STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY ("IPL") FOR AUTHORITY TO INCREASE RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE AND FOR APPROVAL OF: (1) ACCOUNTING RELIEF, INCLUDING IMPLEMENTATION OF MAJOR STORM DAMAGE RESTORATION RESERVE ACCOUNT; (2) REVISED DEPRECIATION RATES; (3) THE INCLUSION IN BASIC RATES AND CHARGES OF THE COSTS OF CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY; (4) IMPLEMENTATION OF NEW OR MODIFIED RATE ADJUSTMENT MECHANISMS TO TIMELY RECOGNIZE FOR RATEMAKING PURPOSES LOST REVENUES FROM DEMAND-SIDE MANAGEMENT PROGRAMS AND CHANGES IN (A) CAPACITY PURCHASE COSTS; (B) REGIONAL TRANSMISSION ORGANIZATION COSTS; AND (C) OFF SYSTEM SALES MARGINS; AND (5) NEW SCHEDULES OF RATES, RULES ANDREGULATIONS FOR SERVICE.	)	**CAUSE NO. 44576**
IN THE MATTER OF THE INDIANA UTILITY REGULATORY COMMISSION'S INVESTIGATION INTO INDIANAPOLIS POWER & LIGHT COMPANY'S ONGOING INVESTMENT IN, AND OPERATION AND MAINTENANCE OF, ITS NETWORK FACILITIES	)	**CAUSE NO. 44602**

VERIFIED DIRECT TESTIMONY

OF

GLENN A. WATKINS – PUBLIC'S EXHIBIT NO. 14

ON BEHALF OF THE

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

JULY 27, 2015

TABLE OF CONTENTS

PAGE

I. INTRODUCTION 1

II. CLASS COST OF SERVICE 2

- **A. Generation Plant 6**
  - **1. Probability of Dispatch Method 15**
  - **2. Base-Intermediate Peak ("BIP") Method 18**
  - **3. Peak & Average ("P&A") Method 20**
- **B. Transmission Plant 24**
- **C. Distribution Plant 25**

III. IPL PROPOSED MIGRATION ADJUSTMENT 45

IV. CLASS REVENUE DISTRIBUTION 48

V. RATE DESIGN 53

- **A. Residential Service 53**
  - **1. Customer Charges 54**
  - **2. Declining-Block Rate Structure 64**
- **B. Water Heating (Rate Schedules CW and UW) 68**
- **C. Small Commercial Rate Design 69**
- **D. Large Commercial/Industrial Rate Design 70**
- **E. Interruptible Credit 70**

VERIFIED DIRECT TESTIMONY OF GLENN A. WATKINS
ON BEHALF OF
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 9030 Stony Point Parkway, Suite 580, Richmond, Virginia 23235.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am a Principal and Senior Economist with Technical Associates, Inc., which is an economics and financial consulting firm with an office in Richmond, Virginia. Except for a six month period during 1987 in which I was employed by Old Dominion Electric Cooperative, as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my 34-year career at Technical Associates, I have conducted hundreds of marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving electric, gas, water/wastewater, and telephone utilities throughout the United States and Canada and have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Illinois, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. In addition, I have provided expert testimony before State and Federal courts as well as before State legislatures. A more complete description of my education and experience is provided in Attachment GAW-1.

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

A. Technical Associates has been retained by the Indiana Office of Utility Consumer Counselor ("OUCC") to assist in its evaluation of the accuracy and reasonableness of Indianapolis Power & Light Company's ("IPL" or "Company") retail class cost of service

study, proposed distribution of revenues by class, rate design, and other tariff issues. The purpose of my testimony, therefore, is to comment on IPL's proposals on these issues and to present my findings and recommendations based on the results of the studies I have undertaken on behalf of the OUCC.

II. CLASS COST OF SERVICE

Q. PLEASE BRIEFLY EXPLAIN THE CONCEPT OF A CLASS COST OF SERVICE STUDY ("CCOSS") AND ITS PURPOSE IN A RATE PROCEEDING.

A. Generally, there are two types of cost of service studies used in public utility ratemaking: marginal cost studies and embedded, or fully allocated, cost studies. Consistent with the practices of the Indiana Utility Regulatory Commission ("Commission"), IPL has utilized a traditional embedded cost of service study for purposes of establishing the overall revenue requirement in this case, as well as for class cost of service purposes.

Embedded class cost of service studies are also referred to as fully allocated cost studies because the majority of a public utility's plant investment and expense is incurred to serve all customers in a joint manner. Accordingly, most costs cannot be specifically attributed to a particular customer or group of customers. To the extent that certain costs can be specifically attributed to a particular customer or group of customers, these costs are directly assigned to that customer or group in the CCOSS. Since most of the utility's costs of providing service are jointly incurred to serve all or most customers, they must be allocated across specific customers or customer rate classes.

It is generally accepted that to the extent possible, joint costs should be allocated to customer classes based on the concept of cost causation. That is, costs are allocated to customer classes based on analyses that measure the causes of the incurrence of costs to the utility. Although the cost analyst strives to abide by this concept to the greatest extent practical, some categories of costs, such as corporate overhead costs, cannot be attributed to specific exogenous measures or factors, and must be subjectively assigned or allocated to customer rate classes. With regard to those costs in which cost causation

can be attributed, there is often disagreement among cost of service experts on what is an appropriate cost causation measure or factor; e.g., peak demand, energy usage, number of customers, etc.

Q. IN YOUR OPINION, HOW SHOULD THE RESULTS OF A CCOSS BE UTILIZED IN THE RATEMAKING PROCESS?

A. Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive individual costs. These disagreements can and do arise as a result of the quality of data and level of detail available from financial records. There are also fundamental differences in opinions regarding the cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned previously, numerous subjective decisions are required to allocate the myriad of jointly incurred costs.

In these regards, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS only as a guide, with the results being used as one of many tools to assign class revenue responsibility when cost causation factors cannot be realistically ascribed to some costs.

Q. HAVE THE HIGHER COURTS OPINED ON THE USEFULNESS OF COST ALLOCATIONS FOR PURPOSES OF ESTABLISHING REVENUE RESPONSIBILITY AND RATES?

A. Yes. In an important regulatory case involving Colorado Interstate Gas Company and the Federal Power Commission (predecessor to FERC), the United States Supreme Court stated:

> But where as here several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.[1]

[1] 324 U.S. 581, 65 S. Ct. 829.

Q. DOES YOUR OPINION, AND THE FINDINGS OF THE U.S. SUPREME COURT, IMPLY THAT COST ALLOCATIONS SHOULD PLAY NO ROLE IN THE RATEMAKING PROCESS?

A. Not at all. It simply means that regulators should consider the fact that cost allocation results are not surgically precise and that alternative, yet equally defensible approaches may produce significantly different results. In this regard, when all reasonable cost allocation approaches consistently show that certain classes are over or under contributing to costs and/or profits, there is a strong rationale for assigning smaller or greater percentage rate increases to these classes. On the other hand, if one set of reasonable cost allocation approaches show dramatically different results than another reasonable approach, caution should be exercised in assigning disproportionately larger or smaller percentage increases to the classes in question.

Q. PLEASE EXPLAIN HOW YOU PROCEEDED WITH YOUR ANALYSIS OF IPL'S CCOSS.

A. In conducting my independent analysis, I reviewed the structure and organization of the Company's CCOSS and reviewed the accuracy and completeness of the primary drivers (allocators) used to assign costs to rate schedules and classes. Next, I reviewed IPL's selection of allocators to specific rate base, revenue, and expense accounts. I then verified the accuracy of IPL's CCOSS model by replicating its results using my own computer model. Finally, I adjusted certain aspects of the Company's study to better reflect cost causation and cost incidence by rate schedule and customer class. It should be noted that I originally completed my analyses based on the Company's original filing. On May 4, 2015, the Company filed its Fifth Revisions To Direct Testimony which revised the testimony of Company witness Stephen Gaske. As a result of Mr. Gaske's revisions, I then incorporated his changes in my analyses such that my testimony and schedules reflect Mr. Gaske's May 4, 2015 revisions to his class cost of service study and revenue distribution.

Q. NOTWITHSTANDING ANY CONCEPTUAL DISAGREEMENTS ON HOW INDIVIDUAL COSTS SHOULD BE ALLOCATED ACROSS CLASSES, DID YOU FIND THE COMPANY'S STUDY TO BE ACCURATE?

A. From an arithmetic perspective, I discovered what appears to be one minor error in the CCOSS study sponsored by IPL witness Dr. Gaske.

Q. PLEASE DISCUSS THE MINOR ERROR YOU DISCOVERED WITHIN DR. GASKE'S CCOSS.

A. This error relates only to the lighting classes and has no impact on other classes within the CCOSS. IPL has two lighting rate classes: Automatic Protective Lighting ("APL"); and, Municipal Lighting ("MU"). Dr. Gaske's CCOSS utilizes current rate revenues of $5,943,255 for rate APL and $10,747,745 for rate MU. However, his detailed revenue proof indicates that APL's rate revenues are $6,428,908 while MU's rate revenues are $10,262,445. It should be noted that these differences equally offset each other such that the total lighting rate revenues are the same in both his CCOSS and revenue proof. Furthermore, this correction does not impact any other rate class' CCOSS results and has no material impact on Dr. Gaske's CCOSS findings as it relates to the two lighting rate classes. A comparison of Dr. Gaske's lighting rates of return to those corrected to comport with his revenue proof is shown below:

Rates of Return at Current Rates

Rate Class	IPL As-Filed	IPL Study Corrected
APL	-15.64%	-12.28%
MU	34.30%	29.89%

Q. ARE THERE CERTAIN ASPECTS OF ELECTRIC UTILITY EMBEDDED CCOSS THAT TEND TO BE MORE CONTROVERSIAL THAN OTHERS?

A. Yes. For decades, cost allocation experts and to some degree, utility commissions, have disagreed on how generation and certain distribution plant accounts should be allocated across classes. Beyond a doubt, these two issue areas are the most contentious and often have the largest impact on the results of achieved class rates of return ("ROR").

A. <u>Generation Plant</u>

Q. BEFORE I DISCUSS SPECIFIC COST ALLOCATION METHODOLOGIES, PLEASE EXPLAIN HOW GENERATION/PRODUCTION-RELATED COSTS ARE INCURRED; I.E., PLEASE EXPLAIN THE COST CAUSATION CONCEPTS RELATING TO GENERATION/PRODUCTION RESOURCES.

A. Utilities design and build generation facilities to meet the energy and demand requirements of their customers on a collective basis. Because of this, and the physical laws of electricity, it is impossible to determine which customers are being served by which facilities. As such, production facilities are joint costs; i.e., used by all customers. Because of this commonality, production-related costs are not directly known for any customer or customer group and must somehow be allocated.

If all customer classes used electricity at a constant rate (load) throughout the year, there would be no disagreement as to the proper assignment of generation-related costs. All analysts would agree that energy usage in terms of kilowatt-hour ("kWh") would be the proper approach to reflect cost causation and cost incidence. However, such is not the case in that IPL experiences periods (hours) of much higher demand during certain times of the year and across various hours of the day. Moreover, all customer classes do not contribute in equal proportions to these varying demands placed on the generation system. To further complicate matters the electric utility industry is unique in that there is a distinct energy/capacity trade-off relating to production costs. That is, utilities design their mix of production facilities (generation and power supply) to minimize the total costs of energy and capacity, while also ensuring there is enough available capacity to meet peak demands. The trade-off occurs between the level of fixed investment per unit of capacity kilowatt ("kW") and the variable cost of producing a unit of output (kWh). Coal and nuclear units require high capital expenditures resulting in large investment per kW, whereas smaller units with higher variable production costs generally require significantly less investment per kW. Due to varying levels of demand placed on the system over the course of each day, month, and year there is a unique optimal mix of

production facilities for each utility that minimizes the total cost of capacity and energy; i.e., its cost of service.

Therefore, as a result of the energy/capacity cost trade-off, and the fact that the service requirements of each utility are unique, many different allocation methodologies have evolved in an attempt to equitably allocate joint production costs to individual classes.

Q. PLEASE EXPLAIN.

A. Total production costs vary each hour of the year. Theoretically, energy and capacity costs should be allocated to customer classes each and every hour of the year. This would result in 8,760 hourly allocations. Although such an analysis is certainly possible with today's technology, hourly supply (generation) and demand (customer load) data is required to conduct such hour-by-hour analyses. While most utilities can and do record hourly production output, they often do not estimate class loads on an hourly basis (at least not for every hour of the year). With these constraints in mind, several allocation methodologies have been developed to allocate electric utility generation plant investment and attendant costs. Each of these methods has strengths and weaknesses regarding the reasonableness in reflecting cost causation.

Q. APPROXIMATELY HOW MANY COST ALLOCATION METHODOLOGIES EXIST RELATING TO THE ALLOCATION OF GENERATION PLANT?

A. The current National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual discusses at least thirteen embedded demand allocation methods, while Dr. James Bonbright notes the existence of at least 29 demand allocation methods in his treatise Principles of Public Utility Rates.[2]

Q. BRIEFLY DISCUSS THE STRENGTHS AND WEAKNESSES OF COMMON GENERATION COST ALLOCATION METHODOLOGIES.

A. A brief description of the most common fully allocated cost methodologies and attendant strengths and weaknesses are as follows:

[2] Principles of Public Utility Rates, Second Edition, page 495.

<u>Single Coincident Peak ("1-CP")</u> -- The basic concept underlying the 1-CP method is that an electric utility must have enough capacity available to meet its customers' peak coincident demand. As such, advocates of the 1-CP method reason that customers (or classes) should be responsible for fixed capacity costs based on their respective contributions to this peak system load. The major advantages to the 1-CP method are that the concepts are easy to understand, the analyses required to conduct a CCOSS are relatively simple, and the data requirements are significantly less than some of the more complex methods.

The 1-CP method has several shortcomings, however. First, and foremost, is the fact that the 1-CP method totally ignores the capacity/energy trade-off inherent in the electric utility industry. That is, under this method, the sole criterion for assigning one hundred percent of fixed generation costs is the classes' relative contributions to load during a single hour of the year. This method does not consider, in any way, the extent to which customers use these facilities during the other 8,759 hours of the year. This may have severe consequences because a utility's planning decisions regarding the amount and type of generation capacity to build and install is predicated not only on the maximum system load, but also on how customers demand electricity throughout the year, i.e., load duration. To illustrate, if a utility such as IPL had a peak load of 3,000 mW and its actual optimal generation mix included an assortment of coal, hydro, combined cycle and combustion turbine units, the total cost of capacity is significantly higher than if the utility only had to consider meeting 3,000 mW for 1 hour of the year. This is because the utility would install the cheapest type of plant (i.e., peaker units) if it only had to consider one hour a year.

There are two other major shortcomings of the 1-CP method. First, the results produced with this method can be unstable from year to year. This is because the hour in which a utility peaks annually is largely a function of weather. Therefore, annual peak load depends on when severe weather occurs. If this occurs on a weekend or holiday, relative class contributions to the peak load will likely be significantly different than if the peak occurred during a weekday. The other major shortcoming of the 1-CP method is often

referred to as the "free ride" problem. This problem can easily be seen with a summer peaking utility that peaks about 5:00 p.m. Because street lights are not on at this time of day, this class will not be assigned any capacity costs and will, therefore, enjoy a “free ride” on the assignment of generation costs that this class requires.

4-CP -- The 4-CP method is identical in concept to the 1-CP method except that the peak loads during the highest four months are utilized. This method generally exhibits the same advantages and disadvantages as the 1-CP method.

Summer and Winter Coincident Peak (“S/W Peak”) -- The S/W Peak method was developed because some utilities’ annual peak load occurs in the summer during some years and in the winter during others. Because customers' usage and load characteristics may vary by season, the S/W Peak attempts to recognize this. This method is essentially the same as the 1-CP method except that two hours of load are considered instead of one. This method has essentially the same strengths and weaknesses as the 1-CP method, and in my opinion, is no more reasonable than the 1-CP method.

12-CP -- Arithmetically, the 12-CP method is essentially the same as the 1-CP method except that class contributions to each monthly peak are considered. Although the 12-CP method bears little resemblance to how utilities design and build their systems, the results produced by this method better reflect the cost incidence of a utility’s generation facilities than does the 1-CP or 4-CP methods.

Most electric utilities have distinct seasonal load patterns such that there are high system peaks during the winter and summer months, and significantly lower system peaks during the spring and autumn months. By assigning class responsibilities based on their respective contributions throughout the year, consideration is given to the fact that utilities will call on all of their resources during the highest peaks, and only use their most efficient plants during lower peak periods. Therefore, the capacity/energy trade-off is implicitly considered to some extent under this method.

The major shortcoming of the 12-CP method is that accurate load data is required by class throughout the year. This generally requires a utility to maintain ongoing load studies. However, once a system to record class load data is in place, the administration and maintenance of such a system is not overly cumbersome for larger utilities.

Peak and Average ("P&A") -- The various P&A methodologies rest on the premise that a utility's actual generation facilities are placed into service to meet peak load and serve consumers demands throughout the entire year. Hence, the P&A method assigns capacity costs partially on the basis of contributions to peak load and partially on the basis of consumption throughout the year. Although there is not universal agreement on how peak demands should be measured or how the weighting between peak and average demands should be performed, most electric P&A studies use class contributions to coincident-peak demand for the "peak" portion, and weight the peak and average loads based on the system coincident load factor, e.g., the load factor represents the portion assigned based on consumption (average demand).

The major strengths of the P&A method are that an attempt is made to recognize the capacity/energy trade-off in the assignment of fixed capacity costs, and that data requirements are minimal.

Although the recognition of the capacity/energy trade-off is admittedly arbitrary under the P&A method, most other allocation methods also suffer some degree of arbitrariness. A potential weakness of the P&A method is that a significant amount of fixed capacity investment is allocated based on energy consumption, with no recognition given to lower variable fuel costs during off-peak periods. To illustrate this shortcoming, consider an off-peak or very high load factor class. This class will consume a constant amount of energy during the many cheaper off-peak periods. As such, this class will be assigned a significant amount of fixed capacity costs, while variable fuel costs will be assigned on a system average basis. This can result in an overburdening of costs if fuel costs vary significantly by hour. However, if the consumption patterns of the utility's various

classes are such that there is little variation between class time differentiated fuel costs on an overall annual basis, the P&A method can produce fair and reasonable results.

Average and Excess ("A&E") -- The A&E method also considers both peak demands and energy consumption throughout the year. However, the A&E method is much different than the P&A method in both concept and application. The A&E method recognizes class load diversity within a system, such that all classes do not call on the utility's resources to the same degree, at the same times. Mechanically, the A&E method weights average and excess demands based on system coincident load factor. Individual class "excess" demands represent the difference between the class non-coincident peak demand and its average annual demand. The classes' "excess" demands are then summed to determine the system excess demand. Under this method, it is important to distinguish between coincident and non-coincident demands. This is because if coincident, instead of non-coincident, demands are used when calculating class excesses, the end result will be exactly the same as that achieved under the 1-CP method.

Although the A&E method bears virtually no resemblance to how generation systems are designed, this method can produce fair and reasonable results for some utilities. This is because no class will receive a "free-ride" under this method, and because recognition is given to average consumption as well as to the additional costs imposed by not maintaining a perfectly constant load.

A potential shortcoming of this method is that customers that only use power during off-peak periods will be overburdened with costs. Under the A&E method, off-peak customers will be assigned a higher percentage of capacity costs because their non-coincident load factor may be very low even though they call on the utility's resources only during off-peak periods. As such, unless fuel costs are time differentiated, this class will be assigned a large percentage of capacity costs and may not receive the benefits of cheaper off-peak energy costs. Another weakness of the A&E method is that extensive and accurate class load data is required.

Base/Intermediate/Peak ("BIP") -- The BIP method is also known as a production stacking method, explicitly recognizes the capacity and energy tradeoff inherent with generating facilities in general, and specifically, recognizes the mix of a particular utility's resources used to serve the varying demands throughout the year. The BIP method classifies and assigns individual generating resources based on their specific purpose and role within the utility's actual portfolio of production resources and also assigns the dollar amount of investment by type of plant such that a proper weighting of investment costs between expensive base load units relative to inexpensive peaker units is recognized within the cost allocation process.

A major strength of the BIP method is explicit recognition of the fact that individual generating units are placed into service to meet various needs of the system. Expensive base load units, with high capacity factors run constantly throughout the year to meet the energy needs of all customers. These units operate during all periods of demand including low system load as well as during peak use periods. Base load units are, therefore, classified and allocated based on their roles within the utility's portfolio of resource; i.e., energy requirements.

At the other extreme are the utility's peaker units that are designed, built, and operated only to run a few hours of the year during peak system requirements. These peaker units serve only peak loads and are, therefore, classified and allocated on peak demand.

Situated between the high capacity cost/low energy cost base load units and the low capacity cost/high energy cost peaker units are intermediate generating resources. These units may not be dispatched during the lowest periods of system load but, due to their relatively efficient energy costs, are operated during many hours of the year. Intermediate resources are classified and allocated based on their relative usage to peak capability ratios; i.e., their capacity factor.

Finally, hydro units are evaluated on a case-by-case basis. This is because there are several types of hydro generating facilities including run of the river units that run most

of the time with no fuel costs, and units powered by stored water in reservoirs that operate under several environmental and hydrological constraints including flood control, downstream flow requirements, management of fisheries, and watershed replenishment. Within the constraints just noted and due to their ability to store potential energy, these units are generally dispatched on a seasonal or diurnal basis to minimize short-term energy costs and also assist with peak load requirements. Pumped storage units are unique in that water is pumped up to a reservoir during off-peak hours (with low energy costs) and released during peak hours of the day. Depending on the characteristics of a unit, hydro facilities may be classified as energy-related (e.g., run of the river), peak-related (e.g., pumped storage) or a combination of energy and demand-related (traditional reservoir storage). The potential weakness of the BIP method is the same as under other methods where no recognition is given to lower variable fuel costs during off-peak periods.

Probability of Dispatch -- The Probability of Dispatch method is the most theoretically correct as well as the most equitable method to allocate generation costs when specific data is available. Under this approach, each generation asset (plant or unit) is evaluated on an hourly basis for every hour of the year. Each generating asset's capital costs are assigned to individual hours based upon how that individual plant is dispatched or utilized. As such, investment or capital costs are distributed based on how a particular plant is actually utilized. For example, the investment costs associated with base load units which operate almost continuously throughout the year, are spread throughout several hours of the year while the investment cost associated with individual peaker units which operate only a few hours during peak periods are assigned to only a few peak hours of the year. The hourly capacity costs for each generating asset are summed to develop hourly investments. These hourly investments are then assigned to individual rate classes based on hourly contributions to peak load. As such, the Probability of Dispatch method requires a significant amount of data such that hourly output from each generator is required as well as detailed load studies encompassing each hour of the year (8,760 hours).

<u>Equivalent Peaker ("EP")</u> -- The EP method combines certain aspects of traditional embedded cost methods with those used in forward-looking marginal cost studies. The EP method often relies on planning information in order to classify individual generating units as energy or demand-related and considers the need for a mix of base load intermediate and peaking generation resources.

The EP method has substantial intuitive appeal in that base load units that operate with high capacity factors are allocated largely on the basis of energy consumption with costs shared by all classes based on their usage, while peaking units that are seldom used and only called upon during peak load periods are allocated based on peak demands to those classes contributing to the system peak load. However, this method requires a significant level of assumptions regarding the current (or future) costs of various generating alternatives.

Q. MR. WATKINS, YOU HAVE DISCUSSED THE STRENGTHS AND WEAKNESSES OF THE MORE COMMON GENERATION ALLOCATION METHODOLOGIES. ARE ANY OF THESE METHODS CLEARLY INFERIOR IN YOUR VIEW?

A. Yes. In my opinion the 1-CP and seasonal CP (such as 4-CP) methods do not reasonably reflect cost causation for integrated electric utilities because these methods totally ignore the utilization of a utility's facilities. Perhaps the simplest way to explain this is to consider that the methodology selected is used to allocate generation plant investment. Generation investment costs vary from a low of a few hundred dollars per kW of capacity for high operating cost (energy cost) peakers to several thousand dollars per kW for base load nuclear facilities with low operating costs. If a utility were only concerned with being able to meet peak load with no regard to operating costs, it would simply install inexpensive peakers. Under such an unrealistic system design, plant costs would be much lower than in reality but variable operating costs (primarily fuel costs) would be astronomical and would result in a higher overall cost to serve customers. The 1-CP and seasonal CP methods totally ignore this very important fact.

Q. WHAT COST ALLOCATION METHODOLOGY DID DR. GASKE UTILIZE TO ALLOCATE GENERATION PLANT COSTS WITHIN HIS CCOSS?

A. Dr. Gaske utilized the 12-CP method to allocate IPL's generation assets.

Q. HAVE YOU CONDUCTED ALTERNATIVE STUDIES THAT MORE ACCURATELY REPRESENT THE CAPACITY AND ENERGY TRADE-OFFS EXHIBITED IN IPL'S GENERATION PLANT INVESTMENT?

A. Yes. As indicated earlier, there is no single, or absolute, correct method to allocate joint generation costs. While some methods are superior to others, it is my opinion that the results of multiple, yet reasonable, methods should be considered in evaluating class profitability as well as class revenue responsibility.

In my opinion, the Probability of Dispatch, BIP and P&A methods better reflect the capacity/energy tradeoffs that exist within an electric utility's generation-related costs. This is particularly true and important for IPL given the fact that the preponderance of its investment in generation plant is associated with base load generation facilities. As such, I have conducted alternative CCOSS utilizing each of these three allocation methodologies.

1. <u>Probability of Dispatch Method</u>

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR CCOSS UTILIZING THE PROBABILITY OF DISPATCH METHOD.

A. As discussed earlier, the Probability of Dispatch method is the most theoretically correct methodology to assign embedded (historical) generation plant investment. However, the data required to utilize this methodology is often not available because this approach requires detailed hourly output data for each generating facility as well as hourly class loads. In this case, IPL provided both of these critical data sets. As such, I was able to conduct CCOSS utilizing the Probability of Dispatch method.

The first step in conducting the Probability of Dispatch method is to assign individual generating plant investments to specific hours. In accordance with the procedures set forth in the NARUC: Electric Utility Cost Allocation Manual,[3] each plant's total gross investment and accumulated depreciation was assigned pro-ratably to each hour of the year based on each respective unit's load (output) in that hour. My Attachment GAW-2 provides two pages of these hourly assignments. It should be noted that this exercise actually assigns costs to 8,760 hours; however, my Attachment GAW-2 only encompasses several of the first hours in the test year to avoid attachments exceeding 125 pages each. My filed workpapers contain the details of this assignment for each and every hour of the test year. Page 1 of Attachment GAW-2 provides the assignment of gross plant, while page 2 of this Attachment provides the assignment of each plant's depreciation reserve. This separate assignment is required due to differences in the net book value of IPL's various generation facilities.

Once hourly investment costs are known, these costs were then assigned to individual rate classes on an hour-by-hour basis. As indicated earlier, IPL provided individual class loads for each hour of the test year. As such, each class' relative contribution to the total system load in a given hour, is multiplied by the hourly generation investment cost. The hourly class investment cost were then summed for all hours of the year to develop class responsibility for IPL's net generation plant. Attachment GAW-3 provides summaries of the hourly assignment of generation costs to individual rate classes. The class assignment to every hour of the test year are provided in my filed workpapers.

Q. PLEASE PROVIDE A SUMMARY OF THE RESULTS OBTAINED UTILIZING THE PROBABILITY OF DISPATCH METHOD.

A. First it should be noted that the following summary and comparison utilizes all other allocations and procedures used by Dr. Gaske in conducting his revised 12-CP CCOSS. The following table provides an apples-to-apples comparison of Dr. Gaske's revised 12-CP results to those obtained utilizing the Probability of Dispatch method:

[3] 1992 Edition, page 62.

CCOSS Comparison Utilizing IPL's Procedures
Except For The Allocation of Generation Plant
(Rate of Return At Current Rates)

Class		IPL Revised 12-CP	Probability Of Dispatch
Residential	RS	2.48%	4.00%
Secondary Small	SS	13.41%	13.71%
Space Conditioning	SH	2.79%	2.75%
Space Conditioning-Schools	SE	3.95%	6.63%
Water Heating-Controlled	CB	-7.14%	-7.10%
Water Heating-Uncontrolled	UW	2.87%	2.99%
Secondary Large	SL	7.26%	6.51%
Primary	PL	4.32%	2.48%
Process Heating	PH	3.13%	4.82%
HLF-Primary	HL1	3.93%	1.34%
HLF-Sub-Tran	HL2	3.50%	0.58%
HLF-Tran	HL3	3.24%	-0.22%
Automatic Protective Lighting	APL	-12.28%	-13.45%
Municipal Lighting	MU1	29.89%	11.20%
Total		4.88%	4.88%

As can be seen in the table above, there are significant differences for some classes and minimal differences for other classes. For example, the residential rate of return ("ROR") increases from 2.48% to 4.00%, while several of the industrial classes RORs are significantly reduced. A summary of my Probability of Dispatch CCOSS results are provided in my Attachment GAW-4, while the details are provided in my filed workpapers.

Q. CAN YOU QUALITATIVELY EXPLAIN WHY THE PROBABILITY OF DISPATCH METHOD PRODUCES SIGNIFICANTLY DIFFERENT RESULTS FOR SOME CLASSES?

A. Yes. IPL's portfolio of generating assets is overwhelmingly comprised of base load coal units that operate at very high capacity factors such that they provide energy to the system throughout the year. At the same time, IPL has a much smaller investment in intermediate and peaker units. The Probability of Dispatch method properly recognizes

the fact that IPL's base load units are much more expensive and assigns these costs based on its actual dispatch (operation) during the year. The 12-CP method does not recognize the investment or operational characteristics of IPL's generation portfolio as it simply allocates the Company's total combined investment in generation plant based on twelve peak hours of the year. As such, the 12-CP method under-assigns generation costs to the high load factor industrial classes and over-assigns costs to the lower load factor residential class.

2. <u>Base-Intermediate-Peak ("BIP") Method</u>

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR CCOSS UTILIZING THE BASE-INTERMEDIATE-PEAK METHOD.

A. In order to reflect the capacity/energy trade-off inherent in IPL's mix of generating resources, each plant's maximum capacity (mW) and output (mWh) during the test year is required. Attachment GAW-5 provides the classification between energy and demand for IPL's generation plant under the BIP method. The BIP method evaluates each plant based on its capacity factor and variable fuel costs to determine whether that plant operates to serve primarily energy needs throughout the year, only peak loads, or is of an intermediate type that serves both energy and peak load requirements. To illustrate, the Petersburg units are clearly base load units in that they are "must run" units and operate throughout the entire year. While the Harding Street units are also largely base load units, I have classified this plant between energy and demand based on its capacity factor.

Q. DOES ATTACHMENT GAW-5 HELP EXPLAIN THE CAPACITY/ENERGY TRADE-OFF CONSIDERATION USED BY ELECTRIC UTILITIES IN DEVELOPING A PARTICULAR MIX OF GENERATING FACILITIES?

A. Yes. As can be seen in Attachment GAW-5, IPL's larger, more expensive, generating plants have high capacity factors and lower fuel costs. The large base load units run most hours of the year supplying energy to all customers. In contrast, the smaller, high operating (fuel) cost plants tend to have lower capacity factors meaning they are primarily used to meet peak loads. Because the vast preponderance of IPL's investment

in generation plant is associated with its base load units, a very large percentage (83.9%) of generation plant is classified as energy-related under the BIP method.

Q. PLEASE PROVIDE A SUMMARY OF RESULTS OBTAINED UTILIZING THE BASE-INTERMEDIATE-PEAK METHOD.

A. The following summary and comparison utilizes all other allocations and procedures used by Dr. Gaske in conducting his 12-CP CCOSS. The following table provides an apples-to-apples comparison of Dr. Gaske's 12-CP results to those obtained utilizing the BIP method:

CCOSS Comparison Utilizing IPL's Procedures
Except For The Allocation of Generation Plant
(Rate of Return At Current Rates)

Class		IPL Revised 12-CP	BIP
Residential	RS	2.48%	3.73%
Secondary Small	SS	13.41%	13.26%
Space Conditioning	SH	2.79%	3.40%
Space Conditioning-Schools	SE	3.95%	5.53%
Water Heating-Controlled	CB	-7.14%	-8.18%
Water Heating-Uncontrolled	UW	2.87%	0.31%
Secondary Large	SL	7.26%	6.47%
Primary	PL	4.32%	3.46%
Process Heating	PH	3.13%	4.41%
HLF-Primary	HL1	3.93%	1.31%
HLF-Sub-Tran	HL2	3.50%	1.08%
HLF-Tran	HL3	3.24%	0.44%
Automatic Protective Lighting	APL	-12.28%	-13.23%
Municipal Lighting	MU1	29.89%	14.33%
Total		4.88%	4.88%

As can be seen in the table above, there are significant differences for some classes and minimal differences for other classes. For example, the residential ROR increases from 2.48% to 3.73%, while several of the industrial classes RORs are significantly reduced. A summary of my BIP CCOSS results are provided in my Attachment GAW-6, while the details are provided in my filed workpapers.

3. Peak & Average ("P&A") Method

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR CCOSS UTILIZING THE P&A METHOD.

A. I used IPL's test year retail load factor of 53.66% in order to weight the energy (average) portion versus the peak portion of the P&A allocator.

Q. WHAT MEASURE OF PEAK DEMAND DID YOU USE FOR THE DEMAND PORTION OF THE P&A ALLOCATOR?

A. I used Dr. Gaske's class contributions to the 1-CP demand rather than the 12-CP demand to reflect the peak nature and responsibility of class loads.[4] I have selected this measure of peak demand because the 12-CP incorporates peak and non-peak months; i.e., spring and fall demands. In my opinion, the use of class contributions to 1-CP better reflect the spirit and concepts of the P&A method.

Q. WHAT ARE THE RESULTS OF YOUR CCOSS UTILIZING THE P&A METHOD TO ALLOCATE GENERATION COSTS?

A. The following summary and comparison utilizes all other allocations and procedures used by Dr. Gaske in conducting his 12-CP CCOSS. The following table provides an apples-to-apples comparison of Dr. Gaske's 12-CP results to those obtained utilizing the P&A method:

[4] Per response to OUCC-18-1, Attachment 2.

CCOSS Comparison Utilizing IPL's Procedures
Except For The Allocation of Generation Plant
(Rate of Return At Current Rates)

Class		IPL Revised 12-CP	P&A
Residential	RS	2.48%	2.64%
Secondary Small	SS	13.41%	13.39%
Space Conditioning	SH	2.79%	3.71%
Space Conditioning-Schools	SE	3.95%	5.55%
Water Heating-Controlled	CB	-7.14%	-7.25%
Water Heating-Uncontrolled	UW	2.87%	2.92%
Secondary Large	SL	7.26%	7.37%
Primary	PL	4.32%	4.35%
Process Heating	PH	3.13%	4.77%
HLF-Primary	HL1	3.93%	2.88%
HLF-Sub-Tran	HL2	3.50%	2.28%
HLF-Tran	HL3	3.24%	2.33%
Automatic Protective Lighting	APL	-12.28%	-12.80%
Municipal Lighting	MU1	29.89%	21.02%
Total		4.88%	4.88%

Unlike the Probability of Dispatch and BIP methods, the P&A approach produces results relatively similar to those obtained under the 12-CP method. A summary of my P&A CCOSS results are provided in my Attachment GAW-7, while the details are provided in my filed workpapers.

Q. EARLIER IN YOUR TESTIMONY YOU INDICATED THAT THE PROBABILITY OF DISPATCH, BIP, AND P&A METHODS MAY NOT PROPERLY RECOGNIZE CLASS VARIANCES IN VARIABLE GENERATION COSTS. HAVE YOU EXAMINED WHETHER THERE ARE MATERIAL DIFFERENCES IN CLASS FUEL COSTS WHEN ANALYZED ON AN HOURLY BASIS?

A. Yes I have. As discussed earlier, IPL provided each generation plant's hourly output during the test year. In addition, in response to OUCC-18-9, Attachment 1, the Company provided monthly fuel costs (per mWh) for each plant. With this data, I was able to

calculate hourly fuel costs by individual generating plant. These hourly fuel costs were then assigned to individual rate classes on an hour-by-hour basis based on class hourly loads also discussed previously.[5] The end result of this analysis yielded very similar hourly fuel costs across all classes such that all classes' fuel costs are within 2.00% of the system average annual fuel cost as shown below[6]:

IPL Class Hourly Fuel Costs

Class		Fuel Cost Per mWh	Deviation From Sys. Average
Residential	RS	$26.30	-0.9%
Secondary Small	SS	$26.73	0.7%
Space Conditioning	SH	$26.61	0.2%
Space Conditioning-Schools	SE	$26.42	-0.5%
Secondary Large	SL	$26.97	1.6%
Primary	PL	$26.28	-1.0%
Process Heating	PH	$26.04	-1.9%
HLF-Primary	HL1	$26.35	-0.8%
HLF-Sub-Tran	HL2	$26.50	0.2%
HLF-Tran	HL3	$26.45	-0.4%
Total		$26.55	--

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE PROPER ALLOCATION OF IPL'S GENERATION PLANT?

A. IPL's portfolio of generating assets is comprised predominately of large base load units that serve the energy needs of IPL throughout the entire year. While IPL does indeed rely upon intermediate and peaker units to some degree, the dollar investment in these facilities pale in comparison to its base load investments. The Probability of Dispatch and BIP methods are very detailed approaches that are theoretically sound and reasonably reflect the capacity/energy trade-off in generation facilities specific to IPL's investment. As such, these two methods are the most "accurate" methods from a cost causation perspective. While the P&A method is much simpler in its data requirements as well as in its analytical application, and is admittedly somewhat arbitrary, it too recognizes the

[5] The class hourly loads were provided at the sales (meter) level. Each class' loads were adjusted for losses back to generation based on each class' respective energy loss factor as provided in response to OUCC-18-1, Attachment 2.

[6] The details of this analysis is provided in my filed workpapers.

fact that much of IPL's generation resources are utilized to meet energy requirements throughout the year. It is my opinion that each of these methods should be considered in evaluating class profitability. Furthermore, because the 12-CP method does not produce results materially different than the P&A method, this approach can also be considered in the context of class profitability.

Q. FOR THE RECORD, PLEASE PROVIDE A SUMMARY OF CLASS RATES OF RETURN UNDER EACH OF THE FOUR GENERATION ALLOCATION METHODOLOGIES YOU HAVE DISCUSSED.

A. The following table provides class rates of return at current rates utilizing all other aspects of Dr. Gaske's CCOSS (except for the minor correction to lighting revenues):

CCOSS Comparison Utilizing IPL's Procedures
Except For The Allocation of Generation Plant
(Rate of Return At Current Rates)

		12-CP	P&A	BIP	Probability of Dispatch
Residential	RS	2.48%	2.64%	3.73%	4.00%
Secondary Small	SS	13.41%	13.39%	13.26%	13.71%
Space Conditioning	SH	2.79%	3.71%	3.40%	2.75%
Space Conditioning - Schools	SE	3.95%	5.55%	5.53%	6.63%
Water Heating - Controlled	CB	-7.14%	-7.25%	-8.18%	-7.10%
Water Heating - Uncontrolled	UW	2.87%	2.92%	0.31%	2.99%
Secondary Large	SL	7.26%	7.37%	6.47%	6.51%
Primary	PL	4.32%	4.35%	3.46%	2.48%
Process Heating	PH	3.13%	4.77%	4.41%	4.82%
HLF - Primary	HL1	3.93%	2.88%	1.31%	1.34%
HLF - Sub-Tran	HL2	3.50%	2.28%	1.08%	0.58%
HLF -Tran	HL3	3.24%	2.33%	0.44%	-0.22%
Automatic Protective Lighting	APL	-12.28%	-12.80%	-13.23%	-13.45%
Municipal Lighting	MU1	29.89%	21.02%	14.33%	11.20%
Total Jurisdictional		4.88%	4.88%	4.88%	4.88%

B. <u>Transmission Plant</u>

Q. PLEASE EXPLAIN THE THEORIES ON HOW TRANSMISSION-RELATED PLANT SHOULD BE ALLOCATED WITHIN AN EMBEDDED CCOSS.

A. There are two general philosophies relating to the proper allocation of transmission-related plant. The first philosophy is based on the premise that transmission facilities are nothing more than an extension of generation plant in that transmission facilities simply act as a conduit to provide power and energy from distant generating facilities to a utility's load center (specific service area). That is, generation facilities are often located well away from load centers and near the resources required to operate generation facilities. For example, coal generation facilities are commonly located near water sources for steam and cooling or near coal mines and/or rail facilities. Similarly, natural gas generators must be located in close proximity to large natural gas pipelines.

The second philosophy relates to the physical capacity of transmission lines. That is, transmission facilities have a known and measurable load capability such that customer contributions to peak load should serve as the basis for allocating these transmission costs. While there is no doubt that any given electricity conductor (i.e., a transmission line) has a physical load carrying capability, this rationale fails to recognize cost causation in three regards.

First, an allocation based simply on contributions to a few hours of peak load fails to recognize the fact that transmission facilities are indeed an extension of generation facilities and are used to move the energy produced by the generators from remote locations to where customers actually consume electricity. Second, and similar to the concept of base load units producing energy to serve customers throughout the year, a peak responsibility approach based on one or only a few hours of maximum demand fails to recognize that transmission facilities are used virtually every hour of an entire year and not just during periods of peak load. Third, any assumption that transmission costs are related to peak load implies that there is a direct and linear relationship between cost and load. In other words, one must assume that if load increases, the cost of transmission

facilities increases, in a direct and linear manner. This is simply not the case since there are significant economies of scale associated with high voltage transmission lines.

Q. WHAT METHOD DID DR. GASKE USE TO ALLOCATE IPL'S TRANSMISSION-RELATED COSTS?

A. Dr. Gaske allocated transmission-related costs based on the 12-CP method.

Q. WHAT IS YOUR OPINION REGARDING DR. GASKE'S USE OF THE 12-CP METHOD TO ALLOCATE TRANSMISSION-RELATED COSTS?

A. In my opinion, the 12-CP approach strikes a reasonable balance between the two general philosophies that were discussed above as it relates to the cost causation and allocation of transmission-related costs.

C. <u>Distribution Plant</u>

Q. PLEASE EXPLAIN THE PHRASE "CLASSIFICATION OF DISTRIBUTION PLANT."

A. It is generally recognized that there are no energy-related costs associated with distribution plant. That is, the distribution system is designed to meet localized peak demands. However, largely as a result of differences in customer densities throughout a utility's service area, electric utility distribution plant sometimes is classified as partially demand-related and partially customer-related.

Q. WHY IS DISTRIBUTION PLANT SOMETIMES CLASSIFIED AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED?

A. Even though investment is made in distribution plant and equipment to meet the needs of customers at their required power levels, there may be considerable differences in both customer densities and the mix of customers throughout a utility's service area. Therefore, if one were to allocate distribution plant investment based simply on class contributions to peak demand, an inequitable allocation of these costs may result. As a hypothetical, suppose a utility serves both an urban area and a rural area. In this

situation, many customers' electrical needs are served with relatively few miles of conductors, few poles, etc. in the urban area, while many more miles of conductors, more poles, etc. are required to serve the requirements of relatively few customers in the rural area. If the distribution of classes of customers (class customer mix) is relatively similar in both the rural and urban areas, there is no need to consider customer counts (number of customers) within the allocation process, because all classes use the utility's joint distribution facilities proportionately across the service area. However, if the customer mix is such that commercial and industrial customers are predominately clustered in the more densely populated urban area, while the less dense (rural) portion of the service territory consists almost entirely of residential customers, it may be unreasonable to allocate the total Company's distribution investments based solely on demand; i.e., a large investment in many miles of line is required to serve predominately residential customers in the rural area while the commercial and industrial electrical needs are met with much fewer miles of lines in the urban area. Under this circumstance, an allocation of costs based on a weighting of customers and demand can be considered equitable and appropriate.

Q. PLEASE PROVIDE AN EXAMPLE THAT ILLUSTRATES THE CONCEPTS OF DENSITY AND CLASS CUSTOMER MIX AS THEY RELATE TO COST ALLOCATIONS.

A. As a starting point, it is important to understand absolute and relative class relationships of an electric utility's number of customers, energy requirements, and maximum loads (demands). In terms of simple customer counts, the number of residential accounts make-up the overwhelming majority of any retail electric utility's number of customers. However, because residential customers tend to be small volume users compared to commercial and industrial customers, the residential class is responsible for a significantly smaller percentage of total kWH energy supplied or peak loads on the system. For example, in IPL's system, the following characteristics are exhibited:

Category	Percentage of Total Jurisdictional Distribution System		
	Customers	kWh	Peak Demand (NCP)
Residential	88.1%	38.3%	55.3%
Comm./Ind. Distribution Voltage	11.7%	61.2%	44.2%
Lighting	0.2%	0.5%	0.5%

While the table above shows the relative class differences between number of customers, energy usage, and peak demands, the following table illustrates the absolute size differences between IPL's different types of customers:

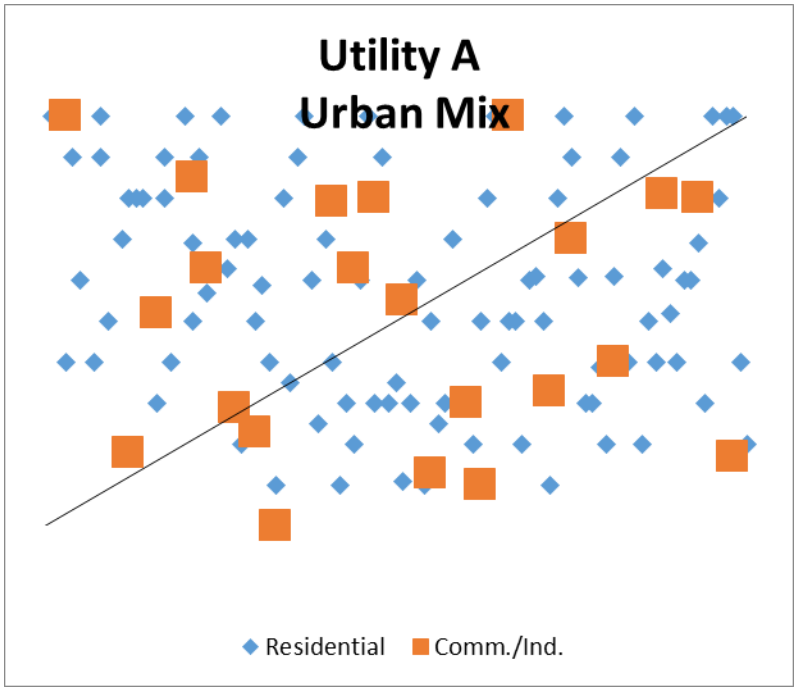
Category	Average Annual kWh Per Customer (kWh)
Residential	11,869
Comm./Ind. Distribution Voltage	143,120

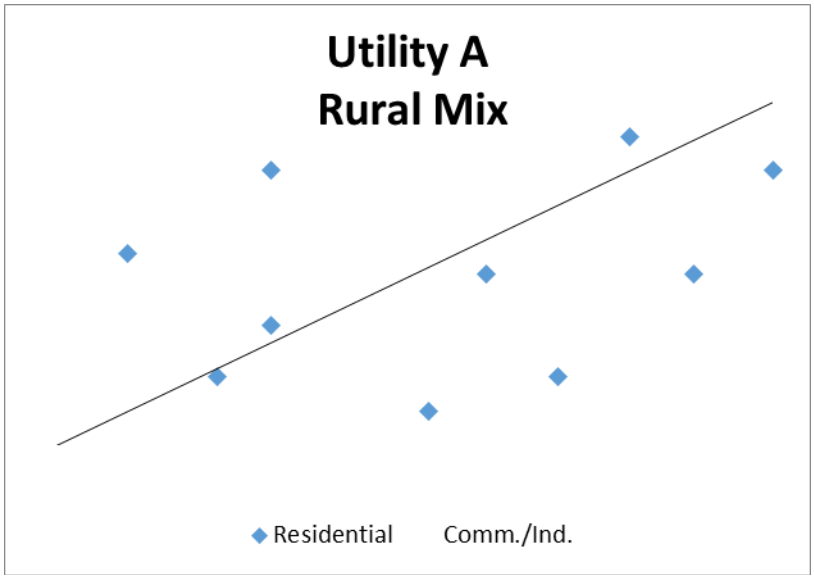
With the above relationships explained, in order to understand the concepts of density and class customer mix, consider examples of two hypothetical electric utilities each of which are comprised of only two distribution lines: one line serving a densely populated area (urban) and another line serving a sparsely populated area (rural). Furthermore, for simplicity and explanatory purposes, assume there are only two classes of customers for each utility: residential and commercial/industrial with the following characteristics:

Class	Absolute			Relative	
	Number of Customers	Peak Load	Peak Load Per Customer	Number of Customers	Peak Load
Residential	110	550	5	83%	33%
Comm./Ind.	22	1,100	50	17%	67%
Total	132	1,650	--	100%	100%

Utility A:

For Utility A, assume all commercial/industrial customers are located on the urban (densely populated) distribution line such that the rural line only serves residential customers as shown graphically below:



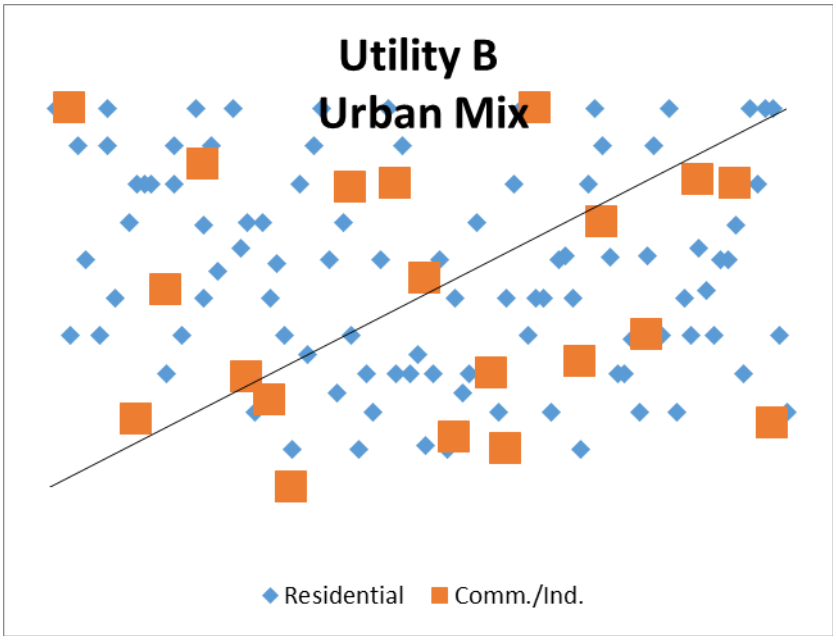


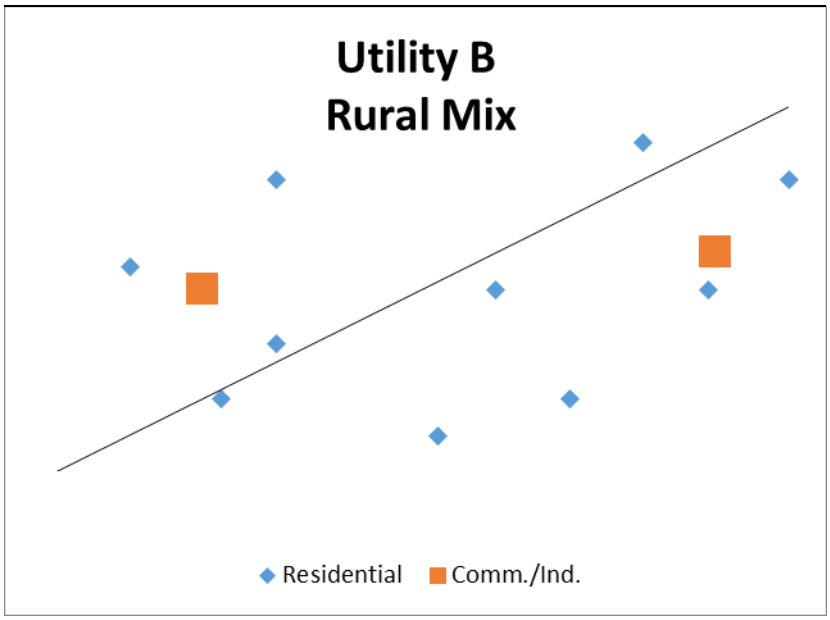
Because the urban line is much shorter in total distance, yet, serves the majority of customers (and loads) and many more miles of line are required to serve relatively few residential only customers in rural areas, it would be unfair, and inconsistent with cost causation to allocate total system line costs only on utilization (kW) because commercial/industrial customers arguably do not cause costs to be incurred for the rural portion of the system. As such, some weighting of relative number of customers and utilization is appropriate to allocate total system line costs.

Utility B:

For Utility B, assume that the relative mix of customers is evenly distributed between the urban and rural lines. In other words, this utility's configuration of customers is as follows:

	Number of Customers			
	Urban Line		Rural Line	
Class	Amount	Percent	Amount	Percent
Residential	100	83%	10	83%
Comm./Ind.	20	17%	2	17%
Total	120	100%	12	100%





As can be seen in the above table and charts, the relative imposition of costs across the two classes for Utility B is the same for the urban and rural lines. That is, while there are more absolute residential customers than commercial/industrial customers on both the urban and rural lines, the proportion (mix) of customers is the same between urban and rural. As such, an allocation of total system lines costs based on utilization (maximum loads) is appropriate such that no consideration of customer counts is needed or desired. Indeed, if distribution costs are classified and allocated partially on number of customers, the residential class will be over burdened with cost responsibility creating a subsidy for commercial/industrial customers.

Q. DOES THE CLASSIFICATION OF DISTRIBUTION PLANT INVESTMENT AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED REFLECT ANY RELATIVE COST (PER MILE) DIFFERENCES BETWEEN URBAN AND RURAL AREAS?

A. No. It is generally more expensive to install a mile of distribution circuit in an urban area than in a rural area. However, although this cost difference may be substantial, this cost difference is usually ignored due to record keeping limitations, in that all costs are simply assumed to be uniform (averaged) across the rural and urban portions of a service area.

Q. DO YOUR EXAMPLES DISCUSSED ABOVE IMPLY THAT IT COSTS MORE TO SERVE RURAL CUSTOMERS THAN URBAN CUSTOMERS AND THAT PERHAPS A UTILITY'S RURAL CUSTOMERS SHOULD PAY MORE PER UNIT THAN URBAN CUSTOMERS?

A. While it is possible that it technically costs more to serve a rural customer versus an urban customer, regulatory policy in the United States has generally been not to price discriminate based on customer densities, urban versus rural, or other geographic differences. Rather, regulatory policy has been such that classes of customers with similar usage and/or load characteristics are established for pricing purposes. In fact, during my 34-plus years practicing utility costing and pricing across the Country, I have not seen a rate structure that discriminates based on customer densities or other geographic characteristics.

Q. IS THERE ACADEMIC SUPPORT FOR YOUR EXPLANATION AND CONCEPTS REGARDING CUSTOMER DENSITIES AND CLASS CUSTOMER MIXES?

A. Yes. In the well-known and often referenced, treatise Principles of Public Utility Rates, Professor James Bonbright states that there:

> is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.[7]

Q. BEFORE I CONTINUE, IS IPL's DISTRIBUTION SYSTEM COMPRISED OF VARIOUS SUB-SYSTEMS?

A. Yes. As is the case with virtually every electric utility, IPL's overall distribution system is comprised of a primary voltage system and a secondary voltage system. The primary

[7] Bonbright, Principles of Public Utility Rates, Second Edition, page 491.

system operates at higher voltage levels than the secondary system and generally consists of plant and equipment between the substations and transformers. The lower voltage secondary system can be thought of as operating downstream from the primary system and delivers electricity to small end-users.

Q. BRIEFLY DESCRIBE THE TYPES OF INVESTMENT (EQUIPMENT) UTILIZED IN IPL's DISTRIBUTION SYSTEM.

A. For accounting purposes, IPL's distribution plant is grouped into various accounts. These accounts include: Land and Land Rights (Account 360); Structures and Improvements (Account 361); Station Equipment (Account 362); Poles, Towers and Fixtures (Account 364); Overhead Conductors (Account 365); Underground Conduit (Account 366); Underground Conductors (Account 367); Line Transformers (Account 368); Meters (Account 370); Area Lighting (Account 371) and Street Lighting (Account 373).

Q. DID DR. GASKE MAKE AN *A PRIORI* ASSUMPTION THAT DISTRIBUTION PLANT SHOULD BE CLASSIFIED AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED?

A. Yes.

Q. WHAT RELATIVE CUSTOMER/DEMAND PERCENTAGES DID DR. GASKE USE IN THIS CASE?

A. The following are Dr. Gaske's customer/demand percentages used for each distribution plant account:

Classification of Distribution Plant

Account	Percent Customer	Percent Demand
Poles (Primary Voltage)	31.5%	68.5%
Poles (Secondary Voltage)	52.9%	47.1%
Overhead Lines (Primary Voltage)	35.3%	64.7%
Overhead Lines (Secondary Voltage)	21.3%	78.7%
Underground Lines (Primary Voltage)	38.7%	61.3%
Underground Lines (Secondary Voltage)	26.1%	73.9%

Q. HAVE YOU CONDUCTED ANALYSES TO DETERMINE IF A CLASSIFICATION OF DISTRIBUTION PLANT AS PARTIALLY CUSTOMER-RELATED IS APPROPRIATE FOR IPL?

A. Yes, I have.

Q. PLEASE EXPLAIN.

A. Dr. Gaske has made an *a priori* assumption that it is appropriate to allocate a portion of its distribution plant based on customer counts and a portion based on demand levels. As indicated earlier, the only reason why it may be appropriate to allocate a portion of distribution plant expenses based on number of customers, rather than peak demand, is due to the possibility that the mix of customers varies significantly across the customer density levels within IPL's service territory. In this regard, I evaluated this assumption by conducting an analysis of the distribution, or mix, of IPL's customer classes across its service area.

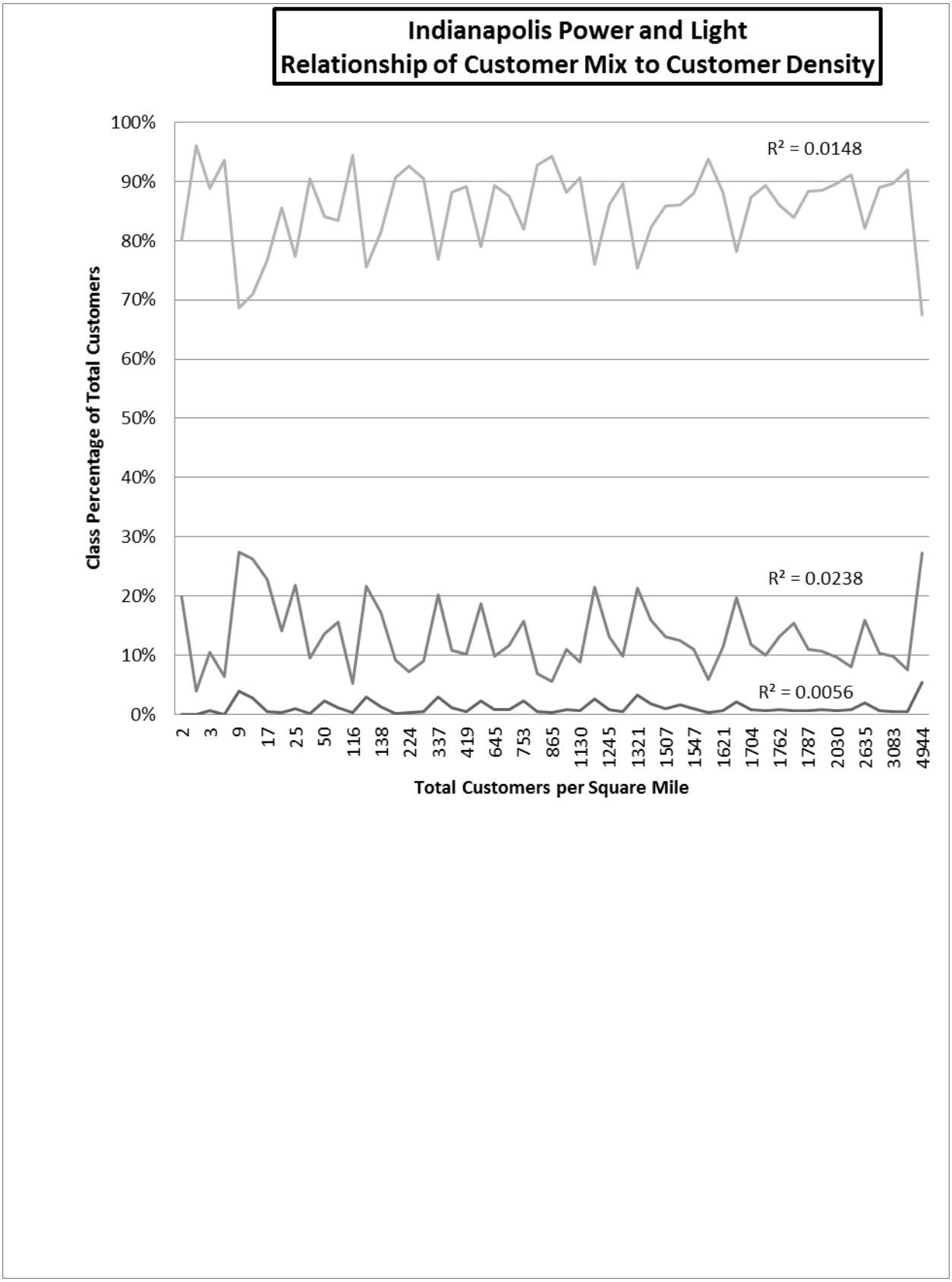
Through discovery, the Company provided a data base of the number of customers by rate schedule for each postal zip-code within its service area. I then evaluated the mix of customers by rate class for each postal zip-code within the IPL service area. In order to evaluate whether any differences exist in the distribution of customers across various customer density areas, I calculated the number of total IPL distribution customers (excluding lighting customers) per square mile for each non-Post Office Box zip-code to serve as a measure of density for relatively small geographic areas. I was then able to readily compare IPL's mix of customers throughout its service area and delineate between sparsely populated and densely populated areas (in terms of number of IPL customers). As a further refinement, I also evaluated the distribution of customers on a stratified basis. That is, for each customer group (residential, small commercial/industrial, and large commercial/industrial)[8] I separated small geographical areas (zip codes) into four separate strata (highest to lowest customer densities). I

[8] Dr. Gaske developed his non-coincident peak ("NCPs") demands based on these same three customer groups, which then serves as the basis for his allocation of the "demand" portion of each distribution plant account.

examined each stratum (by customer group) to determine if any significant differences in customer mix occur within each stratum.

This analysis of the distribution of the various customer groups by density provided a basis to determine whether: (a) utilization alone (demand) is an appropriate and fair method to allocate distribution costs; or, (b) whether a weighting of customers and utilization (demand) is appropriate in order to reasonably reflect the imposition or causation of costs.

If there is any basis for a customer classification of distribution plant, this analysis should show a negative correlation between the residential customer mix (residential percentage of total customers) and density across IPL's service area. In other words, the percentage of residential customers (by zip-code) should decline as customer density per square mile increases from the least dense areas to the most dense areas of IPL's service territory. Similarly, if Dr. Gaske's assumption is correct, you should see a distinct positive correlation between non-residential customer mixes and customer densities by zip-code. The graph below shows the percentage of total customers by rate group (Y axis) compared to total customers per square mile (X axis):


Indianapolis Power and Light
Relationship of Customer Mix to Customer Density
Class Percentage of Total Customers
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
R² = 0.0148
R² = 0.0238
R² = 0.0056
2
3
9
17
25
50
116
138
224
337
419
645
753
865
1130
1245
1321
1507
1547
1621
1704
1762
1787
2030
2635
3083
4944
Total Customers per Square Mile

As can be seen in the graph above, there is absolutely no correlation or trend between the distribution of customers (customer mix) and density levels for any of the three customer groups. Indeed, and as shown in the graph, the correlation coefficients for all three customer groups are essentially zero.

As discussed earlier, I also analyzed this data on a stratified basis. A summary of the approach and data utilized for the stratification analysis is provided below:

			Percent of Total Distribution Customers[9]			
Class	Customers Per Sq. Mile (Density)	Count Of Zip Codes	Simple Avg.	Weighted Avg.	Number	% of Class
Residential						
Strata 1	1,704 Min to 4,944 Max	13	86.50%	87.38%	191,066	40.8%
Strata 2	1,025 Min to 1,703 Max	13	85.24%	86.00%	175,414	37.5%
Strata 3	138 Min to 1,024 Max	13	87.25%	87.69%	87,270	18.7%
Strata 4	Less Than 138	14	83.25%	84.87%	14,090	3.00%
Total		53			467,840	100.0%
Small Comm./Ind.						
Strata 1	1,704 Min to 4,944 Max	13	12.36%	11.72%	25,632	39.2%
Strata 2	1,025 Min to 1,703 Max	13	13.46%	12.83%	26,177	40.0%
Strata 3	138 Min to 1,024 Max	13	11.69%	11.27%	11,218	17.2%
Strata 4	Less Than 138	14	15.61%	14.10%	2,340	3.6%
Total		53			65,367	100.0%
Large Comm./Ind.						
Strata 1	1,704 Min to 4,944 Max	13	1.14%	0.90%	1,959	35.3%
Strata 2	1,025 Min to 1,703 Max	13	1.31%	1.17%	2,382	42.9%
Strata 3	138 Min to 1,024 Max	13	1.06%	1.04%	1,034	18.6%
Strata 4	Less Than 138	14	1.14%	1.03%	171	3.2%
Total		53			5,546	100.0%

Q. WHAT ARE YOUR FINDINGS AS A RESULT OF THIS ANALYSIS?

A. IPL's customers are dispersed in a reasonably proportional manner throughout its service area. In fact, the distribution of residential customers is somewhat greater in the more densely populated zip codes than the less densely populated zip codes, which is contrary to the hypothesis and is opposite of what would be expected if one were to accept the notion that distribution investment should be classified as partially customer-related. As important is the fact that in the less dense areas of IPL's service territory (which requires more miles of distribution lines and number of poles to serve fewer customers),

[9] Excludes Lighting.

the Company actually serves a larger percentage of commercial/industrial customers than in the more densely populated areas within IPL's service territory.

As a result of these analyses, it cannot be said that the less populated portions of IPL's service area (which require significant investment to serve few customers) are disproportionately required to serve any one class of customers. As such, IPL's distribution plant and expenses should be assigned to classes based only on utilization (peak demand) and any consideration of customer counts is improper for the allocation of distribution plant. Therefore, my studies indicate that IPL's distribution plant should be classified as 100% demand-related.

Q. DOES THE NARUC ELECTRIC COST ALLOCATION MANUAL INDICATE IF AN *A PRIORI* ASSUMPTION IS APPROPRIATE REGARDING WHETHER DISTRIBUTION COSTS MUST BE CLASSIFIED AS PARTIALLY CUSTOMER-RELATED AND PARTIALLY DEMAND-RELATED?

A. No. In fact, the NARUC Manual (published in 1992) states the following:

> To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.
>
> Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. (page 89)

Q. HAS NARUC PROVIDED MORE RECENT GUIDANCE CONCERNING THE CLASSIFICATION OF DISTRIBUTION PLANT THAN WHAT WAS PUBLISHED IN THE 1992 NARUC ELECTRIC COST ALLOCATION MANUAL?

A. Yes. The 1992 NARUC Manual was written in an era when all retail utility services were bundled (generation, transmission and distribution). Subsequent to the unbundling of retail rates in the mid to late 1990's by several state jurisdictions, NARUC commissioned a study to examine the costing and pricing of electric distribution service in further detail. In December 2000, NARUC published a report entitled: Charging For

Distribution Services: Issues in Rate Design. As part of the Executive Summary this report states:

> The usefulness of cost analyses of the distribution system in designing rate structures and setting rate levels depends in large measure upon the manner in which the studies are undertaken. Cost studies (both marginal and embedded) are intended, among other things, to determine the nature and causes of costs, so that they can then be reformulated into rates that cost-causers can pay. Such studies must of necessity rely on a host of simplifying assumptions in order to produce workable results; this is especially true of embedded cost studies. Moreover, it is often the case that many of the costs (*e.g.*, administrative and general) that distribution rates recover are not caused by provision of distribution service, but are assigned to it arbitrarily. Too great dependence on cost studies is to be captured by their underlying assumptions and methodological flaws. Utilities and commissions should be cautious before adopting a particular method on the basis of what may be a superficial appeal. More important, however, is the concern that a costing method, once adopted, becomes the predominant and unchallenged determinant of rate design. (page 67)

With specific regard to classification and allocation of certain distribution plant (poles, wires and transformers), Chapter IV of this report is devoted to the costing of distribution services. With respect to embedded cost analyses this updated NARUC report states:

> There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states. A variation is to treat poles, wires, and transformers as energy-related driven by kilowatt-hour sales but, though it has obvious appeal, only a small number of jurisdictions have gone this route.
>
> Two other approaches sometimes used are the minimum size and zero-intercept methods. The minimum size method operates, as its name implies, on the assumption that there is a minimum-size distribution system capable of serving customers minimum requirements. The costs of this hypothetical system are, so the argument goes, driven not by customer demand but rather by numbers of customers, and therefore they are considered customer costs. The demand-related cost portion then is the difference between total distribution investment and the customer-related costs. The zero-intercept approach is a variation on the minimum size. Here the idea is to identify that portion of plant that is necessary to give customers access but which is incapable of serving any level of demand. The logic is that the costs of this system, because it can serve no demand

> and thus is not demand-related, are necessarily customer-related. However, the distinction between customer and demand costs is not always clear, insofar as the number of customers on a system (or particular area of a system) will have impacts on the total demand on the system, to the extent that their demand is coincident with the relevant peak (system, areal, substation, etc.).
>
> Any approach to classifying costs has virtues and vices. The first potential pitfall lies in the assumptions, explicit and implicit, that a method is built upon. In the basic customer method, it is the *a priori* classification of expenditures (which may or may not be reasonable). In the case of the minimum-size and zero-intercept methods, the threshold assumption is that there is some portion of the system whose costs are unrelated to demand (or to energy for that matter). From one perspective, this notion has a certain intuitive appeal these are the lowest costs that must be incurred before any or some minimal amount of power can be delivered but from another viewpoint it seems absurd, since in the absence of any demand no such system would be built at all. Moreover, firms in competitive markets do not indeed, cannot price their products according to such methods: they recover their costs through the sale of goods and services, not merely by charging for the ability to consume, or access. (pages 29 & 30)

In summary, when all of the facts and guidelines are known, it is clear to me that: (a) data and analysis specific to each utility is more appropriate and preferred over an *a priori* assumption that distribution plant must be partially customer-related; and, (b) many (if not most) state regulatory commissions endorse a method in which all distribution plant from substations through line transformers is classified and allocated based solely on demand. A copy of the entire Chapter (IV) from the 2000 NARUC Publication discussing costing studies is provided in my Attachment GAW-8.

Q. WHY IS THE CLASSIFICATION OF DISTRIBUTION PLANT IMPORTANT IN CCOSS ANALYSES?

A. The classification of distribution plant may be the single most important factor affecting class rates of return. To illustrate the importance of this issue, consider the residential class: whereas this class may account for only 40% to 50% of peak demand, it is responsible for a much higher percentage of the number of customers. Therefore, given

the level of investment associated with distribution plant, wide variations in class rates of return can result from different customer/demand classifications.

Q. HOW DID DR. GASKE CLASSIFY DISTRIBUTION PLANT BETWEEN CUSTOMER-RELATED AND DEMAND-RELATED COMPONENTS?

A. In response to OUCC-18-17 and OUCC-18-18, the Company indicated that its fixed asset accounts records do not contain data relating to the installed footage of overhead and underground conductors. As such, in response to OUCC-18-20, Dr. Gaske indicated that he used replacement costs provided by IPL engineering personnel.

In other words, the Company does not maintain records in sufficient detail in order to conduct studies based on actual costs and circuit miles of its distribution system. This data is critical in classifying distribution plant under industry accepted practices. Rather, Dr. Gaske was forced to rely upon estimates of current costs provided by IPL's engineering staff. I will discuss these deficiencies later in my testimony.

When a decision is made to classify a portion of distribution plant as customer-related and a portion as demand-related, there are two industry accepted methods: the first is known as the Minimum-Size approach while the second is known as the Zero-Intercept approach. Dr. Gaske has attempted to utilize the Minimum-Size approach. Under this method, the cost per unit (per pole or per circuit mile) of the minimum-sized equipment actually installed is multiplied by the total number of units within the distribution system (poles or circuit miles) which then serves as the total minimum system cost for a particular distribution plant account. This total minimum system cost is then divided by the total cost for the account such that the quotient serves as the customer percentage; i.e., the minimum-size cost divided by the total cost equals the customer percentage.

There is a significant bias embedded within the so-called Minimum-Size method in that the theory underlying both the Minimum-Size and Zero-Intercept methods is that there is some level of cost required to simply connect customers with no load. In other words, the loads that customers place on the system are related to peak demand such that there

are some costs required to simply connect customers to the system. The bias that results under the Minimum-Size approach is that even the smallest sized conductor actually installed has load carrying capability, and in fact, is installed to meet the collective loads of the customers on a particular distribution line segment. Therefore, there is a substantial level of demand-related costs within the "minimum-size" costs used within this method.

Q. DO YOU HAVE DISAGREEMENTS REGARDING DR. GASKE'S MINIMUM-SIZE STUDIES RELATING TO SPECIFIC ACCOUNTS?

A. Yes. As is typically the case, Dr. Gaske has conducted separate analyses for Account 364 (poles), Account 365 (overhead conductors), and Account 367 (underground conductors). With regard to Dr. Gaske's Minimum-Size analyses for distribution poles, he has used a 30-foot pole as a "minimum-size" secondary voltage pole and a 35-foot pole as a "minimum-size" primary voltage poles. While the Company may indeed typically use 30 to 35-foot poles as a minimum, it must recognized that the reason for these minimum heights is to accommodate telecommunication lines and cables on the same pole, which are typically installed below the energized electrical lines. In response to OUCC-18-21, the Company's design standards require a minimum separation of 40 inches between telecommunication cables and energized lines for secondary voltage poles and 40-60 inches for primary voltage poles. Because of this required separation to accommodate telecommunication carriers, IPL's distribution poles are clearly longer than they otherwise would be. This has nothing to do with the need to simply connect electrical customers, but rather, is no more than an accommodation for telecommunication infrastructure.

In addition, the Company was able to provide an inventory of its actual distribution poles by height in response to OUCC-18-20. This asset inventory report indicates that IPL has 15, 18, 20, and 25-foot poles actually installed in its distribution system which are clearly less expensive than a 30-foot pole.[10]

[10] It should be remembered that the cost used by Dr. Gaske are engineering estimates of replacement costs such that IPL's engineers only provided cost estimates for poles as short as 30 feet.

Q. PLEASE DISCUSS YOUR DISAGREEMENTS WITH DR. GASKE'S MINIMUM-SIZE ANALYSES SPECIFIC TO OVERHEAD AND UNDERGROUND CONDUCTORS.

A. In order to explain my disagreements with Dr. Gaske's Minimum-Size analyses as it relates to overhead and underground conductors, one must understand how an electrical circuit is configured. All electric distribution systems are comprised of both single-phase and multi-phase (3-phase) circuits. While some single-phase circuits are comprised of only two wires, current practices are to generally install three-wire single-phase circuits, while virtually all three-phase circuits require four conductors. Furthermore, three-phase circuits tend to be comprised of larger size conductors than do single-phase circuits. In this regard, the NARUC: Electric Cost Allocation Manual states the following as it relates to studies conducted using the Minimum-Size approach:

> Overhead Conductors –
>
> > Multiply average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component. Balance of plant account is demand component. (Note: two conductors in minimum system.)[11]
>
> Underground Conductors –
>
> > Multiply average installed book cost per mile of minimum size cable by the circuit miles to determine the customer component. Balance of plant Account 367 is demand component. (Note: one cable with ground sheath is minimum system.) Account 366 conduit is assigned, based on ratio of cable account.[12]

In examining the data utilized by Dr. Gaske it is apparent that he has not considered or reflected circuit miles, nor has he utilized a two-wire circuit as set forth in the NARUC Manual for a minimum-size circuit. In response to OUCC-18-20, the data provided to Dr. Gaske by IPL includes the total footage associated with various types of both single-bare wire as well as multiplex cables. In other words, single-bare wire is a single wire that is only a component of a complete circuit. Multiplex cables are comprised of numerous conductors (usually three to four) within the cable that do normally constitute

[11] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, 1992 Edition, page 91.

[12] Id.

an entire circuit. Dr. Gaske has mismatched single wires and complete circuits within his analysis. Furthermore, and as indicated earlier, because of the limited information available to Dr. Gaske it is impossible to determine the number of total circuit miles as well as what the cost of a two-wire circuit mile would be.

Q. ARE YOU AWARE OF ANY OTHER CASE IN INDIANA IN WHICH SUFFICIENT RECORDS WERE NOT AVAILABLE TO PROPERLY CONDUCT A MINIMUM-SIZE OR ZERO-INTERCEPT ANALYSIS TO SEPARATE DISTRIBUTION COSTS BETWEEN CUSTOMER-RELATED AND DEMAND-RELATED COMPONENTS?

A. Yes. In Cause No. 43526 involving Northern Indiana Public Service Company ("NIPSCO"), the Commission's Final Order states:

> Mr. Greneman [Company witness] testified that primary lines, secondary lines and line transformers were classified as 100% demand-related because NIPSCO's property records were not sufficiently detailed as to reliably support a zero-intercept or minimum system analysis. [page 82]

The Commission's Final Order responded to the municipal intervenors' recommendation that NIPSCO be required to conduct a Minimum-Size analysis in the future by stating:

> Based upon those factors, and the arguments raised by Dr. Swan [OUCC] against the use of a minimum system approach, the Commission finds NIPSCO need not modify its cost of service study to reflect the minimum distribution system analysis. [page 86]

Q. WHAT ARE YOUR RECOMMENDATIONS CONCERNING THE CLASSIFICATION OF DISTRIBUTION PLANT IN THIS CASE?

A. Based on my customer density/mix analysis of IPL's distribution system, it is apparent that all of IPL's distribution system should be classified as 100% demand-related. In this regard, I have conducted my various CCOSSs utilizing a 100% demand classification of distribution plant. Furthermore, the Minimum-Size study conducted by Dr. Gaske is based entirely on severely deficient data and estimates. Moreover, Dr. Gaske's approach is not in accordance with accepted industry practices. As such, no credibility can be given to Dr. Gaske's Minimum-Size study.

Q. WHAT ARE THE CCOSS RESULTS UTILIZING THE GENERATION ALLOCATION METHODS YOU DISCUSSED EARLIER AND ALSO CLASSIFIES DISTRIBUTION PLANT AS 100% DEMAND-RELATED?

A. The following provides a summary of my CCOSS results at current rates under each allocation method wherein distribution costs are classified as 100% demand-related:

100% Demand Distribution Plant
Rate of Return At Current Rates

		12-CP	P&A	BIP	Probability of Dispatch
Residential	RS	2.94%	3.11%	4.27%	4.56%
Secondary Small	SS	13.95%	13.93%	13.79%	14.27%
Space Conditioning	SH	2.06%	2.94%	2.65%	2.02%
Space Conditioning - Schools	SE	3.22%	4.76%	4.74%	5.79%
Water Heating - Controlled	CB	-5.54%	-5.69%	-6.92%	-5.48%
Water Heating - Uncontrolled	UW	3.93%	3.99%	1.08%	4.07%
Secondary Large	SL	6.57%	6.67%	5.81%	5.85%
Primary	PL	3.80%	3.83%	2.96%	2.00%
Process Heating	PH	2.32%	3.87%	3.53%	3.92%
HLF - Primary	HL1	3.44%	2.41%	0.88%	0.90%
HLF - Sub-Tran	HL2	3.48%	2.23%	1.01%	0.50%
HLF -Tran	HL3	3.21%	2.28%	0.35%	-0.32%
Automatic Protective Lighting	APL	-13.04%	-13.50%	-13.90%	-14.10%
Municipal Lighting	MU1	29.22	20.54%	13.96%	10.86%
Total Jurisdictional		4.88%	4.88%	4.88%	4.88%

A summary of these CCOSS results are provided in my Attachment GAW-9 which consists of four pages (one page for each methodology). The details of each CCOSS are provided in my filed workpapers.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING CLASS COST ALLOCATIONS RELATING TO THIS CASE?

A. As can be seen in the table above, while absolute class RORs vary across allocation methodologies, there are relative consistencies across several classes. The residential

ROR at current rates tends to be lower than the system average regardless of allocation approach, while the small commercial classes (SS and SL) tend to be greater than the system average ROR and large volume classes (PL, PH, HL1, HL2 and HL3) tend to be significantly below the system average ROR. With regard to the lighting classes, the APL class is consistently shown to have a negative rate of return while the municipal lighting class consistently has exceptionally high ROR at current rates.

These profitability patterns across methodologies can then be used as a tool in evaluating reasonable individual class increases.

III. IPL PROPOSED MIGRATION ADJUSTMENT

Q. ON PAGE 13 OF HIS DIRECT TESTIMONY, DR. GASKE PROPOSES A $1.187 MILLION MIGRATION ADJUSTMENT. PLEASE EXPLAIN HOW THIS PROPOSED MIGRATION ADJUSTMENT IS REFLECTED IN THE COMPANY'S RATE APPLICATION.

A. The Company's proposed migration adjustment does not impact IPL's overall revenue requirement or its overall requested increase. Rather, Dr. Gaske has incorporated his proposed migration adjustment totally within his rate design proposals. In other words, whereas the Company is requesting an increase in its total revenue requirement of $67.774 million, Dr. Gaske has designed rates and charges to collect an additional $68.961 million. This difference of $1.187 million reflects the amount of revenue that Dr. Gaske contends will not be realized under his rate design due to lost revenues associated with customer migrations.

Q. PLEASE EXPLAIN THE BASIS FOR IPL'S PROPOSED MIGRATION ADJUSTMENT.

A. IPL's migration adjustment relates only to two small commercial rate classes: SS and SL. Specifically, Dr. Gaske has calculated those customers currently served under rate schedule SS that would realize lower total electric bills if they elected to switch (migrated) to rate schedule SL. In addition, he has also calculated those individual

customers served under rate schedule SL that would realize lower total electric bills if they elected to switch (migrated) to rate schedule SS. Dr. Gaske's analyses shows there is a maximum potential customer savings of $13,284 for those SS customers that could migrate to SL and a maximum potential customer savings of $1,173,229 for those SL that customers that could migrate to SS.

Q. PLEASE EXPLAIN THE MAJOR DIFFERENCES BETWEEN RATE SCHEDULES SS AND SL.

A. As indicated earlier, both of these rate schedules are designed for small commercial customers. Rate SS is an energy only rate and is available to customers whose maximum load is estimated to be less than 75 kW. Rate SL is a demand plus energy rate in which the minimum billed demand is 50 kW per month (regardless of actual demand) that is also subject to an annual 60% annual demand ratchet.

Q. SHOULD THE COMPANY'S PROPOSED MIGRATION ADJUSTMENT BE APPROVED BY THE COMMISSION?

A. No, the Company's proposed migration adjustment should be rejected for several reasons. As with most utilities, commercial and industrial customers have a host of rate schedule options on which to take service. Under the terms and conditions of the tariff, the customer has the right and option to select the rate schedule that meets their specific needs and desires subject to the limitations of availability set forth in the tariff. As business customers, it is reasonable to conclude that there are rationale reasons why a customer has opted to be served under either an energy only rate (SS) or a demand plus energy rate (SL).

During the test year, IPL had a total number of SS customers of 47,372 and a total number of SL customers of 4,515. With this many customers, one can be reasonably certain that every customer has not selected its absolute optimal rate schedule over a short period of time and indeed, there will be customers who might theoretically be slightly better off under a different rate schedule. However, for reasons that will vary from customer to customer, they have selected which rate schedule to be served by.

Furthermore, the Company has evaluated a very short time period (12 months). It is well known that small commercial customers tend to be very weather sensitive such that the usage and load characteristics of individual customers exhibited during the test year may not portray the same picture under a different weather pattern.

In response to OUCC-18-27, the Company provided a listing of each customer that would potentially save due to migrating from SL to SS or SS to SL. In this response, the Company provided each customer's total bill under both rate schedules. Based on this response, the Company has identified approximately 505 customers that would benefit by switching from rate schedule SL to SS. I evaluated the percent savings that would be realized due to this migration. Approximately 73% of these 505 customers (367) would realize savings less than 10.00% if they elected to switch rate schedules. Similarly, the Company identified six customers that would benefit by switching from rate schedule SS to SL. Of these six customers with potential savings, all six would realize savings less than 10.00%. Given the relatively minor level of savings that could be achieved by the vast majority of customers, there is very little probability or incentive for these customers to change rate schedules.

The next reason the Company's proposal should be rejected is that IPL has indicated that it will notify potential customers of savings if they switch rate schedules (presumably in a mail insert or separate mailing). Clearly, every customer will not respond to the notification provided by IPL let alone act upon it. However, the Company's proposal assumes that each and every potential customer will switch to its most advantageous rate schedule. This assumption goes beyond speculation in that it is clearly unrealistic.

Finally, the Company's proposed adjustment is a bit disingenuous from a public policy or public service perspective. That is, the Company's current rate structure has been in effect for almost 20 years and it has apparently not offered a customer notification service during this long time period. In other words, IPL has been happy to enjoy the additional revenue it receives from inefficient customer rate selection but for purposes of this case,

for an additional $1.187 million of revenue collection, it represents that it will now provide this service to its customers.

IV. CLASS REVENUE DISTRIBUTION

Q. WHAT ARE THE GENERAL CRITERIA THAT SHOULD BE CONSIDERED IN ESTABLISHING CLASS REVENUE RESPONSIBILITY FOR ELECTRIC UTILITY RATES?

A. There are several criteria that should be considered in evaluating class or rate revenue responsibility. First, class cost allocation results should be considered, but as discussed in detail earlier in my testimony, CCOSS results are not surgically precise. They should only be used as a guide and as one of many tools in evaluating class revenue responsibility. Other criteria that should be considered include: gradualism, wherein rates should not drastically change instantaneously; rate stability, which is similar in concept to gradualism but relates to specific rate elements within a given rate structure; affordability of electricity across various classes as well as a relative comparison of electricity prices across classes; and, public policy concerning current economic conditions as well as economic development.

Because embedded class cost allocations cannot be considered surgically precise and the fact that other criteria to be considered in evaluating class revenue responsibility are clearly subjective in nature, proper class revenue distribution can be deemed more of an art than a science. In this regard, there is no universal mathematical methodology that can be applied across all utilities or across all rate classes. However, most experts and regulatory commissions agree on certain broad parameters regarding class revenue increases. These include: some movement towards allocated cost of service; and, maximum/minimum percentage changes across individual rate classes.

Q. DOES IPL WITNESS GASKE CLAIM TO HAVE CONSIDERED AND REFLECTED THE VARIOUS SUBJECTIVE CRITERIA AS WELL AS THE BROAD PARAMETERS DISCUSSED ABOVE WITHIN HIS CLASS REVENUE DISTRIBUTION PROPOSAL?

A. Yes. Although Dr. Gaske utilized a mathematical approach to develop his proposed class revenue increases, his methodology was based on three major requirements.[13] First, no class receives a rate decrease; second, he increased or decreased revenue to eliminate 20.00% of the "subsidy" at current rates; and, third, he mitigated individual class rate revenues to no more than a 10.00% increase.

Q. PLEASE PROVIDE A SUMMARY OF THE COMPANY'S PROPOSED CLASS REVENUE INCREASE.

A. As indicated earlier in my testimony, the Company's class rate designs and attendant revenues reflect a $1.186 million proposed migration adjustment such that under IPL's proposal its designed rates will generate a total revenue increase of $68.961 million which is greater than the Company's requested revenue requirement increase of $67.774 million. The following table provides a summary of current and IPL proposed revenue excluding Riders 21 and 22.[14]

[13] This is based on Mr. Gaske's initially filed testimony. Although Mr. Gaske did not modify his class revenue distribution recommendation with his May 4, 2015 revised testimony, he has struck the "20 percent of subsidy at current rates" consideration in his revised testimony.

[14] Rider 21 (Green Power) and Rider 22 (Core DSM) are reconcilable riders that will continue at the same rate and revenue levels; i.e., will not be reflected in base rates. As such, these riders are excluded for purposes of this comparison.

INDIANAPOLIS POWER & LIGHT COMPANY
Company Proposed Class Revenue Distribution

	Current Revenue	IPL Proposed Revenue	Increase	Percent Increase	Percent of Sys. Average
RS	$447,940,739	$484,546,970	$36,606,231	8.17%	139%
SS	$133,401,548	$134,467,737	$1,066,189	0.80%	14%
SH	$43,752,996	$47,343,935	$3,590,940	8.21%	140%
SE	$1,558,865	$1,676,747	$117,881	7.56%	129%
CB	$42,436	$46,443	$4,007	9.44%	161%
UW	$110,940	$119,384	$8,444	7.61%	130%
SL	$284,465,519	$294,902,030	$10,436,511	3.67%	62%
PL	$88,323,681	$93,336,676	$5,012,995	5.68%	97%
PH	$5,370,399	$5,743,946	$373,547	6.96%	118%
HL1	$87,869,493	$94,512,600	$6,643,107	7.56%	129%
HL2	$14,633,088	$15,694,522	$1,061,434	7.25%	124%
HL3	$21,203,580	$23,025,183	$1,821,603	8.59%	146%
APL	$6,428,908	$6,962,302	$533,394	8.30%	141%
MU	$10,262,445	$10,235,832	-$26,613	-0.26%	-4%
Subtotal	$1,145,364,638	$1,212,614,307	$67,249,670	5.87%	100%
Other Non-Rate Revenues	$20,161,991	$21,872,959	$1,710,968		
Migration Adjustment			-$1,186,513		
Total Base Rate Revenue	$1,165,526,629	$1,234,487,266	$67,774,125		
Rider 21: Green Power	$45,368	$45,368	$0		
Rider 22: Core DSM	$31,664,001	$31,664,001	$0		
Sales For Resale	$6,324,121	$6,324,121	$0		
TOTAL IPL REVENUE	$1,203,560,119	$1,272,520,756	$67,774,125		

It should be noted that the table above (as well as Dr. Gaske's revenue proof) indicates a slight revenue reduction to the municipal street lighting (MU) class. However, Dr. Gaske proposes no change in rates to MU such that the revenue reduction is attributable to a small adjustment between per books revenues and those calculated under his revenue proof.

Q. HAVE YOU CONDUCTED ANALYSES TO EVALUATE THE REASONABLENESS OF DR. GASKE'S PROPOSED CLASS REVENUE INCREASES?

A. Yes. I have evaluated Dr. Gaske's proposed class revenue increases both in terms of relative class magnitudes as well as in terms of whether his proposed changes reflect a reasonable movement towards allocated cost of providing service.

Q. PLEASE EXPLAIN YOUR EVALUATION OF DR. GASKE'S PROPOSED CLASS REVENUE DISTRIBUTION IN TERMS OF RELATIVE MAGNITUDES.

A. A common technique utilized in the industry is to evaluate class percentage increases relative to the overall system increases. While there are no hard and fast rules, a common practice is that no class should receive an increase greater than approximately 150% of the system average percentage increase. Furthermore, I am of the opinion that no class should receive a rate decrease when there is a significant overall increase to the total Company's revenue requirement. In this regard, and with the exception of Rate CB, Dr. Gaske's proposed revenue distribution fulfills this criteria. Furthermore, no class receives a rate reduction (subject to the explanation for MU described above).[15]

Q. PLEASE EXPLAIN YOUR EVALUATION OF DR. GASKE'S PROPOSED CLASS REVENUE DISTRIBUTION IN TERMS OF MOVEMENT TOWARDS ALLOCATED COST OF PROVIDING SERVICE.

A. As discussed earlier in my testimony, class cost allocations are not an exact science. However, they should serve as a guide in evaluating class revenue responsibility. In this regard, I have evaluated class rates of return under Dr. Gaske's proposed rates and revenues utilizing each of the four cost allocation methodologies I have presented.[16] The following table provides class rates of return at Dr. Gaske's proposed revenues under each of the four allocation methodologies:

[15] Mr. Gaske proposes to increase Rate CB by 9.44% which is 161% of the system average percentage increase.

[16] These methodologies reflect distribution plant classified as 100% demand-related and include the 12-CP, P&A, BIP and Probability of Dispatch methods to allocate production-related plant.

Class RORs At IPL Proposed Revenues
(Distribution Plant Classified as 100% Demand-Related)

		Generation Allocation Method				
		12-CP	P&A	BIP	Probability Of Dispatch	Average
Residential	RS	5.59%	5.78%	7.08%	7.40%	6.46%
Secondary Small	SS	14.09%	14.07%	13.93%	14.40%	14.12%
Space Conditioning	SH	4.71%	5.70%	5.37%	4.66%	5.11%
Space Conditioning - Schools	SE	5.70%	7.41%	7.39%	8.55%	7.26%
Water Heating - Controlled	CB	-2.59%	-2.78%	-4.30%	-2.52%	-3.05%
Water Heating - Uncontrolled	UW	6.86%	6.92%	3.65%	7.02%	6.11%
Secondary Large	SL	7.93%	8.04%	7.13%	7.17%	7.57%
Primary	PL	5.80%	5.82%	4.89%	3.85%	5.09%
Process Heating	PH	4.53%	6.23%	5.87%	6.29%	5.73%
HLF - Primary	HL1	6.21%	5.06%	3.34%	3.37%	4.50%
HLF - Sub-Tran	HL2	6.14%	4.74%	3.38%	2.82%	4.27%
HLF -Tran	HL3	6.58%	5.51%	3.29%	2.51%	4.48%
Automatic Protective Lighting	APL	-9.15%	-10.07%	-10.84%	-11.23%	-10.32%
Municipal Lighting	MU1	28.45%	19.98%	13.56%	10.53%	18.13%
Total Jurisdictional		6.97%	6.97%	6.97%	6.97%	6.97%

When the above class RORs at proposed rates are compared with those generated at current rates, there is reasonable movement to unified class RORs (i.e., rate parity). Furthermore, classes that are currently under-contributing to profits do not over-contribute after the increase, while those that over-contribute at current rates do not under-contribute under proposed rates. To illustrate, the residential class' ROR at current rates is below the system average under all methodologies and under the Company's proposed rates, the residential class' ROR moves towards rate parity in a reasonable manner.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING IPL'S PROPOSED CLASS REVENUE INCREASES AT THE COMPANY'S OVERALL PROPOSED INCREASE?

A. In my opinion, Dr. Gaske's proposed class revenue distribution is reasonable. His proposal reasonably reflects gradualism and at the same time, moves classes towards allocated cost of service.

Q. IN THE EVENT THE COMMISSION AUTHORIZES AN OVERALL REVENUE INCREASE LESS THAN THE $67.774 MILLION REQUESTED BY IPL, HOW SHOULD THE ULTIMATE INCREASE BE DISTRIBUTED ACROSS RATE SCHEDULES?

A. I recommend that any overall increase be distributed to rate classes in proportion to the class increases proposed by Dr. Gaske. To be clear, there should be no rate reduction to the MU class, regardless of the overall increase authorized in this case.

V. RATE DESIGN

A. Residential Service

Q. PLEASE EXPLAIN IPL'S CURRENT RESIDENTIAL RATE STRUCTURE.

A. IPL's residential customers are served under Rate Schedule RS. In the most general terms, the residential rate structure is comprised of a fixed monthly customer charge plus a declining block energy charge. However, IPL's residential customer charge is somewhat atypical from the industry norm in that the fixed monthly customer charge varies depending on monthly usage. That is, for those customer bills in which usage is less than 325 kWh, the fixed monthly charge is $6.70. However, if the customer's monthly usage is greater than 325 kWh, the fixed monthly charge is increased to $11.00.

With respect to usage (energy) charges, the first 500 kWh is currently priced at 9.3346¢ per kWh including fuel and ECCR rider. For usage greater than 500 kWh, the energy charge is decreased to 7.0346¢ per kWh. Then, only in circumstances in which a customer has electric space or water heating, the energy charge is further reduced to 5.8146¢ per kWh for all usage greater than 1,000 kWh.

Finally, the Company offers two ancillary rate schedules in which water heating may be metered and billed separately from all other usage (at the customer's request). These ancillary schedules are Rate CW (Controlled Water Heating Service) and Rate UW (Uncontrolled Water Heating Service). Under these ancillary rate schedules, customers currently pay an additional fixed monthly customer charge of $4.60 (over and above the customer charge paid under rate RS) plus an energy charge for water heating usage only of 6.1752¢ per kWh for Rate CW and 7.2052¢ per kWh for Rate UW. The difference between these two ancillary water heating rate schedules is that Rate CW includes a water heating control device owned by the Company in which IPL may interrupt water heating load up to six hours per day while Rate UW is uncontrolled water heating with no curtailment provisions.

1. <u>Customer Charges</u>

Q. DOES IPL PROPOSE SIGNIFICANT INCREASES TO FIXED MONTHLY CUSTOMER CHARGES?

A. Yes. IPL witness Gaske proposes to increase the small volume (below 325 kWh) residential customer charges from $6.70 to $11.25 per month, or by 68%. Similarly, for customers above 325 kWh he proposes to increase the residential customer charges from $11.00 to $17.00 per month, or by 55%.

Q. HOW DOES DR. GASKE SUPPORT HIS EXCEPTIONALLY LARGE INCREASES TO THE FIXED MONTHLY CUSTOMER CHARGES?

A. In response to OUCC-18-26, Dr. Gaske opined:

> Ideally, in order to properly reflect costs and provide appropriate price signals, customers without demand meters should pay straight-fixed variable rates that recover all fixed costs in the Customer Charge with no fixed costs recovered in the Energy Charge.

In this regard, Dr. Gaske states on page 11, lines 2 through 8 of his direct testimony:

> For the Residential class the cost-based customer charge would be approximately $65 and for the Small Secondary rate schedule the cost-based customer charge would be approximately $168. 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.

Q. ARE IPL's PROPOSED 55% TO 68% INCREASES TO RESIDENTIAL CUSTOMER CHARGES REASONABLE OR IN THE PUBLIC INTEREST?

A. No. The proposed increases violate the regulatory principle of gradualism, violate the economic theory of efficient competitive pricing, and are contrary to effective conservation efforts.

Q. DOES IPL'S PROPOSAL TO COLLECT A SUBSTANTIAL PORTION OF RESIDENTIAL BASE RATE REVENUE FROM FIXED MONTHLY CHARGES COMPORT WITH THE ECONOMIC THEORY OF COMPETITIVE MARKETS OR THE ACTUAL PRACTICES OF SUCH COMPETITIVE MARKETS?

A. No. The most basic tenet of competition is that prices determined through a competitive market ensure the most efficient allocation of society's resources. Because public utilities are generally afforded monopoly status under the belief that resources are better utilized without duplicating the fixed facilities required to serve consumers, a fundamental goal of regulatory policy is that regulation should serve as a surrogate for competition to the greatest extent practical.[17] As such, the pricing policy for a regulated public utility should mirror those of competitive firms to the greatest extent practical.

Q. PLEASE BRIEFLY DISCUSS HOW PRICES ARE GENERALLY STRUCTURED IN COMPETITIVE MARKETS.

A. Under economic theory, efficient price signals result when prices are equal to marginal costs.[18] It is well known that costs are variable in the long-run. Therefore, efficient pricing results from the incremental variability of costs even though a firm's short-run cost structure may include a high level of sunk or "fixed" costs or be reflective of excess

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[17] James C. Bonbright, et al., *Principles of Public Utility Rates*, p. 141 (Second Edition, 1988).

[18] Strictly speaking, efficiency is achieved only when there is no excess capacity such that short-run marginal costs equal long-run marginal costs. In practice, there is usually at least some excess capacity present such that pricing based on long-run marginal costs represents the most efficient utilization of resources.

capacity. Indeed, competitive market-based prices are generally structured based on usage; i.e. volume-based pricing.

Q. PLEASE BRIEFLY EXPLAIN THE ECONOMIC PRINCIPLES OF EFFICIENT PRICE THEORY AND HOW SHORT-RUN FIXED COSTS ARE RECOVERED UNDER SUCH EFFICIENT PRICING.

A. Perhaps the best known micro-economic principle is that in competitive markets (i.e., markets in which no monopoly power or excessive profits exist) prices are equal to marginal cost. Marginal cost is equal to the incremental change in cost resulting from an incremental change in output. A full discussion of the calculus involved in determining marginal costs is not appropriate here. However, it is readily apparent that because marginal costs measure the changes in costs with output, short-run "fixed" costs are irrelevant in efficient pricing. This is not to say that efficient pricing does not allow for the recovery of short-run fixed costs. Rather, they are reflected within a firm's production function such that no excess capacity exists and that an increase in output will require an increase in costs -- including those considered "fixed" from an accounting perspective. As such, under efficient pricing principles, marginal costs capture the variability of costs, and prices are variable because prices equal these costs.

Q. PLEASE EXPLAIN HOW EFFICIENT PRICING PRINCIPLES ARE APPLIED TO THE ELECTRIC UTILITY INDUSTRY.

A. Universally, utility marginal cost studies include three separate categories of marginal costs: demand, energy, and customer. Consistent with the general concept of marginal costs, each of these costs vary with incremental changes. Marginal demand costs measure the incremental change in costs resulting from an incremental change in peak load (demand). Marginal energy costs measure the incremental change in costs resulting from an incremental change in kWh (energy) consumption. Marginal customer costs measure the incremental change in costs resulting from an incremental change in number of customers.

Particularly relevant here is understanding what costs are included within, and the procedures used to determine, marginal customer costs. Since marginal customer costs reflect the measurement of how costs vary with the number of customers, they only include those costs that directly vary as a result of adding a new customer. Therefore, marginal customer costs only reflect costs such as service lines, meters, and incremental billing and accounting costs.

Q. PLEASE EXPLAIN HOW THIS THEORY OF COMPETITIVE PRICING SHOULD BE APPLIED TO REGULATED PUBLIC UTILITIES, SUCH AS IPL.

A. Due to IPL's investment in system infrastructure, there is no debate that many of its short-run costs are fixed in nature. However, as discussed above, efficient competitive prices are established based on long-run costs, which are entirely variable in nature.

Marginal cost pricing only relates to efficiency. This pricing does not attempt to address fairness or equity. Fair and equitable pricing of a regulated monopoly's products and services should reflect the benefits received for the goods or services. In this regard, those that receive more benefits should pay more in total than those who receive fewer benefits. Regarding electricity usage, i.e., the level of kWh consumption is the best and most direct indicator of benefits received. Thus, volumetric pricing promotes the fairest pricing mechanism to customers and to the utility.

The above philosophy has consistently been the belief of economists, regulators, and policy makers for many years. For example, consider utility industry pricing in the 1800s, when the industry was in its infancy. Customers paid a fixed monthly fee and consumed as much of the utility commodity/service as they desired (usually water). It soon became apparent that this fixed monthly fee rate schedule was inefficient and unfair. Utilities soon began metering their commodity/service and charging only for the amount actually consumed. In this way, consumers receiving more benefits from the utility paid more, in total, for the utility service because they used more of the commodity.

Q. IS THE ELECTRIC UTILITY INDUSTRY UNIQUE IN ITS COST STRUCTURES, WHICH ARE COMPRISED LARGELY OF FIXED COSTS IN THE SHORT-RUN?

A. No. Most manufacturing and transportation industries are comprised of cost structures predominated with "fixed" costs. Indeed, virtually every capital intensive industry is faced with a high percentage of fixed costs in the short-run. Prices for competitive products and services in these capital-intensive industries are invariably established on a volumetric basis, including those that were once regulated, e.g., motor transportation, airline travel, and rail service.

Accordingly, IPL's position that its fixed costs should be recovered through fixed monthly charges is incorrect. Pricing should reflect the Company's long-run costs, wherein all costs are variable or volumetric in nature, and users requiring more of the Company's products and services should pay more than customers who use less of these products and services. Stated more simply, those customers who conserve or are otherwise more energy efficient, or those who use less of the commodity for any reason, pay less than those who use more electricity.

Q. HOW ARE HIGH FIXED CUSTOMER CHARGE RATE STRUCTURES CONTRARY TO EFFECTIVE CONSERVATION EFFORTS?

A. High fixed charge rate structures actually promote additional consumption because a consumer's price of incremental consumption is less than what an efficient price structure would otherwise be. A clear example of this principle is exhibited in the natural gas transmission pipeline industry. As discussed in its well-known Order 636, the FERC's adoption of a "Straight Fixed Variable" ("SFV") pricing method[19] was a result of national policy (primarily that of Congress) to encourage increased use of domestic natural gas by promoting additional interruptible (and incremental firm) gas usage. The FERC's SFV pricing mechanism greatly reduced the price of incremental (additional) natural gas consumption. This resulted in significantly increasing the demand for, and use of, natural

[19] Under Straight Fixed Variable pricing, customers pay a fixed charge that is designed to recover all of the utility's fixed costs.

gas in the United States after Order 636 was issued in 1992.

FERC Order 636 had two primary goals. The first goal was to enhance gas competition at the wellhead by completely unbundling the merchant and transportation functions of pipelines.[20] The second goal was to encourage the increased consumption of natural gas in the United States. In the introductory statement of the Order, FERC stated:

> The Commission's intent is to further facilitate the unimpeded operation of market forces to stimulate the production of natural gas... [and thereby] contribute to reducing our Nation's dependence upon imported oil… .[21]

With specific regard to the SFV rate design adopted in Order 636, FERC stated:

> Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternate fuels on a timely basis as the prices of alternate fuels change. The Commission believes it is beyond doubt that it is in the national interest to promote the use of clean and abundant gas over alternate fuels such as foreign oil. SFV is the best method for doing that.[22]

Recently, some public utilities have begun to advocate SFV residential pricing. The companies claim a need for enhanced fixed charge revenues. To support their claim, the companies argue that because retail rates have been historically volumetric based, there has been a disincentive for utilities to promote conservation, or encourage reduced consumption. However, the FERC's objective in adopting SFV pricing suggests the exact opposite. The price signal that results from SFV pricing is meant to promote additional consumption, not reduce consumption. Thus, a rate structure that is heavily based on a fixed monthly customer charge sends an even stronger price signal to consumers to use more energy.

Q. ARE CONSERVATION AND EFFICIENCY GAINS A NEW RISK TO PUBLIC UTILITIES?

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[20] Federal Energy Regulatory Commission, Docket Nos. RM91-11-001 and RM87-34-065, Order No. 636 (Apr. 9, 1992), p. 7.

[21] *Id.* p. 8 (alteration in original).

[22] *Id.* pp. 128-129.

A. No. Conservation through efficiency gains has been ongoing for many years and is not a new risk. As a result, even though average residential electric usage per appliance has been declining, utilities have remained financially healthy and have continued their investments under volumetric pricing structures. Also, FERC's movement to straight fixed variable pricing for pipelines was unquestionably initiated to promote additional demand for natural gas, not less, and did in fact do so.

Q. AS A PUBLIC POLICY MATTER, WHAT IS THE MOST EFFECTIVE TOOL THAT REGULATORS HAVE TO PROMOTE COST EFFECTIVE CONSERVATION AND THE EFFICIENT UTILIZATION OF RESOURCES?

A. Unquestionably, one of the most important and effective tools that this, or any, regulatory Commission has to promote conservation is by developing rates that send proper pricing signals to conserve and utilize resources efficiently. A pricing structure that is largely fixed, such that customers' effective prices do not properly vary with consumption, promotes the inefficient utilization of resources. Pricing structures that are weighted heavily on fixed charges are much more inferior from a conservation and efficiency standpoint than pricing structures that require consumers to incur more cost with additional consumption.

Q. A CUSTOMER'S TOTAL ELECTRIC BILL IS COMPRISED OF A BASE RATE COMPONENT, A FUEL ADJUSTMENT CLAUSE ("FAC") RIDER; AND VARIOUS OTHER RIDERS. THESE FUEL AND OTHER RIDERS ARE VOLUMETRICALLY PRICED AND REPRESENT A SIGNIFICANT PORTION OF A CUSTOMER'S BILL. DOES THE VOLUMETRIC PRICING OF THESE COMPONENTS ELIMINATE THE NEED FOR A PROPER PRICING SIGNAL FROM BASE RATES?

A. No, certainly not. The fact that significant revenue may be collected volumetrically through trackers does not lessen the need for reasonable design of the underlying base rates.

Q. NOTWITHSTANDING THE EFFICIENCY REASONS AS TO WHY REGULATION SHOULD SERVE AS A SURROGATE FOR COMPETITION, ARE THERE OTHER RELEVANT ASPECTS TO THE PRICING STRUCTURES IN COMPETITIVE MARKETS *VIS A VIS* THOSE OF REGULATED UTILITIES?

A. Yes. In competitive markets, consumers, by definition, have the ability to choose various suppliers of goods and services. Consumers and the market have a clear preference for volumetric pricing. Utility customers are not so fortunate in that the local utility is a monopoly. The only reason utilities are able to achieve pricing structures with high fixed monthly charges is due to their monopoly status. In my opinion, this is a critical consideration in establishing utility pricing structures. Competitive markets and consumers in the United States have demanded volumetric based prices for generations. Hence, a regulated utility's pricing structure should not be allowed to counter the collective wisdom of markets and consumers simply because of its market power.

Q. HAVE YOU CONDUCTED ANY STUDIES OR ANALYSES TO INDICATE THE LEVELS AT WHICH IPL'S RESIDENTIAL CUSTOMER CHARGES SHOULD BE ESTABLISHED?

A. Yes. In designing public utility rates, there is a method that produces maximum fixed monthly customer charges and is consistent with efficient pricing theory and practice. This technique considers only those costs that vary as a result of connecting a new customer and which are required in order to maintain a customer's account. This technique is a direct customer cost analysis and uses a traditional revenue requirement approach. Under this method, capital cost provisions include an equity return, interest, income taxes, and depreciation expense associated with the investment in service lines and meters. In addition, operating and maintenance provisions are included for customer metering, records, and billing.

Under this direct customer cost approach, there is no provision for corporate overhead expenses or any other indirect costs as these costs are more appropriately recovered through energy (kWh) charges.

Q. HAVE YOU CONDUCTED DIRECT CUSTOMER COST ANALYSES APPLICABLE TO IPL'S RESIDENTIAL CLASS?

A. Yes. I conducted a direct customer cost analyses for each of IPL's metered classes. The details of this analysis are provided in my Attachment GAW-10. As indicated in this Attachment, the residential direct customer cost is at most $4.78 per month. It should be noted that my customer cost analyses is based on the Company's proposed return on equity of 10.93%. If a lower cost of equity is used, the resulting customer costs are somewhat reduced.

Q. WHY IS IT APPROPRIATE TO EXCLUDE CORPORATE OVERHEAD AND OTHER INDIRECT COSTS IN DEVELOPING RESIDENTIAL CUSTOMER CHARGES?

A. Like all electric utilities, IPL is in the business of providing electricity to meet the energy needs of its customers. Because of this and the fact that customers do not subscribe to IPL's services simply to be "connected," overhead and indirect costs are most appropriately recovered through volumetric energy charges.

Q. EARLIER IN YOUR TESTIMONY YOU INDICATED THAT DR. GASKE CLAIMS THAT HIS "COST-BASED" RESIDENTIAL CUSTOMER CHARGE IS APPROXIMATELY $65 PER MONTH. PLEASE EXPLAIN HOW DR. GASKE ARRIVED AT THIS LEVEL.

A. Dr. Gaske's figure of $65 per residential customer per month includes virtually all of the Company's allocated non-variable (primarily fuel) costs to the residential class. In other words, in addition to the direct costs required to connect and maintain a customer's account, Dr. Gaske has included all demand-related costs including the fixed costs associated with generation plant, transmission plant, and distribution plant. Moreover, Dr. Gaske's $65 amount reflects the vast preponderance of general plant and other overhead expenses such as general and administrative expenses. In other words, Dr. Gaske would collect virtually all of the non-fuel residential revenue requirement through fixed monthly customer charges.

Q. HOW MUCH OF THE NON-FUEL RESIDENTIAL REVENUE REQUIREMENT IS INCLUDED WITHIN DR. GASKE'S "CUSTOMER COSTS?"

A. In his Attachment JDT-3, page 14, Dr. Gaske has allocated $502.135 million in total costs (including required return) to the residential class. Of this amount, $159.315 million are fuel-related expenses. Therefore, Dr. Gaske's allocated non-fuel residential revenue requirement is $342.820 million ($502.135 minus $159.315). Dr. Gaske calculates a residential customer cost of $65.81 per month and when multiplied by the number of residential customer bills, a $335.406 million "customer cost" revenue requirement is obtained. As such, Dr. Gaske's calculated customer cost represents 97.8% of the total residential non-fuel revenue requirement. As discussed earlier in my testimony regarding the proper pricing of customer costs, Dr. Gaske's analyses is nothing more than an attempt to recover all non-variable costs from fixed monthly customer charges.

Q. BASED ON YOUR OVERALL EXPERIENCE AS WELL AS THE STUDIES AND ANALYSES YOU HAVE CONDUCTED FOR THIS CASE, WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE CUSTOMER CHARGES FOR IPL'S RESIDENTIAL CUSTOMERS?

A. IPL's two tiered residential customer charge structure is atypical for the industry. The customer charge varies dependent upon usage such that if a customer uses less than 325 kWh in a given month, the customer charge is $6.70. If a customer uses more than 325 kWh, the customer charge is $11.00. While there is no cost basis for this fixed charge differential, in recognition of rate continuity I do not propose to eliminate the differential by adding a single customer charge applied to all customer bills. With this framework and considering all factors including costs, gradualism, and rate continuity, I recommend that the current customer charges and structure be maintained.

Q. PLEASE BRIEFLY SUMMARIZE WHY YOUR RECOMMENDATION TO MAINTAIN THE CURRENT LEVEL OF CUSTOMER CHARGES IS APPROPRIATE.

A. It must be remembered that my proposed rate design will allow the Company a reasonable opportunity to recover all of its costs and earn a fair rate of return. Utility's advocate higher fixed customer charges in order to minimize their risks by guaranteeing revenue recovery through fixed charges. Whether electricity rates are largely volumetric priced or largely based on fixed charges, the reality is the utility will collect its required revenues. This is particularly relevant in this case since the Company has adjusted actual test year energy usages (kWh) for normal weather. Rate designs structured largely based on volumetric charges promote conservation, are efficient, and are in accordance with pricing practices in competitive markets.

Finally, no cross-subsidization issues are created across customers within the same class as long as the fixed customer charge recovers the incremental cost of connecting and maintaining each customer's account. Indeed, the incremental cost of connecting and maintaining a residential customer's account is under $5.00 per month. My recommendation to maintain the current residential customer charges of $6.70 (monthly usage less than 325 kWh) and $11.00 (monthly usage greater than 325 kWh) is considerably higher than this incremental cost. At the same time, my recommendation to maintain the current two-tiered structure and current rate level adheres to the accepted ratemaking principle of rate continuity.

2. <u>Declining-Block Rate Structure</u>

Q. PLEASE PROVIDE A TABLE SHOWING THE CURRENT RESIDENTIAL DECLINING-BLOCK RATE STRUCTURE ALONG WITH A COMPARISON OF THE RATES UNDER EACH USAGE BLOCK.

A. The following table provides a comparison of current residential base energy rates:

Usage Block	Current Base Rate	Percentage of 1st Usage Block
First 500 kWh	$0.0670	100%
Over 500 kWh	$0.0440	66%
Heating Only:		
Over 1,000 kWh	$0.0318	47%

As can be seen above, the current declining-block rate structure is significant in that the second block which would apply to all usage above 500 kWh (for non-heating customers) is only 66% of the first 500 kWh and for heating customers using at least 1,000 kWh, the tail block is less than half (47%) of the rate charged to small volume users using less than 500 kWh.

Q. WHAT IS THE GENERAL PUBLIC POLICY REGARDING DECLINING-BLOCK ENERGY RATES?

A. In 1978, Congress passed the Public Utility Regulatory Policies Act ("PURPA"). Among other things, PURPA established various conservation initiatives and mandates for electric utilities. Included in this Act is a clear policy to eliminate declining-block energy rates unless supported by costs. Specifically, PURPA states:

> DECLINING BLOCK RATES – The energy component of a rate, or the amount attributable to the energy component in a rate, charged by any electric utility for providing electric service during any period to any class of electric consumers may not decrease as kilowatt-hour consumption by such class increases during such period except to the extent that such utility demonstrates that the costs to such utility or providing electric service to such class, which costs are attributable to such energy component, decrease as such consumption increases during such period.[23]

Since this time, most states and commissions have abandoned the once prevalent declining-block rate structures in favor of flat, or inverted, block rates. The general policy supporting the elimination of such declining-block rates is that this type of rate structure is clearly at odds with energy conservation due to the fact that the incremental price of electricity decreases as consumption increases, thereby creating somewhat of an incentive to use more and more electricity. Indeed, declining-block electricity rates became popular in the 1960s and early-1970s and were used as a promotional tool to encourage the increased usage of relatively cheap electricity during a time in which there were significant natural gas shortages throughout the Country.

[23] Subtitle B, SEC. 111(d)(2).

Q. BASED ON YOUR EXPERIENCE AROUND THE COUNTRY, ARE RESIDENTIAL DECLINING-BLOCK ENERGY CHARGES OFTEN COST JUSTIFIED?

A. For electric utilities that have non-seasonally differentiated rates, I have not seen a single instance in which residential declining-block energy charges have been cost justified.[24]

Q. FOR PURPOSES OF THIS CASE, HAS IPL PROVIDED ANY JUSTIFICATION FOR RESIDENTIAL DECLINING-BLOCK ENERGY RATES?

A. The only justification provided by the Company concerning declining-block rates is discussed on pages 11 and 12 of Dr. Gaske's direct testimony where he indicates:

> IPL's declining block rate structure for these rate schedules helps ensure that an appropriate level of fixed costs are 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.

As discussed earlier in my testimony, the recovery of fixed costs has nothing to do with efficient pricing mechanisms. Indeed, Dr. Gaske's advocacy for declining-block rates is to minimize the risks to IPL by guaranteeing revenue recovery.

Q. AS PART OF YOUR INVESTIGATION, DID YOU REQUEST ADDITIONAL INFORMATION CONCERNING THE COMPANY'S SUPPORT FOR DECLINING-BLOCK RATES?

A. Yes. In OUCC-18-26, I requested the Company provide detailed explanations, including quantitative analysis, as to the bases for IPL's proposals for a declining-block rate structure for some schedules. My Attachment GAW-11 provides the Company's complete response to this data request. The only justification provided in this response was a reiteration of Mr. Gaske's testimony. Specifically, the Company's response stated:

[24] Electric utilities that have seasonal rate structures (winter vs. summer) can often justify declining-block energy rates for the off-peak season. For example, in the southern United States, virtually all electric utilities are summer peaking such that declining-block rates can sometimes be justified from a cost basis for the winter period. Similarly, in New England and the Pacific Northwest, declining-block summer rates can sometimes be cost justified.

> . . . the purpose of declining-block Energy Charges is to recover fixed costs from customers who do not have demand meters in a way that helps ensure that each customer pays a reasonable share of the fixed costs of the system, while trying to reduce (i) the distortion in marginal price signals posed by recovering fixed costs in a variable charge, and (ii) the variability of the Company's recovery of fixed costs associated with year-to-year fluctuations in usage.

Perhaps most interesting is the Company's statement in response to OUCC-18-26:

> . . . The reason for changing to flat-rate demand charges is that there is no good economic justification for declining-block demand charges . . .

On the one hand, the Company clearly states that there is no cost justification for declining-block demand charges, but on the other hand, supports declining-block energy charges for those rate schedules that are based only on energy usage. Indeed, IPL is proposing the elimination of declining-block demand charges.

Q. WHAT ARE YOUR RECOMMENDATIONS CONCERNING IPL'S DECLINING-BLOCK ENERGY RATES?

A. I recommend that these declining-block energy rates be eliminated gradually to a flat rate structure. However, this restructuring of residential and small commercial rates should be done in a gradual and systematic manner to avoid rate shock to large volume heating customers. Specifically, I recommend that declining-block rates be phased-out in equal increments over three rate cases (this case plus the next two rate cases) such that for this rate case, the differential between the first and second block will be reduced from 65.67% to 77% and the differential between the first and third (heating) block will be reduced from 47.46% to 65% as shown below:

	Residential Base Rate Energy Charge Percentage of First Usage Block			
Usage Block	Current Rates	This Rate Case	Next Rate Case	Rate Case Plus 2
First 500 kWh	100%	100%	100%	100%
Over 500 kWh	65.67%	77%	89%	100%
Heating Only:				
Over 1,000 kWh	47.46%	65%	82%	100%

B. Water Heating (Rate Schedules CW and UW)

Q. PLEASE PROVIDE YOUR RECOMMENDATIONS REGARDING THE ANCILLARY WATER HEATING RATE SCHEDULES CW AND UW?

A. There is no need to have separate ancillary rate schedules devoted to water heating appliances. Indeed, these rate schedules are not efficient, are unneeded, and are nothing more than promotional rates for electric water heating. I concur with the Company's proposal to close these rate schedules to new service installations, but further recommend that these rate schedules be eliminated in the Company's next rate case. For purposes of this case, I recommend that the fixed monthly customer charges not be changed and remain at the current level of $4.60. In this regard I note that Dr. Gaske proposes to increase the CW customer charge from $4.60 per month to $7.10 per month while he proposes the UW customer charge from $4.60 per month to $27.00 per month. Dr. Gaske's proposed increases are illogical and make little sense for a customer to continue under these ancillary rate schedules. To illustrate, the most popular residential water heater is 50 gallons which uses approximately 410 kWh per month. Under Dr. Gaske's rate design, a residential customer that is currently served under both RS for its main electricity use and UW as an ancillary rate schedule would pay approximately $52 per month for water heating.[25] However, if this customer did not elect to use ancillary Rate UW, his water heating cost would only be about $30 per month if billed under Rate RS.[26]

Q. SHOULD IPL CONTINUE ITS CONTROLLED WATER HEATING SERVICE?

A. Yes. Water heater load control has proven to be an effective demand-side management tool that benefits all stakeholders. In this regard, IPL should continue with this water heating load control program by simply offering a monthly credit of $3.00 to $5.00 for customers that elect to participate in the water heater load control program.

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[25] UW customer charge of $27.00 plus 410 kWh times $0.060973/kWh.

[26] This utilizes Dr. Gaske's proposed RS second usage block rate of $0.073000 times 410 kWh.

C. Small Commercial Rate Design

Q. PLEASE EXPLAIN THE RATE STRUCTURE ASSOCIATED WITH SMALL SECONDARY GENERAL SERVICE RATE SS.

A. Similar to residential Rate RS, this rate schedule is comprised of a two-tiered customer charge and a declining-block energy only rate. Currently, the customer charge for those bills with energy usage under 5,000 kWh is $11.38 per month, while the customer charge for bills with energy usage over 5,000 kWh is $32.14 per month. Dr. Gaske proposes to increase these customer charges to $30.00 and $50.00 per month, respectively. My concerns over the excessively large percentage increases to the SS customer charges mirror those for the residential class. As shown in my Attachment GAW-10, the direct monthly customer cost associated with Rate SS is at most $12.53.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE RATE DESIGN FOR RATE SCHEDULE SS?

A. I recommend increasing the small volume Rate SS customer charge (0 - 5,000 kWh) to $12.50 per month, which represents a 9.8% increase. In the interest of rate continuity, I recommend a similar percentage increase to the large volume Rate SS customer charge of approximately 9.8% to $35.30 per month. With regard to declining-block rates and similar to my discussion of this rate structure for residential customers, I also recommend the gradual elimination of these declining-block rates. However, it should be noted that the current differential between the first and second usage blocks are not nearly as precipitous as that exhibited within the residential class. Currently, the Rate SS tail block is priced at 80.1% of the first usage block. I recommend moving towards a flat rate structure such that the tail block will be priced at 90% of the first usage block.[27]

[27] Because the rate differential for Rate SS is relatively small, this gradual elimination of the declining-block rate structure can be accomplished in this case and in IPL's next rate case; i.e., in two rate cases.

D. Large Commercial/Industrial Rate Design

Q. IN GENERAL, WHAT RATE DESIGN CHANGES DOES IPL PROPOSE FOR THE LARGE COMMERCIAL/INDUSTRIAL CLASSES?

A. In general, IPL proposes to eliminate its declining-block demand charges in favor of flat rate demand charges.

Q. DO YOU SUPPORT THIS RATE STRUCTURE CHANGE?

A. Yes.

Q. DO YOU HAVE ANY CONCERNS REGARDING IPL'S PROPOSED DEMAND CHARGES?

A. Yes. IPL proposes exceptionally large increases to its demand charges with attendant rate decreases to the respective energy charges. For example, the Company proposes to increase the current Rate SL demand charge from $10.18 (for demand over 500 kW) to $18.27. This represents almost an 80% increase (79.57%). Increases of this magnitude certainly violate the accepted regulatory concepts of gradualism and rate continuity. Similar large demand charge increases are proposed for rate schedules: Large Primary Service (Rate PL); and, the High Load Factor rate schedules (Rates HL-1, HL-2, and HL-3). While such increases may be cost justified, I am concerned about the large impact this will have on lower load factor customers within these rate schedules. As such, I recommend that IPL reduce its percentage increases to demand charges by 50%.

E. Interruptible Credit

Q. DOES IPL PROPOSE ANY CHANGES TO ITS RIDER 14, INTERRUPTIBLE POWER CREDIT?

A. Yes. IPL is proposing to increase the contracted curtailable credit (discount) from $3.00 per kW per month to $6.00 per kW per month.

Q. HOW MANY CUSTOMERS PARTICIPATE AND HOW MUCH INTERRUPTIBLE LOAD IS CURRENTLY CONTRACTED UNDER RIDER 14?

A. According to IPL's most recent (October 2014) Integrated Resource Plan ("IRP"), there is one customer that participates under this Rider with a contracted interruptible load of 9.3 mW.

Q. HAS IPL PROVIDED ANY JUSTIFICATION TO SUPPORT ITS PROPOSED $6.00 INTERRUPTIBLE CREDIT?

A. Yes. In response to OUCC-18-29, the Company provided a detailed analysis of its avoided costs associated with a new peaking generating unit. In this response, the Company's analysis supports a theoretical avoided cost of $5.98 per kW per month. Furthermore, the public version of IPL's 2014 IRP indicates that the Company's avoided costs during the last four years have been between $7.19 and $7.42 per kW per month.

Q. DO YOU HAVE ANY CONCERNS OR DISAGREEMENTS WITH THE COMPANY'S PROPOSED DOUBLING OF THE INTERRUPTIBLE CREDIT?

A. Yes. First, it should be remembered that IPL's firm ratepayers pay for this discount. As a result, it stands to reason that firm ratepayers should receive a benefit from this discounted rate. However, the Company has not requested any curtailments in recent history. In response to OUCC-18-14, IPL indicated that there have been no curtailments or interruptions during the last three years. In this regard, it should be remembered that in January 2014, Indiana experienced extreme weather conditions during the Polar Vortex as well as exceptionally high temperatures and peak load demands during the summer of 2012.

In this regard, I would have no objection to increasing the curtailable credit to $6.00 if IPL would actually utilize this resource that ratepayers are paying for. While IPL may not have capacity generation constraints that would otherwise call for the curtailments during periods of high demand, the Company does purchase a significant level of energy in the MISO wholesale market. As such, even though there may be no "capacity" reasons to curtail customers, there certainly have been economic justifications to curtail

this customer in order to reduce purchased energy costs. Had IPL curtailed this customer during high wholesale energy price periods, firm ratepayers would have received a benefit from this program that they are paying for.

The tariff provisions for Rider 14 currently allow for economic curtailments. Specifically, the tariff indicates:

> In addition to interruptions for system integrity, the Company may call, at its discretion, for a limited number of curtailments when the market price of power is at or above $100/MWh ("Dispatchable Curtailment").

Although I have not examined MISO's historic hour-ahead or day-ahead locational marginal prices ("LMP"), I do know that wholesale electric energy prices have been exceptionally high in the mid-west and eastern United States during several periods of extreme weather, such as during the Polar Vortex of January 2014. Furthermore, IPL's tariff provision limiting economic curtailments only when the market price is at or above $100 per mWh is arbitrary and provides limited benefit to firm ratepayers. NIPSCO has a similar interruptible rider in which the Company may call an interruption when the applicable real-time LMPs for the Company's load zone are reasonably forecasted by the Company to be in excess of the Company's current Commission-approved purchased power benchmark that is utilized to develop the Company's fuel cost charge.[28]

Q. WHAT ARE YOUR RECOMMENDATIONS CONCERNING IPL'S INTERRUPTIBLE POWER RIDER 14?

A. I recommend that IPL begin utilizing this tool that captive ratepayers are currently paying for, otherwise this rate credit Rider should be discontinued. Specifically, the tariff should be revised to reflect language similar to that contained in NIPSCO's Rider 675 wherein the Company may call an interruption when the real-time LMP is reasonably forecasted to be in excess of IPL's purchased power benchmark. Furthermore, the Commission should direct IPL to prudently utilize this tool when economic conditions warrant rather

[28] NIPSCO Rider 675.

than the current practice of simply providing a credit to this customer with no attendant benefits to its other customers.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

BACKGROUND & EXPERIENCE PROFILE

GLENN A. WATKINS

VICE PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Mar. 1993-Present	Vice President/Senior Economist, Technical Associates, Inc. (Mar. 1993-June 1995 Traded as C. W. Amos of Virginia)
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. Public Utility Regulation

A. Costing Studies -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. Rate Design Studies -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

GLENN A. WATKINS

C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI's administrative assigned risk plan and pool expenses.

IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market

GLENN A. WATKINS

areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

EXPERT TESTIMONY
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GLENN A. WATKINS

YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
1985	SAVANNAH ELECT. & PWR CO.	GA. PSC	3523U	SALES FORECAST, RATE DESIGN ISSUES
1990	CENTRAL MAINE PWR CO.	ME. PUC	89-68	MARGINAL COST OF SERVICE
1990	COMMONWEALTH GAS SERVICES (Columbia Gas)	VA. SCC	PUE900034	CLASS COST OF SERVICE
1990	WARNER FRUEHAUF	U.S. BANKRUPTCY CT.	n/a	VALUE OF STOCK, COST OF CAPITAL
1991	W. VA. WATER	WVA PSC	91-140-W-42T	RATE DESIGN
1992	S.C. WORKERS COMPENSATION	SC DEPT OF INSUR	92-034	INTERNAL RATE OF RETURN
1992	GRASS v. ATLAS PLUMBING, et.al.	RICHMOND CIRCUT CT	n/a	DAMAGES, BREACH OF COVENANT NOT TO COMPETE (PROFFERED TEST)
1992	VIRGINIA NATURAL GAS	VA SCC	PUE920031	JURISDICTIONAL & CLASS COST OF SERVICE
1992	ALLSTATE INSURANCE COMPANY (DIRECT)	N.J. DEPT OF INSUR	INS 06174-92	COST ALLOCATIONS, PROFITABILITY
1992	ALLSTATE INSURANCE COMPANY (REBUTTAL)	N.J. DEPT OF INSUR	INS 06174-92	COST ALLOCATIONS, PROFITABILITY
1993	MOUNTAIN FORD v FORD MOTOR COMPANY	FEDERAL DISTRICT CT	n/a	VEHICLE ALLOCATIONS, INVENTORY LEVELS, INCREMENTAL PROFIT, & DAMAGES
1993	SOUTH WEST GAS CO.	AZ. CORP COMM	U-1551-92-253	DIRECT: CLASS COST ALLOCATIONS
1993	SOUTH WEST GAS CO.	AZ. CORP COMM	U-1551-92-253	SURREBUTTAL: CLASS COST ALLOCATIONS
1993	POTOMAC EDISON CO.	VA. SCC	PUE930033	COST ALLOCATIONS,RATE DESIGN
1995	VIRGINIA AMERICAN WATER CO.	VA. SCC	PUE950003	JURISDICTIONAL ALLOCATIONS
1995	NEW JERSEY AMERICAN WATER COMPANY	N.J. B.P.U.	WR95040165	COST ALLOCATIONS,RATE DESIGN
1995	PIEDMONT NATURAL GAS COMPANY	S.C. P.S.C.	95-715-G	COST ALLOCATIONS,RATE DESIGN,WEATHER NORMALIZATION
1995	CYCLE WORLD v. HONDA MOTOR CO.	VA. DMV	None	MARKET PERFORMANCE, FINANCIAL IMPACT OF NEW DEALER
1996	HOUSE BILL # 1513	VA. GEN'L ASSEMBLY	N/A	WATER / WASTEWATER CONNECTION FEES
1996	VIRGINIA AMERICAN WATER CO.	VA. SCC	PUE950003	JURISDICTIONAL ALLOCATIONS
1996	ELIZABETHTOWN WATER CO.	N.J. B.P.U.	WR95110557	COST ALLOCATIONS,RATE DESIGN
1996	ELIZABETHTOWN WATER CO.	N.J. B.P.U.	WR95110557	SURREBUTTAL COST ALLOCATIONS,RATE DESIGN
1996	SOUTH JERSEY GAS CO.	N.J. B.P.U.	GR96010032	CLASS COST OF SERVICE
1996	VIRGINIA LIABILITY INSURANCE COMPETITION	VA. SCC	INS960164	COST ALLOCATIONS, INSURANCE PROFITABILITY
1996	SOUTH JERSEY GAS CO.	N.J. B.P.U.	GR96010032	REBUTTAL - CLASS COST OF SERVICE
1996	HOUSE BILL # 1513	VA. GEN'L ASSEMBLY	N/A	WATER / WASTEWATER CONNECTION FEES
1997	NISSAN v. CRUMPLER NISSAN	VA. DMV	None	MARKET DETERMINATION & PERFORMANCE
1997	PHILADELPHIA SUBURBAN WATER CO. (DIRECT)	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	PHILADELPHIA SUBURBAN WATER CO. (REBUTTAL)	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	PHILADELPHIA SUBURBAN WATER CO. (SURREBUTTAL)	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	VIRGINIA AMERICAN WATER CO.	VA. SCC	PUE970523	JURISDICTIONAL/CLASS ALLOCATIONS
1998	VIRGINIA ELECTRIC POWER COMPANY	VA. SCC	PUE960296	CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS
1998	NEW JERSEY AMERICAN WATER COMPANY	N.J. B.P.U.	WR98010015	CLASS COST OF SERVICE,RATE DESIGN, REVENUES
1998	AMERICAN ELECTRIC POWER COMPANY	VA. SCC	PUE960296	CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS
1998	FREEMAN WRONGFUL DEATH	FfEDERAL DISTRICT CT.		LOST INCOME, WORK EXPECTANCY
1998	EASTERN MAINE ELECTRIC COOPERATIVE	MAINE PUC	98-596	REVENUE REQUIREMENT
1998	CREDIT LIFE/AH RATE FILING	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
1999	CREDIT LIFE & A&H LEGISLATION	VA. GEN'L ASSEMBLY	N/A	COST ALLOCATIONS, INSURANCE PROFITABILITY
1999	MILLER VOLKSWAGEN v. VOLKSWAGEN oF AMERICA	VA. DMV	None	VEHICLE ALLOCATIONS/CSI
1999	COLUMBIA GAS of VIRGINIA	VA. SCC	PUE980287	RATE STRUCTURE
1999	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS990165	WORKERS COMPENSATION RATES
1999	ROANOKE GAS	VA. SCC	PUE980626	Rate Design/ Weather Norm
2000	PERSON-SMITH v. DOMINION REALITY	RICHMOND CIRCUIT	n/a	LOST INCOME
2000	CREDIT LIFE/AH RATE FILING	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
2000	UNITED CITIES GAS	VA. SCC		Cost Allocations/ Rate Design
2001	VERMONT WORKERS COMPENSATION RATE CASE	VT. INSURANCE COMM.	n/a	WORKERS COMPENSATION RATES
2001	SERRA CHEVROLET v. GENERAL MOTORS CORP.	ALABAMA CIRCUIT CT.	98-2089	ECONOMIC DAMAGES
2001	VIRGINIA POWER ELECTRIC RESTRUCTURING	VA. SCC	PUE000584	RATE Design (UNBUNDLING)
2001	AMERICAN ELECTRIC POWER RESTRUCTURING	VA. SCC	PUE010011	RATE Design (UNBUNDLING)
2001	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS010190	WORKERS COMPENSATION RATES
2002	PHILADELPHIA SUBURBAN WATER CO. (DIRECT)	PA. PUC	R00016750	COST ALLOCATIONS AND RATE DESIGN
2002	HAROLD MORRIS PERSONAL INJURY	FED. DIST CT (RICHMOND)	n/a	LOST WAGES
2002	PIEDMONT NATURAL GAS	S.C. PSC	2002-63-G	REVENUE RQMT, COST OF CAPITAL
2002	VIRGINIA AMERICAN WATER COMPANY	VA. SCC	PUE-2002-00375	JURISDICTIONAL/CLASS ALLOCATIONS
2002	ROANOKE GAS COMPANY	VA. SCC	PUE-2002-00373	WEATHER NORMALIZATION RIDER
2002	SOUTH CAROLINA ELECTRIC & GAS (ELECTRIC)	S.C. PSC	2002-223-E	REVENUE RQMT.
2003	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS-2003-00157	WORKERS COMPENSATION RATES
2003	CREDIT LIFE/AH RATE FILING	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
2003	ROANOKE GAS	VA. SCC	PUE-2003-00425	WEATHER NORMALIZATION ADJUSTMENT RIDER
2003	SOUTHWESTERN VIRGINIA GAS CO.	VA. SCC	PUE-2003-00426	WEATHER NORMALIZATION ADJUSTMENT RIDER
2004	SOUTH CAROLINA PIPELINE COMPANY	S.C. PSC	2004-6-G	COST OF GAS AND INTERUPT. SALES PROGRAM
2004	VIRGINIA AMERICAN WATER COMPANY	VA. SCC	PUE-2003-00539	JURISDICTIONAL/CLASS ALLOCATIONS

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YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
2004	SCE&G FUEL CONTRACT	S.C. PSC	2004-126-E	GAS CONTRACT FOR COMBINED CYCLE PLANT
2004	WASHINGTON GAS LIGHT	VA. SCC	PUE-2003-00603	RATE DESIGN/ WNA RIDER
2004	ATMOS ENERGY	VA. SCC	PUE-2003-00507	RATE DESIGN/ WNA RIDER
2004	SCE&G RATE CASE (ELECTRIC)	S.C. PSC	2004-178-E	COST OF CAPITAL/ REV RQMT.
2004	MEDICAL MALPRACTICE LEGISLATION	VA. GENERAL ASSEMBLY	N/A	INDUSTRY RESTRUTURE/ PROFITABILITY
2004	ATLAS HONDA v. HONDA MOTOR CO.	VA. DMV	None	NEW DEALER PROTEST
2004	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS-2004-00124	WORKERS COMPENSATION RATES
2004	NATIONAL FUEL GAS DISTRIBUTION	PA. PUC	R00049656	COST ALLOCATIONS/ RATE DESIGN
2005	WASHINGTON GAS LIGHT	VA SCC	PUE-2005-00010	WEATHER NORMALIZATION ADJUSTMENT RIDER
2005	Serra Chevrolet	US Federal Ct.	CV-01-P-2682-S	Dealer incremental profits and costs
2005	NEWTOWN ARTESIAN WATER	PA. PUC		REV. RQMT./ RATE STRUCTURE
2005	CITY OF BETHLEHEM WATER RATE CASE	PA. PUC		REV. RQMT./ RATE STRUCTURE
2005	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2005-00159	WORKERS COMPENSATION RATES
2005	Virginia Natural Gas	VA SCC	PUE-2005-00057	Revenue Requirement/ Alt. Regulation Plan
2006	Olathe Hyundai v. Hyundai Motors of America	KS DMV	None	Dealer impact analysis
2006	Virginia Credit Life & A&H Prima Facia Rates	VA SCC	INS-2006-00013	Market Structure
2006	Columbia Gas of Virginia	VA SCC	PUE-2005-00098	Revenue Requirements/ Alt. Regulation Plan
2006	PPL Gas	PA. PUC	R-00061398	COST ALLOCATIONS/ RATE DESIGN
2006	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2006-00197	WORKERS COMPENSATION RATES
2007	Level of Private Pass. Auto Competition	Ma. Dept of Insur	N/A	Private Pass Auto level of competition
2007	WASHINGTON GAS LIGHT	VA SCC	PUE-2006-00059	Cost Allocations/ Rate Design/ Alt Regulation Plan
2007	Valley Energy	PA. PUC	R-00072349	Cost of Capital/Rate Design
2007	Wellsboro Electric	PA. PUC	R-00072350	Cost of Capital/Rate Design
2007	Citizens' Electric Of Lewisburg, Pa	PA. PUC	R-00072348	Cost of Capital/Rate Design
2007	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2007-00224	WORKERS COMPENSATION RATES
2007	Georgia Power	Ga.PSC	25060-U	Cost Allocations/Rate Design
2008	Columbia Gas of Pennsylvania	PA. PUC	R-2008-2011621	COST ALLOCATIONS/ RATE DESIGN
2008	Greenway Toll Road Investigation	VA. GENERAL ASSEMBLY	N/A	Affiliate Transactions
2008	Puget Sound Energy (Electric)	Wa. UTC	UE-072300	Cost Allocations/Rate Design
2008	Puget Sound Energy (Gas)	Wa. UTC	UE-072301	Cost Allocations/Rate Design
2008	Blue Grass Electric Cooperative	Ky PSC	2008-00011	Cost Allocations/Rate Design
2008	Columbia Gas of Ohio	OH PUC	08-72-GA-AIR, et. al	Cost Allocations/Rate Design
2008	Virginia Natural Gas	Va SCC	PUE-2008-00060	Natl Gas Conservation/ Revenue Decoupling
2008	Equitable Natural Gas	PA. PUC	R-2008-2029325	Cost Allocations/Rate Design/ Discounted Rates
2008	LG&E (Electric)	Ky PSC	2008-000252	Cost Allocations/Rate Design/ Weather Normalization
2008	LG&E (Natural Gas)	Ky PSC	2008-000252	Cost Allocations/Rate Design
2008	Kentucky Utilities	Ky PSC	2008-00251	Cost Allocations/Rate Design/ Weather Normalization
2008	Pike County Natural Gas	PA. PUC	R-2008-2046520	Cost Allocations/Rate Design
2008	Pike County Electric	PA. PUC	R-2008-2046518	Cost Allocations/Rate Design
2008	Newtown Artesian Water	PA. PUC	R-2008-2042293	Revenue Requirement
2009	Leesburg Water & Sewer	Va. Circuit Ct.	Civil Action 42736	Revenue Requirement/ Excess Rates
2009	Central Penn Gas, Inc.	PA. PUC	R-02008-2079675	Cost Allocation/Rate Design
2009	Penn Natural Gas, Inc.	PA. PUC	R-2008-2079660	Cost Allocation/Rate Design
2009	Credit Life/ A&H ratemaking	Va. SCC	n/a	Market Structure and Availability
2009	Fairfax County v. City of Falls Church Virginia	Fairfax Circuit Ct. (Va.)	CL-2008-16114	Water Revenue Requirement
2009	Avista Utilities (Electric)	Wa. UTC	UE-090134	Electric rate Design
2009	Avista Utilities (Gas)	Wa. UTC	UG-090135	Gas Rate design
2009	Columbia Gas of Kentuky	Ky PSC	2009-00141	Cost Allocations/Rate Design
2009	NCCI (Workers Compensation Rates)	VA SCC	INS-2009-00142	Workers Compensation Rates
2009	Duke Energy of Kentucky (Gas)	Ky. PSC	2009-00202	Rate Design
2009	Duke Energy Carolinas (Electric)	NC UC	E-7 Sub 909	Cost Allocations/Rate Design
2009	PacifiCorp	Wa. UTC	UE-090205	Rate Design/Low Income
2009	Puget Sound Energy (Electric)	Wa. UTC	UE-090704	Cost Allocations/Rate Design
2009	Puget Sound Energy (Gas)	Wa. UTC	UG-090705	Cost Allocations/Rate Design
2009	United Water of Pennsylvania	PA PUC	2009-212287	Cost Allocations/Rate Design
2010	Aqua Virginia, Inc.	VA SCC	PUE-2009-00059	Rate Design
2010	Kentucky Utilities	Ky PSC	2009-00548	Cost Allocations/Rate Design/ Weather Normalization
2010	LG&E (Electric)	Ky PSC	2009-00549	Cost Allocations/Rate Design
2010	LG&E (Natural Gas)	Ky PSC	2009-00549	Cost Allocations/Rate Design/ Weather Normalization
2010	Philadelphia Gas Works	PA PUC	2009-2139884	Cost Allocations/Rate Design
2010	Columbia Gas of Pennsylvania	PA PUC	2009-2149262	Cost Allocations/Rate Design
2010	PPL Electric Company	PA PUC	2010-2161694	Cost Allocations/Rate Design

EXPERT TESTIMONY
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YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
2010	York Water Company	PA PUC	2010-2157140	Cost Allocations/Rate Design
2010	Valley Energy, Inc.	PA PUC	2010-2174470	Cost of Capital/Revenue Requirement/Rate Design
2010	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2010-00126	WORKERS COMPENSATION RATES
2010	Columbia Gas of Virginia	VA SCC	PUE-2010-00017	Cost of Capital/Revenue Requirement/Rate Design
2010	Georgia Power Company	GA PSC	Docket No. 31958	Cost Allocations/Rate Design
2010	City of Lancaster, Bureau of Water	PA PUC	R-2010-2179103	Cost of Capital
2011	Columbia Gas of Pennsylvania	PA PUC	R-2010-2215623	Cost Allocations/Rate Design
2011	Owen Electric Cooperative	KY PSC	PUE-2011-00037	Rate Design
2011	Virginia Natural Gas	VA SCC	PUE-2010-00142	Pipeline Prudency/Cost Allocations/Rate Design
2011	United Water of Pennsylvania	PA PUC	2011-2232985	Cost Allocations/Rate Design
2011	PPL Electric Company (Remand)	PA PUC	2010-2161694	Negotiated Industrial Rate
2011	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	2011-00163	WORKERS COMPENSATION RATES
2011	Artesian Water Company	DE PSC	11-207	Cost Allocations/Rate Design
2011	Arizona-American Water Company	AZ. CORP COMM	W-01303A-10-0448	Excess Capacity/Need For Facilities
2012	Tidewater Utilities, Inc.	DE PSC	11-397	Cost of Capital/Revenue Requirement/Rate Design
2012	PPL Electric	PA PUC	R-2012-2290597	Cost Allocations/Rate Design
2012	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	2012-00144	WORKERS COMPENSATION RATES
2012	Credit Life Accident & Health	VA SCC		Market Structure and Performance
2012	Avista Utilities (Electric)	Wa. UTC	UE-120436	Electric rate Design
2012	Avista Utilities (Gas)	Wa. UTC	UG-120437	Gas Rate design
2012	Kentucky Utilities	Ky PSC	2012-00221	Cost Allocations/Rate Design/ Weather Normalization
2012	LG&E (Electric)	Ky PSC	2012-00222	Cost Allocations/Rate Design
2012	LG&E (Natural Gas)	Ky PSC	2012-00222	Cost Allocations/Rate Design/ Weather Normalization
2012	Columbia Gas of Pennsylvania	PA PUC	2012-2321748	Cost Allocations/Rate Design/Revenue Distribution
2013	Virginia Natural Gas - CARE Plan	VA SCC	2012-00118	Energy Conservation and Decoupling
2013	Columbia Gas of Maryland	MD OPC	9316	Cost Allocations/Rate Design
2013	Delmarva Power & Light	DE PSC	12-546	Revenue Requirement/Rate Design
2013	PacifiCorp	Wa. UTC	13-0043	Residential Customer Charges
2013	Gas-On-Gas Competition - Generic Investigation	PA PUC	2012-232-0323	Treatment of Rate Discounts
2013	Northern Virginia Electric Cooperative Pole Attachment Fees	VA SCC	2013-00055	Financial Performance
2013	Georgia Power Company	GA PSC	36989	Cost Allocations/Rate Design
2013	Atmos Energy Kentucky	KY PSC	2013-00148	Cost Allocations/Rate Design
2013	Columbia Gas of Kentuky	KY PSC	2013-00167	Cost Allocations/Rate Design
2013	NCCI (Workers Compensation Insurance)	VA SCC	INS-2013-00158	Workers Compensation Rates
2013	Duquesne Light Company	PA PUC	R-2013-2372129	Cost Allocations/Rate Design
2014	CITY OF BETHLEHEM WATER RATE CASE	PA PUC	R-2013-2390244	Cost of Capital
2014	PEPCO Maryland	MD OPC	9336	Rate Design
2014	Avista Utilities, Inc. (Gas)	Wa. UTC	UG-140189	Cost Allocations/Rate Design
2014	Tidewater Utilities, Inc.	DE PSC	13-466	Cost of Capital/Rate Design
2014	Columbia Gas of Pennsylvania	PA PUC	R-2014-2406274	Cost Allocations/Rate Design
2014	Columbia NAS Pilot	PA PUC	R-2014-2407345	Mains Extension Policy
2014	Emporium Water Company	PA PUC	R-2014-2402324	Cost of Capital
2014	City of Lancaster, Bureau of Water	PA PUC	R-2014-2418872	Cost of Capital
2014	NCCI (Workers Compensation Insurance)	VA SCC	INS-2014-00172	Workers Compensation Rates
2014	Artesian Water Company	DE PSC	14-132	Revenue Requirement/Rate Design
2014	Peoples Service Expansion Tariff	PA PUC	R-2014-2429613	Mains Extension Policy
2014	PacifiCorp	Wa. UTC	UE-140762	Cost Allocations/Rate Design
2014	Exelon/PHI Acquisition	DE PSC	14-193	Merger/Acquisition
2014	Choptank Electric Cooperative	MD OPC	9368	Cost Allocations/Rate Design
2014	PECO Energy Company	PA PUC	R-2014-2451772	Mains Extension Policy

Note: Does not include Expert Reports submitted to Courts or Regulatory agencies in which cases that settled prior to testimony.
Testimony prior to 2003 may be incomplete.

INDIANAPOLIS POWER & LIGHT
Assignment of Generation Plant Investment to Individual Hours
(Gross Plant)

IPL Generating Unit Hourly Output in MWh				Check Value Petersburg				Check Value Harding Street				Check Value Harding Street GT				Check Value Eagle Valley				Check Value Georgetown GT		Check Value - Total Investment Sum
Plant Investment		$1,779,087		$1,779,086	$547,977			$547,977	$133,283			$133,283	$130,122			$130,122	$57,496			$57,496		$2,647,964
Total Output By Plant All Periods		10,755,571			3,698,809				137,563				750,106				27,997					
Start Date/Time	End Date/Time	Petersburg Total Output	Petersburg Period %	Petersburg Plant Investment Allocation (000s)	Harding Street Total Output	Harding Street Period %	Harding Street Plant Investment Allocation (000s)	Harding Street GT Total	Harding Street GT Period %	Harding Street GT Investment Allocation (000s)	Eagle Valley Total	Eagle Valley Period %	Eagle Valley Investment Allocation (000s)	Georgetown GT Total	Georgetown GT Period %	Georgetown GT Investment Allocation (000s)	Total System Investment Period (000s)
7/1/2013 0:00	7/1/2013 1:00	1,297	0.012059%	$214.538	374	0.010111%	$55.408	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$269.946
7/1/2013 1:00	7/1/2013 2:00	1,277	0.011873%	$211.229	351	0.009490%	$52.000	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$263.230
7/1/2013 2:00	7/1/2013 3:00	1,223	0.011371%	$202.297	329	0.008895%	$48.741	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$251.038
7/1/2013 3:00	7/1/2013 4:00	1,209	0.011241%	$199.982	330	0.008922%	$48.889	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$248.871
7/1/2013 4:00	7/1/2013 5:00	1,204	0.011194%	$199.154	332	0.008976%	$49.186	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$248.340
7/1/2013 5:00	7/1/2013 6:00	1,221	0.011352%	$201.966	430	0.011625%	$63.704	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$265.671
7/1/2013 6:00	7/1/2013 7:00	1,313	0.012208%	$217.184	454	0.012274%	$67.260	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$284.444
7/1/2013 7:00	7/1/2013 8:00	1,415	0.013156%	$234.056	506	0.013680%	$74.964	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$309.020
7/1/2013 8:00	7/1/2013 9:00	1,457	0.013546%	$241.003	522	0.014113%	$77.334	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$318.337
7/1/2013 9:00	7/1/2013 10:00	1,460	0.013574%	$241.500	586	0.015843%	$86.816	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$328.315
7/1/2013 10:00	7/1/2013 11:00	1,481	0.013770%	$244.973	606	0.016384%	$89.779	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$334.752
7/1/2013 11:00	7/1/2013 12:00	1,481	0.013770%	$244.973	606	0.016384%	$89.779	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$334.752
7/1/2013 12:00	7/1/2013 13:00	1,481	0.013770%	$244.973	596	0.016113%	$88.297	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$333.270
7/1/2013 13:00	7/1/2013 14:00	1,487	0.013825%	$245.966	593	0.016032%	$87.853	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$333.818
7/1/2013 14:00	7/1/2013 15:00	1,445	0.013435%	$239.018	592	0.016005%	$87.705	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$326.723
7/1/2013 15:00	7/1/2013 16:00	1,440	0.013388%	$238.191	570	0.015410%	$84.445	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$322.637
7/1/2013 16:00	7/1/2013 17:00	1,463	0.013602%	$241.996	561	0.015167%	$83.112	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$325.108
7/1/2013 17:00	7/1/2013 18:00	1,451	0.013491%	$240.011	570	0.015410%	$84.445	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$324.456
7/1/2013 18:00	7/1/2013 19:00	1,440	0.013388%	$238.191	554	0.014978%	$82.075	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$320.266
7/1/2013 19:00	7/1/2013 20:00	1,424	0.013240%	$235.545	538	0.014545%	$79.704	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$315.249
7/1/2013 20:00	7/1/2013 21:00	1,439	0.013379%	$238.026	524	0.014167%	$77.630	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$315.656
7/1/2013 21:00	7/1/2013 22:00	1,417	0.013175%	$234.387	526	0.014221%	$77.927	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$312.314
7/1/2013 22:00	7/1/2013 23:00	1,393	0.012951%	$230.417	493	0.013329%	$73.038	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$303.455
7/1/2013 23:00	7/2/2013 0:00	1,332	0.012384%	$220.327	419	0.011328%	$62.075	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$282.402
7/2/2013 0:00	7/2/2013 1:00	1,290	0.011994%	$213.380	337	0.009111%	$49.926	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$263.306
7/2/2013 1:00	7/2/2013 2:00	1,161	0.010794%	$192.042	318	0.008597%	$47.112	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$239.153
7/2/2013 2:00	7/2/2013 3:00	1,069	0.009939%	$176.824	317	0.008570%	$46.963	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$223.787
7/2/2013 3:00	7/2/2013 4:00	1,027	0.009549%	$169.877	326	0.008814%	$48.297	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$218.174
7/2/2013 4:00	7/2/2013 5:00	1,065	0.009902%	$176.162	354	0.009571%	$52.445	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$228.607
7/2/2013 5:00	7/2/2013 6:00	1,136	0.010562%	$187.907	388	0.010490%	$57.482	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$245.389
7/2/2013 6:00	7/2/2013 7:00	1,220	0.011343%	$201.801	412	0.011139%	$61.038	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$262.839
7/2/2013 7:00	7/2/2013 8:00	1,364	0.012682%	$225.620	454	0.012274%	$67.260	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$292.880
7/2/2013 8:00	7/2/2013 9:00	1,472	0.013686%	$243.485	504	0.013626%	$74.667	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$318.152
7/2/2013 9:00	7/2/2013 10:00	1,449	0.013472%	$239.680	543	0.014680%	$80.445	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$320.125
7/2/2013 10:00	7/2/2013 11:00	1,367	0.012710%	$226.116	553	0.014951%	$81.927	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$308.043
7/2/2013 11:00	7/2/2013 12:00	1,364	0.012682%	$225.620	550	0.014870%	$81.482	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$307.102
7/2/2013 12:00	7/2/2013 13:00	1,366	0.012700%	$225.951	550	0.014870%	$81.482	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$307.433
7/2/2013 13:00	7/2/2013 14:00	1,365	0.012691%	$225.786	586	0.015843%	$86.816	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$312.601
7/2/2013 14:00	7/2/2013 15:00	1,362	0.012663%	$225.289	602	0.016276%	$89.186	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$314.475
7/2/2013 15:00	7/2/2013 16:00	1,365	0.012691%	$225.786	599	0.016194%	$88.742	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$314.527
7/2/2013 16:00	7/2/2013 17:00	1,366	0.012700%	$225.951	598	0.016167%	$88.593	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$314.544
7/2/2013 17:00	7/2/2013 18:00	1,357	0.012617%	$224.462	600	0.016221%	$88.890	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$313.352
7/2/2013 18:00	7/2/2013 19:00	1,358	0.012626%	$224.628	600	0.016221%	$88.890	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$313.517
7/2/2013 19:00	7/2/2013 20:00	1,357	0.012617%	$224.462	597	0.016140%	$88.445	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$312.908
7/2/2013 20:00	7/2/2013 21:00	1,363	0.012673%	$225.455	601	0.016248%	$89.038	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$314.493
7/2/2013 21:00	7/2/2013 22:00	1,351	0.012561%	$223.470	597	0.016140%	$88.445	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$311.915
7/2/2013 22:00	7/2/2013 23:00	1,273	0.011836%	$210.568	567	0.015329%	$84.001	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$294.569
7/2/2013 23:00	7/3/2013 0:00	1,193	0.011092%	$197.335	455	0.012301%	$67.408	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$264.743
7/3/2013 0:00	7/3/2013 1:00	1,111	0.010330%	$183.771	375	0.010138%	$55.556	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$239.327
7/3/2013 1:00	7/3/2013 2:00	1,039	0.009660%	$171.862	326	0.008814%	$48.297	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$220.158
7/3/2013 2:00	7/3/2013 3:00	1,000	0.009298%	$165.411	331	0.008949%	$49.038	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$214.448
7/3/2013 3:00	7/3/2013 4:00	965	0.008972%	$159.621	331	0.008949%	$49.038	0	0.000000%	$0.000	0	0.000000%	$0.000	0	0.000000%	$0.000	$208.659

INDIANAPOLIS POWER & LIGHT
Assignment of Generation Plant Investment to Individual Hours
(Depreciation Reserve)

IPL Generating Unit Hourly Output in MWh				Check Value Petersburg			Check Value Harding Street			Check Value Harding Street GT			Check Value Eagle Valley			Check Value Georgetown GT	Check Value - Total Investment Sum
Plant Depreciation Cost		983,937		$983,936.90	257,180		$257,180.30	91,114		$91,143.70	86,800		$86,800.10	30,992		$30,991.70	$1,450,052.70
Total Output By Plant All Periods		10,755,571			3,698,809			137,583			750,106			27,997			
Start Date/Time	End Date/Time	Petersburg Total Output	Petersburg Period %	Petersburg Plant Depreciation Allocation (000s)	Harding Street Total Output	Harding Street Period %	Harding Street Plant Depreciation Allocation (000s)	Harding Street GT Total	Harding Street GT Period %	Harding Street GT Depreciation Allocation (000s)	Eagle Valley Total	Eagle Valley Period %	Eagle Valley Depreciation Allocation (000s)	Georgetown GT Total	Georgetown GT Period %	Georgetown GT Depreciation Allocation (000s)	Total System Depreciation Period (000s)
7/1/2013 0:00	7/1/2013 1:00	1,297	0.012059%	$118.65	374	0.010111%	$26.00	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$144.66
7/1/2013 1:00	7/1/2013 2:00	1,277	0.011873%	$116.82	351	0.009490%	$24.41	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$141.23
7/1/2013 2:00	7/1/2013 3:00	1,223	0.011371%	$111.88	329	0.008895%	$22.88	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$134.76
7/1/2013 3:00	7/1/2013 4:00	1,209	0.011241%	$110.60	330	0.008922%	$22.95	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$133.55
7/1/2013 4:00	7/1/2013 5:00	1,204	0.011194%	$110.14	332	0.008976%	$23.08	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$133.23
7/1/2013 5:00	7/1/2013 6:00	1,221	0.011352%	$111.70	430	0.011625%	$29.90	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$141.60
7/1/2013 6:00	7/1/2013 7:00	1,313	0.012208%	$120.12	454	0.012274%	$31.57	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$151.68
7/1/2013 7:00	7/1/2013 8:00	1,415	0.013156%	$129.45	506	0.013680%	$35.18	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$164.63
7/1/2013 8:00	7/1/2013 9:00	1,457	0.013546%	$133.29	522	0.014113%	$36.29	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$169.58
7/1/2013 9:00	7/1/2013 10:00	1,460	0.013574%	$133.56	586	0.015843%	$40.74	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$174.31
7/1/2013 10:00	7/1/2013 11:00	1,481	0.013770%	$135.48	606	0.016384%	$42.14	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$177.62
7/1/2013 11:00	7/1/2013 12:00	1,481	0.013770%	$135.48	606	0.016384%	$42.14	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$177.62
7/1/2013 12:00	7/1/2013 13:00	1,481	0.013770%	$135.48	596	0.016113%	$41.44	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$176.92
7/1/2013 13:00	7/1/2013 14:00	1,487	0.013825%	$136.03	593	0.016032%	$41.23	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$177.26
7/1/2013 14:00	7/1/2013 15:00	1,445	0.013435%	$132.19	592	0.016005%	$41.16	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$173.35
7/1/2013 15:00	7/1/2013 16:00	1,440	0.013388%	$131.73	570	0.015410%	$39.63	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$171.37
7/1/2013 16:00	7/1/2013 17:00	1,463	0.013602%	$133.84	561	0.015167%	$39.01	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$172.84
7/1/2013 17:00	7/1/2013 18:00	1,451	0.013491%	$132.74	570	0.015410%	$39.63	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$172.37
7/1/2013 18:00	7/1/2013 19:00	1,440	0.013388%	$131.73	554	0.014978%	$38.52	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$170.25
7/1/2013 19:00	7/1/2013 20:00	1,424	0.013240%	$130.27	538	0.014545%	$37.41	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$167.68
7/1/2013 20:00	7/1/2013 21:00	1,439	0.013379%	$131.64	524	0.014167%	$36.43	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$168.08
7/1/2013 21:00	7/1/2013 22:00	1,417	0.013175%	$129.63	526	0.014221%	$36.57	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$166.20
7/1/2013 22:00	7/1/2013 23:00	1,393	0.012951%	$127.43	493	0.013329%	$34.28	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$161.71
7/1/2013 23:00	7/2/2013 0:00	1,332	0.012384%	$121.85	419	0.011328%	$29.13	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$150.99
7/2/2013 0:00	7/2/2013 1:00	1,290	0.011994%	$118.01	337	0.009111%	$23.43	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$141.44
7/2/2013 1:00	7/2/2013 2:00	1,161	0.010794%	$106.21	318	0.008597%	$22.11	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$128.32
7/2/2013 2:00	7/2/2013 3:00	1,069	0.009939%	$97.79	317	0.008570%	$22.04	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$119.84
7/2/2013 3:00	7/2/2013 4:00	1,027	0.009549%	$93.95	326	0.008814%	$22.67	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$116.62
7/2/2013 4:00	7/2/2013 5:00	1,065	0.009902%	$97.43	354	0.009571%	$24.61	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$122.04
7/2/2013 5:00	7/2/2013 6:00	1,136	0.010562%	$103.92	388	0.010490%	$26.98	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$130.90
7/2/2013 6:00	7/2/2013 7:00	1,220	0.011343%	$111.61	412	0.011139%	$28.65	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$140.25
7/2/2013 7:00	7/2/2013 8:00	1,364	0.012682%	$124.78	454	0.012274%	$31.57	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$156.35
7/2/2013 8:00	7/2/2013 9:00	1,472	0.013686%	$134.66	504	0.013626%	$35.04	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$169.70
7/2/2013 9:00	7/2/2013 10:00	1,449	0.013472%	$132.56	543	0.014680%	$37.76	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$170.31
7/2/2013 10:00	7/2/2013 11:00	1,367	0.012710%	$125.06	553	0.014951%	$38.45	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$163.51
7/2/2013 11:00	7/2/2013 12:00	1,364	0.012682%	$124.78	550	0.014870%	$38.24	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$163.02
7/2/2013 12:00	7/2/2013 13:00	1,366	0.012700%	$124.96	550	0.014870%	$38.24	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$163.21
7/2/2013 13:00	7/2/2013 14:00	1,365	0.012691%	$124.87	586	0.015843%	$40.74	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$165.62
7/2/2013 14:00	7/2/2013 15:00	1,362	0.012663%	$124.60	602	0.016276%	$41.86	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$166.46
7/2/2013 15:00	7/2/2013 16:00	1,365	0.012691%	$124.87	599	0.016194%	$41.65	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$166.52
7/2/2013 16:00	7/2/2013 17:00	1,366	0.012700%	$124.96	598	0.016167%	$41.58	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$166.54
7/2/2013 17:00	7/2/2013 18:00	1,357	0.012617%	$124.14	600	0.016221%	$41.72	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$165.86
7/2/2013 18:00	7/2/2013 19:00	1,358	0.012626%	$124.23	600	0.016221%	$41.72	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$165.95
7/2/2013 19:00	7/2/2013 20:00	1,357	0.012617%	$124.14	597	0.016140%	$41.51	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$165.65
7/2/2013 20:00	7/2/2013 21:00	1,363	0.012673%	$124.69	601	0.016248%	$41.79	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$166.48
7/2/2013 21:00	7/2/2013 22:00	1,351	0.012561%	$123.59	597	0.016140%	$41.51	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$165.10
7/2/2013 22:00	7/2/2013 23:00	1,273	0.011836%	$116.46	567	0.015329%	$39.42	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$155.88
7/2/2013 23:00	7/3/2013 0:00	1,193	0.011092%	$109.14	455	0.012301%	$31.64	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$140.77
7/3/2013 0:00	7/3/2013 1:00	1,111	0.010330%	$101.64	375	0.010138%	$26.07	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$127.71
7/3/2013 1:00	7/3/2013 2:00	1,039	0.009660%	$95.05	326	0.008814%	$22.67	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$117.72
7/3/2013 2:00	7/3/2013 3:00	1,000	0.009298%	$91.48	331	0.008949%	$23.01	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$114.50
7/3/2013 3:00	7/3/2013 4:00	965	0.008972%	$88.28	331	0.008949%	$23.01	0	0.000000%	$0.00	0	0.000000%	$0.00	0	0.000000%	$0.00	$111.29

INDIANAPOLIS POWER & LIGHT
Assignment of Generation Plant Investment to Rate Classes
(Gross Plant)

Start date and hour	RS Loadshare	RS Investment Cost	RH Loadshare	RH Investment Cost	RC Loadshare	RC Investment Cost	SS Loadshare	SS Investment Cost	SH Loadshare	SH Investment Cost	SE Loadshare	SE Investment Cost	PH Loadshare	PH Investment Cost
7/1/2013 0:00	14.6898%	$39.655	11.6622%	$31.482	2.3072%	$6.228	8.8529%	$23.898	3.7946%	$10.243	0.0764%	$0.206	0.3380%	$0.912
7/1/2013 1:00	15.3263%	$40.343	10.2298%	$26.928	2.2710%	$5.978	9.0404%	$23.797	3.5259%	$9.281	0.0780%	$0.205	0.3708%	$0.976
7/1/2013 2:00	13.9526%	$35.026	8.8324%	$22.173	2.3158%	$5.814	9.2577%	$23.240	3.5917%	$9.017	0.0873%	$0.219	0.4797%	$1.204
7/1/2013 3:00	13.6316%	$33.925	10.1163%	$25.177	2.1477%	$5.345	8.9908%	$22.375	3.7916%	$9.436	0.0893%	$0.222	0.4188%	$1.042
7/1/2013 4:00	13.1357%	$32.621	10.4362%	$25.917	2.5578%	$6.352	9.0953%	$22.587	4.0543%	$10.068	0.1626%	$0.404	0.5197%	$1.291
7/1/2013 5:00	12.8542%	$34.150	10.5848%	$28.121	2.9913%	$7.947	9.6060%	$25.520	4.3588%	$11.580	0.1682%	$0.447	0.3949%	$1.049
7/1/2013 6:00	11.7555%	$33.438	10.7971%	$30.712	3.0007%	$8.535	10.2242%	$29.082	4.3134%	$12.269	0.1701%	$0.484	0.4677%	$1.330
7/1/2013 7:00	11.5760%	$35.772	9.0165%	$27.863	2.4898%	$7.694	11.8549%	$36.634	4.0857%	$12.626	0.1710%	$0.528	0.4899%	$1.514
7/1/2013 8:00	12.7211%	$40.496	8.2371%	$26.222	1.9764%	$6.292	12.4318%	$39.575	4.1194%	$13.114	0.1661%	$0.529	0.5572%	$1.774
7/1/2013 9:00	13.0643%	$42.892	8.9608%	$29.420	2.0949%	$6.878	12.6052%	$41.385	4.1028%	$13.470	0.1574%	$0.517	0.5041%	$1.655
7/1/2013 10:00	12.2630%	$41.051	9.3909%	$31.436	2.0228%	$6.771	12.9762%	$43.438	4.0882%	$13.685	0.1523%	$0.510	0.5282%	$1.768
7/1/2013 11:00	12.8899%	$43.149	8.8926%	$29.768	2.3018%	$7.705	12.6168%	$42.235	4.1504%	$13.894	0.1547%	$0.518	0.4476%	$1.498
7/1/2013 12:00	12.0995%	$40.324	9.9236%	$33.072	2.2102%	$7.366	12.4580%	$41.519	4.1146%	$13.713	0.1534%	$0.511	0.4663%	$1.554
7/1/2013 13:00	12.7268%	$42.484	10.8603%	$36.254	1.9573%	$6.534	11.8092%	$39.421	4.2245%	$14.102	0.1488%	$0.497	0.3851%	$1.286
7/1/2013 14:00	14.5617%	$47.576	10.1835%	$33.272	2.1265%	$6.948	11.5673%	$37.793	4.0962%	$13.383	0.1371%	$0.448	0.3819%	$1.248
7/1/2013 15:00	15.5737%	$50.246	10.7872%	$34.803	2.5495%	$8.226	10.7969%	$34.835	4.1285%	$13.320	0.1229%	$0.396	0.3948%	$1.274
7/1/2013 16:00	16.0625%	$52.220	11.5714%	$37.619	3.1747%	$10.321	10.2823%	$33.428	4.0525%	$13.175	0.1153%	$0.375	0.4105%	$1.335
7/1/2013 17:00	16.5748%	$53.778	13.1347%	$42.616	3.5724%	$11.591	9.5287%	$30.916	3.5926%	$11.656	0.1076%	$0.349	0.3885%	$1.261
7/1/2013 18:00	17.7092%	$56.717	13.9166%	$44.570	3.5694%	$11.432	9.0539%	$28.997	3.2077%	$10.273	0.1006%	$0.322	0.3847%	$1.232
7/1/2013 19:00	19.8564%	$62.597	14.6472%	$46.175	2.9740%	$9.376	8.5910%	$27.083	2.8657%	$9.034	0.0924%	$0.291	0.4003%	$1.262
7/1/2013 20:00	18.0855%	$57.088	14.9349%	$47.143	3.1031%	$9.795	8.8283%	$27.867	2.6667%	$8.418	0.0825%	$0.260	0.4397%	$1.388
7/1/2013 21:00	16.4293%	$51.311	13.6739%	$42.706	3.0592%	$9.554	8.9215%	$27.863	2.7539%	$8.601	0.0774%	$0.242	0.4826%	$1.507
7/1/2013 22:00	14.5749%	$44.228	12.6860%	$38.496	2.6590%	$8.069	9.0695%	$27.522	3.1506%	$9.561	0.0678%	$0.206	0.5190%	$1.575
7/1/2013 23:00	15.0683%	$42.553	10.7828%	$30.451	2.8138%	$7.946	9.2201%	$26.038	3.1413%	$8.871	0.0630%	$0.178	0.5081%	$1.435
7/2/2013 0:00	13.4246%	$35.348	9.3570%	$24.638	2.6960%	$7.099	9.4702%	$24.936	3.2674%	$8.603	0.0683%	$0.180	0.5275%	$1.389
7/2/2013 1:00	12.0250%	$28.758	9.1014%	$21.766	2.2552%	$5.393	9.6073%	$22.976	3.2659%	$7.810	0.0848%	$0.203	0.5677%	$1.358
7/2/2013 2:00	11.7901%	$26.385	8.5286%	$19.086	2.1530%	$4.818	9.5296%	$21.326	3.1964%	$7.153	0.0791%	$0.177	0.6780%	$1.517
7/2/2013 3:00	11.0672%	$24.146	9.3154%	$20.324	1.8924%	$4.129	9.5435%	$20.821	3.2634%	$7.120	0.0830%	$0.181	0.5392%	$1.176
7/2/2013 4:00	12.0588%	$27.567	10.5541%	$24.127	2.3128%	$5.287	9.0754%	$20.747	3.2710%	$7.478	0.1493%	$0.341	0.6147%	$1.405
7/2/2013 5:00	12.1469%	$29.807	9.6984%	$23.799	2.5555%	$6.271	9.5936%	$23.542	4.1730%	$10.240	0.1488%	$0.365	0.6435%	$1.579
7/2/2013 6:00	12.5419%	$32.965	10.2724%	$27.000	2.3751%	$6.243	10.3496%	$27.203	3.9599%	$10.408	0.1592%	$0.418	0.6223%	$1.636
7/2/2013 7:00	13.4130%	$39.284	8.3156%	$24.355	1.9617%	$5.745	11.5692%	$33.884	3.8068%	$11.149	0.1667%	$0.488	0.5959%	$1.745
7/2/2013 8:00	11.7543%	$37.397	8.0255%	$25.533	2.3855%	$7.590	12.3824%	$39.395	4.0100%	$12.758	0.1543%	$0.491	0.6141%	$1.954
7/2/2013 9:00	10.6904%	$34.223	8.3524%	$26.738	2.0215%	$6.471	12.7869%	$40.934	3.9153%	$12.534	0.1507%	$0.482	0.5632%	$1.803
7/2/2013 10:00	10.5349%	$32.452	9.6017%	$29.577	1.9421%	$5.983	12.8141%	$39.473	3.8758%	$11.939	0.1512%	$0.466	0.6047%	$1.863
7/2/2013 11:00	9.5568%	$29.349	10.3467%	$31.775	1.8962%	$5.823	12.5819%	$38.639	4.0001%	$12.284	0.1527%	$0.469	0.6017%	$1.848
7/2/2013 12:00	10.9302%	$33.603	10.3322%	$31.764	2.0492%	$6.300	12.3253%	$37.892	4.0763%	$12.532	0.1363%	$0.419	0.6120%	$1.881
7/2/2013 13:00	12.5955%	$39.374	11.0279%	$34.473	1.9693%	$6.156	11.8337%	$36.992	4.1897%	$13.097	0.1445%	$0.452	0.6101%	$1.907
7/2/2013 14:00	13.8624%	$43.594	10.6874%	$33.609	2.0614%	$6.483	11.6933%	$36.772	4.1342%	$13.001	0.1338%	$0.421	0.5633%	$1.772
7/2/2013 15:00	16.4748%	$51.818	11.3134%	$35.584	2.3076%	$7.258	10.7984%	$33.964	4.0864%	$12.853	0.1102%	$0.347	0.5956%	$1.873
7/2/2013 16:00	18.0330%	$56.722	12.2276%	$38.461	3.3100%	$10.412	10.0017%	$31.460	3.9860%	$12.538	0.1146%	$0.360	0.5397%	$1.698

INDIANAPOLIS POWER & LIGHT
Assignment of Generation Plant Investment to Rate Classes
(Gross Plant)

Start date and hour	H1 Loadshare	H1 Investment Cost	H2 Loadshare	H2 Investment Cost	H3 Loadshare	H3 Investment Cost	SL Loadshare	SL Investment Cost	PL Loadshare	PL Investment Cost	Lighting Loadshare	Lighting Investment Cost	Total System Investment Period (000s)
7/1/2013 0:00	10.4639%	$28.247	2.5144%	$6.788	3.4049%	$9.191	28.0576%	$75.740	11.6353%	$31.409	2.2027%	$5.946	$269.95
7/1/2013 1:00	10.6789%	$28.110	2.4602%	$6.476	3.4527%	$9.089	28.4753%	$74.955	11.8343%	$31.151	2.2566%	$5.940	$263.23
7/1/2013 2:00	11.2462%	$28.232	2.5236%	$6.335	3.5821%	$8.993	29.6292%	$74.381	12.1723%	$30.557	2.3294%	$5.848	$251.04
7/1/2013 3:00	10.9666%	$27.293	2.4412%	$6.075	3.4400%	$8.561	29.8130%	$74.196	11.9018%	$29.620	2.2511%	$5.602	$248.87
7/1/2013 4:00	10.6160%	$26.364	2.2919%	$5.692	3.2520%	$8.076	30.1894%	$74.973	11.6139%	$28.842	2.0750%	$5.153	$248.34
7/1/2013 5:00	9.9377%	$26.402	2.2419%	$5.956	2.9530%	$7.845	30.7550%	$81.707	11.2714%	$29.945	1.8828%	$5.002	$265.67
7/1/2013 6:00	10.0290%	$28.527	2.2831%	$6.494	2.9995%	$8.532	32.2687%	$91.786	11.4161%	$32.472	0.2750%	$0.782	$284.44
7/1/2013 7:00	10.0705%	$31.120	2.2538%	$6.965	2.9131%	$9.002	33.4952%	$103.507	11.4844%	$35.489	0.0992%	$0.307	$309.02
7/1/2013 8:00	9.8778%	$31.445	2.2000%	$7.004	2.8058%	$8.932	33.5204%	$106.708	11.2921%	$35.947	0.0949%	$0.302	$318.34
7/1/2013 9:00	9.6271%	$31.607	2.1166%	$6.949	2.6759%	$8.785	33.1572%	$108.860	10.8436%	$35.601	0.0903%	$0.296	$328.32
7/1/2013 10:00	9.6004%	$32.138	2.1313%	$7.134	2.6482%	$8.865	33.2838%	$111.418	10.8244%	$36.235	0.0902%	$0.302	$334.75
7/1/2013 11:00	9.6655%	$32.356	2.0785%	$6.958	2.5968%	$8.693	33.2002%	$111.138	10.9161%	$36.542	0.0889%	$0.298	$334.75
7/1/2013 12:00	9.5739%	$31.907	2.0919%	$6.972	2.6016%	$8.670	33.2613%	$110.850	10.9569%	$36.516	0.0887%	$0.296	$333.27
7/1/2013 13:00	9.5351%	$31.830	2.0859%	$6.963	2.5725%	$8.587	32.7063%	$109.180	10.8998%	$36.386	0.0883%	$0.295	$333.82
7/1/2013 14:00	9.4150%	$30.761	2.1477%	$7.017	2.5842%	$8.443	32.0763%	$104.801	10.6336%	$34.742	0.0890%	$0.291	$326.72
7/1/2013 15:00	9.4441%	$30.470	2.1140%	$6.821	2.5659%	$8.279	31.0802%	$100.276	10.3526%	$33.401	0.0897%	$0.289	$322.64
7/1/2013 16:00	9.4128%	$30.602	2.0928%	$6.804	2.5841%	$8.401	29.7331%	$96.665	10.2117%	$33.199	0.2965%	$0.964	$325.11
7/1/2013 17:00	9.2680%	$30.071	2.0136%	$6.533	2.5110%	$8.147	27.7391%	$90.001	9.9555%	$32.301	1.6135%	$5.235	$324.46
7/1/2013 18:00	9.1282%	$29.235	1.9584%	$6.272	2.4820%	$7.949	26.9793%	$86.406	9.8869%	$31.664	1.6231%	$5.198	$320.27
7/1/2013 19:00	9.1286%	$28.778	1.8138%	$5.718	2.4168%	$7.619	25.9418%	$81.781	9.6747%	$30.499	1.5973%	$5.035	$315.25
7/1/2013 20:00	9.4508%	$29.832	1.7106%	$5.400	2.5253%	$7.971	26.6665%	$84.174	9.8555%	$31.109	1.6505%	$5.210	$315.66
7/1/2013 21:00	10.1392%	$31.666	1.8336%	$5.726	2.8036%	$8.756	27.3747%	$85.495	10.6587%	$33.289	1.7924%	$5.598	$312.31
7/1/2013 22:00	10.9020%	$33.083	1.9598%	$5.947	3.0367%	$9.215	27.9543%	$84.829	11.4647%	$34.790	1.9557%	$5.935	$303.45
7/1/2013 23:00	11.3815%	$32.142	2.0576%	$5.811	3.1177%	$8.804	27.9777%	$79.009	11.8158%	$33.368	2.0522%	$5.796	$282.40
7/2/2013 0:00	12.6271%	$33.248	2.3537%	$6.197	3.2539%	$8.568	28.6992%	$75.567	12.0884%	$31.830	2.1666%	$5.705	$263.31
7/2/2013 1:00	13.1740%	$31.506	2.4240%	$5.797	3.4425%	$8.233	29.2389%	$69.926	12.5497%	$30.013	2.2636%	$5.413	$239.15
7/2/2013 2:00	13.3308%	$29.833	2.4499%	$5.483	3.4875%	$7.805	29.8072%	$66.705	12.6639%	$28.340	2.3061%	$5.161	$223.79
7/2/2013 3:00	12.8727%	$28.085	2.4295%	$5.301	3.4801%	$7.593	30.5324%	$66.614	12.6885%	$27.683	2.2929%	$5.003	$218.17
7/2/2013 4:00	11.9634%	$27.349	2.2617%	$5.170	3.2404%	$7.408	30.5103%	$69.749	11.8861%	$27.173	2.1020%	$4.805	$228.61
7/2/2013 5:00	11.1146%	$27.274	2.1916%	$5.378	3.0109%	$7.388	31.2464%	$76.675	11.5494%	$28.341	1.9275%	$4.730	$245.39
7/2/2013 6:00	10.9046%	$28.661	2.2571%	$5.932	2.8945%	$7.608	32.0786%	$84.315	11.3101%	$29.727	0.2747%	$0.722	$262.84
7/2/2013 7:00	10.7682%	$31.538	2.2322%	$6.538	2.8119%	$8.235	33.1028%	$96.951	11.1567%	$32.676	0.0994%	$0.291	$292.88
7/2/2013 8:00	10.7866%	$34.318	2.2097%	$7.030	2.7716%	$8.818	33.6727%	$107.130	11.1365%	$35.431	0.0969%	$0.308	$318.15
7/2/2013 9:00	10.9040%	$34.906	2.2703%	$7.268	2.7500%	$8.803	34.2847%	$109.754	11.2150%	$35.902	0.0957%	$0.306	$320.13
7/2/2013 10:00	10.6539%	$32.819	2.2010%	$6.780	2.7118%	$8.354	33.7838%	$104.069	11.0321%	$33.984	0.0929%	$0.286	$308.04
7/2/2013 11:00	10.7247%	$32.936	2.1650%	$6.649	2.6920%	$8.267	34.0605%	$104.601	11.1287%	$34.176	0.0928%	$0.285	$307.10
7/2/2013 12:00	10.3765%	$31.901	2.1115%	$6.491	2.6139%	$8.036	33.4448%	$102.820	10.9032%	$33.520	0.0887%	$0.273	$307.43
7/2/2013 13:00	9.9998%	$31.259	2.0405%	$6.379	2.5766%	$8.055	32.3932%	$101.262	10.5337%	$32.929	0.0855%	$0.267	$312.60
7/2/2013 14:00	9.7353%	$30.615	2.0831%	$6.551	2.5731%	$8.092	31.9943%	$100.614	10.3922%	$32.681	0.0861%	$0.271	$314.48
7/2/2013 15:00	9.4182%	$29.623	2.0274%	$6.377	2.5391%	$7.986	30.2596%	$95.175	9.9845%	$31.404	0.0846%	$0.266	$314.53
7/2/2013 16:00	9.1496%	$28.780	1.9713%	$6.201	2.4736%	$7.780	28.3616%	$89.210	9.5619%	$30.077	0.2693%	$0.847	$314.54

INDIANAPOLIS POWER & LIGHT
Assignment of Generation Plant Investment to Rate Classes
(Depreciation Reserve)

Start date and hour	RS Loadshare	RS Depreciation Cost	RH Loadshare	RH Depreciation Cost	RC Loadshare	RC Depreciation Cost	SS Loadshare	SS Depreciation Cost	SH Loadshare	SH Depreciation Cost	SE Loadshare	SE Depreciation Cost	PH Loadshare	PH Depreciation Cost
7/1/2013 0:00	14.6898%	$21.250	11.6622%	$16.870	2.3072%	$3.337	8.8529%	$12.806	3.7946%	$5.489	0.0764%	$0.111	0.3380%	$0.489
7/1/2013 1:00	15.3263%	$21.645	10.2298%	$14.447	2.2710%	$3.207	9.0404%	$12.767	3.5259%	$4.980	0.0780%	$0.110	0.3708%	$0.524
7/1/2013 2:00	13.9526%	$18.802	8.8324%	$11.902	2.3158%	$3.121	9.2577%	$12.475	3.5917%	$4.840	0.0873%	$0.118	0.4797%	$0.646
7/1/2013 3:00	13.6316%	$18.205	10.1163%	$13.510	2.1477%	$2.868	8.9908%	$12.007	3.7916%	$5.064	0.0893%	$0.119	0.4188%	$0.559
7/1/2013 4:00	13.1357%	$17.500	10.4362%	$13.904	2.5578%	$3.408	9.0953%	$12.118	4.0543%	$5.401	0.1626%	$0.217	0.5197%	$0.692
7/1/2013 5:00	12.8542%	$18.201	10.5848%	$14.988	2.9913%	$4.236	9.6060%	$13.602	4.3588%	$6.172	0.1682%	$0.238	0.3949%	$0.559
7/1/2013 6:00	11.7555%	$17.831	10.7971%	$16.377	3.0007%	$4.551	10.2242%	$15.508	4.3134%	$6.543	0.1701%	$0.258	0.4677%	$0.709
7/1/2013 7:00	11.5760%	$19.057	9.0165%	$14.844	2.4898%	$4.099	11.8549%	$19.517	4.0857%	$6.726	0.1710%	$0.282	0.4899%	$0.806
7/1/2013 8:00	12.7211%	$21.573	8.2371%	$13.969	1.9764%	$3.352	12.4318%	$21.082	4.1194%	$6.986	0.1661%	$0.282	0.5572%	$0.945
7/1/2013 9:00	13.0643%	$22.772	8.9608%	$15.619	2.0949%	$3.652	12.6052%	$21.972	4.1028%	$7.152	0.1574%	$0.274	0.5041%	$0.879
7/1/2013 10:00	12.2630%	$21.781	9.3909%	$16.680	2.0228%	$3.593	12.9762%	$23.048	4.0882%	$7.261	0.1523%	$0.271	0.5282%	$0.938
7/1/2013 11:00	12.8899%	$22.895	8.8926%	$15.795	2.3018%	$4.088	12.6168%	$22.410	4.1504%	$7.372	0.1547%	$0.275	0.4476%	$0.795
7/1/2013 12:00	12.0995%	$21.407	9.9236%	$17.557	2.2102%	$3.910	12.4580%	$22.041	4.1146%	$7.280	0.1534%	$0.271	0.4663%	$0.825
7/1/2013 13:00	12.7268%	$22.560	10.8603%	$19.252	1.9573%	$3.470	11.8092%	$20.933	4.2245%	$7.489	0.1488%	$0.264	0.3851%	$0.683
7/1/2013 14:00	14.5617%	$25.243	10.1835%	$17.653	2.1265%	$3.686	11.5673%	$20.052	4.0962%	$7.101	0.1371%	$0.238	0.3819%	$0.662
7/1/2013 15:00	15.5737%	$26.688	10.7872%	$18.486	2.5495%	$4.369	10.7969%	$18.502	4.1285%	$7.075	0.1229%	$0.211	0.3948%	$0.677
7/1/2013 16:00	16.0625%	$27.763	11.5714%	$20.000	3.1747%	$5.487	10.2823%	$17.772	4.0525%	$7.004	0.1153%	$0.199	0.4105%	$0.710
7/1/2013 17:00	16.5748%	$28.570	13.1347%	$22.641	3.5724%	$6.158	9.5287%	$16.425	3.5926%	$6.193	0.1076%	$0.186	0.3885%	$0.670
7/1/2013 18:00	17.7092%	$30.151	13.9166%	$23.693	3.5694%	$6.077	9.0539%	$15.415	3.2077%	$5.461	0.1006%	$0.171	0.3847%	$0.655
7/1/2013 19:00	19.8564%	$33.295	14.6472%	$24.560	2.9740%	$4.987	8.5910%	$14.405	2.8657%	$4.805	0.0924%	$0.155	0.4003%	$0.671
7/1/2013 20:00	18.0855%	$30.397	14.9349%	$25.102	3.1031%	$5.216	8.8283%	$14.838	2.6667%	$4.482	0.0825%	$0.139	0.4397%	$0.739
7/1/2013 21:00	16.4293%	$27.306	13.6739%	$22.726	3.0592%	$5.084	8.9215%	$14.828	2.7539%	$4.577	0.0774%	$0.129	0.4826%	$0.802
7/1/2013 22:00	14.5749%	$23.569	12.6860%	$20.515	2.6590%	$4.300	9.0695%	$14.666	3.1506%	$5.095	0.0678%	$0.110	0.5190%	$0.839
7/1/2013 23:00	15.0683%	$22.751	10.7828%	$16.281	2.8138%	$4.248	9.2201%	$13.921	3.1413%	$4.743	0.0630%	$0.095	0.5081%	$0.767
7/2/2013 0:00	13.4246%	$18.988	9.3570%	$13.235	2.6960%	$3.813	9.4702%	$13.395	3.2674%	$4.622	0.0683%	$0.097	0.5275%	$0.746
7/2/2013 1:00	12.0250%	$15.431	9.1014%	$11.679	2.2552%	$2.894	9.6073%	$12.328	3.2659%	$4.191	0.0848%	$0.109	0.5677%	$0.729
7/2/2013 2:00	11.7901%	$14.129	8.5286%	$10.220	2.1530%	$2.580	9.5296%	$11.420	3.1964%	$3.830	0.0791%	$0.095	0.6780%	$0.812
7/2/2013 3:00	11.0672%	$12.906	9.3154%	$10.863	1.8924%	$2.207	9.5435%	$11.129	3.2634%	$3.806	0.0830%	$0.097	0.5392%	$0.629
7/2/2013 4:00	12.0588%	$14.717	10.5541%	$12.880	2.3128%	$2.823	9.0754%	$11.076	3.2710%	$3.992	0.1493%	$0.182	0.6147%	$0.750
7/2/2013 5:00	12.1469%	$15.900	9.6984%	$12.695	2.5555%	$3.345	9.5936%	$12.558	4.1730%	$5.462	0.1488%	$0.195	0.6435%	$0.842
7/2/2013 6:00	12.5419%	$17.591	10.2724%	$14.407	2.3751%	$3.331	10.3496%	$14.516	3.9599%	$5.554	0.1592%	$0.223	0.6223%	$0.873
7/2/2013 7:00	13.4130%	$20.971	8.3156%	$13.001	1.9617%	$3.067	11.5692%	$18.088	3.8068%	$5.952	0.1667%	$0.261	0.5959%	$0.932
7/2/2013 8:00	11.7543%	$19.948	8.0255%	$13.620	2.3855%	$4.048	12.3824%	$21.014	4.0100%	$6.805	0.1543%	$0.262	0.6141%	$1.042
7/2/2013 9:00	10.6904%	$18.207	8.3524%	$14.225	2.0215%	$3.443	12.7869%	$21.778	3.9153%	$6.668	0.1507%	$0.257	0.5632%	$0.959
7/2/2013 10:00	10.5349%	$17.225	9.6017%	$15.699	1.9421%	$3.176	12.8141%	$20.952	3.8758%	$6.337	0.1512%	$0.247	0.6047%	$0.989
7/2/2013 11:00	9.5568%	$15.580	10.3467%	$16.868	1.8962%	$3.091	12.5819%	$20.511	4.0001%	$6.521	0.1527%	$0.249	0.6017%	$0.981
7/2/2013 12:00	10.9302%	$17.839	10.3322%	$16.863	2.0492%	$3.344	12.3253%	$20.116	4.0763%	$6.653	0.1363%	$0.222	0.6120%	$0.999
7/2/2013 13:00	12.5955%	$20.860	11.0279%	$18.264	1.9693%	$3.262	11.8337%	$19.599	4.1897%	$6.939	0.1445%	$0.239	0.6101%	$1.010
7/2/2013 14:00	13.8624%	$23.075	10.6874%	$17.790	2.0614%	$3.431	11.6933%	$19.464	4.1342%	$6.882	0.1338%	$0.223	0.5633%	$0.938
7/2/2013 15:00	16.4748%	$27.434	11.3134%	$18.839	2.3076%	$3.843	10.7984%	$17.982	4.0864%	$6.805	0.1102%	$0.184	0.5956%	$0.992
7/2/2013 16:00	18.0330%	$30.033	12.2276%	$20.364	3.3100%	$5.513	10.0017%	$16.657	3.9860%	$6.638	0.1146%	$0.191	0.5397%	$0.899

INDIANAPOLIS POWER & LIGHT
Assignment of Generation Plant Investment to Rate Classes
(Depreciation Reserve)

Start date and hour	H1 Loadshare	H1 Depreciation Cost	H2 Loadshare	H2 Depreciation Cost	H3 Loadshare	H3 Depreciation Cost	SL Loadshare	SL Depreciation Cost	PL Loadshare	PL Depreciation Cost	Lighting Loadshare	Lighting Depreciation Cost	Total System Depreciation Period (000s)
7/1/2013 0:00	10.4639%	$15.137	2.5144%	$3.637	3.4049%	$4.925	28.0576%	$40.587	11.6353%	$16.831	2.2027%	$3.186	$144.656
7/1/2013 1:00	10.6789%	$15.081	2.4602%	$3.474	3.4527%	$4.876	28.4753%	$40.215	11.8343%	$16.713	2.2566%	$3.187	$141.227
7/1/2013 2:00	11.2462%	$15.155	2.5236%	$3.401	3.5821%	$4.827	29.6292%	$39.928	12.1723%	$16.403	2.3294%	$3.139	$134.758
7/1/2013 3:00	10.9666%	$14.646	2.4412%	$3.260	3.4400%	$4.594	29.8130%	$39.814	11.9018%	$15.894	2.2511%	$3.006	$133.546
7/1/2013 4:00	10.6160%	$14.144	2.2919%	$3.054	3.2520%	$4.333	30.1894%	$40.221	11.6139%	$15.473	2.0750%	$2.764	$133.228
7/1/2013 5:00	9.9377%	$14.072	2.2419%	$3.174	2.9530%	$4.181	30.7550%	$43.548	11.2714%	$15.960	1.8828%	$2.666	$141.597
7/1/2013 6:00	10.0290%	$15.212	2.2831%	$3.463	2.9995%	$4.550	32.2687%	$48.946	11.4161%	$17.316	0.2750%	$0.417	$151.682
7/1/2013 7:00	10.0705%	$16.579	2.2538%	$3.710	2.9131%	$4.796	33.4952%	$55.143	11.4844%	$18.907	0.0992%	$0.163	$164.629
7/1/2013 8:00	9.8778%	$16.751	2.2000%	$3.731	2.8058%	$4.758	33.5204%	$56.845	11.2921%	$19.150	0.0949%	$0.161	$169.584
7/1/2013 9:00	9.6271%	$16.781	2.1166%	$3.689	2.6759%	$4.664	33.1572%	$57.796	10.8436%	$18.901	0.0903%	$0.157	$174.308
7/1/2013 10:00	9.6004%	$17.052	2.1313%	$3.786	2.6482%	$4.704	33.2838%	$59.119	10.8244%	$19.226	0.0902%	$0.160	$177.620
7/1/2013 11:00	9.6655%	$17.168	2.0785%	$3.692	2.5968%	$4.612	33.2002%	$58.970	10.9161%	$19.389	0.0889%	$0.158	$177.620
7/1/2013 12:00	9.5739%	$16.939	2.0919%	$3.701	2.6016%	$4.603	33.2613%	$58.847	10.9569%	$19.386	0.0887%	$0.157	$176.924
7/1/2013 13:00	9.5351%	$16.902	2.0859%	$3.698	2.5725%	$4.560	32.7063%	$57.977	10.8998%	$19.322	0.0883%	$0.157	$177.265
7/1/2013 14:00	9.4150%	$16.321	2.1477%	$3.723	2.5842%	$4.480	32.0763%	$55.605	10.6336%	$18.434	0.0890%	$0.154	$173.353
7/1/2013 15:00	9.4441%	$16.184	2.1140%	$3.623	2.5659%	$4.397	31.0802%	$53.261	10.3526%	$17.741	0.0897%	$0.154	$171.366
7/1/2013 16:00	9.4128%	$16.269	2.0928%	$3.617	2.5841%	$4.466	29.7331%	$51.392	10.2117%	$17.650	0.2965%	$0.512	$172.844
7/1/2013 17:00	9.2680%	$15.975	2.0136%	$3.471	2.5110%	$4.328	27.7391%	$47.814	9.9555%	$17.161	1.6135%	$2.781	$172.372
7/1/2013 18:00	9.1282%	$15.541	1.9584%	$3.334	2.4820%	$4.226	26.9793%	$45.933	9.8869%	$16.833	1.6231%	$2.763	$170.253
7/1/2013 19:00	9.1286%	$15.307	1.8138%	$3.041	2.4168%	$4.052	25.9418%	$43.498	9.6747%	$16.222	1.5973%	$2.678	$167.677
7/1/2013 20:00	9.4508%	$15.885	1.7106%	$2.875	2.5253%	$4.244	26.6665%	$44.820	9.8555%	$16.565	1.6505%	$2.774	$168.076
7/1/2013 21:00	10.1392%	$16.852	1.8336%	$3.047	2.8036%	$4.660	27.3747%	$45.497	10.6587%	$17.715	1.7924%	$2.979	$166.203
7/1/2013 22:00	10.9020%	$17.630	1.9598%	$3.169	3.0367%	$4.911	27.9543%	$45.206	11.4647%	$18.540	1.9557%	$3.163	$161.712
7/1/2013 23:00	11.3815%	$17.185	2.0576%	$3.107	3.1177%	$4.707	27.9777%	$42.243	11.8158%	$17.840	2.0522%	$3.099	$150.987
7/2/2013 0:00	12.6271%	$17.860	2.3537%	$3.329	3.2539%	$4.602	28.6992%	$40.593	12.0884%	$17.098	2.1666%	$3.064	$141.443
7/2/2013 1:00	13.1740%	$16.905	2.4240%	$3.111	3.4425%	$4.417	29.2389%	$37.520	12.5497%	$16.104	2.2636%	$2.905	$128.321
7/2/2013 2:00	13.3308%	$15.975	2.4499%	$2.936	3.4875%	$4.179	29.8072%	$35.719	12.6639%	$15.176	2.3061%	$2.764	$119.835
7/2/2013 3:00	12.8727%	$15.012	2.4295%	$2.833	3.4801%	$4.058	30.5324%	$35.606	12.6885%	$14.797	2.2929%	$2.674	$116.619
7/2/2013 4:00	11.9634%	$14.600	2.2617%	$2.760	3.2404%	$3.955	30.5103%	$37.235	11.8861%	$14.506	2.1020%	$2.565	$122.042
7/2/2013 5:00	11.1146%	$14.549	2.1916%	$2.869	3.0109%	$3.941	31.2464%	$40.902	11.5494%	$15.118	1.9275%	$2.523	$130.901
7/2/2013 6:00	10.9046%	$15.294	2.2571%	$3.166	2.8945%	$4.060	32.0786%	$44.992	11.3101%	$15.863	0.2747%	$0.385	$140.254
7/2/2013 7:00	10.7682%	$16.836	2.2322%	$3.490	2.8119%	$4.396	33.1028%	$51.755	11.1567%	$17.443	0.0994%	$0.155	$156.348
7/2/2013 8:00	10.7866%	$18.305	2.2097%	$3.750	2.7716%	$4.703	33.6727%	$57.144	11.1365%	$18.899	0.0969%	$0.164	$169.704
7/2/2013 9:00	10.9040%	$18.571	2.2703%	$3.867	2.7500%	$4.684	34.2847%	$58.391	11.2150%	$19.101	0.0957%	$0.163	$170.312
7/2/2013 10:00	10.6539%	$17.420	2.2010%	$3.599	2.7118%	$4.434	33.7838%	$55.238	11.0321%	$18.038	0.0929%	$0.152	$163.506
7/2/2013 11:00	10.7247%	$17.484	2.1650%	$3.529	2.6920%	$4.389	34.0605%	$55.526	11.1287%	$18.142	0.0928%	$0.151	$163.023
7/2/2013 12:00	10.3765%	$16.935	2.1115%	$3.446	2.6139%	$4.266	33.4448%	$54.584	10.9032%	$17.795	0.0887%	$0.145	$163.206
7/2/2013 13:00	9.9998%	$16.561	2.0405%	$3.379	2.5766%	$4.267	32.3932%	$53.649	10.5337%	$17.446	0.0855%	$0.142	$165.617
7/2/2013 14:00	9.7353%	$16.205	2.0831%	$3.467	2.5731%	$4.283	31.9943%	$53.256	10.3922%	$17.298	0.0861%	$0.143	$166.455
7/2/2013 15:00	9.4182%	$15.683	2.0274%	$3.376	2.5391%	$4.228	30.2596%	$50.389	9.9845%	$16.626	0.0846%	$0.141	$166.521
7/2/2013 16:00	9.1496%	$15.238	1.9713%	$3.283	2.4736%	$4.120	28.3616%	$47.234	9.5619%	$15.925	0.2693%	$0.449	$166.543

Class Cost of Service Study
Summary of Results
Probability of Dispatch Utilizing IPL Classification of Distribution Plant

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)
	Rate Base							
1	Plant in Service	$ 4,501,131,701	$ 1,970,045,724	$ 415,300,478	$ 180,926,728	$ 5,459,783	$ 268,159	$ 438,450
2	Accumulated Reserve	(2,827,661,271)	(1,271,283,603)	(259,264,910)	(111,328,577)	(3,329,047)	(186,584)	(287,592)
3	Other Rate Base Items	291,522,000	123,902,283	27,499,677	11,466,780	352,838	17,915	30,337
4	Total Rate Base	$ 1,964,992,430	$ 822,664,404	$ 183,535,245	$ 81,064,931	$ 2,483,574	$ 97,489	$ 181,195
	Revenues at Current Rates							
5	Retail Sales	$ 1,177,074,009	$ 465,528,940	$ 136,179,718	$ 45,434,316	$ 1,621,358	$ 44,356	$ 115,705
6	Other Revenue	20,161,991	12,678,107	1,639,615	492,236	15,270	1,097	1,799
7	Sales for Resale	6,324,121	2,377,999	562,728	273,911	8,556	192	480
8	Total Revenues	$ 1,203,560,121	$ 480,585,046	$ 138,382,060	$ 46,200,463	$ 1,645,184	$ 45,646	$ 117,984
	Expenses at Current Rates							
9	Operations & Maintenance Expenses	$ 396,494,451	$ 177,341,985	$ 37,290,846	$ 15,212,908	$ 465,479	$ 25,416	$ 40,399
10	Depreciation Expense	200,925,821	83,962,927	19,177,483	8,331,989	252,949	10,923	19,264
11	Amortization Expense	7,656,489	3,275,645	702,740	311,325	9,436	422	721
12	Taxes Other Than Income Taxes	45,114,501	19,626,084	4,235,390	1,793,357	54,109	2,708	4,464
13	Fuel Expenses	435,543,947	159,315,107	39,754,620	18,234,219	627,592	19,068	46,665
14	Non-FAC Trackable Fuel Expenses	7,413,035	2,813,880	674,845	312,712	10,939	301	740
15	Income Taxes	14,500,138	1,363,022	11,553,767	(389,622)	51,551	(6,549)	(398)
16	Total Expenses - Current	$ 1,107,648,382	$ 447,698,651	$ 113,389,692	$ 43,806,888	$ 1,472,055	$ 52,289	$ 111,854
17	Current Operating Income	95,911,739	32,886,395	24,992,368	2,393,575	173,130	(6,644)	6,130
18	Return at Current Rates	4.88%	4.00%	13.62%	2.95%	6.97%	-6.81%	3.38%
19	Index Rate of Return	1.00	0.82	2.79	0.60	1.43	-1.40	0.69
	Current Rate Rev	$ 1,177,074,009	$ 465,528,940	$ 136,179,718	$ 45,434,316	$ 1,621,358	$ 44,356	$ 115,705
	IPL Proposed Increase	67,249,670	36,606,231	1,357,032	3,315,652	103,931	3,557	7,289
	IPL Rate Rev @ Proposed Rates	$ 1,244,323,678	$ 502,135,171	$ 137,536,750	$ 48,749,968	$ 1,725,289	$ 47,913	$ 122,994
	Allocated Sales for Resale	6,324,121	2,377,999	562,728	273,911	8,556	192	480
	Allocated other Rev @ Current Rates	20,161,991	12,678,107	1,639,615	492,236	15,270	1,097	1,799
	Allocated Additional Connect Fee Rev	1,710,968	1,654,245	47,641	4,113	28	96	92
	Allocated Migration Impact	(1,186,513)	(469,788)	(134,013)	(43,227)	(1,538)	(40)	(107)
	Subtotal	27,010,567	16,240,564	2,115,970	727,032	22,316	1,346	2,264
	IPL total Proposed Rev	$ 1,271,334,245.41	$ 518,375,734.11	$ 139,652,719.83	$ 49,476,999.99	$ 1,747,604.88	$ 49,258.85	$ 125,257.72
Less:								
	O&M @ Current Rates	$ 396,494,451	$ 177,341,985	$ 37,290,846	$ 15,212,908	$ 465,479	$ 25,416	$ 40,399
	Depreciation	200,925,821	83,962,927	19,177,483	8,331,989	252,949	10,923	19,264
	Amortization	7,656,489	3,275,645	702,740	311,325	9,436	422	721
	Taxes Oter than Income @ Current Rates	45,114,501	19,626,084	4,235,390	1,793,357	54,109	2,708	4,464
	Fuel	435,543,947	159,315,107	39,754,620	18,234,219	627,592	19,068	46,665
	Non FAC Fuel	7,413,035	2,813,880	674,845	312,712	10,939	301	740
	Subtotal	1,093,148,244	446,335,628	101,835,925	44,196,510	1,420,504	58,839	112,252
	Bad Debt increase @ Proposed Rates	264,000	239,478	19,130	1,651	11	39	37
	PUC Fee Increase @ Proposed Rates	80,000	35,033	7,390	3,211	97	5	8
	Other Tax Increase @ Proposed Rates	945,000	400,226	88,366	38,524	1,180	49	89
	Total Expense Before Tax @ Proposed Rates	$ 1,094,437,244	$ 447,010,365	$ 101,950,811	$ 44,239,896	$ 1,421,792	$ 58,931	$ 112,385
	Earnings Before Interest and Income Tax	$ 176,897,001	$ 71,365,369	$ 37,701,908	$ 5,237,104	$ 325,813	$ (9,672)	$ 12,873
	Interest	$ 71,820,000	$ 30,068,186	$ 6,708,169	$ 2,962,904	$ 90,774	$ 3,563	$ 6,623
	Taxable Income	$ 105,077,001	$ 41,297,183	$ 30,993,739	$ 2,274,200	$ 235,039	$ (13,236)	$ 6,250
	Income Tax	$ 40,730,000	$ 16,007,635	$ 12,013,809	$ 881,527	$ 91,106	$ (5,130)	$ 2,423
	Net Operating Income @ Proposed Rates	$ 136,167,001.44	$ 55,357,734.02	$ 25,688,099.60	$ 4,355,577.47	$ 234,706.99	$ (4,542.04)	$ 10,450.00
	Rate Base	$ 1,964,992,430	$ 822,664,404	$ 183,535,245	$ 81,064,931	$ 2,483,574	$ 97,489	$ 181,195
	ROR @ IPL Proposed Rates (Before Correction for Migration)	6.93%	6.73%	14.00%	5.37%	9.45%	-4.66%	5.77%
	Eliminate Migration Adjustment	$ 1,186,513.00	$ 469,787.59	$ 134,012.89	$ 43,227.13	$ 1,537.83	$ 40.31	$ 107.33
	Tax Effect of Migration Adjustment	459,916.76	182,099.30	51,946.15	16,755.72	596.09	15.63	41.60
	Net Migration Effect	726,596	287,688	82,067	26,471	942	25	66
	Corrected Net Operating Income @ IPL Proposed Rates	$ 136,893,598	$ 55,645,422	$ 25,770,166	$ 4,382,049	$ 235,649	$ (4,517)	$ 10,516
	Corrected ROR @ IPL Proposed Rates	6.97%	6.76%	14.04%	5.41%	9.49%	-4.63%	5.80%
	Corrected Indexed ROR @ IPL Proposed Rates	100%	97%	202%	78%	136%	-67%	83%

Class Cost of Service Study
Summary of Results
Probability of Dispatch Utilizing IPL Classification of Distribution Plant

Line No.	Description (A)	System Total (B)	Secondary Large SL (I)	Primary PL (J)	Process Heating PH (K)	HLF - Primary HL1 (L)	HLF - Sub-Tran HL2 (M)	HLF -Tran HL3 (N)	Automatic Protective Lighting APL (O)	Municipal Lighting MU1 (P)
	Rate Base									
1	Plant in Service	$ 4,501,131,701	$ 955,154,203	$ 339,501,662	$ 20,296,657	$ 337,712,580	$ 55,381,895	$ 77,353,800	$ 57,755,556	$ 85,536,025
2	Accumulated Reserve	(2,827,661,271)	(572,146,526)	(198,761,852)	(12,406,877)	(196,853,250)	(30,763,398)	(42,849,209)	(50,141,055)	(78,056,790)
3	Other Rate Base Items	291,522,000	64,407,364	22,129,352	1,282,611	22,433,953	3,788,452	5,467,953	4,909,219	3,833,266
4	Total Rate Base	$ 1,964,992,430	$ 447,415,041	$ 162,869,162	$ 9,172,391	$ 163,293,283	$ 28,406,949	$ 39,972,543	$ 12,523,720	$ 11,312,501
	Revenues at Current Rates									
5	Retail Sales	$ 1,177,074,009	$ 287,702,173	$ 89,530,832	$ 5,428,692	$ 91,369,462	$ 15,102,253	$ 22,324,851	$ 6,428,908	$ 10,262,445
6	Other Revenue	20,161,991	2,698,380	843,323	58,166	845,277	124,425	159,443	235,662	369,192
7	Sales for Resale	6,324,121	1,594,169	584,846	30,524	580,081	103,349	155,978	21,901	29,405
8	Total Revenues	$ 1,203,560,121	$ 291,994,722	$ 90,959,001	$ 5,517,382	$ 92,794,820	$ 15,330,027	$ 22,640,272	$ 6,686,471	$ 10,661,042
	Expenses at Current Rates									
9	Operations & Maintenance Expenses	$ 396,494,451	$ 84,381,896	$ 28,688,353	$ 1,682,248	$ 28,329,240	$ 4,818,003	$ 6,945,272	$ 6,238,650	$ 5,033,755
10	Depreciation Expense	200,925,821	46,097,772	16,469,859	911,555	16,343,693	2,827,206	4,144,186	1,289,716	1,086,300
11	Amortization Expense	7,656,489	1,672,586	598,002	34,849	594,738	99,137	140,722	87,953	128,211
12	Taxes Other Than Income Taxes	45,114,501	9,723,828	3,425,872	199,982	3,412,428	576,154	810,195	636,356	613,575
13	Fuel Expenses	435,543,947	112,801,182	38,900,834	2,183,050	42,179,384	7,158,429	10,891,705	1,465,055	1,967,038
14	Non-FAC Trackable Fuel Expenses	7,413,035	1,889,520	649,426	37,833	682,244	116,375	175,811	20,465	27,945
15	Income Taxes	14,500,138	7,324,058	(1,480,593)	49,712	(1,865,018)	(512,256)	(757,507)	(1,367,502)	537,473
16	Total Expenses - Current	$ 1,107,648,382	$ 263,890,842	$ 87,251,754	$ 5,099,229	$ 89,676,710	$ 15,083,048	$ 22,350,383	$ 8,370,692	$ 9,394,296
17	Current Operating Income	95,911,739	28,103,880	3,707,247	418,153	3,118,110	246,980	289,889	(1,684,221)	1,266,746
18	Return at Current Rates	4.88%	6.28%	2.28%	4.56%	1.91%	0.87%	0.73%	-13.45%	11.20%
19	Index Rate of Return	1.00	1.29	0.47	0.93	0.39	0.18	0.15	-2.76	2.29
	Current Rate Rev	$ 1,177,074,009	$ 287,702,173	$ 89,530,832	$ 5,428,692	$ 91,369,462	$ 15,102,253	$ 22,324,851	$ 6,428,908	$ 10,262,445
	IPL Proposed Increase	67,249,670	12,131,540	5,561,797	413,076	5,111,944	928,143	1,202,697	533,394	-26,613
	IPL Rate Rev @ Proposed Rates	$ 1,244,323,678	$ 299,833,713	$ 95,092,629	$ 5,841,768	$ 96,481,406	$ 16,030,396	$ 23,527,548	$ 6,962,302	$ 10,235,832
	Allocated Sales for Resale	6,324,121	1,594,169	584,846	30,524	580,081	103,349	155,978	21,901	29,405
	Allocated other Rev @ Current Rates	20,161,991	2,698,380	843,323	58,166	845,277	124,425	159,443	235,662	369,192
	Allocated Additional Connect Fee Rev	1,710,968	4,540	146	32	27	5	3	-	-
	Allocated Migration Impact	(1,186,513)	(294,365)	(91,370)	(5,519)	(90,595)	(15,046)	(22,106)	(6,694)	(12,105)
	Subtotal	27,010,567	4,002,724	1,336,945	83,204	1,334,790	212,733	293,318	250,870	386,493
	IPL total Proposed Rev	$ 1,271,334,245.41	$ 303,836,437.89	$ 96,429,573.80	$ 5,924,971.82	$ 97,816,195.42	$ 16,243,128.80	$ 23,820,865.93	$ 7,213,171.54	$ 10,622,324.84
	Less:									
	O&M @ Current Rates	$ 396,494,451	$ 84,381,896	$ 28,688,353	$ 1,682,248	$ 28,329,240	$ 4,818,003	$ 6,945,272	$ 6,238,650	$ 5,033,755
	Depreciation	200,925,821	46,097,772	16,469,859	911,555	16,343,693	2,827,206	4,144,186	1,289,716	1,086,300
	Amortization	7,656,489	1,672,586	598,002	34,849	594,738	99,137	140,722	87,953	128,211
	Taxes Oter than Income @ Current Rates	45,114,501	9,723,828	3,425,872	199,982	3,412,428	576,154	810,195	636,356	613,575
	Fuel	435,543,947	112,801,182	38,900,834	2,183,050	42,179,384	7,158,429	10,891,705	1,465,055	1,967,038
	Non FAC Fuel	7,413,035	1,889,520	649,426	37,833	682,244	116,375	175,811	20,465	27,945
	Subtotal	1,093,148,244	256,566,784	88,732,347	5,049,517	91,541,727	15,595,304	23,107,890	9,738,194	8,856,823
	Bad Debt increase @ Proposed Rates	264,000	3,491	112	25	21	4	2	0	0
	PUC Fee Increase @ Proposed Rates	80,000	16,966	6,022	360	5,990	983	1,373	1,050	1,512
	Other Tax Increase @ Proposed Rates	945,000	212,787	76,647	4,343	76,673	13,294	18,773	7,507	6,541
	Total Expense Before Tax @ Proposed Rates	$ 1,094,437,244	$ 256,800,027	$ 88,815,128	$ 5,054,245	$ 91,624,411	$ 15,609,585	$ 23,128,039	$ 9,746,751	$ 8,864,876
	Earnings Before Interest and Income Tax	$ 176,897,001	$ 47,036,410	$ 7,614,446	$ 870,727	$ 6,191,784	$ 633,544	$ 692,827	$ (2,533,580)	$ 1,757,449
	Interest	$ 71,820,000	$ 16,352,912	$ 5,952,829	$ 335,249	$ 5,968,330	$ 1,038,267	$ 1,460,987	$ 457,739	$ 413,469
	Taxable Income	$ 105,077,001	$ 30,683,498	$ 1,661,617	$ 535,478	$ 223,454	$ (404,723)	$ (768,160)	$ (2,991,319)	$ 1,343,979
	Income Tax	$ 40,730,000	$ 11,393,553	$ 644,077	$ 207,562	$ 86,615	$ (156,879)	$ (297,755)	$ (1,159,496)	$ 520,954
	Net Operating Income @ Proposed Rates	$ 136,167,001.44	$ 35,142,857.38	$ 6,970,368.94	$ 663,164.48	$ 6,105,168.87	$ 790,422.96	$ 990,581.43	$ (1,374,083.30)	$ 1,236,494.65
	Rate Base	$ 1,964,992,430	$ 447,415,041	$ 162,869,162	$ 9,172,391	$ 163,293,283	$ 28,406,949	$ 39,972,543	$ 12,523,720	$ 11,312,501
	ROR @ IPL Proposed Rates (Before Correction for Migration)	6.93%	7.85%	4.28%	7.23%	3.74%	2.78%	2.48%	-10.97%	10.93%
	Eliminate Migration Adjustment	$ 1,186,513.00	$ 294,364.79	$ 91,370.29	$ 5,518.78	$ 90,595.29	$ 15,046.48	$ 22,106.06	$ 6,693.59	$ 12,104.64
	Tax Effect of Migration Adjustment	459,916.76	114,101.83	35,417.00	2,139.19	35,116.59	5,832.33	8,568.76	2,594.57	4,692.01
	Net Migration Effect	726,596	180,263	55,953	3,380	55,479	9,214	13,537	4,099	7,413
	Corrected Net Operating Income @ IPL Proposed Rates	$ 136,893,598	$ 35,323,120	$ 7,026,322	$ 666,544	$ 6,160,648	$ 799,637	$ 1,004,119	$ (1,369,984)	$ 1,243,907
	Corrected ROR @ IPL Proposed Rates	6.97%	7.89%	4.31%	7.27%	3.77%	2.81%	2.51%	-10.94%	11.00%
	Corrected Indexed ROR @ IPL Proposed Rates	100%	113%	62%	104%	54%	40%	36%	-157%	158%

INDIANAPOLIS POWER & LIGHT
Development of Energy and Demand
Separation for the Base-Intermediate-Peak Method

Plant Name	Type	(1) Generator Nameplate (MW) 1/	(2) Test Year Net MWH 2/	(3) Calculated Capacity Factor 3/	(4) IPL Stated Net Capacity Factor 2/	(5) Test Year Fuel Cost Per MWH 4/	(6) Gross Plant Investment ($000) 5/	(7) Depr. Reserve ($000) 5/	(8) Net Plant (6) - (7)	(9) Percent Energy	(10) Weighted Energy
Petersburg #1	Steam/Coal	253.4	1,800,290	81.10%	89.35%						
Petersburg #2	Steam/Coal	471.0	1,950,055	47.26%	53.64%						
Petersburg #3	Steam/Coal	574.4	3,239,292	64.38%	68.48%						
Petersburg #4	Steam/Coal	574.2	3,738,259	74.32%	80.52%						
Subtotal Pburg Steam		1,873	10,727,896	65.38%	71.26%	$22.85	$1,779,087	$983,937	$795,150	100.00%	$795,149.60
Harding Street #5	Steam/Coal	113.6	606,278	60.92%	65.28%						
Harding Street #6	Steam/Coal	113.6	628,069	63.11%	68.26%						
Harding Street #7	Steam/Coal	480.3	2,451,848	58.27%	66.87%						
Subtotal Harding Steam		707.5	3,686,195	59.48%	66.84%	$24.70	$547,977	$257,180	$290,797	66.84%	$194,362.30
Eagle Valley #3	Steam/Coal	50.0	21,655	4.94%	5.75%						
Eagle Valley #4	Steam/Coal	69.0	147,875	24.46%	29.62%						
Eagle Valley #5	Steam/Coal	69.0	178,852	29.59%	32.41%						
Eagle Valley #6	Steam/Coal	113.6	397,169	39.91%	45.41%						
Subtotal Valley Steam		301.6	745,551	28.22%	32.25%	$34.13	$130,122	$86,800	$43,322	32.25%	$13,970.53
Harding Street Turbine #1	Gas/Oil	21.4	206	0.11%	0.10%						
Harding Street Turbine #2	Gas/Oil	21.4	211	0.11%	0.10%						
Harding Street Turbine #4	Gas/Oil	90.0	28,281	3.59%	3.61%						
Harding Street Turbine #5	Gas/Oil	90.0	24,768	3.14%	3.14%						
Harding Street Turbine #6	Gas/Oil	170.0	79,831	5.36%	5.22%						
Subtotal Harding Turbine		392.8	133,297	3.87%	3.82%	$94.95	$133,283	$91,144	$42,139	3.82%	$1,608.31
Georgetown Turbine #1	Gas	85.3	11,222	1.50%	1.45%						
Georgetown Turbine #4	Gas	85.3	15,475	2.07%	1.99%						
Subtotal Georgetown Turbine		170.6	26,697	1.79%	0.75%	$79.12	$57,496	$30,992	$26,504	0.75%	$197.99
Petersburg Diesel	Diesel	8.3	116	0.16%	N/A	$190.67	$931	$1,268	-$337	0.00%	$0.00
Harding Street Diesel	Diesel	2.7	79	0.33%	N/A	$314.59	$232		$232	0.00%	$0.00
Eagle Valley Diesel	Diesel	2.7	70	0.30%	N/A	$270.30	$325	$532	-$207	0.00%	$0.00
							$2,649,452	$1,451,852	$1,197,600		$1,005,289

1/ Per Company response to OUCC-18-3.
2/ Per Company response to OUCC-18-3, Attachment 2, except as noted.
3/ Calculated as: [Column (2) divided by 8,760] divided by Column (1).
4/ Per Company response to OUCC-18-9.
5/ Per Company response to OUCC-18-3, Attachment 1, except Harding Street Diesel unit per 2013 FERC Form 1.

Energy	83.9%
Demand	16.1%

Class Cost of Service Study
Summary of Results
Base-Intermediate-Peak Utilizing IPL Classification of Distribution Plant

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)
	Rate Base							
1	Plant in Service	$ 4,501,131,701	$ 1,991,932,172	$ 420,926,882	$ 175,561,390	$ 5,706,808	$ 294,000	$ 496,562
2	Accumulated Reserve	(2,827,661,271)	(1,283,281,220)	(262,349,167)	(108,387,430)	(3,464,460)	(202,750)	(319,448)
3	Other Rate Base Items	291,522,000	125,057,980	27,796,775	11,183,468	365,882	19,279	33,406
4	Total Rate Base	$ 1,964,992,430	$ 833,708,932	$ 186,374,490	$ 78,357,429	$ 2,608,230	$ 110,529	$ 210,520
	Revenues at Current Rates							
5	Retail Sales	$ 1,177,074,009	$ 465,528,940	$ 136,179,718	$ 45,434,316	$ 1,621,358	$ 44,356	$ 115,705
6	Other Revenue	20,161,991	12,678,107	1,639,615	492,236	15,270	1,097	1,799
7	Sales for Resale	6,324,121	2,426,886	575,295	261,926	9,108	250	610
8	Total Revenues	$ 1,203,560,121	$ 480,633,933	$ 138,394,628	$ 46,188,478	$ 1,645,736	$ 45,703	$ 118,114
	Expenses at Current Rates							
9	Operations & Maintenance Expenses	$ 396,494,451	$ 179,070,536	$ 37,735,209	$ 14,789,163	$ 484,988	$ 27,457	$ 44,989
10	Depreciation Expense	200,925,821	85,211,890	19,498,557	8,025,813	267,045	12,397	22,580
11	Amortization Expense	7,656,489	3,316,673	713,287	301,268	9,899	471	830
12	Taxes Other Than Income Taxes	45,114,501	19,852,259	4,293,533	1,737,912	56,662	2,975	5,064
13	Fuel Expenses	435,543,947	159,315,107	39,754,620	18,234,219	627,592	19,068	46,665
14	Non-FAC Trackable Fuel Expenses	7,413,035	2,813,880	674,845	312,712	10,939	301	740
15	Income Taxes	14,500,138	(38,292)	11,193,528	(46,098)	35,734	(8,204)	(4,119)
16	Total Expenses - Current	$ 1,107,648,382	$ 449,542,053	$ 113,863,581	$ 43,354,988	$ 1,492,860	$ 54,466	$ 116,748
17	Current Operating Income	95,911,739	31,091,879	24,531,047	2,833,490	152,876	(8,762)	1,366
18	Return at Current Rates	4.88%	3.73%	13.16%	3.62%	5.86%	-7.93%	0.65%
19	Index Rate of Return	1.00	0.76	2.70	0.74	1.20	-1.62	0.13
	Current Rate Rev	$ 1,177,074,009	$ 465,528,940	$ 136,179,718	$ 45,434,316	$ 1,621,358	$ 44,356	$ 115,705
	IPL Proposed Increase	67,249,670	36,606,231	1,357,032	3,315,652	103,931	3,557	7,289
	IPL Rate Rev @ Proposed Rates	$ 1,244,323,678	$ 502,135,171	$ 137,536,750	$ 48,749,968	$ 1,725,289	$ 47,913	$ 122,994
	Allocated Sales for Resale	6,324,121	2,426,886	575,295	261,926	9,108	250	610
	Allocated other Rev @ Current Rates	20,161,991	12,678,107	1,639,615	492,236	15,270	1,097	1,799
	Allocated Additional Connect Fee Rev	1,710,968	1,654,245	47,641	4,113	28	96	92
	Allocated Migration Impact	(1,186,513)	(469,788)	(134,013)	(43,227)	(1,538)	(40)	(107)
	Subtotal	27,010,567	16,289,450	2,128,538	715,048	22,868	1,403	2,394
	IPL total Proposed Rev	$ 1,271,334,245.41	$ 518,424,620.68	$ 139,665,287.22	$ 49,465,015.72	$ 1,748,156.65	$ 49,316.57	$ 125,387.52
Less:								
	O&M @ Current Rates	$ 396,494,451	$ 179,070,536	$ 37,735,209	$ 14,789,163	$ 484,988	$ 27,457	$ 44,989
	Depreciation	200,925,821	85,211,890	19,498,557	8,025,813	267,045	12,397	22,580
	Amortization	7,656,489	3,316,673	713,287	301,268	9,899	471	830
	Taxes Oter than Income @ Current Rates	45,114,501	19,852,259	4,293,533	1,737,912	56,662	2,975	5,064
	Fuel	435,543,947	159,315,107	39,754,620	18,234,219	627,592	19,068	46,665
	Non FAC Fuel	7,413,035	2,813,880	674,845	312,712	10,939	301	740
	Subtotal	1,093,148,244	449,580,345	102,670,053	43,401,086	1,457,126	62,670	120,867
	Bad Debt increase @ Proposed Rates	264,000	239,478	19,130	1,651	11	39	37
	PUC Fee Increase @ Proposed Rates	80,000	35,422	7,490	3,115	101	5	9
	Other Tax Increase @ Proposed Rates	945,000	405,337	89,680	37,271	1,238	55	102
	Total Expense Before Tax @ Proposed Rates	$ 1,094,437,244	$ 450,260,582	$ 102,786,353	$ 43,443,124	$ 1,458,476	$ 62,769	$ 121,015
	Earnings Before Interest and Income Tax	$ 176,897,001	$ 68,164,039	$ 36,878,935	$ 6,021,892	$ 289,681	$ (13,452)	$ 4,373
	Interest	$ 71,820,000	$ 30,471,861	$ 6,811,943	$ 2,863,945	$ 95,330	$ 4,040	$ 7,694
	Taxable Income	$ 105,077,001	$ 37,692,178	$ 30,066,992	$ 3,157,947	$ 194,350	$ (17,492)	$ (3,322)
	Income Tax	$ 40,730,000	$ 14,610,261	$ 11,654,582	$ 1,224,085	$ 75,334	$ (6,780)	$ (1,288)
	Net Operating Income @ Proposed Rates	$ 136,167,001.44	$ 53,553,777.88	$ 25,224,352.09	$ 4,797,807.01	$ 214,346.37	$ (6,671.93)	$ 5,660.22
	Rate Base	$ 1,964,992,430	$ 833,708,932	$ 186,374,490	$ 78,357,429	$ 2,608,230	$ 110,529	$ 210,520
	ROR @ IPL Proposed Rates (Before Correction for Migration)	6.93%	6.42%	13.53%	6.12%	8.22%	-6.04%	2.69%
	Eliminate Migration Adjustment	$ 1,186,513.00	$ 469,787.59	$ 134,012.89	$ 43,227.13	$ 1,537.83	$ 40.31	$ 107.33
	Tax Effect of Migration Adjustment	459,916.76	182,099.30	51,946.15	16,755.72	596.09	15.63	41.60
	Net Migration Effect	726,596	287,688	82,067	26,471	942	25	66
	Corrected Net Operating Income @ IPL Proposed Rates	$ 136,893,598	$ 53,841,466	$ 25,306,419	$ 4,824,278	$ 215,288	$ (6,647)	$ 5,726
	Corrected ROR @ IPL Proposed Rates	6.97%	6.46%	13.58%	6.16%	8.25%	-6.01%	2.72%
	Corrected Indexed ROR @ IPL Proposed Rates	100%	93%	195%	88%	118%	-86%	39%

Class Cost of Service Study
Summary of Results
Base-Intermediate-Peak Utilizing IPL Classification of Distribution Plant

Line No.	Description (A)	System Total (B)	Secondary Large SL (I)	Primary PL (J)	Process Heating PH (K)	HLF - Primary HL1 (L)	HLF - Sub-Tran HL2 (M)	HLF -Tran HL3 (N)	Automatic Protective Lighting APL (O)	Municipal Lighting MU1 (P)
	Rate Base									
1	Plant in Service	$ 4,501,131,701	$ 956,797,138	$ 323,500,222	$ 20,655,886	$ 338,110,439	$ 53,766,521	$ 74,205,417	$ 55,940,873	$ 83,237,390
2	Accumulated Reserve	(2,827,661,271)	(573,047,143)	(189,990,253)	(12,603,798)	(197,071,347)	(29,877,889)	(41,123,343)	(49,146,291)	(76,796,734)
3	Other Rate Base Items	291,522,000	64,494,118	21,284,408	1,301,580	22,454,962	3,703,153	5,301,705	4,813,396	3,711,888
4	Total Rate Base	$ 1,964,992,430	$ 448,244,113	$ 154,794,378	$ 9,353,668	$ 163,494,054	$ 27,591,785	$ 38,383,779	$ 11,607,979	$ 10,152,544
	Revenues at Current Rates									
5	Retail Sales	$ 1,177,074,009	$ 287,702,173	$ 89,530,832	$ 5,428,692	$ 91,369,462	$ 15,102,253	$ 22,324,851	$ 6,428,908	$ 10,262,445
6	Other Revenue	20,161,991	2,698,380	843,323	58,166	845,277	124,425	159,443	235,662	369,192
7	Sales for Resale	6,324,121	1,597,839	549,105	31,327	580,970	99,741	148,946	17,848	24,271
8	Total Revenues	$ 1,203,560,121	$ 291,998,392	$ 90,923,259	$ 5,518,185	$ 92,795,709	$ 15,326,419	$ 22,633,239	$ 6,682,418	$ 10,655,908
	Expenses at Current Rates									
9	Operations & Maintenance Expenses	$ 396,494,451	$ 84,511,652	$ 27,424,589	$ 1,710,620	$ 28,360,663	$ 4,690,424	$ 6,696,618	$ 6,095,329	$ 4,852,213
10	Depreciation Expense	200,925,821	46,191,527	15,556,727	932,055	16,366,397	2,735,024	3,964,521	1,186,160	955,127
11	Amortization Expense	7,656,489	1,675,666	568,006	35,523	595,484	96,109	134,820	84,551	123,902
12	Taxes Other Than Income Taxes	45,114,501	9,740,806	3,260,513	203,694	3,416,539	559,460	777,659	617,603	589,821
13	Fuel Expenses	435,543,947	112,801,182	38,900,834	2,183,050	42,179,384	7,158,429	10,891,705	1,465,055	1,967,038
14	Non-FAC Trackable Fuel Expenses	7,413,035	1,889,520	649,426	37,833	682,244	116,375	175,811	20,465	27,945
15	Income Taxes	14,500,138	7,218,867	(456,075)	26,712	(1,890,491)	(408,830)	(555,927)	(1,251,314)	684,647
16	Total Expenses - Current	$ 1,107,648,382	$ 264,029,220	$ 85,904,020	$ 5,129,486	$ 89,710,220	$ 14,946,991	$ 22,085,208	$ 8,217,849	$ 9,200,692
17	Current Operating Income	95,911,739	27,969,172	5,019,239	388,699	3,085,489	379,428	548,031	(1,535,431)	1,455,216
18	Return at Current Rates	4.88%	6.24%	3.24%	4.16%	1.89%	1.38%	1.43%	-13.23%	14.33%
19	Index Rate of Return	1.00	1.28	0.66	0.85	0.39	0.28	0.29	-2.71	2.94
	Current Rate Rev	$ 1,177,074,009	$ 287,702,173	$ 89,530,832	$ 5,428,692	$ 91,369,462	$ 15,102,253	$ 22,324,851	$ 6,428,908	$ 10,262,445
	IPL Proposed Increase	67,249,670	12,131,540	5,561,797	413,076	5,111,944	928,143	1,202,697	533,394	-26,613
	IPL Rate Rev @ Proposed Rates	$ 1,244,323,678	$ 299,833,713	$ 95,092,629	$ 5,841,768	$ 96,481,406	$ 16,030,396	$ 23,527,548	$ 6,962,302	$ 10,235,832
	Allocated Sales for Resale	6,324,121	1,597,839	549,105	31,327	580,970	99,741	148,946	17,848	24,271
	Allocated other Rev @ Current Rates	20,161,991	2,698,380	843,323	58,166	845,277	124,425	159,443	235,662	369,192
	Allocated Additional Connect Fee Rev	1,710,968	4,540	146	32	27	5	3	-	-
	Allocated Migration Impact	(1,186,513)	(294,365)	(91,370)	(5,519)	(90,595)	(15,046)	(22,106)	(6,694)	(12,105)
	Subtotal	27,010,567	4,006,394	1,301,203	84,006	1,335,678	209,125	286,285	246,816	381,359
	IPL total Proposed Rev	$ 1,271,334,245.41	$ 303,840,107.63	$ 96,393,832.24	$ 5,925,774.21	$ 97,817,084.09	$ 16,239,520.62	$ 23,813,833.56	$ 7,209,118.18	$ 10,617,190.50
Less:										
	O&M @ Current Rates	$ 396,494,451	$ 84,511,652	$ 27,424,589	$ 1,710,620	$ 28,360,663	$ 4,690,424	$ 6,696,618	$ 6,095,329	$ 4,852,213
	Depreciation	200,925,821	46,191,527	15,556,727	932,055	16,366,397	2,735,024	3,964,521	1,186,160	955,127
	Amortization	7,656,489	1,675,666	568,006	35,523	595,484	96,109	134,820	84,551	123,902
	Taxes Oter than Income @ Current Rates	45,114,501	9,740,806	3,260,513	203,694	3,416,539	559,460	777,659	617,603	589,821
	Fuel	435,543,947	112,801,182	38,900,834	2,183,050	42,179,384	7,158,429	10,891,705	1,465,055	1,967,038
	Non FAC Fuel	7,413,035	1,889,520	649,426	37,833	682,244	116,375	175,811	20,465	27,945
	Subtotal	1,093,148,244	256,810,353	86,360,096	5,102,774	91,600,711	15,355,821	22,641,135	9,469,163	8,516,045
	Bad Debt increase @ Proposed Rates	264,000	3,491	112	25	21	4	2	0	0
	PUC Fee Increase @ Proposed Rates	80,000	16,995	5,738	366	5,997	954	1,317	1,018	1,472
	Other Tax Increase @ Proposed Rates	945,000	213,171	72,911	4,427	76,766	12,917	18,038	7,084	6,004
	Total Expense Before Tax @ Proposed Rates	$ 1,094,437,244	$ 257,044,009	$ 86,438,856	$ 5,107,592	$ 91,683,495	$ 15,369,696	$ 22,660,493	$ 9,477,264	$ 8,523,521
	Earnings Before Interest and Income Tax	$ 176,897,001	$ 46,796,098	$ 9,954,976	$ 818,182	$ 6,133,589	$ 869,825	$ 1,153,341	$ (2,268,146)	$ 2,093,670
	Interest	$ 71,820,000	$ 16,383,214	$ 5,657,697	$ 341,874	$ 5,975,668	$ 1,008,473	$ 1,402,918	$ 424,269	$ 371,073
	Taxable Income	$ 105,077,001	$ 30,412,884	$ 4,297,279	$ 476,308	$ 157,921	$ (138,648)	$ (249,577)	$ (2,692,415)	$ 1,722,597
	Income Tax	$ 40,730,000	$ 11,788,657	$ 1,665,713	$ 184,627	$ 61,213	$ (53,743)	$ (96,741)	$ (1,043,635)	$ 667,714
	Net Operating Income @ Proposed Rates	$ 136,167,001.44	$ 35,007,440.96	$ 8,289,262.60	$ 633,555.59	$ 6,072,375.97	$ 923,567.63	$ 1,250,081.95	$ (1,224,510.94)	$ 1,425,956.03
	Rate Base	$ 1,964,992,430	$ 448,244,113	$ 154,794,378	$ 9,353,668	$ 163,494,054	$ 27,591,785	$ 38,383,779	$ 11,607,979	$ 10,152,544
	ROR @ IPL Proposed Rates (Before Correction for Migration)	6.93%	7.81%	5.36%	6.77%	3.71%	3.35%	3.26%	-10.55%	14.05%
	Eliminate Migration Adjustment	$ 1,186,513.00	$ 294,364.79	$ 91,370.29	$ 5,518.78	$ 90,595.29	$ 15,046.48	$ 22,106.06	$ 6,693.59	$ 12,104.64
	Tax Effect of Migration Adjustment	459,916.76	114,101.83	35,417.00	2,139.19	35,116.59	5,832.33	8,568.76	2,594.57	4,692.01
	Net Migration Effect	726,596	180,263	55,953	3,380	55,479	9,214	13,537	4,099	7,413
	Corrected Net Operating Income @ IPL Proposed Rates	$ 136,893,598	$ 35,187,704	$ 8,345,216	$ 636,935	$ 6,127,855	$ 932,782	$ 1,263,619	$ (1,220,412)	$ 1,433,369
	Corrected ROR @ IPL Proposed Rates	6.97%	7.85%	5.39%	6.81%	3.75%	3.38%	3.29%	-10.51%	14.12%
	Corrected Indexed ROR @ IPL Proposed Rates	100%	113%	77%	98%	54%	49%	47%	-151%	203%

Class Cost of Service Study
Summary of Results
Peak & Average Utilizing IPL Classification of Distribution Plant

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)
	Rate Base							
1	Plant in Service	$ 4,501,131,701	$ 2,087,475,635	$ 419,292,020	$ 173,177,125	$ 5,702,584	$ 271,484	$ 439,806
2	Accumulated Reserve	(2,827,661,271)	(1,335,655,819)	(261,452,976)	(107,080,433)	(3,462,145)	(190,407)	(288,335)
3	Other Rate Base Items	291,522,000	130,103,081	27,710,448	11,057,568	365,659	18,090	30,409
4	Total Rate Base	$ 1,964,992,430	$ 881,922,897	$ 185,549,492	$ 77,154,260	$ 2,606,098	$ 99,167	$ 181,879
	Revenues at Current Rates							
5	Retail Sales	$ 1,177,074,009	$ 465,528,940	$ 136,179,718	$ 45,434,316	$ 1,621,358	$ 44,356	$ 115,705
6	Other Revenue	20,161,991	12,678,107	1,639,615	492,236	15,270	1,097	1,799
7	Sales for Resale	6,324,121	2,640,296	571,643	256,601	9,098	200	483
8	Total Revenues	$ 1,203,560,121	$ 480,847,343	$ 138,390,976	$ 46,183,153	$ 1,645,727	$ 45,653	$ 117,987
	Expenses at Current Rates							
9	Operations & Maintenance Expenses	$ 396,494,451	$ 186,616,380	$ 37,606,091	$ 14,600,859	$ 484,655	$ 25,679	$ 40,506
10	Depreciation Expense	200,925,821	90,664,137	19,405,263	7,889,753	266,804	11,113	19,341
11	Amortization Expense	7,656,489	3,495,777	710,223	296,798	9,892	428	723
12	Taxes Other Than Income Taxes	45,114,501	20,839,606	4,276,639	1,713,273	56,618	2,742	4,478
13	Fuel Expenses	435,543,947	159,315,107	39,754,620	18,234,219	627,592	19,068	46,665
14	Non-FAC Trackable Fuel Expenses	7,413,035	2,813,880	674,845	312,712	10,939	301	740
15	Income Taxes	14,500,138	(6,155,614)	11,298,202	106,559	36,005	(6,762)	(485)
16	Total Expenses - Current	$ 1,107,648,382	$ 457,589,273	$ 113,725,883	$ 43,154,172	$ 1,492,505	$ 52,569	$ 111,968
17	Current Operating Income	95,911,739	23,258,070	24,665,093	3,028,981	153,222	(6,916)	6,019
18	Return at Current Rates	4.88%	2.64%	13.29%	3.93%	5.88%	-6.97%	3.31%
19	Index Rate of Return	1.00	0.54	2.72	0.80	1.20	-1.43	0.68
	Current Rate Rev	$ 1,177,074,009	$ 465,528,940	$ 136,179,718	$ 45,434,316	$ 1,621,358	$ 44,356	$ 115,705
	IPL Proposed Increase	67,249,670	36,606,231	1,357,032	3,315,652	103,931	3,557	7,289
	IPL Rate Rev @ Proposed Rates	$ 1,244,323,678	$ 502,135,171	$ 137,536,750	$ 48,749,968	$ 1,725,289	$ 47,913	$ 122,994
	Allocated Sales for Resale	6,324,121	2,640,296	571,643	256,601	9,098	200	483
	Allocated other Rev @ Current Rates	20,161,991	12,678,107	1,639,615	492,236	15,270	1,097	1,799
	Allocated Additional Connect Fee Rev	1,710,968	1,654,245	47,641	4,113	28	96	92
	Allocated Migration Impact	(1,186,513)	(469,788)	(134,013)	(43,227)	(1,538)	(40)	(107)
	Subtotal	27,010,567	16,502,860	2,124,886	709,723	22,859	1,353	2,267
	IPL total Proposed Rev	$ 1,271,334,245.41	$ 518,638,030.94	$ 139,661,635.52	$ 49,459,690.12	$ 1,748,147.21	$ 49,266.28	$ 125,260.75
Less:								
	O&M @ Current Rates	$ 396,494,451	$ 186,616,380	$ 37,606,091	$ 14,600,859	$ 484,655	$ 25,679	$ 40,506
	Depreciation	200,925,821	90,664,137	19,405,263	7,889,753	266,804	11,113	19,341
	Amortization	7,656,489	3,495,777	710,223	296,798	9,892	428	723
	Taxes Oter than Income @ Current Rates	45,114,501	20,839,606	4,276,639	1,713,273	56,618	2,742	4,478
	Fuel	435,543,947	159,315,107	39,754,620	18,234,219	627,592	19,068	46,665
	Non FAC Fuel	7,413,035	2,813,880	674,845	312,712	10,939	301	740
	Subtotal	1,093,148,244	463,744,887	102,427,681	43,047,613	1,456,500	59,332	112,452
	Bad Debt increase @ Proposed Rates	264,000	239,478	19,130	1,651	11	39	37
	PUC Fee Increase @ Proposed Rates	80,000	37,119	7,461	3,073	101	5	8
	Other Tax Increase @ Proposed Rates	945,000	427,647	89,298	36,714	1,237	50	89
	Total Expense Before Tax @ Proposed Rates	$ 1,094,437,244	$ 464,449,131	$ 102,543,570	$ 43,089,052	$ 1,457,849	$ 59,425	$ 112,586
	Earnings Before Interest and Income Tax	$ 176,897,001	$ 54,188,900	$ 37,118,066	$ 6,370,638	$ 290,298	$ (10,159)	$ 12,674
	Interest	$ 71,820,000	$ 32,234,069	$ 6,781,789	$ 2,819,970	$ 95,252	$ 3,625	$ 6,648
	Taxable Income	$ 105,077,001	$ 21,954,831	$ 30,336,276	$ 3,550,669	$ 195,046	$ (13,783)	$ 6,027
	Income Tax	$ 40,730,000	$ 8,510,142	$ 11,758,963	$ 1,376,312	$ 75,604	$ (5,343)	$ 2,336
	Net Operating Income @ Proposed Rates	$ 136,167,001.44	$ 45,678,757.59	$ 25,359,102.99	$ 4,994,326.39	$ 214,694.53	$ (4,816.12)	$ 10,338.28
	Rate Base	$ 1,964,992,430	$ 881,922,897	$ 185,549,492	$ 77,154,260	$ 2,606,098	$ 99,167	$ 181,879
	ROR @ IPL Proposed Rates (Before Correction for Migration)	6.93%	5.18%	13.67%	6.47%	8.24%	-4.86%	5.68%
	Eliminate Migration Adjustment	$ 1,186,513.00	$ 469,787.59	$ 134,012.89	$ 43,227.13	$ 1,537.83	$ 40.31	$ 107.33
	Tax Effect of Migration Adjustment	459,916.76	182,099.30	51,946.15	16,755.72	596.09	15.63	41.60
	Net Migration Effect	726,596	287,688	82,067	26,471	942	25	66
	Corrected Net Operating Income @ IPL Proposed Rates	$ 136,893,598	$ 45,966,445	$ 25,441,170	$ 5,020,798	$ 215,636	$ (4,791)	$ 10,404
	Corrected ROR @ IPL Proposed Rates	6.97%	5.21%	13.71%	6.51%	8.27%	-4.83%	5.72%
	Corrected Indexed ROR @ IPL Proposed Rates	100%	75%	197%	93%	119%	-69%	82%

Class Cost of Service Study
Summary of Results
Peak & Average Utilizing IPL Classification of Distribution Plant

Line No.	Description (A)	System Total (B)	Secondary Large SL (I)	Primary PL (J)	Process Heating PH (K)	HLF - Primary HL1 (L)	HLF - Sub-Tran HL2 (M)	HLF -Tran HL3 (N)	Automatic Protective Lighting APL (O)	Municipal Lighting MU1 (P)
	Rate Base									
1	Plant in Service	$ 4,501,131,701	$ 923,127,884	$ 310,266,936	$ 20,343,591	$ 311,641,956	$ 50,235,167	$ 66,467,082	$ 53,060,913	$ 79,629,519
2	Accumulated Reserve	(2,827,661,271)	(554,590,478)	(182,736,088)	(12,432,605)	(182,561,969)	(27,942,087)	(36,881,376)	(47,567,567)	(74,818,987)
3	Other Rate Base Items	291,522,000	62,716,238	20,585,635	1,285,089	21,057,313	3,516,683	4,893,088	4,661,322	3,521,377
4	Total Rate Base	$ 1,964,992,430	$ 431,253,644	$ 148,116,483	$ 9,196,075	$ 150,137,300	$ 25,809,763	$ 34,478,794	$ 10,154,669	$ 8,331,909
	Revenues at Current Rates									
5	Retail Sales	$ 1,177,074,009	$ 287,702,173	$ 89,530,832	$ 5,428,692	$ 91,369,462	$ 15,102,253	$ 22,324,851	$ 6,428,908	$ 10,262,445
6	Other Revenue	20,161,991	2,698,380	843,323	58,166	845,277	124,425	159,443	235,662	369,192
7	Sales for Resale	6,324,121	1,522,634	519,546	30,629	521,849	91,853	131,661	11,415	16,212
8	Total Revenues	$ 1,203,560,121	$ 291,923,187	$ 90,893,701	$ 5,517,487	$ 92,736,588	$ 15,318,531	$ 22,615,955	$ 6,675,985	$ 10,647,849
	Expenses at Current Rates									
9	Operations & Maintenance Expenses	$ 396,494,451	$ 81,852,517	$ 26,379,449	$ 1,685,955	$ 26,270,231	$ 4,411,524	$ 6,085,459	$ 5,867,876	$ 4,567,270
10	Depreciation Expense	200,925,821	44,270,170	14,801,561	914,233	14,855,957	2,533,505	3,522,928	1,021,814	749,242
11	Amortization Expense	7,656,489	1,612,550	543,200	34,937	545,867	89,489	120,314	79,152	117,138
12	Taxes Other Than Income Taxes	45,114,501	9,392,868	3,123,760	200,467	3,143,013	522,967	697,691	587,841	552,537
13	Fuel Expenses	435,543,947	112,801,182	38,900,834	2,183,050	42,179,384	7,158,429	10,891,705	1,465,055	1,967,038
14	Non-FAC Trackable Fuel Expenses	7,413,035	1,889,520	649,426	37,833	682,244	116,375	175,811	20,465	27,945
15	Income Taxes	14,500,138	9,374,594	391,207	46,707	(195,804)	(182,729)	(60,468)	(1,066,920)	915,647
16	Total Expenses - Current	$ 1,107,648,382	$ 261,193,402	$ 84,789,437	$ 5,103,182	$ 87,480,892	$ 14,649,561	$ 21,433,441	$ 7,975,282	$ 8,896,816
17	Current Operating Income	95,911,739	30,729,785	6,104,264	414,305	5,255,695	668,971	1,182,514	(1,299,297)	1,751,033
18	Return at Current Rates	4.88%	7.13%	4.12%	4.51%	3.50%	2.59%	3.43%	-12.80%	21.02%
19	Index Rate of Return	1.00	1.46	0.84	0.92	0.72	0.53	0.70	-2.62	4.31
	Current Rate Rev	$ 1,177,074,009	$ 287,702,173	$ 89,530,832	$ 5,428,692	$ 91,369,462	$ 15,102,253	$ 22,324,851	$ 6,428,908	$ 10,262,445
	IPL Proposed Increase	67,249,670	12,131,540	5,561,797	413,076	5,111,944	928,143	1,202,697	533,394	-26,613
	IPL Rate Rev @ Proposed Rates	$ 1,244,323,678	$ 299,833,713	$ 95,092,629	$ 5,841,768	$ 96,481,406	$ 16,030,396	$ 23,527,548	$ 6,962,302	$ 10,235,832
	Allocated Sales for Resale	6,324,121	1,522,634	519,546	30,629	521,849	91,853	131,661	11,415	16,212
	Allocated other Rev @ Current Rates	20,161,991	2,698,380	843,323	58,166	845,277	124,425	159,443	235,662	369,192
	Allocated Additional Connect Fee Rev	1,710,968	4,540	146	32	27	5	3	-	-
	Allocated Migration Impact	(1,186,513)	(294,365)	(91,370)	(5,519)	(90,595)	(15,046)	(22,106)	(6,694)	(12,105)
	Subtotal	27,010,567	3,931,189	1,271,644	83,308	1,276,557	201,237	269,001	240,383	373,300
	IPL total Proposed Rev	$ 1,271,334,245.41	$ 303,764,902.44	$ 96,364,273.77	$ 5,925,076.65	$ 97,757,962.88	$ 16,231,632.83	$ 23,796,548.86	$ 7,202,685.37	$ 10,609,131.80
Less:										
	O&M @ Current Rates	$ 396,494,451	$ 81,852,517	$ 26,379,449	$ 1,685,955	$ 26,270,231	$ 4,411,524	$ 6,085,459	$ 5,867,876	$ 4,567,270
	Depreciation	200,925,821	44,270,170	14,801,561	914,233	14,855,957	2,533,505	3,522,928	1,021,814	749,242
	Amortization	7,656,489	1,612,550	543,200	34,937	545,867	89,489	120,314	79,152	117,138
	Taxes Oter than Income @ Current Rates	45,114,501	9,392,868	3,123,760	200,467	3,143,013	522,967	697,691	587,841	552,537
	Fuel	435,543,947	112,801,182	38,900,834	2,183,050	42,179,384	7,158,429	10,891,705	1,465,055	1,967,038
	Non FAC Fuel	7,413,035	1,889,520	649,426	37,833	682,244	116,375	175,811	20,465	27,945
	Subtotal	1,093,148,244	251,818,807	84,398,230	5,056,475	87,676,696	14,832,290	21,493,909	9,042,202	7,981,169
	Bad Debt increase @ Proposed Rates	264,000	3,491	112	25	21	4	2	0	0
	PUC Fee Increase @ Proposed Rates	80,000	16,397	5,503	361	5,527	892	1,180	967	1,408
	Other Tax Increase @ Proposed Rates	945,000	205,309	69,820	4,354	70,585	12,092	16,231	6,411	5,162
	Total Expense Before Tax @ Proposed Rates	$ 1,094,437,244	$ 252,044,003	$ 84,473,666	$ 5,061,215	$ 87,752,829	$ 14,845,277	$ 21,511,322	$ 9,049,580	$ 7,987,739
	Earnings Before Interest and Income Tax	$ 176,897,001	$ 51,720,899	$ 11,890,608	$ 863,862	$ 10,005,134	$ 1,386,356	$ 2,285,227	$ (1,846,895)	$ 2,621,393
	Interest	$ 71,820,000	$ 15,762,217	$ 5,413,622	$ 336,114	$ 5,487,482	$ 943,341	$ 1,260,192	$ 371,151	$ 304,529
	Taxable Income	$ 105,077,001	$ 35,958,682	$ 6,476,986	$ 527,747	$ 4,517,651	$ 443,015	$ 1,025,035	$ (2,218,045)	$ 2,316,864
	Income Tax	$ 40,730,000	$ 13,938,322	$ 2,510,613	$ 204,566	$ 1,751,134	$ 171,722	$ 397,325	$ (859,760)	$ 898,064
	Net Operating Income @ Proposed Rates	$ 136,167,001.44	$ 37,782,576.55	$ 9,379,995.45	$ 659,296.03	$ 8,253,999.25	$ 1,214,633.95	$ 1,887,902.16	$ (987,134.77)	$ 1,723,329.16
	Rate Base	$ 1,964,992,430	$ 431,253,644	$ 148,116,483	$ 9,196,075	$ 150,137,300	$ 25,809,763	$ 34,478,794	$ 10,154,669	$ 8,331,909
	ROR @ IPL Proposed Rates (Before Correction for Migration)	6.93%	8.76%	6.33%	7.17%	5.50%	4.71%	5.48%	-9.72%	20.68%
	Eliminate Migration Adjustment	$ 1,186,513.00	$ 294,364.79	$ 91,370.29	$ 5,518.78	$ 90,595.29	$ 15,046.48	$ 22,106.06	$ 6,693.59	$ 12,104.64
	Tax Effect of Migration Adjustment	459,916.76	114,101.83	35,417.00	2,139.19	35,116.59	5,832.33	8,568.76	2,594.57	4,692.01
	Net Migration Effect	726,596	180,263	55,953	3,380	55,479	9,214	13,537	4,099	7,413
	Corrected Net Operating Income @ IPL Proposed Rates	$ 136,893,598	$ 37,962,840	$ 9,435,949	$ 662,676	$ 8,309,478	$ 1,223,848	$ 1,901,439	$ (983,036)	$ 1,730,742
	Corrected ROR @ IPL Proposed Rates	6.97%	8.80%	6.37%	7.21%	5.53%	4.74%	5.51%	-9.68%	20.77%
	Corrected Indexed ROR @ IPL Proposed Rates	100%	126%	91%	103%	79%	68%	79%	-139%	298%

CHARGING FOR DISTRIBUTION UTILITY SERVICES: ISSUES IN RATE DESIGN

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Frederick Weston

with assistance from:
Cheryl Harrington
David Moskovitz
Wayne Shirley
Richard Cowart

The Regulatory Assistance Project
16 State Street, Montpelier, VT 05602
Phone: 802-223-8199
Fax: 802-223-8172
rapvermont@aol.com

IV. THE COSTS OF DISTRIBUTION SERVICES

A first question to be answered when designing rates is what does it cost to provide the service? What are the causes and magnitudes of the relevant costs? It s helpful to observe that the costs recovered by distribution-level rates have historically extended far beyond the distribution system. Are there other costs, not directly related to distribution services, that distribution rates are expected to recover? What follow here are an overview of utility costing methodologies and a discussion of some practical considerations to keep in mind when determining rate structures.

A. Utility Plant Costing Methods

Utilities and regulatory commissions use a variety of methods for determining and allocating cost responsibility among customers and customer classes. There are two general types of cost study, embedded and marginal. Embedded, or fully distributed, seeks to identify and assign the historical, or accounting, costs that make up a utility s revenue requirement. Marginal, as the name connotes, aims at determining the change in total costs imposed on the system by a change in output (whether measured by kilowatt-hour, kilowatt, customer, customer group, or other relevant cost driver). Each commission around the country uses these studies in its own way to inform the rate design process; in the end, most commissions rely on embedded cost studies for ultimate allocations and price levels, constrained as they are by a legal requirement to set rates that offer the prudent utility a reasonable opportunity to earn a fair rate of return on its assets used in service to public.[33] The allocations, however, are often structured to reflect at least relative differences in the marginal costs of providing a company s various services.

1. Cost Causation

There is broad agreement in the literature that distribution investment is causally related to peak demand. Numbers of customers on the system and energy needs are also seen to drive costs, but there is less of a consensus on these points or on their implications for rate design. In addition, not all jurisdictions employ the same methods for analyzing the various cost components, and there is of course a wide range of views on their nature marginal, embedded, fixed, variable, joint, common,[34] etc. and thus on how they should be recovered in rates.

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33. NARUC, p. 32.

34. The costs of multiple products or services supplied by the same plant or process are either common or joint. Common are those that generally do not vary with changes in output. The classic example is the president s desk, which is needed to run the firm as a whole but is incremental to the provision of no particular good or service. Another example is that of an airline flight, the majority of whose costs are incurred in a single lump and do not vary with the number of passengers carried. Put another way, common costs are those for which the unit of production (the single flight), which is the basis of cost incurrence, is larger than the unit of sale (a

(continued...)

Numbers of customers, usage, and demand, however, are only part of the story. Other factors also play an important role: geography (particularly population density), system design (*e.g.*, aerial versus underground lines), and the utility s business practices (for example, the extent of expenditures on billing, answering customers questions/complaints, etc.). The implications of such factors on rate design is unclear, however: one can charge for services on the basis of numbers of customers, usage, and demand, but not on the basis of other such factors.[35]

2. Embedded Costs

a. Cost Classification: Customers, Demand, and Energy

Traditionally, customer costs are those that are seen to vary with the number of customers on the system service drops (the line from the distribution radial to the home or business), meters, and billing and collection. Some utilities and jurisdictions also include some portion of the primary and secondary distribution plant (poles, wires, and transformers) in these costs, on the ground that they also are driven more by numbers of customers than by demand or energy. Similar reasoning leads to the designation of the costs of customer service and customer premises equipment as customer-related. But, since the system and its components are sized to serve a maximum level of anticipated demand, the notion that there are any customer costs (aside from perhaps metering and billing) that are not more properly categorized as demand can be challenged (see Subsections 3 and 4, below).

Utilities classify significant portions of their embedded distribution investment as demand-related, reasoning that it is designed and installed to serve a customer or group of customers according to their contribution to some peak load (system, substation, etc.). Substations are a typical example of such costs, but so too may be a significant portion of the wires and related facilities, since they are sized, at least in part, to serve a peak demand.

There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states. A

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34. (...continued)
single ticket to a single passenger). Kahn, Vol. I, p. 77. If services produced in common can be produced in varying proportions, it may then be possible to identify separate marginal production costs for each.

Products that are produced in fixed proportions (*e.g.*, cotton fiber and cottonseed oil, beef and hides, mutton and wool) are characterized by joint costs. For that aspect of their production process that is joint, the products have no separately identifiable marginal costs. *Id.*, p. 79. See also Bonbright, pp. 355-360.

35. These other cost factors can have huge effects on prices. Three distribution utilities in the American south, owned by the same holding company and using the same costing methodology, recently proposed new metering, customer service rates, and delivery rates. The rates, designed as a combination of monthly per-customer and per-kW of peak demand charges, vary from company to company by ratios ranging from 1.25 to 1.9.

variation is to treat poles, wires, and transformers as energy-related driven by kilowatt-hour sales but, though it has obvious appeal, only a small number of jurisdictions have gone this route.

Two other approaches sometimes used are the minimum size and zero-intercept methods. The minimum size method operates, as its name implies, on the assumption that there is a minimum-size distribution system capable of serving customers minimum requirements. The costs of this hypothetical system are, so the argument goes, driven not by customer demand but rather by numbers of customers, and therefore they are considered customer costs. The demand-related cost portion then is the difference between total distribution investment and the customer-related costs. The zero-intercept approach is a variation on the minimum size. Here the idea is to identify that portion of plant that is necessary to give customers access but which is incapable of serving any level of demand. The logic is that the costs of this system, because it can serve no demand and thus is not demand-related, are necessarily customer-related.[36] However, the distinction between customer and demand costs is not always clear, insofar as the number of customers on a system (or particular area of a system) will have impacts on the total demand on the system, to the extent that their demand is coincident with the relevant peak (system, areal, substation, etc.).

Any approach to classifying costs has virtues and vices. The first potential pitfall lies in the assumptions, explicit and implicit, that a method is built upon. In the basic customer method, it is the *a priori* classification of expenditures (which may or may not be reasonable). In the case of the minimum-size and zero-intercept methods, the threshold assumption is that there is some portion of the system whose costs are unrelated to demand (or to energy for that matter). From one perspective, this notion has a certain intuitive appeal these are the lowest costs that must be incurred before any or some minimal amount of power can be delivered but from another viewpoint it seems absurd, since in the absence of any demand no such system would be built at all. Moreover, firms in competitive markets do not indeed, can not price their products according to such methods: they recover their costs through the sale of goods and services, not merely by charging for the ability to consume, or access.

Other assumptions are of a more technical nature. What constitutes the minimum system? What are the proper types of equipment to be modeled? What cost data are applicable (historical, current installations, etc.)? Doesn t the minimum system in fact include demand costs, since such a system can serve some amount of demand? The zero-intercept method attempts to model a system that has no demand-serving capability whatsoever, but what remains is not necessarily a system whose costs are driven any more by the number of customers than it is by geographical considerations, whose causative properties are neither squarely demand- nor customer-related. Does use of an abstract minimum system place a disproportionate share of the cost burden on

36. It is called zero-intercept because it relates installed cost to current carrying capacity or demand rating, creat[ing] a curve for various sizes of the equipment involved, using regression techniques, and extend[ing] the curve to a no-load intercept. NARUC, p. 92.

certain customers or classes, in certain cases even resulting in double-counting? The answers chosen to these and other questions will have impacts upon the respective assignments (by type and customer class) of costs.[37]

Historically, the investment decisions of system planners in vertically-integrated utilities were constrained by the least total cost objective: simply, that they would make that combination of investments that were expected, given their assessments of risk, to meet expected demand for service over some reasonable planning horizon. Given the inability to store electricity and the typical obligation to serve all customers *on demand*, a utility was required to have sufficient capacity available to meet peak demand. And, if its only obligation were to meet peak demand, then it would install only the most inexpensive capacity. However, it had also to serve energy needs at other times, and it is a general characteristic of electric generation technology that as capacity costs decrease variable operating costs increase. There is, therefore, a trade-off between capacity and energy costs that system planners considered when building (or purchasing) new capacity, if they hoped to minimize total costs. Put another way, significant portions of generating capacity were purchased not to meet demand, but to serve energy, when the fuel cost savings that the more expensive generation would produce were greater than the additional costs of that capacity. These incremental capacity costs were therefore correctly viewed as energy costs.

A similar kind of analysis can inform the design of distribution systems, as it also does transmission. The question is whether there is some amount of capacity in excess of the minimum needed to meet peak demand that can cost-effectively be installed. The additional capacity larger substations, conductors, transformers will reduce energy losses; if the cost of energy saved is greater than that of the additional capacity, then the investment will be cost-effective and should be made.[38] For the purposes of cost analysis and rate design, these kinds of distribution investments are rightly treated as energy-related.[39]

b. Cost Allocation

As a general matter, distribution facilities are designed and operated to serve localized area loads. Substations are designed to meet the maximum expected load of the distribution feeders radiating from them. The feeders are designed to meet at least the maximum expected loads at the primary

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37. Sterzinger, George, The Customer Charge and Problems of Double Allocation of Costs, *Public Utilities Fortnightly*, July 2, 1981, p. 31; see also Bonbright, p. 347-348.

38. Losses vary with the square of the load. We note also that there is some minimum amount of losses that cannot be avoided, and that conductors must be sized such that the losses can be absorbed while still meeting peak load. To this degree, losses impose a capacity, rather than energy, cost.

39. An unhappy consequence of separating distribution and transmission planning from that of generation in restructured markets is the potential loss of this capacity-versus-energy consideration when making new investment. Certainly, without some sort of regulatory or legislative requirement, wires-only companies have no generation cost-savings motive to guide their planning decisions.

and secondary service levels. (As noted above, some investment in distribution capacity may be seen as reducing energy losses rather than serving peak demand.) For costing purposes it is the relevant subsystem s (substation, feeder, etc.?) peak that matters, but these peaks may or may not be coincident with each other or with the overall system s peak. There can be significant variation among them. Consequently, one practice is to allocate the costs of substations and primary feeders (which usually enjoy relatively high load factors) to customer class non-coincident peaks and to allocate secondary feeders and line transformers (with lower load factors) to the individual customer s maximum demand.[40] In addition, costs are allocated according to voltage level; customers taking service at higher levels are typically not assigned any of the costs of the lower-voltage systems that do not serve them. Costs are then allocated among customer rate groups (or classes) which requires, among other things, information and judgments about coincidence of demand when customers of different classes share facilities, as is often the case.

3. Marginal Costs

For the reasons stated earlier, it is the long-run marginal cost that is most relevant to designing rates. It can be described as the cost of that lumpy, geographically dispersed set of investments that a utility must make if demand continues to grow after the distribution system has initially been built out.

a. Demand and Energy

As already noted, the drivers of distribution costs are typically seen to be peak demand (itself driven by both customer demand and numbers of customers) and energy needs.[41] For the purposes of marginal cost analysis, it is also necessary to identify investments that are not made to serve incremental demands, but are made for some other purpose reliability, replacement of existing systems, etc. The costs of these investments are generally not included in marginal cost calculations, although, in certain cases, there may be legitimate arguments to the contrary.[42]

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40. Class non-coincident peak may not be the best measure of cost causation, since much of the system serves a variety of customer classes. Chernick, Paul, *From Here to Efficiency: Securing Demand-Management Resources*, Vol. 5, 1993, p. 81. Ideally, the object is to design rates that reflect the costs of customers contributions to the relevant peak.

41. It is worth noting that, in the short run, distribution costs vary more closely with numbers of customers than with load (except in capacity-constrained areas). For rate design, with its focus on the long run, this fact need not be a distraction. It does, however, have implications for setting revenue requirements. We address this question in Chapter V, below.

42. For instance, at the time that an investment to replace existing facilities (whose loads, let us say, are not expected to change over some extended period) is being contemplated, there are costs that can potentially be avoided. In the extreme, replacement would be unnecessary if all customers served by the facility were to decide to go offgrid. Other, more likely alternatives involve combinations of end-use efficiency, distributed generation, and smaller, more efficient distribution technologies. On these bases, the marginal or, more reasonably, the larger

(continued...)

Many of the same cost classification and assignment questions that pervade embedded cost analyses also recur in marginal cost studies, although their answers have different analytical effects. Whereas an embedded cost study strives to identify and assign total historical costs to classes of service (on the basis of any of a number of principles, including cost causation and fairness), a marginal cost analysis aims to determine the cost consequences of changes in output and thus the value of resources that must be used to serve incremental demand. Therefore, costs that are unaffected by changes in output (which describes all common and many joint costs) are excluded from the costs under examination.[43]

The study period for a marginal cost analysis is forward-looking and should be of sufficient duration to assure that all incremental demand is related to the investments forecast to serve that demand: a mismatch of timing and investment could result in significantly over- or understated costs. Those incremental costs are then discounted to their present value and annualized over the planning horizon. This has the effect of smoothing out the lumpiness of investment in relation to changes in demand.[44] This analysis relates changes in total costs to changes in demand (aggregating demand increases caused by the addition of customers with those caused by increases in demand per customer).[45] Since new customers create additional demand, this approach is not unreasonable.

Even so, some jurisdictions consider certain costs customer-related and treat them separately for the purpose of marginal cost analysis. Customer premises equipment that which is dedicated specifically to individual customers and unrelated to variations in demand (meters and perhaps service drops) are probably the only distribution costs that can be directly assigned to customers (except in the cases of customers who have additional facilities transformers, wires, even

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42. (...continued)
incremental costs of distribution can be calculated. If replacement of the particular component of the system is forecast for some time in the future, then its expected future costs would need to be discounted appropriately to yield a present-value incremental cost.

43. Because marginal cost is defined as the change in total cost arising from a change in output, all costs are, strictly speaking, included in the analysis. It just happens that most are netted out, to reveal those that are caused by the change in output. As a practical matter, however, an analyst may simply identify the costs that vary with output and exclude the rest. It is this second approach, however, that raises debates about the nature of costs and whether they should be included in the analysis. Are they joint or common? Do they vary with demand, energy, customers, or not at all? Resolving the issues usually requires large doses of judgment.

44. An alternative approach is to calculate the cost (savings) of advancing (deferring) by one year the planned stream of investments to meet the increment (decrement) in demand. This approach yields a cost that is equal to the value of the marginal investments for one year (which is the same as the economic carrying charge on those investments). This method is often used, for example, to determine an annual cost per kW of generating capacity.

45. For sizing much of the distribution system, demand is the critical factor. One customer contributing six kilowatts to peak demand has the same impact as two each contributing three kilowatts.

substations, dedicated solely to their needs).[46] Some jurisdictions also consider other facilities (line transformers, secondary level conductors) in some measure customer-related, but, to the extent that they are jointly-used to serve more than one customer, it may be difficult to establish that the addition or loss of any one customer will affect the costs of those facilities.[47] In any event, if some costs are deemed marginal customer costs (which means that they are avoidable only at the time of hook-up), it by no means follows that they should be recovered in recurring monthly fixed fees (see Section V.A.5., below).

Other approaches sometimes used to resolve the cost-causation question are the minimum system and zero intercept methods. Here, instead of using embedded cost data, the distribution system is modeled to determine the cost (in current dollars) of a hypothetical system that could serve all customers minimum demand or (in the case of zero-intercept) that could provide voltage but not power.[48] This cost would be deemed customer-related and separated from the total incremental cost previously determined, to identify the demand (or, more properly, the demand- and energy-related) portion. For the reasons stated earlier, we challenge the wisdom of these approaches.[49]

Other methodological difficulties may also arise. By definition, joint and common costs are not marginal, but occasionally they creep into the analysis, when, for example, they make use of what are in effect *average*, not *marginal*, investments and expenditures.[50] And, as with embedded costs, marginal costs are typically broken out by customer class. Here, again, the analysis requires

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46. After the meter, the customer service drop is typically seen as the least demand-related component of the system: it is sized to exceed any realistic maximum demand that the consumer might impose and it will last a very long time. However, although it is true that no investment would be made unless a customer were present, it is also true that the amount of the initial investment increases as the customer s forecasted load increases. Thus, customer investments can be seen as demand-related, as can investments farther up the system transformers, wires, and substations whose sizing depends on expected peak demand. Bouford, James D., Standardized Component Method for the Determination of Marginal and Avoided Demand Cost at the Distribution Level, Central Maine Power Company, (unpublished and undated), pp. 3-4.

47. NARUC, p. 136.

48. A handbook published by the National Economic Research Associates (NERA), which is often cited in support of the minimum system distribution cost classification, states that only the labor costs necessary to put together a minimum system and no conductor and transformer costs are customer-related. NERA, How To Quantify Marginal Costs: Topic 4, (prepared for the Electric Utility Rate Design Study, March 10, 1977), pp. 76.

49. California, for instance, has rejected the minimum system approach to marginal costs, favoring instead a method which uses the weighted average of the costs of continuing to serve existing customers and the costs of initiating service to new customers.

50. See, *e.g.*, NARUC, p. 127, which notes that, because calculating marginal distribution and customer costs can be difficult, it is still common for analysts to use some variation of a projected embedded methodology for these elements, rather than a strictly marginal approach. This tack is justified by the sweeping assumption that projected embedded distribution costs are a reasonable approximation of marginal costs. The assumption is, however, contestable. FERC accounting requirements, which form the basis of most embedded cost analyses, include in distribution certain, and often substantial, administrative and general (A&G) costs (Accounts 920 to 935). A&G is not caused by the provision of distribution service.

reasonable assessments of the coincidence of demand, when customers of different classes share facilities.

Another dimension of cost, and perhaps most revealing, is the geographic. There are several aspects to it. First are the topographical and meteorological characteristics of the area over which the distribution system is laid. Elevations, plant life, weather, soil conditions, and so on all have effects on costs. So too demography, which is captured partly by demand and numbers of customers, but also affecting costs is the density of customers in an area (sometimes expressed as customers per mile). These influences combine in assorted ways, with themselves but also with changes in load and rates of investment, to produce variations in costs from one area of the distribution system to another. It is not unusual to see marginal distribution costs varying greatly from one place to another, even when the distances between the different areas is comparatively short. Table 1 describes the significant variations in costs for incremental distribution investments in a large mid-western utility.

	Average System Marginal Costs per kW	Area Specific High-Low Marginal Costs per kW	Annual Cost @ 15% Capital Cost Recovery Factor	Average Marginal Costs per kWh @ 20% Load Factor[51]	High Marginal Costs per kWh @ 20% Load Factor
Transmission	$230	NA	$34	$0.02	$0.04
Distribution Lines	$960	$1,575 - 0	$140	$0.08	$0.135
Distribution Transformers	$60	$300 - 0	$9	$0.0015	$0.025
Total	$1,250	$1,875 - 0	$183	$.1015	$0.20

Table 1

Differentiating marginal costs along these lines will tell a utility where investment (whether in new facilities, end-use efficiency, or distributed generation) is needed and what the minimum value of that investment is. Whether for rate-making purposes this information is useful should distribution rates be geographically deaveraged ? is a tougher question. We take it up in Chapter V, below.

51. This is estimated load factor for the incremental distribution investment alone, not for the entire distribution system altogether. Incremental investment to meet peak needs typically manifests low load factors; 20% is a conservatively high estimate.

4. Key Concern in Determining Costs: Follow the Money

The occasionally technical and arcane matters taken up in embedded and marginal cost studies are, of course, important, but it is perhaps more important to bear in mind that, in rate design cases, what is fundamentally at issue is who should bear what revenue responsibilities. In the interplay between cost allocation and rate structures, the debate over money is played out. First is the question of what costs will be categorized as *distribution*, as opposed to transmission or generation in the case of vertically integrated utilities, or perhaps competitive services in other instances. This is no small matter, since significant portions of a firm s joint and common costs (typically, administrative and general) are often attributed to the distribution business, even though there is no causal relationship between them. Then there is the designation of a cost as either *customer* or *demand*, which will affect both how costs are divvied up among classes and who within each class will pay them (*i.e.*, both inter- and intra-class allocations). While there is a touch of cynicism in the observation that there is no shortage of academic arguments to justify particular outcomes, it is nevertheless largely true. Always be aware of the revenue effects of a particular rate structure. Who benefits, who loses? Fixed prices, because they recover revenues by customer rather than by usage, invariably shift a larger proportion of the system s costs to the lower-volume consumers (residential and small business). The positions that interested parties take with respect to rate design should, in part, be considered in light of their impacts on class revenue burdens and on the profitability of the utility. Here the admonition to be practical cannot be stressed enough. Seemingly small changes in a rate design can have very significant consequences for different customers.[52]

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52. Consider the following example (the hypothetical rates cover distribution services only). A residential customer using 500 kWh per month and paying $0.05 per delivered kWh and a monthly customer charge of $5.00 sees a monthly bill of $30. If rates were revised so that residential customers paid a fixed charge of $20 per month plus $0.02 cents per kWh, a customer using 500 kWh would receive the same total bill of $30. For this customer, the rate redesign is revenue neutral. However, for a customer using 300 kWh/month, the monthly bill under the original rate structure is $20 and, under the new rates, is $26 a 30% increase, even though there is no change in usage. For a customer using 700 kWh/month, the original bill is $40 and the revised bill is $34, a 15% reduction.

Consider again the customer using 500 kWh/month. If, under the original rate structure, she reduced her electricity use to 300 kWh per month (whether by load reduction, demand-side management, the installation of a rooftop solar electric system, or some combination of these options), she would reduce her bill by $10. However, under the revised rate structure, she would only reduce her bill by $4.

Whether the impacts of a rate design change are immediate and substantial depends, of course, on a variety of factors. The extent to which class cost allocations are altered will determine whether particular customers total bills (all else being equal) will go up or down. Even those changes that are meant to be class revenue-neutral will affect individual customer bills: as already noted, shifts from usage-based to fixed charges recover disproportionately higher revenues from low-volume users and then, more subtly, there are the effects (both positive and negative) on bills and revenues that flow from demand responses to the changes in rate structure.

5. Usage Sensitivity: What s Avoidable?

a. Peak Demand and Sizing the Wires

Distribution investment is made to serve an expected level of demand over a period of time, often determined by the useful life of the equipment. To the extent that, once a network (or component of it) is built, there is excess capacity in it, the marginal cost of using that excess capacity will be quite low (possibly very close to zero, insofar as there is little in the way of variable cost). It is this phenomenon that the short-run marginal cost of delivering a kilowatt-hour is zero that underlies the argument that there should be no per-kilowatt-hour charge for doing so.

As peak load grows, it will press up against the capacity limits of the system. At the time of constraint, the marginal cost of delivering a kilowatt-hour is, in fact, significantly greater than zero: at a minimum it is the cost of the additional investment needed to carry that marginal kilowatt-hour to end-users.[53] At that point, presumably, the new investment is made, and it is sized to minimize the total costs of delivery over the long term and thus, as before, there is suddenly excess capacity causing once again the marginal cost to fall to almost zero.

This non-linearity of investment with demand is a characteristic of much of the distribution system, the closer one gets to the end-user. To the extent that there are not an infinite number of equipment sizes to enable precise matching of investment and demand, excess capacity is almost necessarily built into the system, from substation facilities to feeders, transformers, customer service drops. But this has less to do with the finitude of equipment options than it does with the least total cost planning objective (optimizing total construction and operations costs over the investment horizon). The analytical key is to view the system over a time period long enough to smooth out the lumpiness of investment in relation to changes in demand.[54]

What emerges from such analysis is the recognition that there are costs associated with load growth, savings generated by reductions in load growth, and savings flowing from reductions in existing load. These values, not necessarily equal to each other, reflect in part the fungibility of significant portions of the system (*e.g.*, substations and feeders). Capacity unused, or freed up, by one customer can be used by others.[55]

Sometimes cited as an interesting and somewhat anomalous characteristic of some distribution investment, specifically that closest to customers (such as the service drop) is its manifestation of positive marginal costs with load growth but seemingly zero marginal (or avoided) costs with load reductions. This is because, so the argument goes, load reduction makes no capacity available for

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53. And it may indeed be greater, if the value to consumers of that marginal delivery is greater than the cost of the additional investment. See Appendix A.

54. The justification for analyzing costs over the long run, and for setting prices on that basis, is discussed in Appendix A.

55. Chernick, Vol. 5, p. 68.

alternative uses, that did not already exist. This not so, however, because the inability to re-use capacity does not mean that there is no value to not using it. At the very least, future replacement costs can be deferred and the equipment installed on replacement can be down-sized, thereby reducing costs for all users.[56]

The differences in costs and savings associated with load growth, reduced growth rates, and reductions in existing load may leave some room for debate about their implications for rate design; but, given the declining-cost nature of the distribution system, these differences will probably have less of an impact than will the need to recover an embedded revenue requirement. The critical point here is that distribution costs vary primarily with load over the longer term.

b. Energy: The Costs of Throughput

As discussed earlier, to the extent that distribution investments are made to offset energy needs, there are necessarily costs associated with avoiding those investments. Losses, heat build-up, frequency of overloads, etc., are aspects of energy use that affect distribution investment and operations; thus there are marginal energy costs in distribution. Whether avoiding those costs make alternatives to distribution cost-effective is an empirical question. But, for purposes of rate design, it is sufficient to say that these marginal costs should be understood and appropriately reflected in rates. They are unquestionably volumetric in nature.

B. Conclusion: The Costs of Distribution Services

Cost studies are intended to provide useful information about the causes and magnitudes of costs, to inform a rate design process that is guided by the general principle that those who cause a cost should pay that cost. However, the usual drivers ascribed to distribution costs (both embedded and marginal) describe only part of the story, and the force-fitting of square costs into round drivers can lead to rate designs that will not best promote long-run dynamic efficiency. This is especially true of embedded cost studies, in which a central objective is to assign or allocate costs to particular services or classes of customers, even though many of those costs cannot be assigned unequivocally according to the principle of causation. By their very nature, many utility costs are joint or common to two or more services; consequently there can be no unshakeable assertion that any one service in fact caused a cost and, therefore, that a particular rate element should recover it. And marginal cost studies often suffer from this deficiency as well. This means that regulators should be very careful before relying upon what are essentially (though not necessarily

56. *Id.*, pp. 68-71. Also affected is the magnitude and cost of over-sizing equipment in order to serve forecast demand. See also NERA, pp. 17-18.

unreasonable) arbitrary cost assignments for the purposes of designing rates.[57] Too great a dependence on cost studies is to be captured by their underlying assumptions and methodological flaws. Utilities and commissions should be cautious before adopting a particular method on the basis of what may be a superficial appeal. More important, however, is the concern that a costing method, once adopted, becomes the predominant and unchallenged determinant of rate design.

Marginal cost analysis demonstrates that distribution costs vary with load in the long run. This has important implications for rate design. Embedded cost analysis, though it relies on *a priori* assumptions about causes (and allocations therefore) of historical costs, is useful in rate design at least insofar as it informs the process of reconciling marginal cost-based rates with revenue requirements.[58] We recognize that there are honest disagreements over approaches to both kinds of analysis.[59] But what is important here is for regulators to be aware of the fundamental relationships between costs and demand for electric service, in order to devise rates that best serve the objectives they seek.

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57. To ensure that [embedded distribution plant] costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst s evaluation of how the costs in these accounts were incurred. NARUC, p. 89. Interestingly, the manual, in a table on page 34, acknowledges that there is an energy-related component to embedded distribution costs, but is otherwise silent on the question.

58. Bonbright, pp. 366-367. Bonbright expresses some skepticism as to the usefulness of most embedded cost studies for rate design, on the ground that they often ignore the relationship between cost causation and apportionment. One may suspect that the choice of [allocation] formula depends, not on principles of cost imputation but rather on types of apportionment which tend to justify whatever rate structure is advocated for non-cost reasons. *Id.*, p. 368.

59. See, *e.g.*, Chernick, Vol. 5, pp. 58-83, and NARUC, pp. 86-104 and 137-146.

Class Cost of Service Study
Summary of Results
12-CP Utilizing 100% Demand Classification of Distribution Plant

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)
	Rate Base							
1	Plant in Service	$ 4,501,131,701	$ 2,026,648,998	$ 411,173,624	$ 190,001,422	$ 6,440,255	$ 226,406	$ 408,753
2	Accumulated Reserve	(2,827,661,271)	(1,281,725,077)	(254,863,809)	(118,991,841)	(3,959,215)	(153,781)	(262,406)
3	Other Rate Base Items	291,522,000	127,746,403	27,370,439	11,841,684	401,002	16,186	29,128
4	Total Rate Base	$ 1,964,992,430	$ 872,670,324	$ 183,680,255	$ 82,851,264	$ 2,882,043	$ 88,811	$ 175,475
	Revenues at Current Rates							
5	Retail Sales	$ 1,177,074,009	$ 465,528,940	$ 136,179,718	$ 45,434,316	$ 1,621,358	$ 44,356	$ 115,705
6	Other Revenue	20,161,991	12,379,429	1,609,906	530,797	16,603	935	1,677
7	Sales for Resale	6,324,121	2,672,653	570,967	273,060	10,016	194	485
8	Total Revenues	$ 1,203,560,121	$ 480,581,022	$ 138,360,591	$ 46,238,172	$ 1,647,977	$ 45,485	$ 117,867
	Expenses at Current Rates							
9	Operations & Maintenance Expenses	$ 396,494,451	$ 183,197,792	$ 37,108,494	$ 15,763,603	$ 537,163	$ 22,882	$ 38,630
10	Depreciation Expense	200,925,821	89,532,918	19,184,809	8,555,757	298,740	9,865	18,563
11	Amortization Expense	7,656,489	3,415,063	698,461	324,156	11,130	363	679
12	Taxes Other Than Income Taxes	45,114,501	20,398,836	4,212,243	1,863,136	63,413	2,384	4,237
13	Fuel Expenses	435,543,947	159,315,107	39,754,620	18,234,219	627,592	19,068	46,665
14	Non-FAC Trackable Fuel Expenses	7,413,035	2,813,880	674,845	312,712	10,939	301	740
15	Income Taxes	14,500,133	(3,752,968)	11,277,034	(692,698)	(2,381)	(4,743)	729
16	Total Expenses - Current	$ 1,107,648,377	$ 454,920,629	$ 112,910,506	$ 44,360,885	$ 1,546,596	$ 50,120	$ 110,243
17	Current Operating Income	95,911,744	25,660,393	25,450,085	1,877,287	101,381	(4,635)	7,624
18	Return at Current Rates	4.88%	2.94%	13.86%	2.27%	3.52%	-5.22%	4.35%
19	Index Rate of Return	1.00	0.60	2.84	0.46	0.72	-1.07	0.89
	Current Rate Rev	$ 1,177,074,009	$ 465,528,940	$ 136,179,718	$ 45,434,316	$ 1,621,358	$ 44,356	$ 115,705
	IPL Proposed Increase	67,249,670	36,606,231	1,357,032	3,315,652	103,931	3,557	7,289
	IPL Rate Rev @ Proposed Rates	$ 1,244,323,678	$ 502,135,171	$ 137,536,750	$ 48,749,968	$ 1,725,289	$ 47,913	$ 122,994
	Allocated Sales for Resale	6,324,121	2,672,653	570,967	273,060	10,016	194	485
	Allocated other Rev @ Current Rates	20,161,991	12,379,429	1,609,906	530,797	16,603	935	1,677
	Allocated Additional Connect Fee Rev	1,710,968	1,654,245	47,641	4,113	28	96	92
	Allocated Migration Impact	(1,186,513)	(469,788)	(134,013)	(43,227)	(1,538)	(40)	(107)
	Subtotal	27,010,567	16,236,539	2,094,501	764,742	25,109	1,185	2,147
	IPL total Proposed Rev	$ 1,271,334,245.41	$ 518,371,709.86	$ 139,631,250.21	$ 49,514,709.50	$ 1,750,397.58	$ 49,098.53	$ 125,140.82
Less:								
	O&M @ Current Rates	$ 396,494,451	$ 183,197,792	$ 37,108,494	$ 15,763,603	$ 537,163	$ 22,882	$ 38,630
	Depreciation	200,925,821	89,532,918	19,184,809	8,555,757	298,740	9,865	18,563
	Amortization	7,656,489	3,415,063	698,461	324,156	11,130	363	679
	Taxes Oter than Income @ Current Rates	45,114,501	20,398,836	4,212,243	1,863,136	63,413	2,384	4,237
	Fuel	435,543,947	159,315,107	39,754,620	18,234,219	627,592	19,068	46,665
	Non FAC Fuel	7,413,035	2,813,880	674,845	312,712	10,939	301	740
	Subtotal	1,093,148,244	458,673,597	101,633,472	45,053,582	1,548,977	54,864	109,514
	Bad Debt increase @ Proposed Rates	264,000	239,478	19,130	1,651	11	39	37
	PUC Fee Increase @ Proposed Rates	80,000	36,044	7,317	114	4	4	7
	Other Tax Increase @ Proposed Rates	945,000	422,577	88,351	39,459	1,366	45	86
	Total Expense Before Tax @ Proposed Rates	$ 1,094,437,244	$ 459,371,695	$ 101,748,270	$ 45,098,064	$ 1,550,470	$ 54,951	$ 109,644
	Earnings Before Interest and Income Tax	$ 176,897,001	$ 59,000,015	$ 37,882,980	$ 4,416,645	$ 199,927	$ (5,852)	$ 15,497
	Interest	$ 71,820,000	$ 31,895,890	$ 6,713,469	$ 3,028,194	$ 105,338	$ 3,246	$ 6,414
	Taxable Income	$ 105,077,001	$ 27,104,124	$ 31,169,511	$ 1,388,452	$ 94,589	$ (9,098)	$ 9,083
	Income Tax	$ 40,730,000	$ 10,506,114	$ 12,081,941	$ 538,192	$ 36,665	$ (3,527)	$ 3,521
	Net Operating Income @ Proposed Rates	$ 136,167,001.44	$ 48,493,900.29	$ 25,801,038.41	$ 3,878,453.01	$ 163,262.46	$ (2,325.68)	$ 11,976.08
	Rate Base	$ 1,964,992,430	$ 872,670,324	$ 183,680,255	$ 82,851,264	$ 2,882,043	$ 88,811	$ 175,475
	ROR @ IPL Proposed Rates (Before Correction for Migration)	6.93%	5.56%	14.05%	4.68%	5.66%	-2.62%	6.82%
	Eliminate Migration Adjustment	$ 1,186,513.00	$ 469,787.59	$ 134,012.89	$ 43,227.13	$ 1,537.83	$ 40.31	$ 107.33
	Tax Effect of Migration Adjustment	459,916.76	182,099.30	51,946.15	16,755.72	596.09	15.63	41.60
	Net Migration Effect	726,596	287,688	82,067	26,471	942	25	66
	Corrected Net Operating Income @ IPL Proposed Rates	$ 136,893,598	$ 48,781,589	$ 25,883,105	$ 3,904,924	$ 164,204	$ (2,301)	$ 12,042
	Corrected ROR @ IPL Proposed Rates	6.97%	5.59%	14.09%	4.71%	5.70%	-2.59%	6.86%
	Corrected Indexed ROR @ IPL Proposed Rates	100%	80%	202%	68%	82%	-37%	99%

Class Cost of Service Study
Summary of Results
12-CP Utilizing 100% Demand Classification of Distribution Plant

Line No.	Description	System Total	Secondary Large SL	Primary PL	Process Heating PH	HLF - Primary HL1	HLF - Sub-Tran HL2	HLF -Tran HL3	Automatic Protective Lighting APL	Municipal Lighting MU1
	(A)	(B)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
	Rate Base									
1	Plant in Service	$ 4,501,131,701	$ 973,927,314	$ 322,942,998	$ 23,222,952	$ 307,254,273	$ 47,055,916	$ 63,278,066	$ 51,397,640	$ 77,153,081
2	Accumulated Reserve	(2,827,661,271)	(596,144,297)	(192,558,311)	(14,332,060)	(182,750,571)	(26,199,299)	(35,133,235)	(46,926,215)	(73,661,156)
3	Other Rate Base Items	291,522,000	64,690,986	21,100,226	1,420,645	20,685,930	3,348,805	4,724,694	4,562,945	3,382,929
4	Total Rate Base	$ 1,964,992,430	$ 442,874,004	$ 151,484,913	$ 10,311,537	$ 145,189,633	$ 24,205,422	$ 32,869,525	$ 9,034,370	$ 6,874,855
	Revenues at Current Rates									
5	Retail Sales	$ 1,177,074,009	$ 287,702,173	$ 89,530,832	$ 5,428,692	$ 91,369,462	$ 15,102,253	$ 22,324,851	$ 6,428,908	$ 10,262,445
6	Other Revenue	20,161,991	2,889,331	894,466	63,687	891,525	124,465	159,458	226,352	373,361
7	Sales for Resale	6,324,121	1,531,173	520,325	34,076	487,193	84,752	124,538	5,569	9,119
8	Total Revenues	$ 1,203,560,121	$ 292,122,678	$ 90,945,623	$ 5,526,455	$ 92,748,181	$ 15,311,470	$ 22,608,847	$ 6,660,829	$ 10,644,925
	Expenses at Current Rates									
9	Operations & Maintenance Expenses	$ 396,494,451	$ 85,066,438	$ 27,115,975	$ 1,885,416	$ 25,684,850	$ 4,160,433	$ 5,833,596	$ 5,719,693	$ 4,359,484
10	Depreciation Expense	200,925,821	45,706,999	15,143,399	1,037,166	14,261,177	2,352,079	3,340,945	897,225	586,179
11	Amortization Expense	7,656,489	1,687,011	561,503	39,743	532,714	83,530	114,336	75,612	112,187
12	Taxes Other Than Income Taxes	45,114,501	9,797,196	3,226,011	227,068	3,071,725	490,113	664,736	568,235	525,168
13	Fuel Expenses	435,543,947	112,801,182	38,900,834	2,183,050	42,179,384	7,158,429	10,891,705	1,465,055	1,967,038
14	Non-FAC Trackable Fuel Expenses	7,413,035	1,889,520	649,426	37,833	682,244	116,375	175,811	20,465	27,945
15	Income Taxes	14,500,133	7,136,883	(70,736)	(97,955)	386,791	24,727	145,161	(907,636)	1,057,925
16	Total Expenses - Current	$ 1,107,648,377	$ 264,085,229	$ 85,526,413	$ 5,312,321	$ 86,798,887	$ 14,385,685	$ 21,166,291	$ 7,838,648	$ 8,635,925
17	Current Operating Income	95,911,744	28,037,448	5,419,211	214,134	5,949,294	925,785	1,442,556	(1,177,819)	2,009,000
18	Return at Current Rates	4.88%	6.33%	3.58%	2.08%	4.10%	3.82%	4.39%	-13.04%	29.22%
19	Index Rate of Return	1.00	1.30	0.73	0.43	0.84	0.78	0.90	-2.67	5.99
	Current Rate Rev	$ 1,177,074,009	$ 287,702,173	$ 89,530,832	$ 5,428,692	$ 91,369,462	$ 15,102,253	$ 22,324,851	$ 6,428,908	$ 10,262,445
	IPL Proposed Increase	67,249,670	12,131,540	5,561,797	413,076	5,111,944	928,143	1,202,697	533,394	-26,613
	IPL Rate Rev @ Proposed Rates	$ 1,244,323,678	$ 299,833,713	$ 95,092,629	$ 5,841,768	$ 96,481,406	$ 16,030,396	$ 23,527,548	$ 6,962,302	$ 10,235,832
	Allocated Sales for Resale	6,324,121	1,531,173	520,325	34,076	487,193	84,752	124,538	5,569	9,119
	Allocated other Rev @ Current Rates	20,161,991	2,889,331	894,466	63,687	891,525	124,465	159,458	226,352	373,361
	Allocated Additional Connect Fee Rev	1,710,968	4,540	146	32	27	5	3	-	-
	Allocated Migration Impact	(1,186,513)	(294,365)	(91,370)	(5,519)	(90,595)	(15,046)	(22,106)	(6,694)	(12,105)
	Subtotal	27,010,567	4,130,680	1,323,567	92,276	1,288,150	194,175	261,893	225,227	370,376
	IPL total Proposed Rev	$ 1,271,334,245.41	$ 303,964,393.44	$ 96,416,195.84	$ 5,934,044.44	$ 97,769,556.02	$ 16,224,571.57	$ 23,789,440.96	$ 7,187,529.04	$ 10,606,207.59
Less:										
	O&M @ Current Rates	$ 396,494,451	$ 85,066,438	$ 27,115,975	$ 1,885,416	$ 25,684,850	$ 4,160,433	$ 5,833,596	$ 5,719,693	$ 4,359,484
	Depreciation	200,925,821	45,706,999	15,143,399	1,037,166	14,261,177	2,352,079	3,340,945	897,225	586,179
	Amortization	7,656,489	1,687,011	561,503	39,743	532,714	83,530	114,336	75,612	112,187
	Taxes Oter than Income @ Current Rates	45,114,501	9,797,196	3,226,011	227,068	3,071,725	490,113	664,736	568,235	525,168
	Fuel	435,543,947	112,801,182	38,900,834	2,183,050	42,179,384	7,158,429	10,891,705	1,465,055	1,967,038
	Non FAC Fuel	7,413,035	1,889,520	649,426	37,833	682,244	116,375	175,811	20,465	27,945
	Subtotal	1,093,148,244	256,948,346	85,597,148	5,410,276	86,412,095	14,360,958	21,021,130	8,746,284	7,578,000
	Bad Debt increase @ Proposed Rates	264,000	3,491	112	25	21	4	2	0	0
	PUC Fee Increase @ Proposed Rates	80,000	17,296	5,727	412	5,448	835	1,123	937	1,364
	Other Tax Increase @ Proposed Rates	945,000	211,164	71,463	4,880	68,371	11,350	15,486	5,904	4,496
	Total Expense Before Tax @ Proposed Rates	$ 1,094,437,244	$ 257,180,297	$ 85,674,450	$ 5,415,593	$ 86,485,935	$ 14,373,147	$ 21,037,742	$ 8,753,125	$ 7,583,860
	Earnings Before Interest and Income Tax	$ 176,897,001	$ 46,784,096	$ 10,741,745	$ 518,451	$ 11,283,621	$ 1,851,425	$ 2,751,699	$ (1,565,596)	$ 3,022,348
	Interest	$ 71,820,000	$ 16,179,628	$ 5,536,737	$ 376,884	$ 5,306,646	$ 884,702	$ 1,201,373	$ 330,204	$ 251,274
	Taxable Income	$ 105,077,001	$ 30,604,468	$ 5,205,008	$ 141,567	$ 5,976,975	$ 966,722	$ 1,550,326	$ (1,895,800)	$ 2,771,074
	Income Tax	$ 40,730,000	$ 11,862,919	$ 2,017,568	$ 54,874	$ 2,316,798	$ 374,721	$ 600,938	$ (734,851)	$ 1,074,125
	Net Operating Income @ Proposed Rates	$ 136,167,001.44	$ 34,921,176.97	$ 8,724,177.45	$ 463,577.10	$ 8,966,822.84	$ 1,476,703.30	$ 2,150,761.06	$ (830,744.88)	$ 1,948,223.01
	Rate Base	$ 1,964,992,430	$ 442,874,004	$ 151,484,913	$ 10,311,537	$ 145,189,633	$ 24,205,422	$ 32,869,525	$ 9,034,370	$ 6,874,855
	ROR @ IPL Proposed Rates (Before Correction for Migration)	6.93%	7.89%	5.76%	4.50%	6.18%	6.10%	6.54%	-9.20%	28.34%
	Eliminate Migration Adjustment	$ 1,186,513.00	$ 294,364.79	$ 91,370.29	$ 5,518.78	$ 90,595.29	$ 15,046.48	$ 22,106.06	$ 6,693.59	$ 12,104.64
	Tax Effect of Migration Adjustment	459,916.76	114,101.83	35,417.00	2,139.19	35,116.59	5,832.33	8,568.76	2,594.57	4,692.01
	Net Migration Effect	726,596	180,263	55,953	3,380	55,479	9,214	13,537	4,099	7,413
	Corrected Net Operating Income @ IPL Proposed Rates	$ 136,893,598	$ 35,101,440	$ 8,780,131	$ 466,957	$ 9,022,302	$ 1,485,917	$ 2,164,298	$ (826,646)	$ 1,955,636
	Corrected ROR @ IPL Proposed Rates	6.97%	7.93%	5.80%	4.53%	6.21%	6.14%	6.58%	-9.15%	28.45%
	Corrected Indexed ROR @ IPL Proposed Rates	100%	114%	83%	65%	89%	88%	95%	-131%	408%

Class Cost of Service Study
Summary of Results
Peak & Average Utilizing 100% Demand Classification of Distribution Plant

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)
	Rate Base							
1	Plant in Service	$ 4,501,131,701	$ 2,012,163,021	$ 411,476,543	$ 182,632,746	$ 6,029,287	$ 228,866	$ 407,818
2	Accumulated Reserve	(2,827,661,271)	(1,273,784,217)	(255,029,861)	(114,952,513)	(3,733,932)	(155,130)	(261,893)
3	Other Rate Base Items	291,522,000	126,981,481	27,386,434	11,452,586	379,301	16,316	29,078
4	Total Rate Base	$ 1,964,992,430	$ 865,360,286	$ 183,833,116	$ 79,132,820	$ 2,674,656	$ 90,052	$ 175,003
	Revenues at Current Rates							
5	Retail Sales	$ 1,177,074,009	$ 465,528,940	$ 136,179,718	$ 45,434,316	$ 1,621,358	$ 44,356	$ 115,705
6	Other Revenue	20,161,991	12,379,429	1,609,906	530,797	16,603	935	1,677
7	Sales for Resale	6,324,121	2,640,296	571,643	256,601	9,098	200	483
8	Total Revenues	$ 1,203,560,121	$ 480,548,665	$ 138,361,267	$ 46,221,713	$ 1,647,059	$ 45,491	$ 117,865
	Expenses at Current Rates							
9	Operations & Maintenance Expenses	$ 396,494,451	$ 182,053,717	$ 37,132,418	$ 15,181,639	$ 504,706	$ 23,077	$ 38,556
10	Depreciation Expense	200,925,821	88,706,267	19,202,095	8,135,258	275,288	10,005	18,510
11	Amortization Expense	7,656,489	3,387,908	699,029	310,342	10,360	367	678
12	Taxes Other Than Income Taxes	45,114,501	20,249,137	4,215,373	1,786,988	59,166	2,409	4,228
13	Fuel Expenses	435,543,947	159,315,107	39,754,620	18,234,219	627,592	19,068	46,665
14	Non-FAC Trackable Fuel Expenses	7,413,035	2,813,880	674,845	312,712	10,939	301	740
15	Income Taxes	14,500,133	(2,857,827)	11,258,315	(237,361)	23,014	(4,895)	787
16	Total Expenses - Current	$ 1,107,648,377	$ 453,668,190	$ 112,936,696	$ 43,723,798	$ 1,511,064	$ 50,333	$ 110,162
17	Current Operating Income	95,911,744	26,880,475	25,424,571	2,497,915	135,995	(4,842)	7,703
18	Return at Current Rates	4.88%	3.11%	13.83%	3.16%	5.08%	-5.38%	4.40%
19	Index Rate of Return	1.00	0.64	2.83	0.65	1.04	-1.10	0.90
	Current Rate Rev	$ 1,177,074,009	$ 465,528,940	$ 136,179,718	$ 45,434,316	$ 1,621,358	$ 44,356	$ 115,705
	IPL Proposed Increase	67,249,670	36,606,231	1,357,032	3,315,652	103,931	3,557	7,289
	IPL Rate Rev @ Proposed Rates	$ 1,244,323,678	$ 502,135,171	$ 137,536,750	$ 48,749,968	$ 1,725,289	$ 47,913	$ 122,994
	Allocated Sales for Resale	6,324,121	2,640,296	571,643	256,601	9,098	200	483
	Allocated other Rev @ Current Rates	20,161,991	12,379,429	1,609,906	530,797	16,603	935	1,677
	Allocated Additional Connect Fee Rev	1,710,968	1,654,245	47,641	4,113	28	96	92
	Allocated Migration Impact	(1,186,513)	(469,788)	(134,013)	(43,227)	(1,538)	(40)	(107)
	Subtotal	27,010,567	16,204,183	2,095,177	748,283	24,191	1,191	2,145
	IPL total Proposed Rev	$ 1,271,334,245.41	$ 518,339,353.31	$ 139,631,926.83	$ 49,498,250.49	$ 1,749,479.62	$ 49,104.03	$ 125,138.73
Less:								
	O&M @ Current Rates	$ 396,494,451	$ 182,053,717	$ 37,132,418	$ 15,181,639	$ 504,706	$ 23,077	$ 38,556
	Depreciation	200,925,821	88,706,267	19,202,095	8,135,258	275,288	10,005	18,510
	Amortization	7,656,489	3,387,908	699,029	310,342	10,360	367	678
	Taxes Oter than Income @ Current Rates	45,114,501	20,249,137	4,215,373	1,786,988	59,166	2,409	4,228
	Fuel	435,543,947	159,315,107	39,754,620	18,234,219	627,592	19,068	46,665
	Non FAC Fuel	7,413,035	2,813,880	674,845	312,712	10,939	301	740
	Subtotal	1,093,148,244	456,526,017	101,678,380	43,961,159	1,488,050	55,228	109,375
	Bad Debt increase @ Proposed Rates	264,000	239,478	19,130	1,651	11	39	37
	PUC Fee Increase @ Proposed Rates	80,000	35,786	7,323	3,240	107	4	7
	Other Tax Increase @ Proposed Rates	945,000	419,194	88,422	37,738	1,272	45	85
	Total Expense Before Tax @ Proposed Rates	$ 1,094,437,244	$ 457,220,475	$ 101,793,255	$ 44,003,789	$ 1,489,440	$ 55,316	$ 109,505
	Earnings Before Interest and Income Tax	$ 176,897,001	$ 61,118,878	$ 37,838,672	$ 5,494,461	$ 260,040	$ (6,212)	$ 15,634
	Interest	$ 71,820,000	$ 31,628,710	$ 6,719,056	$ 2,892,285	$ 97,758	$ 3,291	$ 6,396
	Taxable Income	$ 105,077,001	$ 29,490,168	$ 31,119,616	$ 2,602,176	$ 162,281	$ (9,504)	$ 9,238
	Income Tax	$ 40,730,000	$ 11,430,994	$ 12,062,601	$ 1,008,657	$ 62,904	$ (3,684)	$ 3,581
	Net Operating Income @ Proposed Rates	$ 136,167,001.44	$ 49,687,884.23	$ 25,776,070.81	$ 4,485,804.59	$ 197,135.89	$ (2,528.46)	$ 12,053.20
	Rate Base	$ 1,964,992,430	$ 865,360,286	$ 183,833,116	$ 79,132,820	$ 2,674,656	$ 90,052	$ 175,003
	ROR @ IPL Proposed Rates (Before Correction for Migration)	6.93%	5.74%	14.02%	5.67%	7.37%	-2.81%	6.89%
	Eliminate Migration Adjustment	$ 1,186,513.00	$ 469,787.59	$ 134,012.89	$ 43,227.13	$ 1,537.83	$ 40.31	$ 107.33
	Tax Effect of Migration Adjustment	459,916.76	182,099.30	51,946.15	16,755.72	596.09	15.63	41.60
	Net Migration Effect	726,596	287,688	82,067	26,471	942	25	66
	Corrected Net Operating Income @ IPL Proposed Rates	$ 136,893,598	$ 49,975,573	$ 25,858,138	$ 4,512,276	$ 198,078	$ (2,504)	$ 12,119
	Corrected ROR @ IPL Proposed Rates	6.97%	5.78%	14.07%	5.70%	7.41%	-2.78%	6.92%
	Corrected Indexed ROR @ IPL Proposed Rates	100%	83%	202%	82%	106%	-40%	99%

Class Cost of Service Study
Summary of Results
Peak & Average Utilizing 100% Demand Classification of Distribution Plant

Line No.	Description (A)	System Total (B)	Secondary Large SL (I)	Primary PL (J)	Process Heating PH (K)	HLF - Primary HL1 (L)	HLF - Sub-Tran HL2 (M)	HLF -Tran HL3 (N)	Automatic Protective Lighting APL (O)	Municipal Lighting MU1 (P)
	Rate Base									
1	Plant in Service	$ 4,501,131,701	$ 970,104,127	$ 322,594,314	$ 21,679,677	$ 322,769,454	$ 50,235,167	$ 66,467,082	$ 54,015,075	$ 80,328,525
2	Accumulated Reserve	(2,827,661,271)	(594,048,518)	(192,367,171)	(13,486,074)	(191,255,614)	(27,942,087)	(36,881,376)	(48,361,029)	(75,401,857)
3	Other Rate Base Items	291,522,000	64,689,106	21,081,814	1,339,153	21,505,197	3,516,683	4,893,088	4,701,156	3,550,606
4	Total Rate Base	$ 1,964,992,430	$ 440,744,714	$ 151,308,957	$ 9,532,756	$ 153,019,036	$ 25,809,763	$ 34,478,794	$ 10,355,202	$ 8,477,275
	Revenues at Current Rates									
5	Retail Sales	$ 1,177,074,009	$ 287,702,173	$ 89,530,832	$ 5,428,692	$ 91,369,462	$ 15,102,253	$ 22,324,851	$ 6,428,908	$ 10,262,445
6	Other Revenue	20,161,991	2,889,331	894,466	63,687	891,525	124,465	159,458	226,352	373,361
7	Sales for Resale	6,324,121	1,522,634	519,546	30,629	521,849	91,853	131,661	11,415	16,212
8	Total Revenues	$ 1,203,560,121	$ 292,114,138	$ 90,944,844	$ 5,523,008	$ 92,782,836	$ 15,318,571	$ 22,615,970	$ 6,666,675	$ 10,652,018
	Expenses at Current Rates									
9	Operations & Maintenance Expenses	$ 396,494,451	$ 84,764,490	$ 27,088,437	$ 1,763,531	$ 26,910,210	$ 4,411,524	$ 6,085,459	$ 5,926,413	$ 4,610,275
10	Depreciation Expense	200,925,821	45,488,827	15,123,501	949,098	15,146,561	2,533,505	3,522,928	1,046,590	767,388
11	Amortization Expense	7,656,489	1,679,844	560,850	36,850	561,799	89,489	120,314	80,519	118,140
12	Taxes Other Than Income Taxes	45,114,501	9,757,687	3,222,408	211,120	3,232,059	522,967	697,691	595,283	557,983
13	Fuel Expenses	435,543,947	112,801,182	38,900,834	2,183,050	42,179,384	7,158,429	10,891,705	1,465,055	1,967,038
14	Non-FAC Trackable Fuel Expenses	7,413,035	1,889,520	649,426	37,833	682,244	116,375	175,811	20,465	27,945
15	Income Taxes	14,500,133	7,373,132	(49,189)	(2,590)	(571,948)	(171,731)	(51,900)	(1,069,377)	861,703
16	Total Expenses - Current	$ 1,107,648,377	$ 263,754,681	$ 85,496,266	$ 5,178,892	$ 88,140,309	$ 14,660,559	$ 21,442,009	$ 8,064,948	$ 8,910,470
17	Current Operating Income	95,911,744	28,359,457	5,448,578	344,116	4,642,527	658,013	1,173,961	(1,398,273)	1,741,548
18	Return at Current Rates	4.88%	6.43%	3.60%	3.61%	3.03%	2.55%	3.40%	-13.50%	20.54%
19	Index Rate of Return	1.00	1.32	0.74	0.74	0.62	0.52	0.70	-2.77	4.21
	Current Rate Rev	$ 1,177,074,009	$ 287,702,173	$ 89,530,832	$ 5,428,692	$ 91,369,462	$ 15,102,253	$ 22,324,851	$ 6,428,908	$ 10,262,445
	IPL Proposed Increase	67,249,670	12,131,540	5,561,797	413,076	5,111,944	928,143	1,202,697	533,394	-26,613
	IPL Rate Rev @ Proposed Rates	$ 1,244,323,678	$ 299,833,713	$ 95,092,629	$ 5,841,768	$ 96,481,406	$ 16,030,396	$ 23,527,548	$ 6,962,302	$ 10,235,832
	Allocated Sales for Resale	6,324,121	1,522,634	519,546	30,629	521,849	91,853	131,661	11,415	16,212
	Allocated other Rev @ Current Rates	20,161,991	2,889,331	894,466	63,687	891,525	124,465	159,458	226,352	373,361
	Allocated Additional Connect Fee Rev	1,710,968	4,540	146	32	27	5	3	-	-
	Allocated Migration Impact	(1,186,513)	(294,365)	(91,370)	(5,519)	(90,595)	(15,046)	(22,106)	(6,694)	(12,105)
	Subtotal	27,010,567	4,122,140	1,322,788	88,829	1,322,806	201,277	269,016	231,073	377,468
	IPL total Proposed Rev	$ 1,271,334,245.41	$ 303,955,853.80	$ 96,415,417.00	$ 5,930,597.31	$ 97,804,211.44	$ 16,231,672.89	$ 23,796,564.09	$ 7,193,375.46	$ 10,613,300.41
Less:										
	O&M @ Current Rates	$ 396,494,451	$ 84,764,490	$ 27,088,437	$ 1,763,531	$ 26,910,210	$ 4,411,524	$ 6,085,459	$ 5,926,413	$ 4,610,275
	Depreciation	200,925,821	45,488,827	15,123,501	949,098	15,146,561	2,533,505	3,522,928	1,046,590	767,388
	Amortization	7,656,489	1,679,844	560,850	36,850	561,799	89,489	120,314	80,519	118,140
	Taxes Oter than Income @ Current Rates	45,114,501	9,757,687	3,222,408	211,120	3,232,059	522,967	697,691	595,283	557,983
	Fuel	435,543,947	112,801,182	38,900,834	2,183,050	42,179,384	7,158,429	10,891,705	1,465,055	1,967,038
	Non FAC Fuel	7,413,035	1,889,520	649,426	37,833	682,244	116,375	175,811	20,465	27,945
	Subtotal	1,093,148,244	256,381,550	85,545,455	5,181,482	88,712,257	14,832,290	21,493,909	9,134,325	8,048,767
	Bad Debt increase @ Proposed Rates	264,000	3,491	112	25	21	4	2	0	0
	PUC Fee Increase @ Proposed Rates	80,000	17,228	5,721	384	5,724	892	1,180	983	1,420
	Other Tax Increase @ Proposed Rates	945,000	210,272	71,382	4,520	71,994	12,092	16,231	6,515	5,237
	Total Expense Before Tax @ Proposed Rates	$ 1,094,437,244	$ 256,612,540	$ 85,622,670	$ 5,186,411	$ 88,789,996	$ 14,845,277	$ 21,511,322	$ 9,141,823	$ 8,055,425
	Earnings Before Interest and Income Tax	$ 176,897,001	$ 47,343,314	$ 10,792,747	$ 744,186	$ 9,014,216	$ 1,386,396	$ 2,285,242	$ (1,948,448)	$ 2,557,876
	Interest	$ 71,820,000	$ 16,109,113	$ 5,530,306	$ 348,420	$ 5,592,809	$ 943,341	$ 1,260,192	$ 378,480	$ 309,842
	Taxable Income	$ 105,077,001	$ 31,234,201	$ 5,262,441	$ 395,766	$ 3,421,407	$ 443,055	$ 1,025,050	$ (2,326,928)	$ 2,248,034
	Income Tax	$ 40,730,000	$ 12,107,017	$ 2,039,830	$ 153,407	$ 1,326,207	$ 171,737	$ 397,331	$ (901,965)	$ 871,384
	Net Operating Income @ Proposed Rates	$ 136,167,001.44	$ 35,236,297.23	$ 8,752,917.19	$ 590,779.17	$ 7,688,008.41	$ 1,214,658.49	$ 1,887,911.48	$ (1,046,482.80)	$ 1,686,491.99
	Rate Base	$ 1,964,992,430	$ 440,744,714	$ 151,308,957	$ 9,532,756	$ 153,019,036	$ 25,809,763	$ 34,478,794	$ 10,355,202	$ 8,477,275
	ROR @ IPL Proposed Rates (Before Correction for Migration)	6.93%	7.99%	5.78%	6.20%	5.02%	4.71%	5.48%	-10.11%	19.89%
	Eliminate Migration Adjustment	$ 1,186,513.00	$ 294,364.79	$ 91,370.29	$ 5,518.78	$ 90,595.29	$ 15,046.48	$ 22,106.06	$ 6,693.59	$ 12,104.64
	Tax Effect of Migration Adjustment	459,916.76	114,101.83	35,417.00	2,139.19	35,116.59	5,832.33	8,568.76	2,594.57	4,692.01
	Net Migration Effect	726,596	180,263	55,953	3,380	55,479	9,214	13,537	4,099	7,413
	Corrected Net Operating Income @ IPL Proposed Rates	$ 136,893,598	$ 35,416,560	$ 8,808,870	$ 594,159	$ 7,743,487	$ 1,223,873	$ 1,901,449	$ (1,042,384)	$ 1,693,905
	Corrected ROR @ IPL Proposed Rates	6.97%	8.04%	5.82%	6.23%	5.06%	4.74%	5.51%	-10.07%	19.98%
	Corrected Indexed ROR @ IPL Proposed Rates	100%	115%	84%	89%	73%	68%	79%	-144%	287%

Class Cost of Service Study
Summary of Results
Base-Intermediate Peak Utilizing 100% Demand Classification of Distribution Plant

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)
	Rate Base							
1	Plant in Service	$ 4,501,131,701	$ 1,916,619,558	$ 413,111,405	$ 185,017,012	$ 6,033,511	$ 251,382	$ 464,574
2	Accumulated Reserve	(2,827,661,271)	(1,221,409,618)	(255,926,053)	(116,259,509)	(3,736,247)	(167,473)	(293,005)
3	Other Rate Base Items	291,522,000	121,936,381	27,472,762	11,578,486	379,524	17,505	32,075
4	Total Rate Base	$ 1,964,992,430	$ 817,146,321	$ 184,658,114	$ 80,335,988	$ 2,676,788	$ 101,414	$ 203,644
	Revenues at Current Rates							
5	Retail Sales	$ 1,177,074,009	$ 465,528,940	$ 136,179,718	$ 45,434,316	$ 1,621,358	$ 44,356	$ 115,705
6	Other Revenue	20,161,991	12,379,429	1,609,906	530,797	16,603	935	1,677
7	Sales for Resale	6,324,121	2,426,886	575,295	261,926	9,108	250	610
8	Total Revenues	$ 1,203,560,121	$ 480,335,255	$ 138,364,919	$ 46,227,039	$ 1,647,068	$ 45,541	$ 117,992
	Expenses at Current Rates							
9	Operations & Maintenance Expenses	$ 396,494,451	$ 174,507,872	$ 37,261,536	$ 15,369,944	$ 505,039	$ 24,855	$ 43,038
10	Depreciation Expense	200,925,821	83,254,021	19,295,389	8,271,318	275,529	11,290	21,749
11	Amortization Expense	7,656,489	3,208,805	702,094	314,812	10,367	409	784
12	Taxes Other Than Income Taxes	45,114,501	19,261,790	4,232,268	1,811,628	59,209	2,642	4,814
13	Fuel Expenses	435,543,947	159,315,107	39,754,620	18,234,219	627,592	19,068	46,665
14	Non-FAC Trackable Fuel Expenses	7,413,035	2,813,880	674,845	312,712	10,939	301	740
15	Income Taxes	14,500,133	3,046,149	11,157,291	(384,693)	22,753	(6,287)	(2,721)
16	Total Expenses - Current	$ 1,107,648,377	$ 445,407,624	$ 113,078,044	$ 43,929,939	$ 1,511,429	$ 52,280	$ 115,069
17	Current Operating Income	95,911,744	34,927,631	25,286,875	2,297,100	135,640	(6,738)	2,923
18	Return at Current Rates	4.88%	4.27%	13.69%	2.86%	5.07%	-6.64%	1.44%
19	Index Rate of Return	1.00	0.88	2.81	0.59	1.04	-1.36	0.29
	Current Rate Rev	$ 1,177,074,009	$ 465,528,940	$ 136,179,718	$ 45,434,316	$ 1,621,358	$ 44,356	$ 115,705
	IPL Proposed Increase	67,249,670	36,606,231	1,357,032	3,315,652	103,931	3,557	7,289
	IPL Rate Rev @ Proposed Rates	$ 1,244,323,678	$ 502,135,171	$ 137,536,750	$ 48,749,968	$ 1,725,289	$ 47,913	$ 122,994
	Allocated Sales for Resale	6,324,121	2,426,886	575,295	261,926	9,108	250	610
	Allocated other Rev @ Current Rates	20,161,991	12,379,429	1,609,906	530,797	16,603	935	1,677
	Allocated Additional Connect Fee Rev	1,710,968	1,654,245	47,641	4,113	28	96	92
	Allocated Migration Impact	(1,186,513)	(469,788)	(134,013)	(43,227)	(1,538)	(40)	(107)
	Subtotal	27,010,567	15,990,773	2,098,829	753,609	24,201	1,241	2,272
	IPL total Proposed Rev	$ 1,271,334,245.41	$ 518,125,943.05	$ 139,635,578.53	$ 49,503,576.10	$ 1,749,489.05	$ 49,154.32	$ 125,265.50
	Less:							
	O&M @ Current Rates	$ 396,494,451	$ 174,507,872	$ 37,261,536	$ 15,369,944	$ 505,039	$ 24,855	$ 43,038
	Depreciation	200,925,821	83,254,021	19,295,389	8,271,318	275,529	11,290	21,749
	Amortization	7,656,489	3,208,805	702,094	314,812	10,367	409	784
	Taxes Oter than Income @ Current Rates	45,114,501	19,261,790	4,232,268	1,811,628	59,209	2,642	4,814
	Fuel	435,543,947	159,315,107	39,754,620	18,234,219	627,592	19,068	46,665
	Non FAC Fuel	7,413,035	2,813,880	674,845	312,712	10,939	301	740
	Subtotal	1,093,148,244	442,361,475	101,920,752	44,314,632	1,488,676	58,566	117,789
	Bad Debt increase @ Proposed Rates	264,000	239,478	19,130	1,651	11	39	37
	PUC Fee Increase @ Proposed Rates	80,000	34,090	7,352	3,283	107	4	8
	Other Tax Increase @ Proposed Rates	945,000	396,884	88,804	38,295	1,273	51	99
	Total Expense Before Tax @ Proposed Rates	$ 1,094,437,244	$ 443,031,926	$ 102,036,038	$ 44,357,861	$ 1,490,067	$ 58,660	$ 117,933
	Earnings Before Interest and Income Tax	$ 176,897,001	$ 75,094,017	$ 37,599,541	$ 5,145,715	$ 259,422	$ (9,506)	$ 7,332
	Interest	$ 71,820,000	$ 29,866,501	$ 6,749,210	$ 2,936,261	$ 97,836	$ 3,707	$ 7,443
	Taxable Income	$ 105,077,001	$ 45,227,516	$ 30,850,331	$ 2,209,454	$ 161,586	$ (13,212)	$ (111)
	Income Tax	$ 40,730,000	$ 17,531,112	$ 11,958,221	$ 856,430	$ 62,634	$ (5,121)	$ (43)
	Net Operating Income @ Proposed Rates	$ 136,167,001.44	$ 57,562,904.53	$ 25,641,319.90	$ 4,289,285.22	$ 196,787.74	$ (4,384.27)	$ 7,375.15
	Rate Base	$ 1,964,992,430	$ 817,146,321	$ 184,658,114	$ 80,335,988	$ 2,676,788	$ 101,414	$ 203,644
	ROR @ IPL Proposed Rates (Before Correction for Migration)	6.93%	7.04%	13.89%	5.34%	7.35%	-4.32%	3.62%
	Eliminate Migration Adjustment	$ 1,186,513.00	$ 469,787.59	$ 134,012.89	$ 43,227.13	$ 1,537.83	$ 40.31	$ 107.33
	Tax Effect of Migration Adjustment	459,916.76	182,099.30	51,946.15	16,755.72	596.09	15.63	41.60
	Net Migration Effect	726,596	287,688	82,067	26,471	942	25	66
	Corrected Net Operating Income @ IPL Proposed Rates	$ 136,893,598	$ 57,850,593	$ 25,723,387	$ 4,315,757	$ 197,729	$ (4,360)	$ 7,441
	Corrected ROR @ IPL Proposed Rates	6.97%	7.08%	13.93%	5.37%	7.39%	-4.30%	3.65%
	Corrected Indexed ROR @ IPL Proposed Rates	100%	102%	200%	77%	106%	-62%	52%

Class Cost of Service Study
Summary of Results
Base-Intermediate Peak Utilizing 100% Demand Classification of Distribution Plant

Line No.	Description	System Total	Secondary Large SL	Primary PL	Process Heating PH	HLF - Primary HL1	HLF - Sub-Tran HL2	HLF -Tran HL3	Automatic Protective Lighting APL	Municipal Lighting MU1
	(A)	(B)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
	Rate Base									
1	Plant in Service	$ 4,501,131,701	$ 1,003,773,382	$ 335,827,600	$ 21,991,972	$ 349,237,937	$ 53,766,521	$ 74,205,417	$ 56,895,035	$ 83,936,396
2	Accumulated Reserve	(2,827,661,271)	(612,505,184)	(199,621,336)	(13,657,267)	(205,764,992)	(29,877,889)	(41,123,343)	(49,939,753)	(77,379,604)
3	Other Rate Base Items	291,522,000	66,466,985	21,780,587	1,355,644	22,902,846	3,703,153	5,301,705	4,853,231	3,741,117
4	Total Rate Base	$ 1,964,992,430	$ 457,735,183	$ 157,986,852	$ 9,690,349	$ 166,375,790	$ 27,591,785	$ 38,383,779	$ 11,808,513	$ 10,297,910
	Revenues at Current Rates									
5	Retail Sales	$ 1,177,074,009	$ 287,702,173	$ 89,530,832	$ 5,428,692	$ 91,369,462	$ 15,102,253	$ 22,324,851	$ 6,428,908	$ 10,262,445
6	Other Revenue	20,161,991	2,889,331	894,466	63,687	891,525	124,465	159,458	226,352	373,361
7	Sales for Resale	6,324,121	1,597,839	549,105	31,327	580,970	99,741	148,946	17,848	24,271
8	Total Revenues	$ 1,203,560,121	$ 292,189,343	$ 90,974,403	$ 5,523,705	$ 92,841,957	$ 15,326,459	$ 22,633,254	$ 6,673,108	$ 10,660,077
	Expenses at Current Rates									
9	Operations & Maintenance Expenses	$ 396,494,451	$ 87,423,625	$ 28,133,577	$ 1,788,196	$ 29,000,641	$ 4,690,424	$ 6,696,618	$ 6,153,867	$ 4,895,218
10	Depreciation Expense	200,925,821	47,410,183	15,878,667	966,919	16,657,001	2,735,024	3,964,521	1,210,937	973,273
11	Amortization Expense	7,656,489	1,742,960	585,656	37,436	611,416	96,109	134,820	85,918	124,903
12	Taxes Other Than Income Taxes	45,114,501	10,105,626	3,359,161	214,348	3,505,585	559,460	777,659	625,045	595,267
13	Fuel Expenses	435,543,947	112,801,182	38,900,834	2,183,050	42,179,384	7,158,429	10,891,705	1,465,055	1,967,038
14	Non-FAC Trackable Fuel Expenses	7,413,035	1,889,520	649,426	37,833	682,244	116,375	175,811	20,465	27,945
15	Income Taxes	14,500,133	5,292,587	(866,922)	(21,888)	(2,207,531)	(389,946)	(530,080)	(1,247,340)	638,759
16	Total Expenses - Current	$ 1,107,648,377	$ 266,665,682	$ 86,640,399	$ 5,205,892	$ 90,428,740	$ 14,965,875	$ 22,111,056	$ 8,313,946	$ 9,222,402
17	Current Operating Income	95,911,744	25,523,661	4,334,004	317,813	2,413,217	360,584	522,199	(1,640,838)	1,437,675
18	Return at Current Rates	4.88%	5.58%	2.74%	3.28%	1.45%	1.31%	1.36%	-13.90%	13.96%
19	Index Rate of Return	1.00	1.14	0.56	0.67	0.30	0.27	0.28	-2.85	2.86
	Current Rate Rev	$ 1,177,074,009	$ 287,702,173	$ 89,530,832	$ 5,428,692	$ 91,369,462	$ 15,102,253	$ 22,324,851	$ 6,428,908	$ 10,262,445
	IPL Proposed Increase	67,249,670	12,131,540	5,561,797	413,076	5,111,944	928,143	1,202,697	533,394	-26,613
	IPL Rate Rev @ Proposed Rates	$ 1,244,323,678	$ 299,833,713	$ 95,092,629	$ 5,841,768	$ 96,481,406	$ 16,030,396	$ 23,527,548	$ 6,962,302	$ 10,235,832
	Allocated Sales for Resale	6,324,121	1,597,839	549,105	31,327	580,970	99,741	148,946	17,848	24,271
	Allocated other Rev @ Current Rates	20,161,991	2,889,331	894,466	63,687	891,525	124,465	159,458	226,352	373,361
	Allocated Additional Connect Fee Rev	1,710,968	4,540	146	32	27	5	3	-	-
	Allocated Migration Impact	(1,186,513)	(294,365)	(91,370)	(5,519)	(90,595)	(15,046)	(22,106)	(6,694)	(12,105)
	Subtotal	27,010,567	4,197,346	1,352,346	89,527	1,381,927	209,165	286,300	237,506	385,527
	IPL total Proposed Rev	$ 1,271,334,245.41	$ 304,031,058.99	$ 96,444,975.48	$ 5,931,294.86	$ 97,863,332.66	$ 16,239,560.69	$ 23,813,848.79	$ 7,199,808.28	$ 10,621,359.11
Less:										
	O&M @ Current Rates	$ 396,494,451	$ 87,423,625	$ 28,133,577	$ 1,788,196	$ 29,000,641	$ 4,690,424	$ 6,696,618	$ 6,153,867	$ 4,895,218
	Depreciation	200,925,821	47,410,183	15,878,667	966,919	16,657,001	2,735,024	3,964,521	1,210,937	973,273
	Amortization	7,656,489	1,742,960	585,656	37,436	611,416	96,109	134,820	85,918	124,903
	Taxes Oter than Income @ Current Rates	45,114,501	10,105,626	3,359,161	214,348	3,505,585	559,460	777,659	625,045	595,267
	Fuel	435,543,947	112,801,182	38,900,834	2,183,050	42,179,384	7,158,429	10,891,705	1,465,055	1,967,038
	Non FAC Fuel	7,413,035	1,889,520	649,426	37,833	682,244	116,375	175,811	20,465	27,945
	Subtotal	1,093,148,244	261,373,095	87,507,321	5,227,780	92,636,271	15,355,821	22,641,135	9,561,286	8,583,643
	Bad Debt increase @ Proposed Rates	264,000	3,491	112	25	21	4	2	0	0
	PUC Fee Increase @ Proposed Rates	80,000	17,826	5,956	390	6,194	954	1,317	1,035	1,484
	Other Tax Increase @ Proposed Rates	945,000	218,134	74,472	4,593	78,175	12,917	18,038	7,187	6,080
	Total Expense Before Tax @ Proposed Rates	$ 1,094,437,244	$ 261,612,546	$ 87,587,860	$ 5,232,788	$ 92,720,661	$ 15,369,696	$ 22,660,493	$ 9,569,508	$ 8,591,206
	Earnings Before Interest and Income Tax	$ 176,897,001	$ 42,418,513	$ 8,857,115	$ 698,507	$ 5,142,672	$ 869,865	$ 1,153,356	$ (2,369,699)	$ 2,030,153
	Interest	$ 71,820,000	$ 16,730,111	$ 5,774,381	$ 354,180	$ 6,080,995	$ 1,008,473	$ 1,402,918	$ 431,598	$ 376,386
	Taxable Income	$ 105,077,001	$ 25,688,402	$ 3,082,734	$ 344,327	$ (938,323)	$ (138,608)	$ (249,562)	$ (2,801,298)	$ 1,653,767
	Income Tax	$ 40,730,000	$ 9,957,351	$ 1,194,931	$ 133,468	$ (363,713)	$ (53,727)	$ (96,735)	$ (1,085,840)	$ 641,034
	Net Operating Income @ Proposed Rates	$ 136,167,001.44	$ 32,461,161.64	$ 7,662,184.34	$ 565,038.73	$ 5,506,385.13	$ 923,592.16	$ 1,250,091.27	$ (1,283,858.98)	$ 1,389,118.87
	Rate Base	$ 1,964,992,430	$ 457,735,183	$ 157,986,852	$ 9,690,349	$ 166,375,790	$ 27,591,785	$ 38,383,779	$ 11,808,513	$ 10,297,910
	ROR @ IPL Proposed Rates (Before Correction for Migration)	6.93%	7.09%	4.85%	5.83%	3.31%	3.35%	3.26%	-10.87%	13.49%
	Eliminate Migration Adjustment	$ 1,186,513.00	$ 294,364.79	$ 91,370.29	$ 5,518.78	$ 90,595.29	$ 15,046.48	$ 22,106.06	$ 6,693.59	$ 12,104.64
	Tax Effect of Migration Adjustment	459,916.76	114,101.83	35,417.00	2,139.19	35,116.59	5,832.33	8,568.76	2,594.57	4,692.01
	Net Migration Effect	726,596	180,263	55,953	3,380	55,479	9,214	13,537	4,099	7,413
	Corrected Net Operating Income @ IPL Proposed Rates	$ 136,893,598	$ 32,641,425	$ 7,718,138	$ 568,418	$ 5,561,864	$ 932,806	$ 1,263,629	$ (1,279,760)	$ 1,396,532
	Corrected ROR @ IPL Proposed Rates	6.97%	7.13%	4.89%	5.87%	3.34%	3.38%	3.29%	-10.84%	13.56%
	Corrected Indexed ROR @ IPL Proposed Rates	100%	102%	70%	84%	48%	49%	47%	-156%	195%

Class Cost of Service Study
Summary of Results
Probability of Dispatch Utilizing 100% Demand Classification of Distribution Plant

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)
	Rate Base							
1	Plant in Service	$ 4,501,131,701	$ 1,894,733,111	$ 407,485,001	$ 190,382,349	$ 5,786,486	$ 225,541	$ 406,462
2	Accumulated Reserve	(2,827,661,271)	(1,209,412,001)	(252,841,795)	(119,200,656)	(3,600,834)	(153,307)	(261,150)
3	Other Rate Base Items	291,522,000	120,780,683	27,175,664	11,861,798	366,480	16,140	29,007
4	Total Rate Base	$ 1,964,992,430	$ 806,101,793	$ 181,818,870	$ 83,043,491	$ 2,552,132	$ 88,374	$ 174,319
	Revenues at Current Rates							
5	Retail Sales	$ 1,177,074,009	$ 465,528,940	$ 136,179,718	$ 45,434,316	$ 1,621,358	$ 44,356	$ 115,705
6	Other Revenue	20,161,991	12,379,429	1,609,906	530,797	16,603	935	1,677
7	Sales for Resale	6,324,121	2,377,999	562,728	273,911	8,556	192	480
8	Total Revenues	$ 1,203,560,121	$ 480,286,368	$ 138,352,351	$ 46,239,023	$ 1,646,517	$ 45,484	$ 117,862
	Expenses at Current Rates							
9	Operations & Maintenance Expenses	$ 396,494,451	$ 172,779,322	$ 36,817,174	$ 15,793,688	$ 485,530	$ 22,814	$ 38,449
10	Depreciation Expense	200,925,821	82,005,057	18,974,315	8,577,494	261,432	9,816	18,433
11	Amortization Expense	7,656,489	3,167,777	691,546	324,870	9,904	361	675
12	Taxes Other Than Income Taxes	45,114,501	19,035,615	4,174,125	1,867,073	56,657	2,375	4,214
13	Fuel Expenses	435,543,947	159,315,107	39,754,620	18,234,219	627,592	19,068	46,665
14	Non-FAC Trackable Fuel Expenses	7,413,035	2,813,880	674,845	312,712	10,939	301	740
15	Income Taxes	14,500,133	4,398,592	11,504,967	(716,237)	38,017	(4,690)	870
16	Total Expenses - Current	$ 1,107,648,377	$ 443,515,350	$ 112,591,592	$ 44,393,819	$ 1,490,071	$ 50,046	$ 110,044
17	Current Operating Income	95,911,744	36,771,018	25,760,759	1,845,204	156,445	(4,562)	7,817
18	Return at Current Rates	4.88%	4.56%	14.17%	2.22%	6.13%	-5.16%	4.48%
19	Index Rate of Return	1.00	0.93	2.90	0.46	1.26	-1.06	0.92
	Current Rate Rev	$ 1,177,074,009	$ 465,528,940	$ 136,179,718	$ 45,434,316	$ 1,621,358	$ 44,356	$ 115,705
	IPL Proposed Increase	67,249,670	36,606,231	1,357,032	3,315,652	103,931	3,557	7,289
	IPL Rate Rev @ Proposed Rates	$ 1,244,323,678	$ 502,135,171	$ 137,536,750	$ 48,749,968	$ 1,725,289	$ 47,913	$ 122,994
	Allocated Sales for Resale	6,324,121	2,377,999	562,728	273,911	8,556	192	480
	Allocated other Rev @ Current Rates	20,161,991	12,379,429	1,609,906	530,797	16,603	935	1,677
	Allocated Additional Connect Fee Rev	1,710,968	1,654,245	47,641	4,113	28	96	92
	Allocated Migration Impact	(1,186,513)	(469,788)	(134,013)	(43,227)	(1,538)	(40)	(107)
	Subtotal	27,010,567	15,941,886	2,086,262	765,593	23,649	1,183	2,142
	IPL total Proposed Rev	$ 1,271,334,245.41	$ 518,077,056.48	$ 139,623,011.14	$ 49,515,560.36	$ 1,748,937.29	$ 49,096.60	$ 125,135.70
Less:								
	O&M @ Current Rates	$ 396,494,451	$ 172,779,322	$ 36,817,174	$ 15,793,688	$ 485,530	$ 22,814	$ 38,449
	Depreciation	200,925,821	82,005,057	18,974,315	8,577,494	261,432	9,816	18,433
	Amortization	7,656,489	3,167,777	691,546	324,870	9,904	361	675
	Taxes Oter than Income @ Current Rates	45,114,501	19,035,615	4,174,125	1,867,073	56,657	2,375	4,214
	Fuel	435,543,947	159,315,107	39,754,620	18,234,219	627,592	19,068	46,665
	Non FAC Fuel	7,413,035	2,813,880	674,845	312,712	10,939	301	740
	Subtotal	1,093,148,244	439,116,758	101,086,625	45,110,056	1,452,054	54,735	109,174
	Bad Debt increase @ Proposed Rates	264,000	239,478	19,130	1,651	11	39	37
	PUC Fee Increase @ Proposed Rates	80,000	33,701	7,252	3,378	103	4	7
	Other Tax Increase @ Proposed Rates	945,000	391,773	87,490	39,548	1,215	45	85
	Total Expense Before Tax @ Proposed Rates	$ 1,094,437,244	$ 439,781,710	$ 101,200,497	$ 45,154,633	$ 1,453,383	$ 54,822	$ 109,304
	Earnings Before Interest and Income Tax	$ 176,897,001	$ 78,295,347	$ 38,422,515	$ 4,360,927	$ 295,554	$ (5,726)	$ 15,832
	Interest	$ 71,820,000	$ 29,462,826	$ 6,645,436	$ 3,035,220	$ 93,280	$ 3,230	$ 6,371
	Taxable Income	$ 105,077,001	$ 48,832,520	$ 31,777,079	$ 1,325,707	$ 202,274	$ (8,956)	$ 9,461
	Income Tax	$ 40,730,000	$ 18,928,486	$ 12,317,447	$ 513,871	$ 78,406	$ (3,472)	$ 3,667
	Net Operating Income @ Proposed Rates	$ 136,167,001.44	$ 59,366,860.66	$ 26,105,067.41	$ 3,847,055.67	$ 217,148.35	$ (2,254.38)	$ 12,164.93
	Rate Base	$ 1,964,992,430	$ 806,101,793	$ 181,818,870	$ 83,043,491	$ 2,552,132	$ 88,374	$ 174,319
	ROR @ IPL Proposed Rates (Before Correction for Migration)	6.93%	7.36%	14.36%	4.63%	8.51%	-2.55%	6.98%
	Eliminate Migration Adjustment	$ 1,186,513.00	$ 469,787.59	$ 134,012.89	$ 43,227.13	$ 1,537.83	$ 40.31	$ 107.33
	Tax Effect of Migration Adjustment	459,916.76	182,099.30	51,946.15	16,755.72	596.09	15.63	41.60
	Net Migration Effect	726,596	287,688	82,067	26,471	942	25	66
	Corrected Net Operating Income @ IPL Proposed Rates	$ 136,893,598	$ 59,654,549	$ 26,187,134	$ 3,873,527	$ 218,090	$ (2,230)	$ 12,231
	Corrected ROR @ IPL Proposed Rates	6.97%	7.40%	14.40%	4.66%	8.55%	-2.52%	7.02%
	Corrected Indexed ROR @ IPL Proposed Rates	100%	106%	207%	67%	123%	-36%	101%

Class Cost of Service Study
Summary of Results
Probability of Dispatch Utilizing 100% Demand Classification of Distribution Plant

Line No.	Description (A)	System Total (B)	Secondary Large SL (I)	Primary PL (J)	Process Heating PH (K)	HLF - Primary HL1 (L)	HLF - Sub-Tran HL2 (M)	HLF -Tran HL3 (N)	Automatic Protective Lighting APL (O)	Municipal Lighting MU1 (P)
	Rate Base									
1	Plant in Service	$ 4,501,131,701	$ 1,002,130,446	$ 351,829,040	$ 21,632,743	$ 348,840,078	$ 55,381,895	$ 77,353,800	$ 58,709,717	$ 86,235,031
2	Accumulated Reserve	(2,827,661,271)	(611,604,566)	(208,392,935)	(13,460,346)	(205,546,895)	(30,763,398)	(42,849,209)	(50,934,517)	(78,639,660)
3	Other Rate Base Items	291,522,000	66,380,231	22,625,532	1,336,675	22,881,837	3,788,452	5,467,953	4,949,054	3,862,495
4	Total Rate Base	$ 1,964,992,430	$ 456,906,111	$ 166,061,636	$ 9,509,072	$ 166,175,019	$ 28,406,949	$ 39,972,543	$ 12,724,253	$ 11,457,867
	Revenues at Current Rates									
5	Retail Sales	$ 1,177,074,009	$ 287,702,173	$ 89,530,832	$ 5,428,692	$ 91,369,462	$ 15,102,253	$ 22,324,851	$ 6,428,908	$ 10,262,445
6	Other Revenue	20,161,991	2,889,331	894,466	63,687	891,525	124,465	159,458	226,352	373,361
7	Sales for Resale	6,324,121	1,594,169	584,846	30,524	580,081	103,349	155,978	21,901	29,405
8	Total Revenues	$ 1,203,560,121	$ 292,185,673	$ 91,010,144	$ 5,522,903	$ 92,841,069	$ 15,330,067	$ 22,640,287	$ 6,677,161	$ 10,665,211
	Expenses at Current Rates									
9	Operations & Maintenance Expenses	$ 396,494,451	$ 87,293,869	$ 29,397,341	$ 1,759,824	$ 28,969,219	$ 4,818,003	$ 6,945,272	$ 6,297,187	$ 5,076,760
10	Depreciation Expense	200,925,821	47,316,428	16,791,799	946,419	16,634,297	2,827,206	4,144,186	1,314,493	1,104,446
11	Amortization Expense	7,656,489	1,739,880	615,652	36,762	610,670	99,137	140,722	89,319	129,212
12	Taxes Other Than Income Taxes	45,114,501	10,088,648	3,524,520	210,635	3,501,473	576,154	810,195	643,798	619,021
13	Fuel Expenses	435,543,947	112,801,182	38,900,834	2,183,050	42,179,384	7,158,429	10,891,705	1,465,055	1,967,038
14	Non-FAC Trackable Fuel Expenses	7,413,035	1,889,520	649,426	37,833	682,244	116,375	175,811	20,465	27,945
15	Income Taxes	14,500,133	5,394,110	(1,855,709)	310	(2,182,946)	(489,766)	(724,630)	(1,359,476)	496,718
16	Total Expenses - Current	$ 1,107,648,377	$ 266,523,636	$ 88,023,863	$ 5,174,834	$ 90,394,342	$ 15,105,538	$ 22,383,261	$ 8,470,841	$ 9,421,139
17	Current Operating Income	95,911,744	25,662,037	2,986,281	348,069	2,446,727	224,529	257,026	(1,793,679)	1,244,072
18	Return at Current Rates	4.88%	5.62%	1.80%	3.66%	1.47%	0.79%	0.64%	-14.10%	10.86%
19	Index Rate of Return	1.00	1.15	0.37	0.75	0.30	0.16	0.13	-2.89	2.22
	Current Rate Rev	$ 1,177,074,009	$ 287,702,173	$ 89,530,832	$ 5,428,692	$ 91,369,462	$ 15,102,253	$ 22,324,851	$ 6,428,908	$ 10,262,445
	IPL Proposed Increase	67,249,670	12,131,540	5,561,797	413,076	5,111,944	928,143	1,202,697	533,394	-26,613
	IPL Rate Rev @ Proposed Rates	$ 1,244,323,678	$ 299,833,713	$ 95,092,629	$ 5,841,768	$ 96,481,406	$ 16,030,396	$ 23,527,548	$ 6,962,302	$ 10,235,832
	Allocated Sales for Resale	6,324,121	1,594,169	584,846	30,524	580,081	103,349	155,978	21,901	29,405
	Allocated other Rev @ Current Rates	20,161,991	2,889,331	894,466	63,687	891,525	124,465	159,458	226,352	373,361
	Allocated Additional Connect Fee Rev	1,710,968	4,540	146	32	27	5	3	-	-
	Allocated Migration Impact	(1,186,513)	(294,365)	(91,370)	(5,519)	(90,595)	(15,046)	(22,106)	(6,694)	(12,105)
	Subtotal	27,010,567	4,193,676	1,388,088	88,724	1,381,038	212,773	293,333	241,560	390,661
	IPL total Proposed Rev	$ 1,271,334,245.41	$ 304,027,389.25	$ 96,480,717.03	$ 5,930,492.47	$ 97,862,443.98	$ 16,243,168.86	$ 23,820,881.16	$ 7,203,861.63	$ 10,626,493.45
Less:										
	O&M @ Current Rates	$ 396,494,451	$ 87,293,869	$ 29,397,341	$ 1,759,824	$ 28,969,219	$ 4,818,003	$ 6,945,272	$ 6,297,187	$ 5,076,760
	Depreciation	200,925,821	47,316,428	16,791,799	946,419	16,634,297	2,827,206	4,144,186	1,314,493	1,104,446
	Amortization	7,656,489	1,739,880	615,652	36,762	610,670	99,137	140,722	89,319	129,212
	Taxes Oter than Income @ Current Rates	45,114,501	10,088,648	3,524,520	210,635	3,501,473	576,154	810,195	643,798	619,021
	Fuel	435,543,947	112,801,182	38,900,834	2,183,050	42,179,384	7,158,429	10,891,705	1,465,055	1,967,038
	Non FAC Fuel	7,413,035	1,889,520	649,426	37,833	682,244	116,375	175,811	20,465	27,945
	Subtotal	1,093,148,244	261,129,526	89,879,572	5,174,524	92,577,288	15,595,304	23,107,890	9,830,317	8,924,421
	Bad Debt increase @ Proposed Rates	264,000	3,491	112	25	21	4	2	0	0
	PUC Fee Increase @ Proposed Rates	80,000	17,797	6,240	384	6,187	983	1,373	1,067	1,525
	Other Tax Increase @ Proposed Rates	945,000	217,750	78,208	4,509	78,082	13,294	18,773	7,611	6,616
	Total Expense Before Tax @ Proposed Rates	$ 1,094,437,244	$ 261,368,564	$ 89,964,132	$ 5,179,441	$ 92,661,577	$ 15,609,585	$ 23,128,039	$ 9,838,995	$ 8,932,562
	Earnings Before Interest and Income Tax	$ 176,897,001	$ 42,658,825	$ 6,516,585	$ 751,051	$ 5,200,867	$ 633,584	$ 692,842	$ (2,635,133)	$ 1,693,931
	Interest	$ 71,820,000	$ 16,699,808	$ 6,069,513	$ 347,554	$ 6,073,657	$ 1,038,267	$ 1,460,987	$ 465,068	$ 418,782
	Taxable Income	$ 105,077,001	$ 25,959,017	$ 447,072	$ 403,497	$ (872,790)	$ (404,683)	$ (768,145)	$ (3,100,201)	$ 1,275,149
	Income Tax	$ 40,730,000	$ 10,062,247	$ 173,294	$ 156,404	$ (338,311)	$ (156,863)	$ (297,749)	$ (1,201,702)	$ 494,274
	Net Operating Income @ Proposed Rates	$ 136,167,001.44	$ 32,596,578.06	$ 6,343,290.68	$ 594,647.62	$ 5,539,178.04	$ 790,447.50	$ 990,590.76	$ (1,433,431.33)	$ 1,199,657.48
	Rate Base	$ 1,964,992,430	$ 456,906,111	$ 166,061,636	$ 9,509,072	$ 166,175,019	$ 28,406,949	$ 39,972,543	$ 12,724,253	$ 11,457,867
	ROR @ IPL Proposed Rates (Before Correction for Migration)	6.93%	7.13%	3.82%	6.25%	3.33%	2.78%	2.48%	-11.27%	10.47%
	Eliminate Migration Adjustment	$ 1,186,513.00	$ 294,364.79	$ 91,370.29	$ 5,518.78	$ 90,595.29	$ 15,046.48	$ 22,106.06	$ 6,693.59	$ 12,104.64
	Tax Effect of Migration Adjustment	459,916.76	114,101.83	35,417.00	2,139.19	35,116.59	5,832.33	8,568.76	2,594.57	4,692.01
	Net Migration Effect	726,596	180,263	55,953	3,380	55,479	9,214	13,537	4,099	7,413
	Corrected Net Operating Income @ IPL Proposed Rates	$ 136,893,598	$ 32,776,841	$ 6,399,244	$ 598,027	$ 5,594,657	$ 799,662	$ 1,004,128	$ (1,429,332)	$ 1,207,070
	Corrected ROR @ IPL Proposed Rates	6.97%	7.17%	3.85%	6.29%	3.37%	2.82%	2.51%	-11.23%	10.53%
	Corrected Indexed ROR @ IPL Proposed Rates	100%	103%	55%	90%	48%	40%	36%	-161%	151%

INDIANAPOLIS POWER & LIGHT
Customer Cost Analysis

	Residential RS	Secondary Small SS	Space Conditioning SH	Space Conditioning - Schools SE	Water Heating - Controlled CB	Water Heating - Uncontrolled UW	Secondary Large SL	Primary PL	Process Heating PH	HLF - Primary HL1	HLF - Sub-Tran HL2	HLF -Tran HL3
Gross Plant												
369 Services	$66,250,244	$44,599,861		$26,126			$4,250,367	$136,435	$30,049	$25,184	$4,550	$2,824
370 Meters	$41,938,915	$11,574,778	$1,643,458	$17,793	$9,318	$13,826	$3,299,455	$143,415	$29,019	$43,844	$9,943	$9,567
Total Gross Plant	**$108,189,160**	**$56,174,639**	**$1,643,458**	**$43,919**	**$9,318**	**$13,826**	**$7,549,822**	**$279,851**	**$59,068**	**$69,029**	**$14,493**	**$12,391**
Depreciation Reserve												
Services	-54,993,524	-37,021,803		-21,687			-3,528,178	-113,253	-24,943	-20,905	-3,777	-2,345
Meters	-10,182,726	-2,810,344	-399,030	-4,320	-2,262	-3,357	-801,104	-34,821	-7,046	-10,645	-2,414	-2,323
Total Depreciation Reserve	**-$65,176,250**	**-$39,832,148**	**-$399,030**	**-$26,007**	**-$2,262**	**-$3,357**	**-$4,329,282**	**-$148,074**	**-$31,989**	**-$31,551**	**-$6,191**	**-$4,667**
Total Net Plant	**$43,012,910**	**$16,342,492**	**$1,244,428**	**$17,912**	**$7,056**	**$10,469**	**$3,220,540**	**$131,776**	**$27,079**	**$37,478**	**$8,302**	**$7,724**
Operation & Maintenance Expenses												
586 Dist Oper - Meter	$2,049,211	$565,565	$80,302	$869	$455	$676	$161,217	$7,008	$1,418	$2,142	$486	$467
902 Meter Reading	$4,651,332	$518,112	$44,727	$304	$1,045	$1,004	$49,376	$1,585	$349	$293	$53	$33
903 Records & Collections	$7,025,843	$1,750,955	$151,154	$1,026	$3,533	$3,394	$1,144,444	$36,736	$8,091	$6,781	$1,225	$760
597 Dist Maint - Meters	$977,481	$269,776	$38,304	$415	$217	$322	$76,901	$3,343	$676	$1,022	$232	$223
Total O & M Expenses	**$14,703,867**	**$3,104,408**	**$314,488**	**$2,613**	**$5,251**	**$5,396**	**$1,431,939**	**$48,671**	**$10,534**	**$10,238**	**$1,996**	**$1,484**
Depreciation Expense												
403 Services	$2,139,883	$1,440,576		$844			$137,287	$4,407	$971	$813	$147	$91
403 Meters	$2,347,066	$647,770	$91,974	$996	$521	$774	$184,650	$8,026	$1,624	$2,454	$556	$535
Total Depreciation Expense	**$4,486,950**	**$2,088,346**	**$91,974**	**$1,840**	**$521**	**$774**	**$321,937**	**$12,433**	**$2,595**	**$3,267**	**$703**	**$627**
Revenue Requirement												
Interest	$1,311,116	$498,151	$37,933	$546	$215	$319	$98,168	$4,017	$825	$1,142	$253	$235
Equity return	$2,106,924	$800,513	$60,956	$877	$346	$513	$157,753	$6,455	$1,326	$1,836	$407	$378
Income Tax	$1,333,513	$506,660	$38,581	$555	$219	$325	$99,845	$4,085	$840	$1,162	$257	$239
Revenue For Return	4,751,553	1,805,324	137,470	1,979	779	1,156	355,767	14,557	2,991	4,140	917	853
O & M Expenses	$14,703,867	$3,104,408	$314,488	$2,613	$5,251	$5,396	$1,431,939	$48,671	$10,534	$10,238	$1,996	$1,484
Depreciation Expense	$4,486,950	$2,088,346	$91,974	$1,840	$521	$774	$321,937	$12,433	$2,595	$3,267	$703	$627
Subtotal Customer Revenue Requirement	$23,942,370	$6,998,078	$543,932	$6,432	$6,552	$7,327	$2,109,643	$75,661	$16,120	$17,645	$3,616	$2,964
Total Revenue Requirement	**$23,942,370**	**$6,998,078**	**$543,932**	**$6,432**	**$6,552**	**$7,327**	**$2,109,643**	**$75,661**	**$16,120**	**$17,645**	**$3,616**	**$2,964**
Number of Customers	425,283	47,372	4,090	28	96	92	4,515	145	32	27	5	3
Number of Bills	5,103,397	568,468	49,074	333	1,147	1,102	54,175	1,739	383	321	58	36
Monthly Cost Before Bad Debts & Utility Receipts Tax	$4.69	$12.31	$11.08	$19.31	$5.71	$6.65	$38.94	$43.51	$42.09	$54.97	$62.35	$82.32
Bad Debts + Utility Receipts Tax Rate	1.7891%	1.7891%	1.7891%	1.7891%	1.7891%	1.7891%	1.7891%	1.7891%	1.7891%	1.7891%	1.7891%	1.7891%
TOTAL MONTHLY CUSTOMER COST	$4.78	$12.53	$11.28	$19.66	$5.81	$6.77	$39.64	$44.29	$42.84	$55.95	$63.46	$83.79

	% of Total	Cost Rate	Wgtd. Cost
L-T Debt	0.5376	5.67%	3.05%
Pref. Stock	0.028	5.37%	0.15%
Common	0.4344	10.93%	4.75%
Total	1		7.95%

Debt	0.5376	5.67%	3.05%
Equity	0.4624	10.59%	4.90%
Total			7.95%

Data Request OUCC DR 18 - 26

With respect to the discussion in IPL Witness Gaske's Direct Testimony, Pages 11 and 12, please provide detailed explanations, including quantitative analyses, as to the bases for IPL's proposals for a declining-block rate structure for some classes, and a flat rate structure for other classes. Include in this response specific explanations and analyses for each rate class wherein a declining-block rate structure or flat rate structure is proposed.

Objection:

Response:

No change is being proposed to the structure of any of the Energy Charge blocks. Customers who currently have declining-block Energy Charges will continue to have declining block rates, and customers who currently have flat-rate Energy Charges will continue to have flat rates.

Ideally, in order to properly reflect costs and provide appropriate price signals, customers without demand meters should pay straight-fixed variable rates that recover all fixed costs in the Customer Charge, with no fixed costs recovered in the Energy Charge. However, in order to hold the Customer Charge below costs it is common to recover some portion of fixed costs in the Energy Charge.

As described in the cited testimony, the purpose of declining-block Energy Charges is to recover fixed costs from customers who do not have demand meters in a way that helps to ensure that each customer pays a reasonable share of the fixed costs of the system, while trying to reduce (i) the distortion in marginal price signals posed by recovering fixed costs in a variable charge, and (ii) the variability of the Company's recovery of fixed costs associated with year-to-year fluctuations in usage. Thus, declining-block rates are a second-best alternative to adopting a straight-fixed variable rate design. Over time, in future rate filings, it would be appropriate to reduce the use of declining-block Energy Charges by increasing the Customer Charge.

There are four Rate Codes that have declining-block Energy Charges: RS, SS, SE and PH. No changes are proposed to the consumption levels covered by each block in these rate schedules. The continuation of the existing Energy Charge structures for all Rate Codes is intended to minimize changes in the rate structures experienced by customers.

The charge for each block of the SS, SE and PH rates was increased by the same amount in order to retain the same dollar difference and price signals between the blocks of each of these rates. For the RS rate, the Energy Charge increase was greater in blocks 2 and 3 than in the first block. For example, Block 1 is increased by 0.59 mills, Block 2 is increased by 2.65 mills, and Block 3 is increased by 2.25 mills. The amount of the changes in each block of the RS rate design was specifically designed to ensure that the amount of overall bill increase experienced by a smaller

residential customer would be less than that experienced by a larger residential customer. The effect of that design can be seen in column (E) on page 1 of Petitioner's Witness JSG Attachment-6. A customer who uses 100 kWh would experience a monthly bill increase of $4.61, while larger customers would experience progressively larger increases in their monthly bills. As noted on page 16, lines 6-7 of Dr. Gaske's testimony, this rate design ensures that approximately 90 percent of the residential customers will experience a rate increase of less than $10 per month.

The proposed rate design would eliminate declining-block Demand Charges for rates SL, PL, HL1, HL2 and HL3. The reason for changing to flat-rate demand charges is that there is no good economic justification for declining-block demand charges and the differences between the rates for each block in the existing rate structure are relatively small. Consequently, moving to flat rate Demand Charges would not be a major change.

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Glenn A. Watkins
Principal and Senior Economist
Technical Associates, Inc.
Consultant for:
Indiana Office of Utility Consumer Counselor

July 27, 2015
Date

Cause No. 44576/44602
IPL