10,947,330
7	Over 325 kWh	4,310,624	$ 17.00	$ 73,280,608	$ -	$ -	$ 73,280,608
8	Resid (CR/CW)	300	$ 7.10	$ 2,130	$ -	$ -	$ 2,130
9		5,284,020		$ 84,230,068	$ -	$ -	$ 84,230,068
10	Residential Service (RS, RC,RH)			$ 464,446,071	$ -	$ -	$ 464,446,071
	Contract Riders						
11	No. 3 Demand Side Management			$ -	$ -	$ -	$ -
12	No. 6 Fuel Cost Adjustment			$ 5,419,128	$ -	$ -	$ 5,419,128
13	No. 7 Employee Discount			$ (137,221)	$ -	$ -	$ (137,221)
14	No. 9 Net Metering			$ -	$ -	$ -	$ -
15	No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
16	No. 20 Environmental Compliance Cost Recovery			$ 33,297,915	$ -	$ -	$ 33,297,915
17	No. 21 Green Power			$ 37,578	$ -	$ -	$ 37,578
18	No. 22 Core and Core Demand Side Management			$ 12,785,000	$ -	$ -	$ 12,785,000
19	No. 26 Regional Transmission Organization Rider			$ 6,535,329	$ -	$ -	$ 6,535,329
20	Total Rider			$ 57,937,729	$ -	$ -	$ 57,937,729
21	Grand Total			$ 522,383,800	$ -	$ -	$ 522,383,800
22					*Balancing Adjustment*		*1.00074*
23						**Total Revenue**	**$ 522,771,476**
						Check	TRUE

Indianapolis Power and Light Company
Pro Forma Revenue at Proposed Rates
Test Year Ended June 30, 2016
Residential Service (RS, RC,RH, CR/CW)

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 500 kWh	2,263,769,994	$ 0.098630	$ 223,275,673	$ -	$ -	$ 223,275,673
Over 500 kWh	1,717,862,460	$ 0.081531	$ 140,059,044	$ -	$ -	$ 140,059,044
Over 1,000	946,853,725	$ 0.067401	$ 63,818,888	$ -	$ -	$ 63,818,888
Resid (CR/CW)	72,123	$ 0.064880	$ 4,679	$ -	$ -	$ 4,679
Total kWh	4,928,558,302		$ 427,158,284	$ -	$ -	$ 427,158,284
		Target	$ 427,158,284			
		Difference	$ -			
Customer Charge						
0 to 325 kWh	973,096	$ 19.0000	$ 18,488,824	$ -	$ -	$ 18,488,824
Over 325 kWh	4,310,624	$ 27.0000	$ 116,386,848	$ -	$ -	$ 116,386,848
Resid (CR/CW)	300	$ 17.0000	$ 5,100	$ -	$ -	$ 5,100
	5,284,020		$ 134,880,772	$ -	$ -	$ 134,880,772
		Target	$ 134,880,772			
		Difference	$ -			
Residential Service (RS, RC,RH)			$ 562,039,056	$ -	$ -	$ 562,039,056
		Target	$ 562,039,056			
		Difference	$ -			
Contract Riders						
No. 3 Demand Side Management			$ -	$ -	$ -	$ -
No. 6 Fuel Cost Adjustment			$ -	$ -	$ -	$ -
No. 7 Employee Discount			$ (204,302)	$ -	$ -	$ (204,302)
No. 9 Net Metering			$ -	$ -	$ -	$ -
No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
No. 20 Environmental Compliance Cost Recovery			$ -	$ -	$ -	$ -
No. 21 Green Power			$ 37,578	$ -	$ -	$ 37,578
No. 22 Core and Core Demand Side Management			$ 11,253,000	$ -	$ -	$ 11,253,000
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 11,086,276	$ -	$ -	$ 11,086,276
Grand Total			$ 573,125,332	$ -	$ -	$ 573,125,332
		Check	TRUE			

Indianapolis Power and Light Company
Pro Forma Revenue at Current Rates
Test Year Ended June 30, 2016
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	871,281,098	$ 0.095094	$ 82,853,605	$ -	$ -	$ 82,853,605
2	Over 5,000	348,878,024	$ 0.080394	$ 28,047,700	$ -	$ -	$ 28,047,700
3	Total kWh	1,220,159,122		$ 110,901,305	$ -	$ -	$ 110,901,305
	Customer Charge						
4	0 to 5,000 kWh	506,209	$ 30.00	$ 15,186,270	$ -	$ -	$ 15,186,270
5	Over 5,000 kWh	73,511	$ 50.00	$ 3,675,550	$ -	$ -	$ 3,675,550
		579,720		$ 18,861,820	$ -	$ -	$ 18,861,820
6	Secondary Service (SS)			$ 129,763,125	$ -	$ -	$ 129,763,125
	Contract Riders						
7	Special Contract Revenue			$ 1,432,977	$ -	$ -	$ 1,432,977
8	No. 3 Demand Side Management			$ -	$ -	$ -	$ -
9	No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
10	No. 6 Fuel Cost Adjustment			$ 1,341,609	$ -	$ -	$ 1,341,609
11	No. 9 Net Metering			$ -	$ -	$ -	$ -
12	No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
13	No. 20 Environmental Compliance Cost Recovery			$ 7,331,938	$ -	$ -	$ 7,331,938
14	No. 21 Green Power			$ 4,802	$ -	$ -	$ 4,802
15	No. 22 Core and Core Demand Side Management			$ 2,969,167	$ -	$ -	$ 2,969,167
16	No. 26 Regional Transmission Organization Rider			$ 1,439,028	$ -	$ -	$ 1,439,028
17	Total Rider			$ 14,519,522	$ -	$ -	$ 14,519,522
18	Grand Total			$ 144,282,646	$ -	$ -	$ 144,282,646
19						*Balancing Adjustment*	0.999246
20						**Total Revenue**	**$ 144,173,818**
						Check	TRUE

Indianapolis Power and Light Company
Pro Forma Revenue at Proposed Rates
Test Year Ended June 30, 2016
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	871,281,098	$ 0.104366	$ 90,932,391	$ -	$ -	$ 90,932,391
Over 5,000	348,878,024	$ 0.089666	$ 31,282,604	$ -	$ -	$ 31,282,604
Total kWh	1,220,159,122		$ 122,214,995	$ -	$ -	$ 122,214,995
		Target	$ 122,214,995			
		Difference	$ -			
Customer Charge						
0 to 5,000 kWh	506,209	$ 40.00	$ 20,248,360	$ -	$ -	$ 20,248,360
Over 5,000 kWh	73,511	$ 55.00	$ 4,043,105	$ -	$ -	$ 4,043,105
	579,720		$ 24,291,465	$ -	$ -	$ 24,291,465
		Target	$ 24,291,465			
		Difference	$ -			
Secondary Service (SS)			$ 146,506,460	$ -	$ -	$ 146,506,460
		Target	$ 146,506,460			
		Difference	$ -			
Contract Riders						
Special Contract Revenue			$ 1,432,977	$ -	$ -	$ 1,432,977
No. 3 Demand Side Management			$ -	$ -	$ -	$ -
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			$ 4,802	$ -	$ -	$ 4,802
No. 22 Core and Core Demand Side Management			$ 2,709,004	$ -	$ -	$ 2,709,004
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 4,146,783	$ -	$ -	$ 4,146,783
Grand Total			$ 150,653,243	$ -	$ -	$ 150,653,243
		Check	TRUE			

Indianapolis Power and Light Company
Pro Forma Revenue at Current Rates
Test Year Ended June 30, 2016
Secondary Service - Electric Space Conditioning Separately Metered (SH)

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	532,539,165	$ 0.077134	$ 41,076,876	$ -	$ -	$ 41,076,876
	Customer Charge						
2	All Customers	48,072	$ 30.00	$ 1,442,160	$ -	$ -	$ 1,442,160
3	Secondary Service (SH)			$ 42,519,036	$ -	$ -	$ 42,519,036
	Contract Riders						
4	No. 3 Demand Side Management			$ -	$ -	$ -	$ -
5	No. 6 Fuel Cost Adjustment			$ 585,546	$ -	$ -	$ 585,546
6	No. 9 Net Metering			$ -	$ -	$ -	$ -
7	No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
8	No. 15 Load Displacement			$ -	$ -	$ -	$ -
9	No. 20 Environmental Compliance Cost Recovery			$ 3,200,029	$ -	$ -	$ 3,200,029
10	No. 21 Green Power			$ 649	$ -	$ -	$ 649
11	No. 22 Core and Core Demand Side Management			$ 1,295,895	$ -	$ -	$ 1,295,895
12	No. 26 Regional Transmission Organization Rider			$ 628,065	$ -	$ -	$ 628,065
13	Total Rider			$ 5,710,183	$ -	$ -	$ 5,710,183
14	Grand Total			$ 48,229,219	$ -	$ -	$ 48,229,219
15					*Balancing Adjustment*		*0.999820*
16						**Total Revenue**	**$ 48,220,530**
						Check	TRUE

Indianapolis Power and Light Company
Pro Forma Revenue at Proposed Rates
Test Year Ended June 30, 2016
Secondary Service - Electric Space Conditioning Separately Metered (SH)

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	532,539,165	$ 0.092593	$ 49,309,592	$ -	$ -	$ 49,309,592
		Target	$ 49,309,592			
		Difference	$ -			
Customer Charge						
All Customers	48,072	$ 55.00	$ 2,643,960	$ -	$ -	$ 2,643,960
		Target	$ 2,643,960			
		Difference	$ -			
Secondary Service (SH)			$ 51,953,552	$ -	$ -	$ 51,953,552
		Target	$ 51,953,552			
		Difference	$ -			
Contract Riders						
No. 3 Demand Side Management			$ -	$ -	$ -	$ -
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			$ 649	$ -	$ -	$ 649
No. 22 Core and Core Demand Side Management			$ 1,182,346	$ -	$ -	$ 1,182,346
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 1,182,995	$ -	$ -	$ 1,182,995
Grand Total			$ 53,136,547	$ -	$ -	$ 53,136,547
		Check	TRUE			

Indianapolis Power and Light Company
Pro Forma Revenue at Current Rates
Test Year Ended June 30, 2016
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	1,317,294	$ 0.106205	$ 139,903	$ -	$ -	$ 139,903
2	Over 5,000 kWh	2,315,275	$ 0.091505	$ 211,859	$ -	$ -	$ 211,859
3	Excess of 155 x Connected load	14,688,272	$ 0.077605	$ 1,139,883	$ -	$ -	$ 1,139,883
	Total kWh	18,320,841		$ 1,491,646	$ -	$ -	$ 1,491,646
	Customer Charge						
4	All Customers	324	$ 30.00	$ 9,720	$ -	$ -	$ 9,720
5	Secondary Service (SE)			$ 1,501,366	$ -	$ -	$ 1,501,366
	Contract Riders						
6	No. 3 Demand Side Management			$ -	$ -	$ -	$ -
7	No. 6 Fuel Cost Adjustment			$ 20,144	$ -	$ -	$ 20,144
8	No. 9 Net Metering			$ -	$ -	$ -	$ -
9	No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
10	No. 15 Load Displacement			$ -	$ -	$ -	$ -
11	No. 20 Environmental Compliance Cost Recovery			$ 110,090	$ -	$ -	$ 110,090
12	No. 21 Green Power			$ -	$ -	$ -	$ -
13	No. 22 Core and Core Demand Side Management			$ 44,582	$ -	$ -	$ 44,582
14	No. 26 Regional Transmission Organization Rider			$ 21,607	$ -	$ -	$ 21,607
15	Total Rider			$ 196,424	$ -	$ -	$ 196,424
16	Grand Total			$ 1,697,790	$ -	$ -	$ 1,697,790
17						*Balancing Adjustment*	*1.0026*
18						**Total Revenue**	**$1,702,175**
						Check	TRUE

Indianapolis Power and Light Company
Pro Forma Revenue at Proposed Rates
Test Year Ended June 30, 2016
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	1,317,294	$ 0.120655	$ 158,938	$ -	$ -	$ 158,938
Over 5,000 kWh	2,315,275	$ 0.105955	$ 245,315	$ -	$ -	$ 245,315
Excess of 155 x Connected load	14,688,272	$ 0.092055	$ 1,352,131	$ -	$ -	$ 1,352,131
Total kWh	18,320,841		$ 1,756,384	$ -	$ -	$ 1,756,384
		Target	$ 1,756,384			
		Difference	$ 0			
Customer Charge						
All Customers	324	$ 55.00	$ 17,820	$ -	$ -	$ 17,820
		Target	$ 17,820			
		Difference	$ -			
Secondary Service (SE)			$ 1,774,204	$ -	$ -	$ 1,774,204
		Target	$ 1,774,204			
		Difference	$ 0			
Contract Riders						
No. 3 Demand Side Management			$ -	$ -	$ -	$ -
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 Core and Core Demand Side Management			$ 40,676	$ -	$ -	$ 40,676
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 40,676	$ -	$ -	$ 40,676
Grand Total			$ 1,814,880	$ -	$ -	$ 1,814,880
		Check	TRUE			

Indianapolis Power and Light Company
Pro Forma Revenue at Current Rates
Test Year Ended June 30, 2016
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	420,505	$ 0.064316	$ 27,045	$ -	$ -	$ 27,045
	Customer Charge						
2	All Customers	1,128	$ 7.10	$ 8,009	$ -	$ -	$ 8,009
3	Water Heating - Controlled (CB)			$ 35,054	$ -	$ -	$ 35,054
	Contract Riders						
4	No. 3 Demand Side Management			$ -	$ -	$ -	$ -
5	No. 6 Fuel Cost Adjustment			$ 462	$ -	$ -	$ 462
6	No. 9 Net Metering			$ -	$ -	$ -	$ -
7	No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
8	No. 20 Environmental Compliance Cost Recovery			$ 2,527	$ -	$ -	$ 2,527
9	No. 21 Green Power			$ 1	$ -	$ -	$ 1
10	No. 22 Core and Core Demand Side Management			$ 1,023	$ -	$ -	$ 1,023
11	No. 26 Regional Transmission Organization Rider			$ 496	$ -	$ -	$ 496
12	Total Rider			$ 4,509	$ -	$ -	$ 4,509
13	Grand Total			$ 39,563	$ -	$ -	$ 39,563
14						*Balancing Adjustment*	0.9998
15						**Total Revenue**	**$ 39,556**
						Check	TRUE

Indianapolis Power and Light Company
Pro Forma Revenue at Proposed Rates
Test Year Ended June 30, 2016
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	420,505	$ 0.064880	$ 27,282	$ -	$ -	$ 27,282
		Target	$ 27,282			
		Difference	$ -			
Customer Charge						
All Customers	1,128	$ 17.00	$ 19,176	$ -	$ -	$ 19,176
		Target	$ 19,176			
		Difference	$ -			
Water Heating - Controlled (CB)			$ 46,458	$ -	$ -	$ 46,458
		Target	$ 46,458			
		Difference	$ -			
Contract Riders						
No. 3 Demand Side Management			$ -	$ -	$ -	$ -
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			$ 1	$ -	$ -	$ 1
No. 22 Core and Core Demand Side Management			$ 934	$ -	$ -	$ 934
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 934	$ -	$ -	$ 934
Grand Total			$ 47,393	$ -	$ -	$ 47,393
		Check	TRUE			

Indianapolis Power and Light Company
Pro Forma Revenue at Current Rates
Test Year Ended June 30, 2016
Water Heating - Uncontrolled Service (UW)

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	1,368,082	$ 0.058139	$ 79,539	$ -	$ -	$ 79,539
	Customer Charge						
2	All Customers	1,032	$ 27.00	$ 27,864	$ -	$ -	$ 27,864
3	Water Heating - Uncontrolled (UW)			$ 107,403	$ -	$ -	$ 107,403
	Contract Riders						
4	No. 3 Demand Side Management			$ -	$ -	$ -	$ -
5	No. 6 Fuel Cost Adjustment			$ 1,504	$ -	$ -	$ 1,504
6	No. 9 Net Metering			$ -	$ -	$ -	$ -
7	No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
8	No. 20 Environmental Compliance Cost Recovery			$ 8,221	$ -	$ -	$ 8,221
9	No. 21 Green Power			$ -	$ -	$ -	$ -
10	No. 22 Core and Core Demand Side Management			$ 3,329	$ -	$ -	$ 3,329
11	No. 26 Regional Transmission Organization Rider			$ 1,613	$ -	$ -	$ 1,613
12	Total Rider			$ 14,668	$ -	$ -	$ 14,668
13	Grand Total			$ 122,071	$ -	$ -	$ 122,071
14						*Balancing Adjustment*	*1.000220*
15						**Total Revenue**	**$ 122,097**
						Check	TRUE

Indianapolis Power and Light Company
Pro Forma Revenue at Proposed Rates
Test Year Ended June 30, 2016
Water Heating - Uncontrolled Service (UW)

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	1,368,082	$ 0.066839	$ 91,441	$ -	$ -	$ 91,441
		Target	$ 91,441			
		Difference	$ -			
Customer Charge						
All Customers	1,032	$ 37.00	$ 38,184	$ -	$ -	$ 38,184
		Target	$ 38,184			
		Difference	$ -			
Water Heating - Uncontrolled (UW)			$ 129,625	$ -	$ -	$ 129,625
		Target	$ 129,625			
		Difference	$ -			
Contract Riders						
No. 3 Demand Side Management			$ -	$ -	$ -	$ -
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 Core and Core Demand Side Management			$ 3,037	$ -	$ -	$ 3,037
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 3,037	$ -	$ -	$ 3,037
Grand Total			$ 132,663	$ -	$ -	$ 132,663
		Check	TRUE			

Indianapolis Power and Light Company
Pro Forma Revenue at Current Rates
Test Year Ended June 30, 2016
Secondary Service (Large) (SL)

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	3,501,932,620	$ 0.035112	$ 122,959,858	$ -	$ -	$ 122,959,858
	Billed kW						
2	All kW	9,227,969	$ 17.10	$ 157,798,270	$ -	$ -	$ 157,798,270
3	Power factor			$ (4,795,180)			$ (4,795,180)
	Customer Charge						
4	All Customers	54,864	$ 120.00	$ 6,583,680	$ -	$ -	$ 6,583,680
5	Secondary Service (Large) (SL)			$ 282,546,628	$ -	$ -	$ 282,546,628
	Contract Riders						
6	No. 3 Demand Side Management			$ -	$ -	$ -	$ -
7	No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
8	No. 6 Fuel Cost Adjustment			$ 3,850,501	$ -	$ -	$ 3,850,501
9	No. 8 Off Peak Service			$ (256,728)	$ -	$ -	$ (256,728)
10	No. 9 Net Metering			$ -	$ -	$ -	$ -
11	No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
12	No. 15 Load Displacement			$ -	$ -	$ -	$ -
13	No. 16 Load Displacement			$ -	$ -	$ -	$ -
14	No. 17 Curtailment Energy			$ (6,935)	$ -	$ -	$ (6,935)
15	No. 18 Curtailment Energy II			$ -	$ -	$ -	$ -
16	No. 20 Environmental Compliance Cost Recovery			$ 19,075,390	$ -	$ -	$ 19,075,390
17	No. 21 Green Power			$ 14,557	$ -	$ -	$ 14,557
18	No. 22 Core and Core Demand Side Management			$ 5,014,054	$ -	$ -	$ 5,014,054
19	No. 26 Regional Transmission Organization Rider			$ 3,743,897	$ -	$ -	$ 3,743,897
20	Total Rider			$ 31,434,737	$ -	$ -	$ 31,434,737
21	Grand Total			$ 313,981,365	$ -	$ -	$ 313,981,365
22						*Balancing Adjustment*	*1.002117*
23						**Total Revenue**	**$ 314,645,975**
						Check	TRUE

Indianapolis Power and Light Company
Pro Forma Revenue at Proposed Rates
Test Year Ended June 30, 2016
Secondary Service (Large) (SL)

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	3,501,932,620	$ 0.037221	$ 130,345,314	$ -	$ -	$ 130,345,314
		Target	$ 130,345,314			
		Difference	$ -			
Billed kW						
All kW	9,227,969	$ 21.06	$ 194,341,027	$ -	$ -	$ 194,341,027
		Target	$ 194,341,027			
		Difference	$ -			
Power factor			$ (5,510,208)			$ (5,510,208)
Customer Charge						
All Customers	54,864	$ 120.00	$ 6,583,680	$ -	$ -	$ 6,583,680
		Target	$ 6,583,680			
		Difference	$ -			
Secondary Service (Large) (SL)			$ 325,759,814	$ -	$ -	$ 325,759,814
		Target	$ 325,759,814			
		Difference	$ -			
Contract Riders						
No. 3 Demand Side Management			$ -	$ -	$ -	$ -
No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
No. 6 Fuel Cost Adjustment			$ -	$ -	$ -	$ -
No. 8 Off Peak Service			$ (316,174)	$ -	$ -	$ (316,174)
No. 9 Net Metering			$ -	$ -	$ -	$ -
No. 13 Air Conditioning Load Management			$ -	$ -	$ -	$ -
No. 15 Load Displacement			$ -	$ -	$ -	$ -
No. 16 Load Displacement			$ -	$ -	$ -	$ -
No. 17 Curtailment Energy			$ (6,935)	$ -	$ -	$ (6,935)
No. 18 Curtailment Energy II			$ -	$ -	$ -	$ -
No. 20 Environmental Compliance Cost Recovery			$ -	$ -	$ -	$ -
No. 21 Green Power			$ 14,557	$ -	$ -	$ 14,557
No. 22 Core and Core Demand Side Management			$ 4,587,575	$ -	$ -	$ 4,587,575
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 4,279,024	$ -	$ -	$ 4,279,024
Grand Total			$ 330,038,838	$ -	$ -	$ 330,038,838
		Check	TRUE			

Indianapolis Power and Light Company
Pro Forma Revenue at Current Rates
Test Year Ended June 30, 2016
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	1,230,822,724	$ 0.034047	$ 41,905,821	$ -	$ -	$ 41,905,821
	Billed kW						
2	All kW	2,794,988	$ 18.20	$ 50,868,782	$ -	$ -	$ 50,868,782
3	Power factor			$ (2,019,194)			$ (2,019,194)
	Customer Charge						
4	All Customers	1,692	$ 120.00	$ 203,040	$ -	$ -	$ 203,040
5	Primary Service (Large) (PL)			$ 90,958,449	$ -	$ -	$ 90,958,449
	Contract Riders						
6	Special Contract Revenue			$ (791,000)	$ -	$ -	$ (791,000)
7	No. 3 Demand Side Management			$ -	$ -	$ -	$ -
8	No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
9	No. 6 Fuel Cost Adjustment			$ 1,353,334	$ -	$ -	$ 1,353,334
10	No. 8 Off Peak Service			$ (56,711)	$ -	$ -	$ (56,711)
11	No. 9 Net Metering			$ -	$ -	$ -	$ -
12	No. 14 Interruptible Power			$ -	$ -	$ -	$ -
13	No. 15 Load Displacement			$ -	$ -	$ -	$ -
14	No. 16 Load Displacement			$ -	$ -	$ -	$ -
15	No. 17 Curtailment Energy			$ -	$ -	$ -	$ -
16	No. 18 Curtailment Energy II			$ -	$ -	$ -	$ -
17	No. 20 Environmental Compliance Cost Recovery			$ 6,704,419	$ -	$ -	$ 6,704,419
18	No. 21 Green Power			$ 51,510	$ -	$ -	$ 51,510
19	No. 22 Core and Core Demand Side Management			$ 1,762,287	$ -	$ -	$ 1,762,287
20	No. 26 Regional Transmission Organization Rider			$ 1,315,866	$ -	$ -	$ 1,315,866
21	Total Rider			$ 10,339,706	$ -	$ -	$ 10,339,706
22	Grand Total			$ 101,298,154	$ -	$ -	$ 101,298,154
23					*Balancing Adjustment*		*0.988134*
24						**Total Revenue**	**$ 100,096,102**
						Check	TRUE

Indianapolis Power and Light Company
Pro Forma Revenue at Proposed Rates
Test Year Ended June 30, 2016
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	1,230,822,724	$ 0.036110	$ 44,445,501	$ -	$ -	$ 44,445,501
		Target	$ 44,445,501			
		Difference	$ -			
Billed kW						
All kW	2,794,988	$ 23.22	$ 64,899,621	$ -	$ -	$ 64,899,621
		Target	$ 64,899,621			
		Difference	$ -			
Power factor			$ (2,347,708)			$ (2,347,708)
Customer Charge						
All Customers	1,692	$ 120.00	$ 203,040	$ -	$ -	$ 203,040
		Target	$ 203,040			
		Difference	$ -			
Primary Service (Large) (PL)			$ 107,200,454	$ -	$ -	$ 107,200,454
		Target	$ 107,200,454			
		Difference	$ -			
Contract Riders						
Special Contract Revenue			$ (791,000)	$ -	$ -	$ (791,000)
No. 3 Demand Side Management			$ -	$ -	$ -	$ -
No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
No. 6 Fuel Cost Adjustment			$ -	$ -	$ -	$ -
No. 8 Off Peak Service			$ (72,354)	$ -	$ -	$ (72,354)
No. 9 Net Metering			$ -	$ -	$ -	$ -
No. 14 Interruptible Power			$ -	$ -	$ -	$ -
No. 15 Load Displacement			$ -	$ -	$ -	$ -
No. 16 Load Displacement			$ -	$ -	$ -	$ -
No. 17 Curtailment Energy			$ -	$ -	$ -	$ -
No. 18 Curtailment Energy II			$ -	$ -	$ -	$ -
No. 20 Environmental Compliance Cost Recovery			$ -	$ -	$ -	$ -
No. 21 Green Power			$ 51,510	$ -	$ -	$ 51,510
No. 22 Core and Core Demand Side Management			$ 1,612,393	$ -	$ -	$ 1,612,393
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 800,550	$ -	$ -	$ 800,550
Grand Total			$ 108,001,004	$ -	$ -	$ 108,001,004
		Check	TRUE			

Indianapolis Power and Light Company
Pro Forma Revenue at Current Rates
Test Year Ended June 30, 2016
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	30,373,360	$ 0.073311	$ 2,226,701	$ -	$ -	$ 2,226,701
2	Additional kWh	7,465,964	$ 0.058311	$ 435,348	$ -	$ -	$ 435,348
3	Total kWh	37,839,324		$ 2,662,049	$ -	$ -	$ 2,662,049
4	*Minimum Charge Adj.*			$ 120,389			$ 120,389
5	*Power factor*			$ 25,006			$ 25,006
	Customer Charge						
6	All Customers	372	$ 1,000.00	$ 372,000	$ -	$ -	$ 372,000
7	Process Heating (PH)			$ 3,179,444	$ -	$ -	$ 3,179,444
	Contract Riders						
8	No. 3 Demand Side Management			$ -	$ -	$ -	$ -
9	No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
10	No. 6 Fuel Cost Adjustment			$ 41,606	$ -	$ -	$ 41,606
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			$ 206,115	$ -	$ -	$ 206,115
16	No. 21 Green Power			$ -	$ -	$ -	$ -
17	No. 22 Core and Core Demand Side Management			$ 54,178	$ -	$ -	$ 54,178
18	No. 26 Regional Transmission Organization Rider			$ 40,454	$ -	$ -	$ 40,454
19	Total Rider			$ 342,352	$ -	$ -	$ 342,352
20	Grand Total			$ 3,521,797	$ -	$ -	$ 3,521,797
21						*Balancing Adjustment*	*0.985039*
22						**Total Revenue**	**$ 3,469,108**
						Check	TRUE

Indianapolis Power and Light Company
Pro Forma Revenue at Proposed Rates
Test Year Ended June 30, 2016
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	30,373,360	$ 0.082904	$ 2,518,076	$ -	$ -	$ 2,518,076
Additional kWh	7,465,964	$ 0.067904	$ 506,969	$ -	$ -	$ 506,969
Total kWh	37,839,324		$ 3,025,045	$ -	$ -	$ 3,025,045
		Target	$ 3,025,045			
		Difference	$ -			
Minimum Charge Adj.			$ 136,143			$ 136,143
Power factor			$ 28,386			$ 28,386
Customer Charge						
All Customers	372	$ 1,250.00	$ 465,000	$ -	$ -	$ 465,000
		Target	$ 465,000			
		Difference	$ -			
Process Heating (PH)			$ 3,654,575	$ -	$ -	$ 3,654,575
		Target	$ 3,654,575			
		Difference	$ -			
Contract Riders						
No. 3 Demand Side Management			$ -	$ -	$ -	$ -
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 Core and Core Demand Side Management			$ 49,570	$ -	$ -	$ 49,570
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 49,570	$ -	$ -	$ 49,570
Grand Total			$ 3,704,144	$ -	$ -	$ 3,704,144
		Check TRUE				

Indianapolis Power and Light Company
Pro Forma Revenue at Current Rates
Test Year Ended June 30, 2016
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	1,317,040,818	$ 0.045502	$ 59,927,991	$ -	$ -	$ 59,927,991
	Billed kW						
2	All kW	2,462,182	$ 12.05	$ 29,669,293	$ -	$ -	$ 29,669,293
3	Power factor			$ (2,798,059)			$ (2,798,059)
	Customer Charge						
4	All Customers	324	$ 135.00	$ 43,740	$ -	$ -	$ 43,740
5	High Load Factor Service (HL1)			$ 86,842,965	$ -	$ -	$ 86,842,965
	Contract Riders						
6	No. 3 Demand Side Management			$ -	$ -	$ -	$ -
7	No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
8	No. 6 Fuel Cost Adjustment			$ 1,448,134	$ -	$ -	$ 1,448,134
9	No. 8 Off Peak Service			$ (128,923)	$ -	$ -	$ (128,923)
10	No. 9 Net Metering			$ -	$ -	$ -	$ -
11	No. 14 Interruptible Power			$ -	$ -	$ -	$ -
12	No. 15 Load Displacement			$ -	$ -	$ -	$ -
13	No. 16 Load Displacement			$ -	$ -	$ -	$ -
14	No. 17 Curtailment Energy			$ -	$ -	$ -	$ -
15	No. 18 Curtailment Energy II			$ -	$ -	$ -	$ -
16	No. 20 Environmental Compliance Cost Recovery			$ 6,295,585	$ -	$ -	$ 6,295,585
17	No. 21 Green Power			$ 49,159	$ -	$ -	$ 49,159
18	No. 22 Core and Core Demand Side Management			$ 1,885,734	$ -	$ -	$ 1,885,734
19	No. 26 Regional Transmission Organization Rider			$ 1,235,625	$ -	$ -	$ 1,235,625
20	Total Rider			$ 10,785,314	$ -	$ -	$ 10,785,314
21	Grand Total			$ 97,628,280	$ -	$ -	$ 97,628,280
22						*Balancing Adjustment*	*1.000884*
23						**Total Revenue**	**$ 97,714,606**
						Check	TRUE

Indianapolis Power and Light Company
Pro Forma Revenue at Proposed Rates
Test Year Ended June 30, 2016
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	1,317,040,818	$ 0.036088	$ 47,529,993	$ -	$ -	$ 47,529,993
		Target	$ 47,529,993			
		Difference	$ -			
Billed kW						
All kW	2,462,182	$ 23.21	$ 57,147,244	$ -	$ -	$ 57,147,244
		Target	$ 57,147,244			
		Difference	$ -			
Power factor			$ (3,259,315)			$ (3,259,315)
Customer Charge						
All Customers	324	$ 135.00	$ 43,740	$ -	$ -	$ 43,740
		Target	$ 43,740			
		Difference	$ -			
High Load Factor Service (HL1)			$ 101,461,662	$ -	$ -	$ 101,461,662
		Target	$ 101,461,662			
		Difference	$ -			
Contract Riders						
No. 3 Demand Side Management			$ -	$ -	$ -	$ -
No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
No. 6 Fuel Cost Adjustment			$ -	$ -	$ -	$ -
No. 8 Off Peak Service			$ (248,324)	$ -	$ -	$ (248,324)
No. 9 Net Metering			$ -	$ -	$ -	$ -
No. 14 Interruptible Power			$ -	$ -	$ -	$ -
No. 15 Load Displacement			$ -	$ -	$ -	$ -
No. 16 Load Displacement			$ -	$ -	$ -	$ -
No. 17 Curtailment Energy			$ -	$ -	$ -	$ -
No. 18 Curtailment Energy II			$ -	$ -	$ -	$ -
No. 20 Environmental Compliance Cost Recovery			$ -	$ -	$ -	$ -
No. 21 Green Power			$ 49,159	$ -	$ -	$ 49,159
No. 22 Core and Core Demand Side Management			$ 1,725,340	$ -	$ -	$ 1,725,340
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 1,526,175	$ -	$ -	$ 1,526,175
Grand Total			$ 102,987,837	$ -	$ -	$ 102,987,837
		Check	TRUE			

Indianapolis Power and Light Company
Pro Forma Revenue at Current Rates
Test Year Ended June 30, 2016
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	225,993,534	$ 0.046626	$ 10,537,175	$ -	$ -	$ 10,537,175
	Billed kW						
2	All kW	429,135	$ 11.50	$ 4,935,053	$ -	$ -	$ 4,935,053
3	Power factor			$ (651,582)			$ (651,582)
	Customer Charge						
4	All Customers	60	$ 140.00	$ 8,400	$ -	$ -	$ 8,400
5	High Load Factor Service (HL2)			$ 14,829,045	$ -	$ -	$ 14,829,045
	Contract Riders						
6	No. 3 Demand Side Management			$ -	$ -	$ -	$ -
7	No. 4 Additional Charges for other facilities			$ -	$ -	$ -	$ -
8	No. 6 Fuel Cost Adjustment			$ 248,488	$ -	$ -	$ 248,488
9	No. 8 Off Peak Service			$ -	$ -	$ -	$ -
10	No. 9 Net Metering			$ -	$ -	$ -	$ -
11	No. 14 Interruptible Power			$ -	$ -	$ -	$ -
12	No. 15 Load Displacement			$ -	$ -	$ -	$ -
13	No. 16 Load Displacement			$ -	$ -	$ -	$ -
14	No. 17 Curtailment Energy			$ -	$ -	$ -	$ -
15	No. 18 Curtailment Energy II			$ -	$ -	$ -	$ -
16	No. 20 Environmental Compliance Cost Recovery			$ 1,080,271	$ -	$ -	$ 1,080,271
17	No. 21 Green Power			$ 15,355	$ -	$ -	$ 15,355
18	No. 22 Core and Core Demand Side Management			$ 323,577	$ -	$ -	$ 323,577
19	No. 26 Regional Transmission Organization Rider			$ 212,023	$ -	$ -	$ 212,023
20	Total Rider			$ 1,879,714	$ -	$ -	$ 1,879,714
21	Grand Total			$ 16,708,759	$ -	$ -	$ 16,708,759
22						*Balancing Adjustment*	*0.992167*
23						**Total Revenue**	**$ 16,577,885**
						Check	TRUE

Indianapolis Power and Light Company
Pro Forma Revenue at Proposed Rates
Test Year Ended June 30, 2016
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	225,993,534	$ 0.035892	$ 8,111,254	$ -	$ -	$ 8,111,254
		Target	$ 8,111,254			
		Difference	$ -			
Billed kW						
All kW	429,135	$ 21.49	$ 9,222,111	$ -	$ -	$ 9,222,111
		Target	$ 9,222,111			
		Difference	$ -			
Power factor			$ (729,912)			$ (729,912)
Customer Charge						
All Customers	60	$ 215.00	$ 12,900	$ -	$ -	$ 12,900
		Target	$ 12,900			
		Difference	$ -			
High Load Factor Service (HL2)			$ 16,616,353	$ -	$ -	$ 16,616,353
		Target	$ 16,616,353			
		Difference	$ -			
Contract Riders						
No. 3 Demand Side Management			$ -	$ -	$ -	$ -
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. 16 Load Displacement			$ -	$ -	$ -	$ -
No. 17 Curtailment Energy			$ -	$ -	$ -	$ -
No. 18 Curtailment Energy II			$ -	$ -	$ -	$ -
No. 20 Environmental Compliance Cost Recovery			$ -	$ -	$ -	$ -
No. 21 Green Power			$ 15,355	$ -	$ -	$ 15,355
No. 22 Core and Core Demand Side Management			$ 296,054	$ -	$ -	$ 296,054
No. 26 Regional Transmission Organization Rider			$ -	$ -	$ -	$ -
Total Rider			$ 311,409	$ -	$ -	$ 311,409
Grand Total			$ 16,927,762	$ -	$ -	$ 16,927,762
		Check	TRUE			

Indianapolis Power and Light Company
Lighting Rate Design

Line No.	Code	Description	Inventory	Current Rate with ECCR, RTO and Fuel (Base Fuel and FCA)	Current Revenue Proforma @ Present Rates	Proposed Annual Rate	Proposed Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Company Installed, Owned, and Maintained (APL)				**3.4%**	
		LIGHTS INSTALLED BEFORE LAST RATE CASE					
1	68	175 WATT LIGHT	12,053	$91.78	$1,106,203	$94.92	$1,144,071
2	69	400 WATT MV REDDY SENT.	1,693	$172.48	$292,007	$178.32	$301,896
3	70	1000 WATT MV REDDY SENT.	166	$302.43	$50,203	$312.72	$51,912
4	71	100 WATT LIGHT	6,349	$81.69	$518,626	$84.48	$536,364
5	72	150 WATT HPS REDDY SENT.	1,151	$173.19	$199,339	$179.16	$206,213
6	73	250 WATT HPS REDDY SENT.	1,038	$229.48	$238,200	$237.36	$246,380
7	74	400 WATT HPS REDDY SENT.	1,389	$264.90	$367,946	$273.96	$380,530
8	78	175 WATT MV - SEC. METERED - OVERHEAD	74	$67.68	$5,008	$69.96	$5,177
9	79	400 WATT MV - SEC. METERED OVERHEAD	16	$131.28	$2,100	$135.72	$2,172
10	80	1000 WATT MV - SEC. METERED - OVERHEAD	1	$203.28	$203	$210.24	$210
11	81	100 WATT HPS - SEC. METERED - OVERHEAD	15	$70.08	$1,051	$72.48	$1,087
12	82	150 WATT HPS - SEC. METERED - OVERHEAD	1	$160.44	$160	$165.96	$166
13	83	250 WATT HPS - SEC. METERED - OVERHEAD	2	$202.68	$405	$209.64	$419
14	84	400 WATT HPS - SEC. METERED - OVERHEAD	12	$223.56	$2,683	$231.24	$2,775
15	85	ENERGY AND CONTROL ONLY	1	$39.60	$40	$40.92	$41
16	86	400 WATT MV FLOOD - OVERHEAD	631	$172.72	$108,986	$178.56	$112,671
17	87	150 WATT HPS FLOOD - OVERHEAD	542	$173.79	$94,193	$179.76	$97,430
18	88	250 WATT HPS FLOOD - OVERHEAD	749	$229.60	$171,970	$237.48	$177,873
19	89	400 WATT HPS FLOOD - OVERHEAD	6,999	$265.02	$1,854,872	$274.08	$1,918,286
20	90	400 WATT METAL HALIDE FLOOD - OVERHEAD	1,534	$264.78	$406,178	$273.84	$420,071
21	91	400 WATT MV FLOOD - SEC. METERED	6	$131.28	$788	$135.72	$814
22	92	150 WATT HPS FLOOD - SEC. METERED	1	$160.44	$160	$165.96	$166
23	93	250 WATT HPS FLOOD - SEC. METERED	6	$202.68	$1,216	$209.64	$1,258
24	94	400 WATT HPS FLOOD - SEC. METERED	38	$223.56	$8,495	$231.24	$8,787
25	95	400 WATT METAL HALIDE FLOOD-SEC. METERED	2	$223.56	$447	$231.24	$462
26	96	- WOOD POLE WITH OVERHEAD FEED -	9,086	$45.60	$414,322	$47.16	$428,496
27	97	- WOOD POLE WITH UNDERGROUND FEED -	915	$112.68	$103,102	$116.52	$106,616
28	127	400 WATT MV-1ST FIXTURE	19	$256.60	$4,875	$265.32	$5,041
29	128	175 WATT MV-1ST FIXTURE	3	$209.26	$628	$216.36	$649
30	129	400 WATT HPS-1ST FIXTURE	139	$374.34	$52,033	$387.12	$53,810
31	130	250 WATT HPS-1ST FIXTURE	216	$252.04	$54,441	$260.64	$56,298
32	131	150 WATT HPS-1ST FIXTURE	197	$217.59	$42,865	$225.00	$44,325
33	132	100 WATT HPS-1ST FIXTURE	32	$200.37	$6,412	$207.24	$6,632
34	135	400 WATT HPS-1ST FIXTURE-SHOEBOX	119	$310.50	$36,949	$321.12	$38,213
35	136	250 WATT HPS-1ST FIXTURE-SHOEBOX	113	$253.72	$28,670	$262.44	$29,656
36	137	400 WATT METAL HALIDE-1ST FIX-SHOEBOX	383	$310.26	$118,831	$320.88	$122,897
37	138	400 WATT MV-1ST FIXTURE-FLOOD	5	$256.60	$1,283	$265.32	$1,327
38	139	150 WATT HPS-1ST FIXTURE-FLOOD	46	$217.59	$10,009	$225.00	$10,350
39	140	250 WATT HPS-1ST FIXTURE-FLOOD	77	$252.04	$19,407	$260.64	$20,069
40	141	400 WATT HPS-1ST FIXTURE-FLOOD	314	$374.34	$117,543	$387.12	$121,556
41	142	400 WATT METAL HALIDE-1ST FIX-FLOOD	113	$310.26	$35,060	$320.88	$36,259
42	144	400 WATT MV-ADDIT'L FIXTURE	7	$172.48	$1,207	$178.32	$1,248
43	145	175 WATT MV-ADDIT'L FIXTURE	2	$91.78	$184	$94.92	$190
44	146	400 WATT HPS-ADDIT'L FIXTURE	59	$264.90	$15,629	$273.96	$16,164
45	147	250 WATT HPS-ADDIT'L FIXTURE	20	$229.48	$4,590	$237.36	$4,747
46	148	150 WATT HPS-ADDIT'L FIXTURE	16	$173.19	$2,771	$179.16	$2,867
47	149	100 WATT HPS-ADDIT'L FIXTURE	3	$81.69	$245	$84.48	$253
48	152	400 WATT HPS-ADDIT'L FIXTURE-SHOEBOX	28	$109.98	$3,079	$113.76	$3,185
49	153	250 WATT HPS-ADDIT'L FIXTURE-SHOEBOX	13	$86.20	$1,121	$89.16	$1,159
50	154	400 WATT METAL HALIDE-ADDT'L FIX-SHOEBOX	114	$109.74	$12,511	$113.52	$12,941
51	155	400 WATT MV-ADDIT'L FIXTURE-FLOOD	7	$172.48	$1,207	$178.32	$1,248
52	156	150 WATT HPS-ADDIT'L FIXTURE-FLOOD	50	$173.19	$8,659	$179.16	$8,958
53	157	250 WATT HPS-ADDIT'L FIXTURE-FLOOD	60	$229.48	$13,769	$237.36	$14,242
54	158	400 WATT HPS-ADDIT'L FIXTURE-FLOOD	382	$264.90	$101,192	$273.96	$104,653
55	159	400 WATT METAL HALIDE-ADDT'L FIX-FLOOD	221	$109.74	$24,253	$113.52	$25,088
56	160	175 W MV POST TOP WASH	44	$317.98	$13,991	$328.80	$14,467
57	161	175 W MV POST TOP	32	$203.74	$6,520	$210.72	$6,743
58	162	100 W HPS POST TOP WASH	74	$310.77	$22,997	$321.36	$23,781
59	163	100 W HPS POST TOP	413	$199.41	$82,355	$206.16	$85,144
60	164	150 W HPS POST TOP WASH	132	$356.55	$47,064	$368.76	$48,676
61	165	150 W HPS POST TOP BALL	60	$245.19	$14,711	$253.56	$15,214
62	180	250 WATT MET HAL 18 FT DIR EMBEDDED	91	$585.29	$53,261	$605.28	$55,080
63	181	250 WATT MET HAL 12 FT ANCHOR BASED	89	$642.29	$57,164	$664.20	$59,114
64	182	2-250 WATT MET HAL 18 FT DIR EMBEDDED	89	$807.82	$71,896	$835.44	$74,354
65	183	2-250 WATT MET HAL 12 FT ANCHOR BASED	3	$864.70	$2,594	$894.24	$2,683
66	188	250 WATT MET HAL 18 FT DIR EMBED PRI METER	32	$534.24	$17,096	$552.48	$17,679
67	189	250 WATT MET HAL 12 FT ANCHOR BASE PRI METER	16	$591.12	$9,458	$611.28	$9,780
68	190	2-250 WATT MET HAL 18 FT DIR EMBED PRI METER	17	$712.20	$12,107	$736.56	$12,522
69	191	2-250 WATT MET HAL 12 FT ANCHOR BASE PRI METER	9	$769.20	$6,923	$795.48	$7,159
70		***Sub-Total***	**48,329**		**$7,086,464**		**$7,328,763**
71		**New Lights Installed After Last Rate Case**					**$68,820**
72		**Total APL**					**$7,397,583**

Indianapolis Power and Light Company
Lighting Rate Design

Line No.	Code	Description	Inventory	Current Rate with ECCR, RTO and Fuel (Base Fuel and FCA)	Current Revenue Proforma @ Present Rates	Proposed Annual Rate	Proposed Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Company Installed, Owned, and Maintained (MU-1)				**2.6%**	
		LIGHTS INSTALLED BEFORE LAST RATE CASE					
73	1	1000 WATT MV - OVERHEAD	1	$272.07	$272	$279.24	$279
74	3	1000 WATT MV - METAL COLUMN	7	$400.47	$2,803	$411.12	$2,878
75	4	400 WATT MV - OVERHEAD	40	$149.56	$5,982	$153.48	$6,139
76	6	400 WATT MV - METAL COLUMN	203	$209.56	$42,540	$215.16	$43,677
77	7	175 WATT MV - OVERHEAD	1,058	$104.74	$110,813	$107.52	$113,756
78	9	175 WATT MV - METAL COLUMN	1,038	$170.50	$176,977	$174.96	$181,608
79	10	175 W MV - POST TOP	556	$166.06	$92,328	$170.40	$94,742
80	11	175 W MV - POST TOP WASH	207	$258.94	$53,600	$265.80	$55,021
81	12	400 WATT HPS - OVERHEAD	1,525	$176.82	$269,650	$181.56	$276,879
82	13	400 WATT HPS - TRAFFIC COLUMN	391	$176.82	$69,136	$181.56	$70,990
83	14	400 WATT HPS - METAL COLUMN	2,184	$305.22	$666,600	$313.32	$684,291
84	15	250 WATT HPS - OVERHEAD	5,453	$144.28	$786,758	$148.08	$807,480
85	16	250 WATT HPS - TRAFFIC COLUMN	208	$144.28	$30,010	$148.08	$30,801
86	17	250 WATT HPS - METAL COLUMN	2,099	$205.48	$431,302	$210.96	$442,805
87	18	150 WATT HPS - OVERHEAD	1,791	$114.03	$204,224	$117.00	$209,547
88	19	150 WATT HPS - TRAFFIC COLUMN	26	$114.03	$2,965	$117.00	$3,042
89	20	150 WATT HPS - METAL COLUMN	759	$177.27	$134,546	$181.92	$138,077
90	21	100 WATT HPS - OVERHEAD	12,131	$97.29	$1,180,180	$99.84	$1,211,159
91	22	100 WATT HPS - TRAFFIC COLUMN	3	$97.29	$292	$99.84	$300
92	23	100 WATT HPS - METAL COLUMN	2,723	$163.05	$443,975	$167.40	$455,830
93	24	100 W HPS - POST TOP	5,954	$162.33	$966,491	$166.68	$992,413
94	25	100 W HPS - POST TOP WASH	1,793	$252.69	$453,066	$259.32	$464,961
95	26	150 W HPS- POST TOP BALL	28	$195.87	$5,484	$201.00	$5,628
96	27	150 W HPS - POST TOP WASH	3,194	$290.07	$926,477	$297.72	$950,918
97	32	1-150 & 4-100 WATT HPS - CLUSTER	22	$654.37	$14,396	$671.64	$14,776
98	33	400 WATT HPS-METAL COLUMN-PAINTED BRONZE	328	$332.70	$109,125	$341.52	$112,019
99	34	400 WATT HPS-TRAFFIC COLUMN-PAINT BRONZE	46	$181.38	$8,343	$186.24	$8,567
100	35	250 WATT HPS-METAL COLUMN-PAINTED BRONZE	11	$232.96	$2,563	$239.16	$2,631
101	37	175 WATT MV - FIBERGLASS COLUMN	7	$162.34	$1,136	$166.68	$1,167
102	38	100 WATT HPS - FIBERGLASS COLUMN	307	$154.89	$47,550	$159.00	$48,813
103	39	150 WATT HPS - FIBERGLASS COLUMN	785	$168.99	$132,656	$173.52	$136,213
104	40	250 WATT HPS - FIBERGLASS COLUMN	695	$197.32	$137,137	$202.56	$140,779
105	41	400 WATT HPS - FIBERGLASS COLUMN	619	$283.38	$175,412	$290.88	$180,055
106	42	400 WATT MH SHOEBOX - FIBERGLASS COLUMN	116	$259.14	$30,061	$266.04	$30,861
107	43	2-400 WATT MH SHOEBOX-FIBERGLASS COLUMN	51	$355.21	$18,116	$364.56	$18,593
108	45	150 WATT HPS UPASS -WALL MOUNTED	202	$149.67	$30,233	$153.60	$31,027
109	46	250 W HPS - SHOEBOX	72	$206.80	$14,890	$212.28	$15,284
110	50	400 WATT HPS UPASS 8760HRS WALL MOUNTED	85	$319.66	$27,171	$328.08	$27,887
111	51	150 WATT HPS UPASS 8760HRS WALL MOUNTED	104	$192.81	$20,052	$197.88	$20,580
112	65	400 W HPS - SHOEBOX	49	$253.38	$12,416	$260.04	$12,742
113	66	2-400 W HPS-SHOEBOX	18	$343.80	$6,188	$352.92	$6,353
114	101	400 WATT METAL HALIDE - METAL COLUMN	1	$304.98	$305	$313.08	$313
115	184	EXCESS MATERIAL FOR CIRCLE CENTRE MALL	1	$5,520.60	$5,521	$5,666.76	$5,667
116	185	PEDESTRIAN LIGHT FOR CIRCLE CENTRE MALL	77	$693.51	$53,400	$711.84	$54,812
117	187	TWIN 80W LED POST TOP	80	$688.63	$55,090	$706.80	$56,544
		Customer Installed, Owned, and Maintained (MU-1)					
		LIGHTS INSTALLED BEFORE LAST RATE CASE					
118	55	250 WATT MV - CUSTOMER OWNED	16	$131.49	$2,104	$135.00	$2,160
119	56	175 WATT MV - CUSTOMER OWNED	26	$82.54	$2,146	$84.72	$2,203
120	59	400 WATT HPS - CUSTOMER OWNED	2,544	$124.74	$317,338	$128.04	$325,734
121	60	250 WATT HPS - CUSTOMER OWNED	1,221	$100.00	$122,100	$102.60	$125,275
122	61	150 WATT HPS - CUSTOMER OWNED	567	$76.71	$43,493	$78.72	$44,634
123	63	1000 WATT HPS - CUSTOMER OWNED	1,344	$256.83	$345,181	$263.64	$354,332
124	64	175 WATT MV ORNIMENTAL - CUSTOMER OWNED	2	$127.66	$255	$131.04	$262
125	109	400 WATT HPS-CUSTOMER OWNED WO/MAINT	240	$106.74	$25,618	$109.56	$26,294
126	111	150 WATT HPS - CUSTOMER OWNED WO/MAINT	12	$58.71	$704	$60.24	$723
127	112	1000 WATT HPS - CUSTOMER OWNED WO/MAINT	42	$238.83	$10,031	$245.16	$10,297

Indianapolis Power and Light Company
Lighting Rate Design

Line No.	Code	Description	Inventory	Current Rate with ECCR, RTO and Fuel (Base Fuel and FCA)	Current Revenue Proforma @ Present Rates	Proposed Annual Rate	Proposed Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Customer Installed, Owned, but Company Maintained (MU-1)					
		LIGHTS INSTALLED BEFORE LAST RATE CASE					
128	120	400 WATT HPS - CUSTOMER OWNED W/MAINT	13	$124.74	$1,622	$128.04	$1,665
129		***Sub-Total***	**53,075**		**$8,828,825**		**$9,062,480**
		Company Installed, Owned, and Maintained (MU-1)					
130		**New Lights Installed After Last Rate Case**					**$580**
131		**Total MU-1**					**$9,063,060**

Line No.	Code	Description	Inventory	Watts Adjusted for Min. Bill	Current Revenue Proforma @ Present Rates	Proposed Price Per Watt	Proposed Revenue
		Customer Installed, Owned, and Maintained (MU-4)				**2.6%**	
132	1	SEWER MONITOR	2	120	$69		
133	2	TRAFFIC SIGNAL	981	758,787	$438,262		
134	3	AIR RAID SIRENS	165	27,448	$15,853		
135	4	TRAFFIC COUNTING DEVICE	3	180	$104		
136	9	STREET LIGHT	618	77,322	$44,645		
137	11	CITY TERRITORY	10	600	$334		
138	17	SURVEILLANCE CAMERAS	44	7,788	$4,498		
139		**Total MU-4**	**1,823**	**872,246**	**$503,766**	**$ 0.59**	**$514,625**
140		**Total MU (MU-1 and MU-4)**					**$9,577,685**
141		**Total Lighting (APL and MU)**					**$16,975,267**
142		**Proposed Target Revenue**					**$16,975,073**
143		Rounding Difference					($194)

Line No.	Code	Description	Minimum Wattage	Minimum Per Fixture or Device
		Customer Installed, Owned, and Maintained (MU-4)		
144		**MU-4 Rate Calculation**	**60**	**$ 35.40**

Indianapolis Power and Light Company
Lighting Rate Design
New APL and MU Lights Installed Post Last Rate Case

Line No.	Code	Description	Inventory	Current Rate with ECCR, RTO and Fuel (Base Fuel and FCA)	Current Revenue Proforma @ Present Rates	Proposed Annual Rate	Revenue	% Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Company Installed, Owned, and Maintained (APL)						
		LIGHTS INSTALLED AFTER LAST RATE CASE						
1	271	100 WATT LIGHT	188	$224.85	$42,271	$178.80	$33,614	-20.5%
2	272	150 WATT HPS REDDY SENT.	6	$245.31	$1,472	$198.72	$1,192	-19.0%
3	273	250 WATT HPS REDDY SENT.	19	$269.08	$5,113	$229.80	$4,366	-14.6%
4	296	- WOOD POLE WITH OVERHEAD FEED -	47	$237.84	$11,178	$90.60	$4,258	-61.9%
5	274	400 WATT HPS REDDY SENT.	6	$306.78	$1,841	$268.68	$1,612	-12.4%
6	287	150 WATT HPS FLOOD - OVERHEAD	3	$313.95	$942	$205.20	$616	-34.6%
7	288	250 WATT HPS FLOOD - OVERHEAD	1	$284.44	$284	$235.08	$235	-17.4%
8	289	400 WATT HPS FLOOD - OVERHEAD	68	$319.86	$21,750	$272.76	$18,548	-14.7%
9	297	- WOOD POLE WITH UNDERGROUND FEED -	2	$289.44	$579	$114.72	$229	-60.4%
10	336	250 WATT HPS-1ST FIXTURE-SHOEBOX	10	$466.12	$4,661	$359.88	$3,599	-22.8%
11	358	400 WATT HPS-ADDIT'L FIXTURE-FLOOD	1	$347.10	$347	$288.12	$288	-17.0%
12	363	100 W HPS POST TOP	1	$305.61	$306	$261.72	$262	-14.4%
13				**Total**	**$90,744**		**$68,820**	
		Company Installed, Owned, and Maintained (MU-1)						
		LIGHTS INSTALLED AFTER LAST RATE CASE						
14	221	100 WATT HPS - OVERHEAD	2	$298.17	$596	$290.04	$580	-2.7%
15				**Total**	**$596**		**$580**	

INDIANAPOLIS POWER AND LIGHT COMPANY
Rate Design Summary

Test Year Ended June 30, 2016

Line No.	(A) Rate RS	(B)	(C) Current Rate with ECCR, DSM, RTO and Fuel (Base Fuel and FCA)	(D) Proposed Rates
	Billed kwh			
1		First 500 kWh	$ 0.100379	$ 0.098630
2		Over 500 kWh	$ 0.079444	$ 0.081531
3		Over 1,000	$ 0.066841	$ 0.067401
	Customer Charge			
4		0 to 325 kWh	$ 11.25	$ 19.00
5		Over 325 kWh	$ 17.00	$ 27.00

Line No.	(A) Rate SS	(B)	(C) Current Rate with ECCR, DSM, RTO and Fuel (Base Fuel and FCA)	(D) Proposed Rates
	Billed kwh			
1		First 5,000 kWh	$ 0.103595	$ 0.104366
2		Over 5,000 kWh	$ 0.088895	$ 0.089666
	Customer Charge			
3		0 to 5,000 kWh	$ 30.00	$ 40.00
4		Over 5,000 kWh	$ 50.00	$ 55.00

Line No.	(A) Rate SH	(B)	(C) Current Rate with ECCR, DSM, RTO and Fuel (Base Fuel and FCA)	(D) Proposed Rates
	Billed kwh			
1		All kWh	$ 0.085635	$ 0.092593
	Customer Charge			
2		All Customers	$ 30.00	$ 55.00

INDIANAPOLIS POWER AND LIGHT COMPANY
Rate Design Summary

Test Year Ended June 30, 2016

	(A)	(B)	(C)	(D)
Line No.	**Rate SE**		**Current Rate with ECCR, DSM, RTO and Fuel (Base Fuel and FCA)**	**Proposed Rates**
	Billed kwh			
1		First 5,000 kWh	$ 0.114706	$ 0.120655
2		Over 5,000 kWh	$ 0.100006	$ 0.105955
3		Excess of 155 x Con	$ 0.086106	$ 0.092055
	Customer Charge			
4		All Customers	$ 30.00	$ 55.00

	(A)	(B)	(C)	(D)
Line No.	**Rate UW**		**Current Rate with ECCR, DSM, RTO and Fuel (Base Fuel and FCA)**	**Proposed Rates**
	Billed kwh			
1		All kWh	$ 0.066640	$ 0.066839
	Customer Charge			
2		All Customers	$ 27.00	$ 37.00

	(A)	(B)	(C)	(D)
Line No.	**Rate CB**		**Current Rate with ECCR, DSM, RTO and Fuel (Base Fuel and FCA)**	**Proposed Rates**
	Billed kwh			
1		All kWh	$ 0.072817	$ 0.064880
	Customer Charge			
2		All Customers	$ 7.10	$ 17.00

INDIANAPOLIS POWER AND LIGHT COMPANY
Rate Design Summary

Test Year Ended June 30, 2016

	(A)	(B)	(C)	(D)
Line No.	**Rate SL**		**Current Rate with ECCR, DSM, RTO and Fuel (Base Fuel and FCA)**	**Proposed Rates**
	Billed kwh			
1		All kWh	$ 0.042850	$ 0.037221
	Billed kW			
2		All kW	$ 17.10	$ 21.06
	Customer Charge			
3		All Customers	$ 120.00	$ 120.00

	(A)	(B)	(C)	(D)
Line No.	**Rate PL**		**Current Rate with ECCR, DSM, RTO and Fuel (Base Fuel and FCA)**	**Proposed Rates**
	Billed kwh			
1		All kWh	$ 0.041785	$ 0.036110
	Billed kW			
2		All kW	$ 18.20	$ 23.22
	Customer Charge			
3		All Customers	$ 120.00	$ 120.00

	(A)	(B)	(C)	(D)
Line No.	**Rate PH**		**Current Rate with ECCR, DSM, RTO and Fuel (Base Fuel and FCA)**	**Proposed Rates**
	Billed kwh			
1		First 250 Hrs use	$ 0.081049	$ 0.082904
2		Additional kWh	$ 0.066049	$ 0.067904
	Customer Charge			
3		All Customers	$ 1,000.00	$ 1,250.00

INDIANAPOLIS POWER AND LIGHT COMPANY
Rate Design Summary

Test Year Ended June 30, 2016

	(A)	(B)	(C)	(D)
Line No.	**Rate HL1**		**Current Rate with ECCR, DSM, RTO and Fuel (Base Fuel and FCA)**	**Proposed Rates**
	Billed kwh			
1		All kWh	$ 0.052442	$ 0.036088
	Billed kW			
2		All kW	$ 12.05	$ 23.21
	Customer Charge			
3		All Customers	$ 135.00	$ 135.00

	(A)	(B)	(C)	(D)
Line No.	**Rate HL2**		**Current Rate with ECCR, DSM, RTO and Fuel (Base Fuel and FCA)**	**Proposed Rates**
	Billed kwh			
1		All kWh	$ 0.053566	$ 0.035892
	Billed kW			
2		All kW	$ 11.50	$ 21.49
	Customer Charge			
3		All Customers	$ 140.00	$ 215.00

INDIANAPOLIS POWER AND LIGHT COMPANY
Rate Design Summary

Test Year Ended June 30, 2016

	(A)	(B)	(C)	(D)
Line No.	**Rate HL3 - High Load Factor**		**Current Rate with ECCR, DSM, RTO and Fuel (Base Fuel and FCA)**	**Proposed Rates**
	Billed kwh			
1		All kWh	$ 0.051848	$ 0.035493
	Billed kW			
2		All kW	$ 11.07	$ 21.14
	Customer Charge			
3		All Customers	$ 180.00	$ 500.00

	(A)	(B)	(C)	(D)
Line No.	**Rate HL4 - Low Load Factor**		**Current Rate with ECCR, DSM, RTO and Fuel (Base Fuel and FCA)**	**Proposed Rates**
	Billed kwh			
1		All kWh	$ 0.051848	$ 0.045583
	Billed kW			
2		All kW	$ 11.07	$ 15.33
	Customer Charge			
3		All Customers	$ 180.00	$ 500.00

Indianapolis Power and Light Company
Proposed Rates - Residential Bill Impacts - RS Customers

Proposed Rates

Energy Charge		Including Fuel Current Rate	Including Fuel Proposed Rate	Including Fuel & DSM Current Rate	Including Fuel & DSM Proposed Rate	Excluding Fuel Current Rate	Excluding Fuel Proposed Rate
First 500 kWh		$ 0.100379	$ 0.098630	$ 0.102662	$ 0.100913	$ 0.070042	$ 0.068283
Over 500 kWh	500	$ 0.079444	$ 0.081531	$ 0.081727	$ 0.083814	$ 0.049107	$ 0.051184

Customer Charge		Including Fuel Current Rate	Including Fuel Proposed Rate	Including Fuel & DSM Current Rate	Including Fuel & DSM Proposed Rate
0 to 325 kWh		$ 11.25	$ 19.00	$ 11.25	$ 19.00
Over 325 kWh	325	$ 17.00	$ 27.00	$ 17.00	$ 27.00

DSM Charge ($/kWh)	$ 0.002283

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	Present Rates	Proposed Rates	Amount	Percent	Proposed ¢ / kWh	Present Rates	Proposed Rates	Amount	Percent	Proposed ¢ / kWh
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	100	4.2%	$ 21.52	$ 29.09	$ 7.57	35.18%	0.29090	$ 18.25	$ 25.83	$ 7.58	41.53%	0.25830
2	200	4.5%	31.78	39.18	7.40	23.29%	0.19590	25.26	32.66	7.40	29.30%	0.16330
3	400	15.7%	58.06	67.37	9.31	16.04%	0.16843	45.02	54.31	9.29	20.64%	0.13578
4	600	19.9%	76.50	85.84	9.34	12.21%	0.14307	56.93	66.26	9.33	16.39%	0.11043
5	800	18.1%	92.85	102.60	9.75	10.50%	0.12825	66.75	76.50	9.75	14.61%	0.09563
6	1,000	13.4%	109.19	119.37	10.18	9.32%	0.11937	76.57	86.73	10.16	13.27%	0.08673
7	1,200	8.9%	125.54	136.13	10.59	8.44%	0.11344	86.40	96.97	10.57	12.23%	0.08081
8	1,500	7.6%	150.06	161.27	11.21	7.47%	0.10751	101.13	112.32	11.19	11.06%	0.07488
9	1,800	3.6%	174.58	186.42	11.84	6.78%	0.10357	115.86	127.68	11.82	10.20%	0.07093
10	2,000	1.4%	190.92	203.18	12.26	6.42%	0.10159	125.68	137.92	12.24	9.74%	0.06896
11	2,400	1.4%	223.61	236.71	13.10	5.86%	0.09863	145.32	158.39	13.07	8.99%	0.06600
12	2,700	0.5%	248.13	261.85	13.72	5.53%	0.09698	160.06	173.74	13.68	8.55%	0.06435
13	3,000	0.3%	272.65	287.00	14.35	5.26%	0.09567	174.79	189.10	14.31	8.19%	0.06303
14	4,000	0.3%	354.37	370.81	16.44	4.64%	0.09270	223.90	240.28	16.38	7.32%	0.06007
15	5,000	0.1%	436.10	454.62	18.52	4.25%	0.09092	273.00	291.47	18.47	6.77%	0.05829
16	7,000	0.1%	599.56	622.25	22.69	3.78%	0.08889	371.22	393.84	22.62	6.09%	0.05626
17	>7,000	0.0%										
18	760		89.58	99.25	9.67	10.79%	0.13059	64.79	74.45	9.66	14.91%	0.09796

Indianapolis Power and Light Company
Proposed Rates - Residential Bill Impacts - RH/RC Customers

Proposed Rates

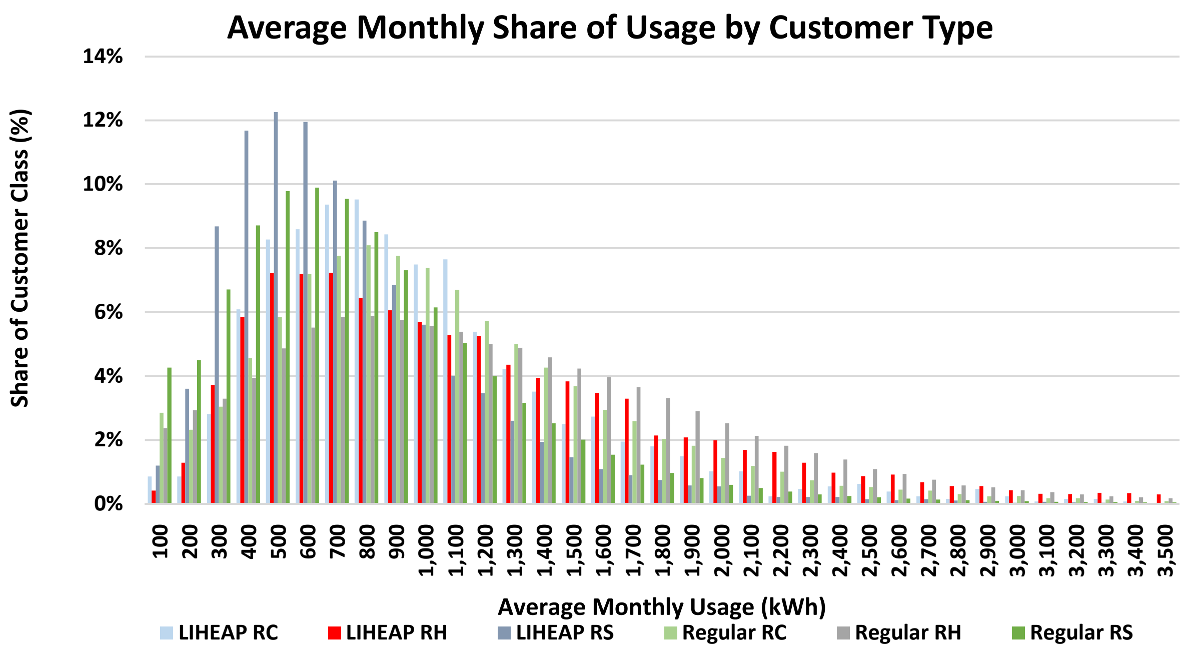
Energy Charge		Including Fuel: Current Rate	Including Fuel: Proposed Rate	Including Fuel & DSM: Current Rate	Including Fuel & DSM: Proposed Rate	Excluding Fuel: Current Rate	Excluding Fuel: Proposed Rate
First 500 kWh		$ 0.100379	$ 0.098630	$ 0.102662	$ 0.100913	$ 0.070042	$ 0.068283
Over 500 kWh	500	$ 0.079444	$ 0.081531	$ 0.081727	$ 0.083814	$ 0.049107	$ 0.051184
Over 1,000	1000	$ 0.066841	$ 0.067401	$ 0.069124	$ 0.069684	$ 0.036504	$ 0.037054
Customer Charge							
0 to 325 kWh		$ 11.25	$ 19.00	$ 11.25	$ 19.00		
Over 325 kWh	325	$ 17.00	$ 27.00	$ 17.00	$ 27.00		

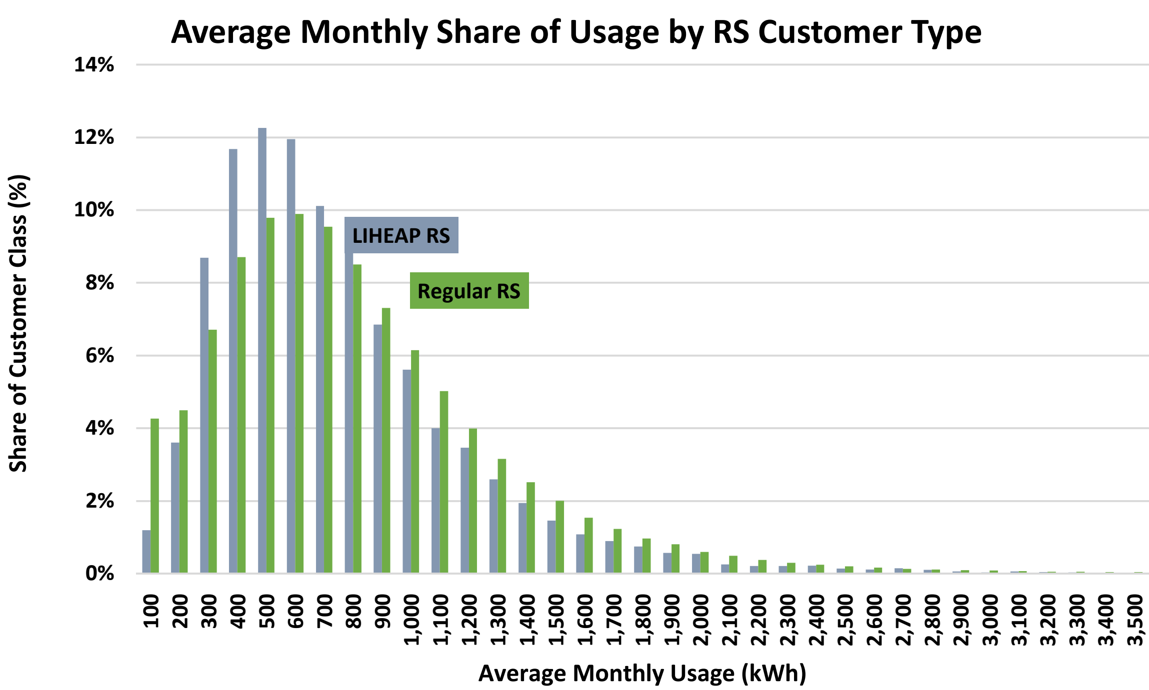
DSM Charge ($/kWh)	$ 0.002283

Bill Impacts for RH/RC Customers

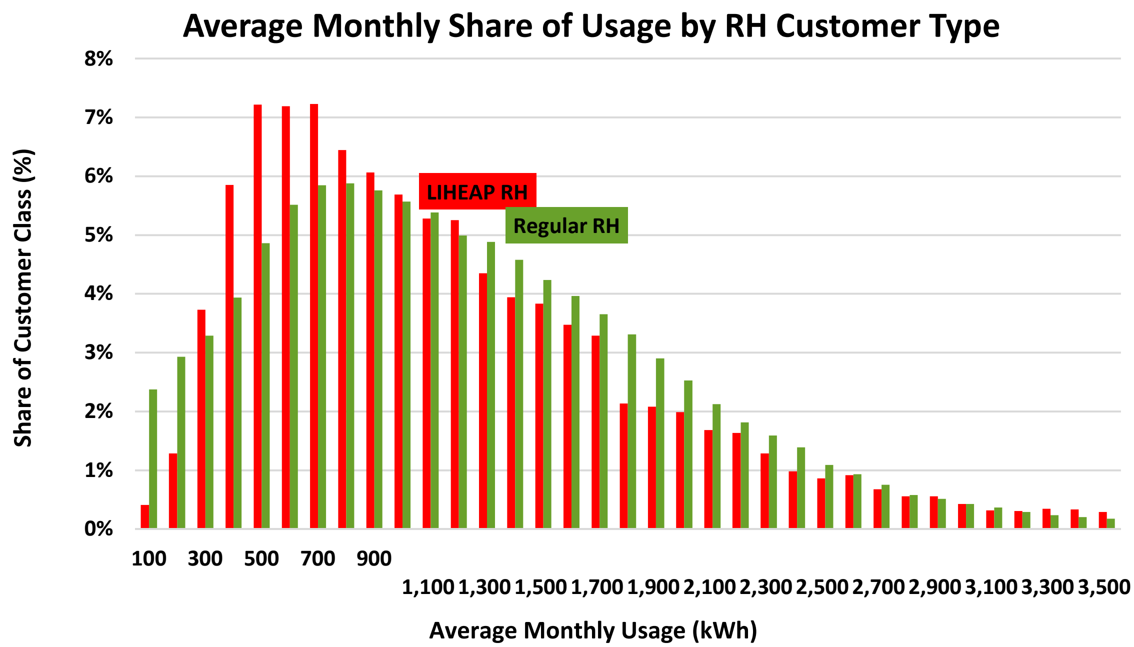
Line No.	Monthly kWh	% of Customers	Including Fuel & DSM — Monthly Margin or Base Rate: Present Rates	Proposed Rates	Increase / <Decrease>: Amount	Percent	Proposed ¢ / kWh	Excluding Fuel — Monthly Total Bill: Present Rates	Proposed Rates	Increase / <Decrease>: Amount	Percent	Proposed ¢ / kWh
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	100	2.4%	$ 21.52	$ 29.09	$ 7.57	35.18%	0.29090	$ 18.25	$ 25.83	$ 7.58	41.53%	0.25830
2	200	2.7%	31.78	39.18	7.40	23.29%	0.19590	25.26	32.66	7.40	29.30%	0.16330
3	400	7.3%	58.06	67.37	9.31	16.04%	0.16843	45.02	54.31	9.29	20.64%	0.13578
4	600	11.0%	76.50	85.84	9.34	12.21%	0.14307	56.93	66.26	9.33	16.39%	0.11043
5	800	12.5%	92.85	102.60	9.75	10.50%	0.12825	66.75	76.50	9.75	14.61%	0.09563
6	1,000	12.0%	109.19	119.37	10.18	9.32%	0.11937	76.57	86.73	10.16	13.27%	0.08673
7	1,200	10.7%	123.01	133.31	10.30	8.37%	0.11109	83.87	94.14	10.27	12.25%	0.07845
8	1,500	13.5%	143.75	154.21	10.46	7.28%	0.10281	94.82	105.26	10.44	11.01%	0.07017
9	1,800	10.3%	164.49	175.12	10.63	6.46%	0.09729	105.77	116.37	10.60	10.02%	0.06465
10	2,000	5.0%	178.31	189.05	10.74	6.02%	0.09453	113.07	123.78	10.71	9.47%	0.06189
11	2,400	6.3%	205.96	216.93	10.97	5.33%	0.09039	127.68	138.61	10.93	8.56%	0.05775
12	2,700	2.5%	226.70	237.83	11.13	4.91%	0.08809	138.63	149.72	11.09	8.00%	0.05545
13	3,000	1.4%	247.44	258.74	11.30	4.57%	0.08625	149.58	160.84	11.26	7.53%	0.05361
14	4,000	1.7%	316.56	328.42	11.86	3.75%	0.08211	186.08	197.89	11.81	6.35%	0.04947
15	5,000	0.3%	385.69	398.11	12.42	3.22%	0.07962	222.59	234.95	12.36	5.55%	0.04699
16	7,000	0.2%	523.93	537.47	13.54	2.58%	0.07678	295.60	309.05	13.45	4.55%	0.04415
17	>7,000	0.1%										
18	1,171		121.01	131.29	10.28	8.50%	0.11212	82.81	93.07	10.26	12.39%	0.07948

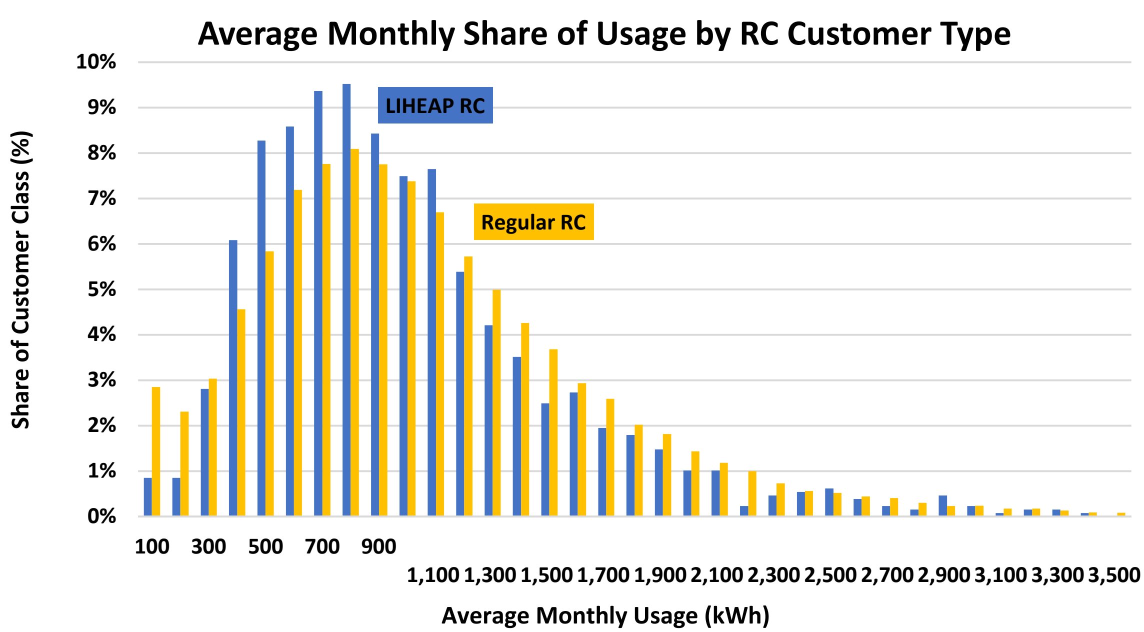
Analysis of Low-Income Customer Usage





Analysis of Low-Income Customer Usage





Analysis of Low-Income Customer Usage