STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN RATE ADJUSTMENT; AND FOR APPROVAL OF RELATED RELIEF INCLUDING: (1) REVISED DEPRECIATION RATES; (2) ACCOUNTING RELIEF; (3) INCLUSION IN RATE BASE OF QUALIFIED POLLUTION CONTROL PROPERTY AND CLEAN ENERGY PROJECT; (4) ENHANCEMENTS TO THE DRY SORBENT INJECTION SYSTEM; (5) ADVANCED METERING INFRASTRUCTURE; (6) RATE ADJUSTMENT MECHANISM PROPOSALS; AND (7) NEW SCHEDULES OF RATES, RULES AND REGULATIONS.	)	**CAUSE NO. 45235**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

PUBLIC'S EXHIBIT NO. 12

PUBLIC (REDACTED) TESTIMONY OF

OUCC WITNESS GLENN A. WATKINS

August 20, 2019

Respectfully submitted,

Tiffany T. Murray
Attorney No. 28916-49
Deputy Consumer Counselor

Public's Exhibit No. 12

STATE OF INDIANA

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<u>PUBLIC VERSION</u>
VERIFIED DIRECT TESTIMONY

OF

GLENN A. WATKINS

ON BEHALF OF THE

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

AUGUST 20, 2019

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VERIFIED DIRECT TESTIMONY OF GLENN A. WATKINS
CAUSE NO. 45235
INDIANA MICHIGAN POWER COMPANY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 6377 Mattawan Trail, Mechanicsville, Virginia 23116.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am President and Senior Economist of 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 39-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, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, Montana, 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. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE INDIANA UTILITY REGULATORY COMMISSION ("COMMISSION")?

A. Yes. In addition to Indiana Michigan Power's ("I&M", "Company" or "Petitioner") last general rate case (Cause No. 44967), I have provided testimony on behalf of the Office of Utility Consumer Counselor ("OUCC") in the two most recent Indianapolis Power & Light

Company (Cause Nos. 44576 and 45029) and Northern Indiana Public Service Company (Cause Nos. 44688 and 45159) rate cases.

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

A. Technical Associates has been engaged by the OUCC to assist in its evaluation of the accuracy and reasonableness of I&M's retail class cost of service study, proposed distribution of revenues by class, and rate design as it relates to this rate application. In addition, I have also conducted analyses of the cost to serve I&M's special contract customer, which is for information purposes. Finally, I provide a revenue adjustment to correct the Company's Future Test Year customer billing determinants. The purpose of my testimony, is to comment on I&M'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. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS IN THIS CASE.

A. I&M's proposed allocation of fixed generation and transmission costs based on the 6-CP method does not reasonably reflect cost causation imposed upon I&M and should not be primarily relied upon. Instead, I have conducted alternative studies based upon the Peak & Average, 12-CP and Base-Intermediate-Peak methods. When my recommended cost of service studies are considered, significantly different rates of return are obtained for some classes.

With regard to the distribution of any overall increase in base rates authorized in this case to individual classes, I have developed a different recommendation to that proposed by I&M witness Matthew Nollenberger. My recommendation considers the results of several cost allocation methodologies as well as recognition of the ratemaking principle of gradualism.

I recommend the Commission maintain the current level of Residential customer charges and reject I&M's proposed declining-block rate structure for Rate Schedule RS. Furthermore, I do not oppose I&M's proposed optional Pilot Residential Demand-Metered tariff, but recommend the Commission require I&M to collect and maintain data relating to customers' usages and billings under this experimental rate and provide periodic reports to interested parties.

For informational purposes I have calculated the fully allocated cost to serve the Company's special contract customer and have determined that the cost to serve this customer is substantially greater than the revenues currently contributed by this customer.

III. 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. 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. WHAT ARE THE PRIMARY DRIVERS INFLUENCING ELECTRIC UTILITY COST ALLOCATION STUDIES?

A. Although electric utility cost allocation studies tend to be somewhat complex in that several rate base and expense items tend to be allocated based on internally generated allocation factors, all allocation factors are ultimately a direct function of class contributions to: (a) demands (KW); (b) energy usage (KWH); or, (c) number of customers. In this regard, energy usage (KWH) and number of customers are readily known and measured from billing and financial records. However, class contributions to demands (KW) are not always readily known for every rate class. That is, while some larger user class demands are known with certainty because they are metered and measured utilizing interval demand meters, other small volume class demands must be estimated based on sample data since these class' meters only measure monthly energy (KWH) usage. Because the vast majority of vertically integrated electric utilities' rate base and expense account items are allocated based on some measure of demand, this is a most critical component within the cost allocation process. In other words, the estimation of class contributions to demand serve as the foundation for any class cost allocation study. Therefore, if there are deficiencies or biases within the estimation of class contributions to demand, the resulting cost allocation study will have serious deficiencies or biases and may even be meaningless.

Q. 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]

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 I&M'S CCOSS.

A. In conducting my independent analysis, I reviewed the structure and organization of Petitioner'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 I&M's selection of allocators to specific rate base, revenue, and expense accounts. I then verified the accuracy of I&M's CCOSS model by replicating its results using my own computer

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

model. Finally, I adjusted certain aspects of Petitioner's study to better reflect cost causation and cost incidence by rate schedule and customer class.

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. Generation Plant

Q. BEFORE YOU 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 I&M 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 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.

[2] Principles of Public Utility Rates, Second Edition, 1988, page 495.

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

<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 are 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 I&M had a peak load of 4,000 MW and its actual optimal generation mix included an assortment of coal, hydro, combined cycle and combustion turbine units, the actual total cost of installed capacity is significantly higher than if the utility only had to consider meeting 4,000 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. Second, 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.

6-CP -- The 6-CP method is identical in concept to the 1-CP method except that the monthly peak loads during the three summer months and three winter 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 or more hours of load are considered instead of one. This method has essentially the same strengths and weaknesses as the 1-CP method, and 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; i.e., are planned and installed to minimize total costs (capacity and energy). 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, i.e., the load factor that 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).

Probability of Dispatch -- The Probability of Dispatch method is the most theoretically correct and most equitable method to allocate generation costs when specific data is available. Under this approach, each generation asset's (plant or unit) investment is evaluated on an hourly basis over every hour of the year. That is, each generating unit's gross investment is assigned to individual hours based upon how that individual plant is operated during each hour of the year. In this method, the investment costs associated with base load units which operate almost continuously throughout the year, are spread throughout numerous 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 capacity costs for all generating units operating in a particular hour are then summed to develop the total hourly investment assigned to each hour. These hourly generating unit investments are then assigned to individual rate classes based on class contributions to system load for every hour of the year.

As a result of such analyses, the Probability of Dispatch method properly reflects the cost causation imposed by individual classes because it reflects the actual utilization of a utility's generation resources. Put differently, the assignment of generation costs is consistent with the utility's planning process to invest in a portfolio of generation resources wherein high fixed cost/low variable cost base load generation units are assigned to classes, based on these units' output, over the majority of hours during the year (because they will, on an expected basis, be called upon to operate over the majority of hours during the year). In contrast, the investment costs associated with the low fixed cost/high variable cost peaker units are assigned to those classes in proportion over relatively fewer hours during a year (because they will, on an expected basis, be called upon to operate over fewer hours). As is evident from the above discussion, 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).

Equivalent Peaker ("EP") -- 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. Cost allocation methods that only consider peak loads (demands) such as the 1-CP, 4-CP, and 6-CP do not reasonably reflect cost causation for electric utilities because these methods totally ignore the type and level of investments made to provide generation service. When generation cost responsibility is assigned to rate classes only on a few hours of peak demand, there is an explicit assumption that there is a direct and proportional correlation between peak load (for a few hours) and the utility's total investment in its portfolio of generation assets. Such is certainly not the case with utilities such as I&M wherein the portfolio of generation assets are predominately comprised of nuclear and coal units installed coupled with run of the river hydro facilities that provide power throughout the year.

Perhaps the simplest way to explain how a utility plans and builds its portfolio of generation assets and facilities is to consider the differences between capital costs and operating costs of various generation alternatives. Most utilities have a mix of different types of generation facilities including large base load units, intermediate plants, and small peaker units. Individual generating unit 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 coal and 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.

Peak responsibility methods such as the 1-CP, 4-CP, and 6-CP totally ignore the planning criteria used by utilities to minimize the total cost of providing service, do not reflect the utilization of its portfolio of generating assets throughout the year, and therefore, do not reflect in any way how capital costs are incurred; i.e., do not reflect cost causation.

Q. PLEASE BRIEFLY DESCRIBE I&M'S PORTFOLIO OF GENERATION ASSETS.

A. As discussed in the testimonies of Toby Thomas, Shane Lies, and Timothy Kerns, I&M's generation portfolio is comprised of a base load nuclear facility with two units (Cook) and two base load coal plants (Rockport).[3] In addition, Petitioner has six run of the river hydro facilities and four solar plants.[4]

The Cook and Rockport facilities are considered base load units in that they provide very low cost energy and operate almost continuously throughout the year. With regard to Petitioner's hydro and solar generation investment, Company witness Kerns explains that because I&M's hydro units are run of the river, the output of these units are primarily dictated by river flow conditions such that their output varies. Similarly, Mr. Kerns acknowledges that the time of day and amount of atmospheric interference dictates solar generation output. These are important considerations in that these facilities are in place to provide very cheap energy but cannot be relied upon to necessarily meet peak load requirements.

Q. DOES I&M'S PORTFOLIO OF GENERATION ASSETS INCLUDE ANY PEAKER OR INTERMEDIATE FACILITIES?

[3] I&M owns 50% of Rockport 1 while Rockport 2 is operated under a lease agreement with its affiliate, AEP Generating Company ("AEG"). I&M is entitled to 50% of the output of both units and purchases 70% of the AEG entitlement. As such, I&M is entitled to 85% of the total output of Rockport 1 and 2.

[4] In addition, the Company has purchased power agreements for 450 MW of wind generation.

A. Not really. Although the Company's Rockport Plant is currently operated under what can be considered an "intermediate" facility, this plant was originally designed as a base load unit. With this understanding, I&M is somewhat unique in that its generation rate base is comprised almost entirely of base load units with a small amount of net investment in run of the river hydro and solar generation facilities. Although this mix of generation might be considered inefficient as a standalone vertically integrated utility, it should be remembered that when I&M's plants were built and installed, I&M's parent (AEP), dispatched generation based on the parent company's entire fleet of assets which did include a portfolio of peak and intermediate facilities. However, a much different situation exists today in that I&M is now a member of PJM. As a result of the low energy cost power produced by I&M's generation facilities, Petitioner is a large net seller into the PJM wholesale market. In other words, I&M's generation portfolio consists of very low energy cost plants that meet not only its internal load but also enables Petitioner to sell excess capacity to the wholesale PJM market.

Q. CAN YOU EXPLAIN AND SHOW HOW I&M'S PORTFOLIO OF GENERATING ASSETS ARE UTILIZED?

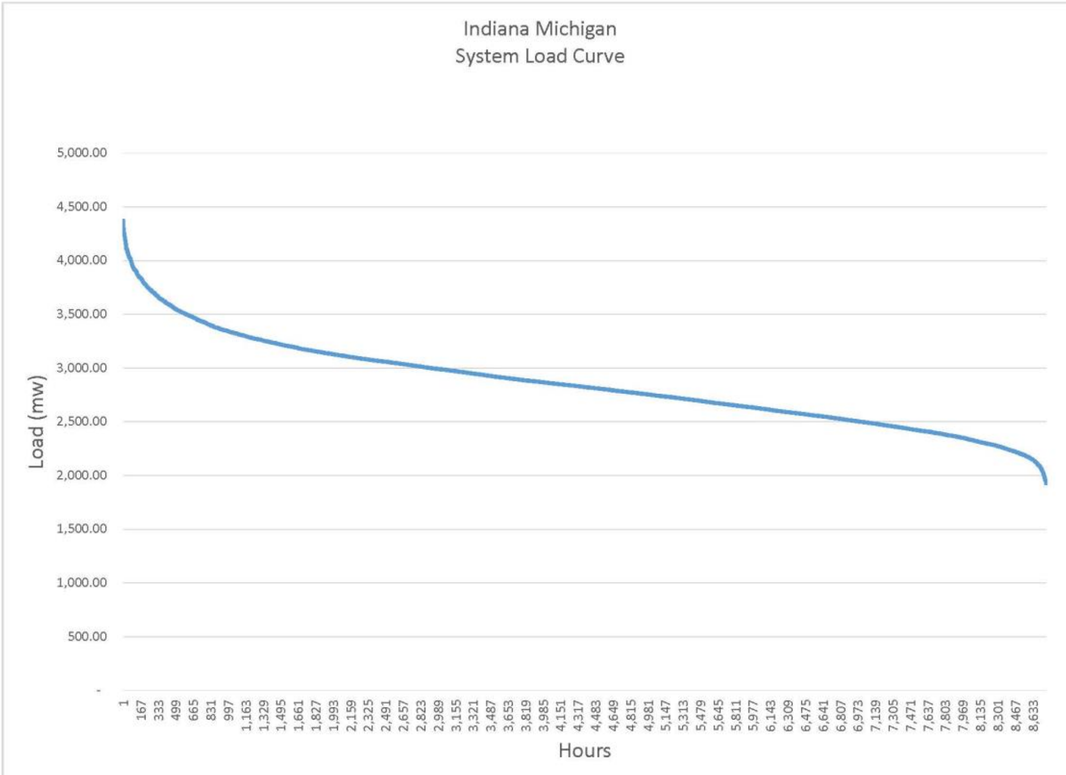
A. Yes. As shown in my Confidential Attachment GAW-2, during the two year period (2017 through 2018), the Company's Cook Nuclear Plant (both units combined) produced [**BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of I&M's total owned generation energy (KWH) and had an operational capacity factor of **[BEGIN CONFIDENTIAL]** [redacted].[5] **[END CONFIDENTIAL]** This exceptionally high capacity factor means that the Cook Nuclear Plant is dispatched almost continuously each and every hour of the year (except for refueling). As is the case with virtually every nuclear power plant in the industry, Cook was designed and built to provide low cost energy throughout the year. The trade-off with these low energy costs (primarily fuel) is that the capital investment costs (per KW) are very high. This has important implications as it relates to cost causation and how Cook's capital costs (rate base) should be assigned to classes; i.e., cost causation dictates that Cook's capital costs are primarily energy-related and not peak demand-related.

[5] The operational capacity factor excludes the refueling periods for Cook 1 and Cook 2.

With regard to I&M's share of the Rockport Plant (both units combined), these units produced **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of I&M's total owned generation energy (KWH) and had an operational capacity factor of **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** I&M's hydro facilities only provide **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the Company's owned generation energy (KWH) and because these are run of the river units, they operate at a relatively high capacity factor of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Similarly, the Company's solar facilities have provided only **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the Company's owned generation energy (KWH) and have operated at a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** capacity factor.

Q. HAVE YOU EXAMINED THE COMPANY'S SYSTEM LOAD REQUIREMENTS THROUGHOUT THE YEAR?

A. Yes. In response to OUCC-26-06, the Company provided I&M system internal loads for every hour of 2018. As a result, I was able to develop the Company's actual load duration curve. A graph of I&M's system load duration curve is provided below:

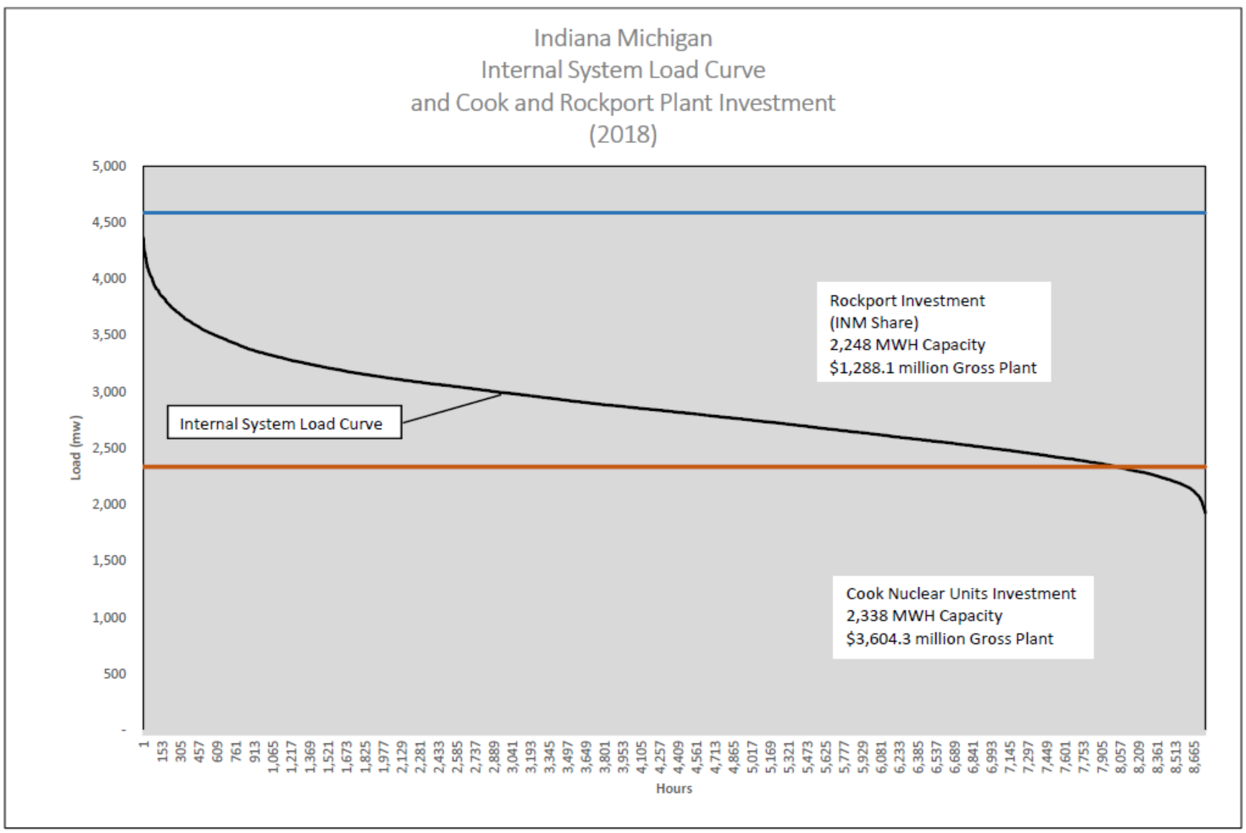


Q. PLEASE EXPLAIN WHAT A LOAD DURATION CURVE REPRESENTS.

A. A load duration curve shows the demand by hour for an entire year such that the first hour on the graph represents the annual system peak while the last hour shows the lowest hourly demand for the test year. In other words, it is a curve that is sorted from highest hourly demand to lowest hourly demand. The area under the curve represents the total energy required during a year and most importantly, shows the incidence and duration of load requirements.

Q. CAN YOU GRAPHICALLY SHOW THE RELATIONSHIP BETWEEN THE COMPANY'S GENERATION GROSS INVESTMENT TO ITS SYSTEM LOAD DURATION CURVE?

A. Yes. The following graph provides the Company's load duration curve along with the capacity associated with its various owned generation assets. In developing this graph, I have only included I&M's Cook and Rockport generation plants wherein these two plants' capacity alone are greater than the system peak demand. Furthermore, I have dispatched the Cook nuclear plant units first and the Rockport units after Cook due to Rockport's higher running costs. As shown in this graph, the area under the Cook nuclear portion of the load duration curve serves all customers' load requirements for the plurality of the year and represents the majority of the Company's total investment in generation plant.[6] The area under the Rockport portion of the load duration curve serves customers' load requirements for a smaller portion of the year with a smaller gross investment of $1,288.1 million.[7] As indicated in this graph, the capacity and output of the Company's Cook and Rockport units alone are more than enough to serve I&M's load requirements throughout the year and these generating facilities are utilized to meet energy requirements throughout the year and not simply peak load requirements.



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[6] The total forecasted test year Cook gross investment is $3,604.3 million and the total I&M production plant gross investment is $5,014.0 million.

[7] This is the I&M share of Rockport Units 1 and 2. Note: the capacity and costs associated with solar and hydro are not included in this graph due to their inability to serve load every hour of the year.

In my view this is a most important consideration in that I&M's jurisdictional ratepayers are asked to pay for the entire investment in these generation facilities designed and utilized to serve energy needs throughout the year such that the allocation of costs should not be predicated only on class contributions to peak demand for only a few hours of the year. Furthermore, to allocate this base load generation investment to customer classes based on peak demand but then provide off-system sale credits to customers based on energy sales, produces a distinct bias against small volume lower load factor customers such as the residential class. This is because large, higher load factor customers (with large amounts of energy and relatively small amounts of peak load) are not assigned enough capital costs (rate base and depreciation expense) but then receive a disproportionate benefit of off-system energy sales based on KWH energy usage.

Q. WHAT COST ALLOCATION METHODOLOGY DOES I&M UTILIZE TO ALLOCATE GENERATION PLANT COSTS WITHIN ITS PROPOSED CCOSS?

A. I&M witness Michael Spaeth (originally filed by Daniel High) conducted his CCOSS utilizing the 6-CP method to allocate I&M's generation assets. These 6-CPs reflect the highest demands in the three summer months (June-August) and the three winter months (December-February).

Q. WHAT CRITERIA DID MR. SPAETH CONSIDER IN SELECTING HIS 6-CP METHOD TO ALLOCATE GENERATION COSTS?

A. On page 10 of his direct testimony, Mr. Spaeth claims to have considered four criteria which are as follows:

(1) The method should match customer benefit from the use of the system with the appropriate cost responsibility for the system.

(2) The method should reflect the planning and operating characteristics of the utility's system.

(3) The method should recognize customer class characteristics such as energy usage, peak demand on the system, diversity characteristics, number of customers, etc.

(4) The method should produce stable results on a year-to-year basis.

Q. DOES MR. SPAETH'S SELECTED 6-CP METHOD COMPORT WITH HIS FIRST CRITERIA THAT "THE METHOD SHOULD MATCH CUSTOMER BENEFIT FROM THE USE OF THE SYSTEM WITH THE APPROPRIATE COST RESPONSIBILITY FOR THE SYSTEM?"

A. No. As discussed earlier and as it relates to the "use of the system," the vast majority of I&M's generation is produced by its Cook and Rockport plants. These plants provide low cost energy throughout the year such that the use of the system is predominately based on output from the Cook and Rockport facilities.

In addition, and as it relates to use of the system, I&M is a net off-system seller of electricity the majority of the year. That is, even though I&M purchases power for many hours of the year, during most of these hours, I&M is a net off-system seller; i.e., its off-system sales are greater than its power purchases. As points of comparison, I&M is a net seller 7,332 hours of the year (84% of the time). Perhaps more importantly is the fact that I&M tends to be a net seller even during system peak load hours. As illustrations, during 2018, I&M was a net seller during both the winter peak and summer peak hours.[8] Furthermore, during the 25 highest system peak load hours in 2018, I&M was a net seller during 23 of these hours.

The fact that I&M is a net off-system seller of electricity the vast majority of the year as well as during peak periods is important because I&M's generation is based predominately on low energy cost base load units which enables the Company to make off-system sales over and above its internal load obligations. I will discuss the cost allocation implications of I&M's large amount of net off-system sales later in my testimony.

Q. DOES MR. SPAETH'S SELECTED 6-CP METHOD COMPORT WITH HIS SECOND CRITERIA THAT "THE METHOD SHOULD REFLECT THE PLANNING AND OPERATING CHARACTERISTICS OF THE UTILITY'S SYSTEM?"

A. No. As discussed earlier, I&M's portfolio of generation assets is somewhat atypical in the industry in that the Company does not have a traditional mix of base, intermediate, and peaker units. Indeed, the cornerstone of I&M's generation fleet is its Cook and Rockport

[8] The winter peak was 3,723 MW on January 16 at 1000 hours in which I&M was a net seller of 1,139 MW. The summer peak was 4,369 on June 18 at 1600 hours in which I&M was a net seller of 142 MW.

units which were planned and built as base load units to serve customers' loads and energy requirements throughout the year. With regard to the Company's hydro and solar facilities, these units were not planned or built to serve peak load requirements, but rather, provide low cost energy when these units are able to operate. With regard to the operating characteristics of I&M's generation system, I have already discussed that the vast majority of the Company's generation operations come from its Cook and Rockport units.

Q. DOES MR. SPAETH'S SELECTED 6-CP METHOD COMPORT WITH HIS THIRD CRITERIA THAT "THE METHOD SHOULD RECOGNIZE CUSTOMER CLASS CHARACTERISTICS SUCH AS ENERGY USAGE, PEAK DEMAND ON THE SYSTEM, DIVERSITY CHARACTERISTICS, NUMBER OF CUSTOMERS, ETC.?"

A. No. Mr. Spaeth's 6-CP method only considers class contributions to peak demand during six hours of the year and does not in any way consider energy usage. This is most important because there is no doubt that I&M's investment in generation plant is comprised predominately on its Cook and Rockport generation units as shown in the table below:

TABLE 1
I&M Generation Gross Investment

Generating Plant	Gross Investment	Percent Investment
Nuclear (Cook)	$2,546,579,187	71.8%
Steam (Rockport)	$910,129,918	25.7%
Hydro	$38,944,227	1.1%
Solar	$48,938,660	1.4%
Total	$3,544,591,992	100.0%

As can be seen above, 71.8% of the Company's investment in generation plant is attributable to its Cook Nuclear units. These units operate almost continuously throughout the year at a relatively constant load and are clearly not in place simply to meet peak load requirements. Indeed, these plants are in place to provide low cost energy throughout the year. Furthermore, the Company's investment in its combined Cook and Rockport facilities comprise 97.5% of I&M's investment in generation plant wherein these units are operated to provide low cost energy throughout the year and are not devoted to simply meeting peak load requirements.

Q. DOES MR. SPAETH'S SELECTED 6-CP METHOD COMPORT WITH HIS FOURTH CRITERIA THAT "THE METHOD SHOULD PRODUCE STABLE RESULTS ON A YEAR-TO-YEAR BASIS?"

A. Yes. While this is an important criterion to be considered, I also participated in the Company's last general rate case (Cause No. 44967). I have determined that class contributions to both peak demand and energy usage have been relatively stable over the last several years.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING MR. SPAETH'S PROPOSAL TO ALLOCATE GENERATION PLANT BASED ON THE 6-CP METHOD?

A. Mr. Spaeth's proposed 6-CP method to allocate generation plant investment is inappropriate for I&M for the reasons discussed above. As a result, Mr. Spaeth's 6-CP method significantly over-allocates costs to smaller volume classes (e.g., Residential and Small Commercial) and under-allocates costs to large industrial classes. There is no doubt that I&M's portfolio of generation assets were planned and are operated primarily to serve energy needs of its customers throughout the year and that it has virtually no investment in generation plant devoted only to meet peak load requirements.

In order to better understand why Mr. Spaeth's proposed 6-CP method to allocate generation costs is biased against small volume customers, consider the following relative relationships between Mr. Spaeth's 6-CP class allocators and energy usage:

TABLE 2
6-CP Load and Energy Usage Characteristics

Class	6-CP	Energy @ Generation
Residential	41.86%	34.45%
GS-Secondary	12.36%	10.17%
IP-SubTrans	4.68%	5.92%
IP-Trans	3.23%	4.61%

Q. HAVE YOU CONDUCTED ALTERNATIVE STUDIES THAT MORE ACCURATELY REPRESENT THE CAPACITY AND ENERGY TRADE-OFFS EXHIBITED IN I&M'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, the results of multiple, yet reasonable, methods should be considered in evaluating class profitability as well as class revenue responsibility.

The BIP, Probability of Dispatch, and P&A methods better reflect the capacity/energy tradeoffs that exist within an electric utility's generation-related costs. However due to the forecasted test year utilized in this case, it is virtually impossible to realistically forecast class and system loads for each and every hour of the year (8,760 hours), let alone, forecast how I&M's generation facilities will be dispatched every hour of the year. As such, the Probability of Dispatch is not appropriate in this case. Therefore, I have conducted alternative CCOSS utilizing the P&A, 12-CP and BIP methods to allocate I&M's generation costs.

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. Under this philosophy, transmission costs are allocated using the same method as that used to allocate generation-related costs.

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 MR. SPAETH USE TO ALLOCATE I&M'S TRANSMISSION-RELATED COSTS?

A. Mr. Spaeth allocated transmission-related costs based on the 6-CP method.

Q. WHAT IS YOUR OPINION REGARDING THE PROPER ALLOCATION OF TRANSMISSION-RELATED COSTS?

A. 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. HOW DID MR. SPAETH CLASSIFY AND ALLOCATE DISTRIBUTION PLANT RELATED COSTS?

A. First, it should be understood that Mr. Spaeth has bifurcated Petitioner's distribution system into primary and secondary voltage subsystems. In doing so, Mr. Spaeth properly recognizes that primary voltage customers should not be assigned secondary voltage distribution costs and he also properly recognizes load diversity and cost causation by utilizing different allocation factors between the primary and secondary subsystems. With this understanding, Mr. Spaeth has classified distribution Accounts 360 through 368 as totally demand-related while Accounts 369 and 370 were classified as customer-related.[9] On pages 14 through 16 of his direct testimony, Mr. Spaeth provides support for his classification and allocation of distribution plant. While I will not reiterate Mr. Spaeth's rationale for his classification and allocation procedures relating to distribution plant, I agree that his rationale and methods reasonably reflect cost causation and fairly allocate distribution-related costs across classes.

D. <u>Peak & Average CCOSS Results</u>

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR CCOSS UTILIZING THE P&A METHOD TO ALLOCATE GENERATION COSTS.

A. First, I calculated I&M's forecasted test year Indiana retail load factor in order to weight between the "peak" and "average" portions for the P&A allocation factor. This resulted in 62.24% of generation costs being assigned based on average demand and 37.76% allocated based on peak demand.

I then utilized firm class contributions to the forecast test year 1-CP demand (experienced in June) to reflect the peak nature and responsibility of class loads.[10] I have selected this measure of peak demand because the use of class contributions to 1-CP better reflect the spirit and concepts of the P&A method.

Q. PLEASE PROVIDE A COMPARISON OF GENERATION ALLOCATION FACTORS UNDER MR. SPAETH'S 6-CP APPROACH TO THOSE OBTAINED UNDER THE P&A METHOD.

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[9] These Account numbers are as follows: 360 (Land Rights); 361 (Structures & Improvements); 362 (Station Equipment; 363 (Storage Battery Equipment); 364 (Poles); 365 (Overhead Conductors); 366 (Underground Conduit); 367 (Underground Conductors); 368 (Line Transformers); 369 (Services); 370 (Meters).

[10] The derivation of my P&A allocator is provided in my filed workpapers.

A. The following table provides a comparison of retail class allocation factors under the 6-CP and P&A methods:

TABLE 3
Comparison of 6-CP and P&A
Allocation Factors

Rate Class	I&M 6-CP	P&A
RS	41.857%	37.267%
GS-SEC	12.365%	10.974%
GS-PRI	0.218%	0.189%
GS-SUB	0.004%	0.003%
LGS-SEC	19.819%	21.664%
LGS-PRI	1.053%	1.129%
LGS-SUB	0.042%	0.043%
LGS-TRAN	0.002%	0.002%
IP-SEC	3.987%	4.367%
IP-PRI	11.602%	13.370%
IP-SUB	4.682%	5.261%
IP-TRAN	3.227%	3.966%
MS	0.272%	0.246%
WSS-SEC	0.437%	0.558%
WSS-PRI	0.267%	0.334%
WSS-SUB	0.061%	0.075%
EHG	0.055%	0.047%
IS	0.004%	0.004%
OL	0.017%	0.192%
SL	0.028%	0.307%
Total	100.000%	100.000%

Q. HOW DID YOU ALLOCATE TRANSMISSION-RELATED COSTS WITHIN YOUR P&A MODEL?

A. As indicated earlier, I allocated transmission-related costs based on 12-CP demands.

Q. WHAT ARE THE RESULTS OF YOUR CCOSS UTILIZING THE P&A METHOD TO ALLOCATE GENERATION COSTS AND THE 12-CP METHOD TO ALLOCATE TRANSMISSION-RELATED COSTS?

A. The following summary and comparison utilizes all other allocations and procedures used by Mr. Spaeth in conducting his 6-CP CCOSS. The following table provides an apples-to-apples comparison of Mr. Spaeth's 6-CP results to those obtained utilizing the P&A method to allocate generation costs and the 12-CP method to allocate transmission costs:

TABLE 4
Comparison of 6-CP and P&A
ROR @ Current Rates

Rate Class	I&M 6-CP	P&A
RS	3.18%	4.47%
GS-SEC	4.36%	5.96%
GS-PRI	5.69%	7.93%
GS-SUB	6.50%	8.84%
LGS-SEC	3.49%	2.37%
LGS-PRI	3.20%	2.22%
LGS-SUB	3.05%	2.74%
LGS-TRAN	1.36%	-0.68%
IP-SEC	3.04%	1.81%
IP-PRI	3.21%	1.14%
IP-SUB	2.46%	0.51%
IP-TRAN	2.17%	-1.64%
MS	3.55%	4.83%
WSS-SEC	4.17%	1.09%
WSS-PRI	3.59%	0.39%
WSS-SUB	4.65%	0.94%
EHG	5.38%	7.30%
IS	11.38%	10.90%
OL	8.53%	4.31%
SL	11.27%	3.06%
Total	3.41%	3.41%

As can be seen above, there are material differences in achieved rates of return for several classes. A summary of my CCOSS utilizing the P&A method to allocate generation costs and the 12-CP method to allocate transmission costs is provided in my Attachment GAW-3 while the details of this CCOSS are provided in my filed workpapers.

E. <u>12-CP CCOSS Results</u>

Q. PLEASE PROVIDE A SUMMARY COMPARISON OF YOUR CCOSS UTILIZING THE 12-CP METHOD TO ALLOCATE BOTH GENERATION AND TRANSMISSION-RELATED COSTS.

A. The following summary and comparison utilizes all other allocations and procedures used by Mr. Spaeth in conducting his 6-CP CCOSS. The following table provides an apples-to-apples comparison of Mr. Spaeth's 6-CP results to those obtained utilizing the 12-CP method to allocate generation and transmission costs:

TABLE 5
Comparison of 6-CP and 12-CP
ROR @ Current Rates

Rate Class	I&M 6-CP	12-CP
RS	3.18%	3.89%
GS-SEC	4.36%	4.11%
GS-PRI	5.69%	4.76%
GS-SUB	6.50%	2.33%
LGS-SEC	3.49%	2.88%
LGS-PRI	3.20%	2.49%
LGS-SUB	3.05%	2.06%
LGS-TRAN	1.36%	0.84%
IP-SEC	3.04%	2.43%
IP-PRI	3.21%	2.44%
IP-SUB	2.46%	1.78%
IP-TRAN	2.17%	0.93%
MS	3.55%	2.62%
WSS-SEC	4.17%	2.95%
WSS-PRI	3.59%	2.58%
WSS-SUB	4.65%	3.35%
EHG	5.38%	4.99%
IS	11.38%	12.76%
OL	8.53%	8.76%
SL	11.27%	11.87%
Total	3.41%	3.41%

A summary of my CCOSS utilizing the 12-CP method to allocate generation and transmission-related costs is provided in my Attachment GAW-4 while the details of this CCOSS are provided in my filed workpapers.

F. <u>BIP CCOSS Results</u>

Q. PLEASE EXPLAIN HOW YOU CONDUCTED YOUR CCOSS UTILIZING THE BIP METHOD TO ALLOCATE GENERATION PLANT COSTS.

A. Although I&M does not have a typical generation portfolio consisting of base, intermediate, and peaker units, I have classified and allocated each generation plant individually based on each plant's two-year average (2017 and 2018) operational capacity factor which is the typical approach used to classify and allocate costs under the BIP method. To better explain, generation plants such as Cook have a high capacity factor in that these plants operate almost continuously throughout the year. Under this approach, each plant is classified between energy and demand based on that plant's capacity factor wherein the energy classification is equal to the plant's capacity factor and the demand classification is based on one minus the capacity factor.[11]

As discussed earlier in my testimony, my Confidential Attachment GAW-2 provides each generation plant's capacity factors. Furthermore, it should be noted that I have classified gross plant, depreciation reserve, and depreciation expense individually for each plant. This is noteworthy because I&M's solar plant is much newer than some of its other generation plant such that there is relatively less accumulated depreciation relating to its solar facilities than its Rockport or hydro facilities. Furthermore, the useful life of its various generation plants vary considerably such that depreciation is also classified and allocated on a plant-by-plant basis.

Q. PLEASE PROVIDE A SUMMARY COMPARISON OF YOUR CCOSS UTILIZING THE BIP METHOD TO ALLOCATE GENERATION COSTS AND THE 12-CP METHOD TO ALLOCATE TRANSMISSION COSTS.

A. The following summary and comparison utilizes all other allocations and procedures used by Mr. Spaeth in conducting his 6-CP CCOSS. The following table provides an apples-to-apples comparison of Mr. Spaeth's 6-CP results to those obtained utilizing the BIP method to allocate generation and the 12-CP method to allocate transmission costs:

[11] The demand portion utilizes class contributions to 1-CP consistent with the approach under the P&A method.

TABLE 6
Comparison of 6-CP and BIP
ROR @ Current Rates

Rate Class	I&M 6-CP	BIP
RS	3.18%	4.79%
GS-SEC	4.36%	6.34%
GS-PRI	5.69%	8.10%
GS-SUB	6.50%	7.32%
LGS-SEC	3.49%	2.28%
LGS-PRI	3.20%	2.03%
LGS-SUB	3.05%	2.27%
LGS-TRAN	1.36%	-0.50%
IP-SEC	3.04%	1.49%
IP-PRI	3.21%	0.71%
IP-SUB	2.46%	0.01%
IP-TRAN	2.17%	-2.59%
MS	3.55%	4.89%
WSS-SEC	4.17%	0.49%
WSS-PRI	3.59%	-0.22%
WSS-SUB	4.65%	0.28%
EHG	5.38%	7.27%
IS	11.38%	9.67%
OL	8.53%	3.45%
SL	11.27%	1.66%
Total	3.41%	3.41%

A summary of my CCOSS utilizing the BIP method to allocate generation and the 12-CP method to allocate transmission-related costs is provided in my Attachment GAW-5 while the details of this CCOSS are provided in my filed workpapers.

Q. PLEASE PROVIDE A COMPARISON OF MR. SPAETH'S CLASS RORs TO THOSE OBTAINED UNDER YOUR ANALYSES.

A. The following tables provides a comparison of Mr. Spaeth's and my calculated class RORs and indexed RORs utilizing the P&A, 12-CP, and BIP methods:

TABLE 7
Comparison of Class RORs Under Alternative Allocation Methods

Rate Class	I&M 6-CP Gen 6-CP Trans	OUCC P&A Gen 12-CP Trans	OUCC 12-CP Gen 12-CP Trans	OUCC BIP Gen 12-CP Trans	OUCC Average All Methods
RS	3.18%	4.47%	3.89%	4.79%	4.38%
GS-SEC	4.36%	5.96%	4.11%	6.34%	5.47%
GS-PRI	5.69%	7.93%	4.76%	8.10%	6.93%
GS-SUB	6.50%	8.84%	2.33%	7.32%	6.16%
LGS-SEC	3.49%	2.37%	2.88%	2.28%	2.51%
LGS-PRI	3.20%	2.22%	2.49%	2.03%	2.25%
LGS-SUB	3.05%	2.74%	2.06%	2.27%	2.36%
LGS-TRAN	1.36%	-0.68%	0.84%	-0.50%	-0.11%
IP-SEC	3.04%	1.81%	2.43%	1.49%	1.91%
IP-PRI	3.21%	1.14%	2.44%	0.71%	1.43%
IP-SUB	2.46%	0.51%	1.78%	0.01%	0.77%
IP-TRAN	2.17%	-1.64%	0.93%	-2.59%	-1.10%
MS	3.55%	4.83%	2.62%	4.89%	4.11%
WSS-SEC	4.17%	1.09%	2.95%	0.49%	1.51%
WSS-PRI	3.59%	0.39%	2.58%	-0.22%	0.92%
WSS-SUB	4.65%	0.94%	3.35%	0.28%	1.52%
EHG	5.38%	7.30%	4.99%	7.27%	6.52%
IS	11.38%	10.90%	12.76%	9.67%	11.11%
OL	8.53%	4.31%	8.76%	3.45%	5.51%
SL	11.27%	3.06%	11.87%	1.66%	5.53%
Total	3.41%	3.41%	3.41%	3.41%	3.41%

TABLE 8
Comparison of Class Indexed RORs Under Alternative Allocation Methods

	I&M	OUCC			
Rate Class	6-CP Gen 6-CP Trans	P&A Gen 12-CP Trans	12-CP Gen 12-CP Trans	BIP Gen 12-CP Trans	Average All Methods
RS	93%	131%	114%	140%	128%
GS-SEC	128%	174%	120%	186%	160%
GS-PRI	167%	232%	139%	237%	203%
GS-SUB	190%	259%	68%	214%	180%
LGS-SEC	102%	70%	84%	67%	74%
LGS-PRI	94%	65%	73%	59%	66%
LGS-SUB	89%	80%	60%	66%	69%
LGS-TRAN	40%	-20%	25%	-15%	-3%
IP-SEC	89%	53%	71%	44%	56%
IP-PRI	94%	33%	71%	21%	42%
IP-SUB	72%	15%	52%	0%	22%
IP-TRAN	64%	-48%	27%	-76%	-32%
MS	104%	141%	77%	143%	120%
WSS-SEC	122%	32%	86%	14%	44%
WSS-PRI	105%	12%	76%	-7%	27%
WSS-SUB	136%	27%	98%	8%	44%
EHG	158%	214%	146%	213%	191%
IS	333%	319%	374%	283%	325%
OL	250%	126%	257%	101%	161%
SL	330%	90%	348%	49%	162%
Total	100%	100%	100%	100%	100%

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE PROPER CLASS ALLOCATION OF I&M'S COST OF SERVICE?

A. The P&A, 12-CP, and BIP methods recognize the fact that I&M's generation resources are utilized to meet energy requirements throughout the year, yet, also places some cost responsibility on class peak demands. Furthermore, the allocation of transmission costs based on 12-CP demands strikes a reasonable balance between varying theories concerning cost causation for transmission-related costs. It is my opinion that each of these three methods should be considered in evaluating class profitability.

IV. <u>CLASS REVENUE ALLOCATION</u>

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 schedule revenue responsibility. Class cost allocation results should be considered, but as discussed in detail earlier in my testimony, are not surgically precise. As such, they should only be used as a guide and used 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 that should 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 I&M WITNESS NOLLENBERGER CLAIM TO HAVE CONSIDERED THE VARIOUS SUBJECTIVE CRITERIA AS WELL AS THE BROAD PARAMETERS DISCUSSED ABOVE WITHIN HIS CLASS REVENUE DISTRIBUTION PROPOSAL?

A. In general, yes. Although Mr. Nollenberger utilized a purely mathematical approach to develop his proposed class revenue increases to base rates, his approach was to provide above average increases to those classes with rates of return below the total retail current rate of return and below average increases to those classes with rates of return in excess of the total retail current rate of return. Moreover, Mr. Nollenberger indicates that he considered gradualism in his method by only eliminating 25% of each class's so-called subsidy"[12] with a constraint that no class should receive a rate decrease. Mr.

[12] Mr. Nollenberger's "subsidy" calculations are based on Mr. Spaeth's 6-CP CCOSS results wherein each class's allocated required rate of return is compared to the earned rate of return at current rates.

Nollenberger's recommended class revenue increases to base rates are provided in his Attachment MWN-2, page 4. In this regard, it should be understood that the class increases shown in Attachment MWN-2, page 4 do not reflect the "all in" revenues or revenue increases proposed in this case, but rather, only reflect the Company's proposed changes to base rates net of the change to those riders that are now proposed to be reflected in base rates. I&M witness Duncan provides I&M's proposed "all in" revenue increases that reflect the impacts of base rates as well as all proposed riders. These "all in" increases are provided in Ms. Duncan's Attachment JCD-2, page 1.

Q. PLEASE PROVIDE A SUMMARY OF THE COMPANY'S PROPOSED CLASS REVENUE INCREASES TO BASE RATES AS WELL AS ITS PROPOSED "ALL IN" REVENUE INCREASES.

A. The following two tables provide a summary of current and proposed class revenue increases both on a base rate and "all in" basis:

TABLE 9
I&M (Witness Nollenberger)
Proposed Base Rate Revenue Distribution[13]
($000)

Class	Current Base Rate Revenues	I&M Proposed Increase	I&M Percent Increase
RS	$500,723	$81,246	16.23%
GS-SEC	$147,100	$17,729	12.05%
GS-PRI	$2,501	$99	3.95%
GS-SUB	$59	$0	-0.09%
LGS-SEC	$222,374	$30,910	13.90%
LGS-PRI	$11,029	$1,671	15.15%
LGS-SUB	$391	$62	15.74%
LGS-TRAN	$17	$4	24.92%
IP-SEC	$43,408	$6,389	14.72%
IP-PRI	$122,933	$15,890	12.93%
IP-SUB	$42,746	$7,377	17.26%
IP-TRAN	$30,665	$4,686	15.28%
MS	$3,059	$431	14.10%
WSS-SEC	$5,579	$644	11.54%
WSS-PRI	$3,007	$426	14.17%
WSS-SUB	$636	$49	7.74%
EHG	$701	$66	9.37%
IS	$138	$12	8.85%
OL	$6,169	$411	6.66%
SL	$5,442	$380	6.98%
Total Firm	$1,148,678	$168,480	14.67%

[13] Per Attachment MWN-2, page 4.

TABLE 10
I&M (Witness Duncan)
Proposed "All In" Rate Revenue Distribution Including Riders[14]
($000)

Class	Current Revenues	I&M Proposed Increase	I&M Percent Increase
Residential	$595,757	$82,681	13.88%
Total GS	$182,483	$18,115	9.93%
Total LGS	$274,116	$33,119	12.08%
Total IP Incl. Firm IRP	$287,126	$33,365	11.62%
MS	$3,657	$379	10.36%
Total WSS	$10,792	$961	8.91%
EHG	$849	$53	6.28%
IS	$162	$0	0.00%
OL	$6,364	$159	2.50%
SL	$5,751	$0	0.00%
Total Firm	$1,367,058	$168,833	12.35%
Interruptible-Juris.	$97,359	$3,166	3.25%
Total	$1,464,416	$171,998	11.75%
Rate Design Rounding Difference		$6,197	
Grand Total	$1,464,416	$172,005	11.75%

Q. ARE THE COMPANY'S PROPOSED CLASS REVENUE ALLOCATIONS REASONABLE?

A. No. Mr. Nollenberger's proposed class base rate revenue increases are predicated entirely upon the results of Mr. Spaeth's 6-CP CCOSS, which does not fairly reflect cost causation nor produce reasonable class rates of return. Similarly, the Company's proposed "all in" revenue increases are also predicated upon Mr. Spaeth's 6-CP CCOSS.

Q. DO YOU RECOMMEND AN ALTERNATIVE CLASS REVENUE ALLOCATION?

A. Yes. In order to provide an apples-to-apples comparison of Mr. Nollenberger's recommended class revenue increases to base rates, I have developed a class revenue allocation utilizing I&M's requested increase to base rates of $168.480 million. In addition, I have also carried my recommendations through to include Petitioner's proposed

[14] Per Attachment JCD-2, page 1.

rider revenues and rider increases consistent with the "all in" revenue allocation shown in Ms. Duncan's Attachment JCD-2.

In developing my proposed base rate class revenue allocation, I have considered the results of my recommended class cost of service studies utilizing the P&A, 12-CP, and BIP methods. I then required that all classes move closer to rate parity, considered gradualism, limited all firm class increases to no more than 1.50 times the system-wide average firm percentage increase, and required that all classes receive at least half of the system-wide average firm percentage increase. The development of my recommended base rate class revenue allocation is provided in my Attachment GAW-6.

To illustrate how each firm class' increase was determined and as shown in my Attachment GAW-6, consider Rate GS-Secondary. This class exhibits a current rate of return somewhat above the system average rate of return such that I have assigned this class 80% of the system average percentage increase to firm base rate revenues; i.e., a 11.73% increase compared to a total firm increase of 14.67%. To further explain, consider Rate IP-Transmission. All cost of service methods show that this class' rate of return is substantially lower than the system average rate of return. As a result, I have increased this class' base rate revenues at 150% of the system average percent increase to base rate firm revenues; i.e., 22.00%. Each class was evaluated separately wherein the Residential class was treated as the residual in order to achieve an increase of $168.480 million in firm base rate revenues.

Q. PLEASE PROVIDE A COMPARISON OF YOUR BASE RATE REVENUE ALLOCATION TO THAT PROPOSED BY I&M WITNESS NOLLENBERGER.

A. The following table provides a comparison of base rate revenue increases under Mr. Nollenberger's and my proposed revenue allocations:

TABLE 11
Comparison of Base Rate Revenue Allocations
($000)

Class	Current Revenue	I&M Proposed Increase $	I&M Proposed Increase %	OUCC Proposed Increase $	OUCC Proposed Increase %
RS	$500,723	$81,246	16.23%	$62,827	12.55%
GS-SEC	$147,100	$17,729	12.05%	$17,260	11.73%
GS-PRI	$2,501	$99	3.95%	$275	11.00%
GS-SUB	$59	$0	-0.09%	$6	11.00%
LGS-SEC	$222,374	$30,910	13.90%	$35,878	16.13%
LGS-PRI	$11,029	$1,671	15.15%	$1,860	16.87%
LGS-SUB	$391	$62	15.74%	$66	16.87%
LGS-TRAN	$17	$4	24.92%	$4	22.00%
IP-SEC	$43,408	$6,389	14.72%	$7,959	18.33%
IP-PRI	$122,933	$15,890	12.93%	$22,539	18.33%
IP-SUB	$42,746	$7,377	17.26%	$9,405	22.00%
IP-TRAN	$30,665	$4,686	15.28%	$6,747	22.00%
MS	$3,059	$431	14.10%	$404	13.20%
WSS-SEC	$5,579	$644	11.54%	$1,023	18.33%
WSS-PRI	$3,007	$426	14.17%	$662	22.00%
WSS-SUB	$636	$49	7.74%	$117	18.33%
EHG	$701	$66	9.37%	$77	11.00%
IS	$138	$12	8.85%	$10	7.33%
OL	$6,169	$411	6.66%	$724	11.73%
SL	$5,442	$380	6.98%	$639	11.73%
Total Firm	$1,148,678	$168,480	14.67%	$168,480	14.67%
Interruptible-Juris.	$94,345	$0	0%	$0	0%
Total Juris.	$1,243,023	$168,480	13.55%	$168,480	13.55%

Q. PLEASE PROVIDE A COMPARISON OF YOUR "ALL IN" REVENUE ALLOCATION TO THAT PROPOSED BY I&M.

A. As mentioned earlier, I&M is proposing changes to several of its existing riders as well as new riders. For comparison purposes, I have incorporated my recommended base rate revenue increases to the changes in rider revenues proposed by I&M in order to provide an "all in" rate comparison to that of Petitioner. The following table provides a comparison of the "all in" increases by major rate class:

TABLE 12
Comparison of Total "All In" Revenue Allocations ($000)

Class	Total Current Revenues[17]	I&M Proposed Total Increase[15] $	I&M Proposed Total Increase[15] %	OUCC Proposed Total Increase[16] $	OUCC Proposed Total Increase[16] %
Residential	$595,757	$82,687	13.88%	$64,268	10.79%
Total GS	$182,483	$18,115	9.93%	$17,829	9.77%
Total LGS	$274,116	$33,119	12.08%	$38,282	13.97%
Total IP Incl. Firm IRP	$287,126	$33,365	11.62%	$45,671	15.91%
MS	$3,657	$379	10.36%	$352	9.61%
Total WSS	$10,792	$961	8.91%	$1,643	15.23%
EHG	$849	$53	6.28%	$65	7.63%
IS	$162	$0	0.00%	-$2	-1.29%
OL	$6,364	$159	2.50%	$472	7.42%
SL	$5,751	$0	0.00%	$259	4.50%
Total Firm	$1,367,058	$168,839	12.35%	$168,839	12.35%
Interruptible-Juris.	$97,359	$3,166	3.25%	$3,166	3.25%
Total	$1,464,416	$172,005	11.75%	$172,005	11.75%

Q. IN THE EVENT THE COMMISSION AUTHORIZES AN OVERALL BASE RATE REVENUE INCREASE LESS THAN THE $168.480 MILLION REQUESTED BY I&M, HOW SHOULD THE ULTIMATE INCREASE TO BASE RATE REVENUES BE DISTRIBUTED ACROSS RATE SCHEDULES?

A. I recommend that any overall increase be distributed to rate classes in proportion to the class revenue increases I propose above.

V. RESIDENTIAL RATE DESIGN

Q. PLEASE EXPLAIN THE COMPANY'S CURRENT AND PROPOSED RESIDENTIAL RATE STRUCTURES.

A. I&M offers three separate rate schedules for Residential customers: Rate RS; Rate RS-TOD; and, an experimental Rate RS-TOD2. Although the vast majority of Residential customers take service under Rate RS, approximately 1,428 customers have elected for the

[15] Per Attachment JCD-2, page 1, includes rate design rounding (per Reconciliation tab of Attachment JCD-2 Workpaper).
[16] OUCC base rate revenue increase applied to I&M's proposed riders provided in Attachment JCD-2.
[17] Per Attachment JCD-2, page 1.

optional RS-TOD Rate and approximately 131 customers participate in the optional RS-TOD2 Rate. With regard to Rate RS, the rate structure is currently comprised of a fixed monthly customer charge of $10.50 and a flat base energy charge per KWH. The Company proposes to increase the fixed monthly customer charge by 43% to $15.00 and change the rate structure to a declining-block energy charge. With regard to Rate RS-TOD, the current monthly customer charge is $11.50 wherein the Company proposes to increase this fixed charge to $16.50 per month. The current Rate RS-TOD2 is $10.50 per month and the Company proposes to increase this fixed charge to $15.00 per month.

Q. DOES MR. NOLLENBERGER OFFER HIS OPINIONS REGARDING THE REASONABLENESS OF HIS PROPOSED 43% INCREASE IN THE RATE RS CUSTOMER CHARGE ALONG WITH HIS PROPOSAL TO IMPLEMENT A DECLINING-BLOCK RATE STRUCTURE FOR THIS RATE SCHEDULE?

A. Yes. Mr. Nollenberger offers several opinions in these regards. First, as a general matter, Mr. Nollenberger claims on page 14 of his direct testimony that "Today's Tariff R.S. rate structure presents several challenges for both customers and the Company alike." In response to this opinion, it is well known that a Residential rate structure comprised of a relatively low fixed monthly customer charge and a flat usage (energy or KWH) charge has been used successfully for well over 100 years in the industry. The electric industry has, and continues to, remain profitable under this historically accepted rate structure. I am unaware of any new "challenges" confronting I&M or the electric industry in general regarding this issue. With regard to specifics, Mr. Nollenberger provides three opinions on pages 14 and 15 of his direct testimony in support of his proposed Rate RS customer charge and proposed declining-block energy charge.

Mr. Nollenberger's first opinion is that "there is a potential for the Company to significantly over- or under-collect its fixed costs when actual weather presents extreme temperature deviations from the estimated Test Year weather assumptions." In response to this opinion, I provide the following factual responses. First, it should be remembered that I&M is utilizing a forecasted test year that incorporates normal weather conditions such that the revenue requirement established in this case is not based upon any abnormal weather or other abnormal usage characteristics. Second, and perhaps most important, is the fact that I&M is a business enterprise and should not act as governmental taxing agency with guaranteed revenue recovery. Indeed, it is often said and generally agreed that for investor-owned utilities, regulation should serve surrogate for competition to the largest extent practical.

Mr. Nollenberger's second opinion in support of his Residential rate design proposals is that "rate design does not send price signals that effectively reflect the underlying nature of the cost incurred to serve the Company's residential customers." Mr. Nollenberger's statement is based on his assertion that:

> While cost causation principles may support recovery of 100% of fixed costs through fixed charges, or a "straight fixed variable" ("SFV") rate design, that is not what the Company proposes in this case. Rather I&M's proposed declining block energy rate structure provides a compromise structure that maintains a large amount of fixed cost recovery through the volumetric kWh charge, but one that prices the higher usage block closer to the true variable cost of energy. Therefore, the Company's proposal in this proceeding improves the alignment of residential costs and rates without introducing a straight fixed variable rate design.[18]

What Mr. Nollenberger is saying above is that his proposed 43% increase to the Residential fixed monthly customer charge along with the reduced risk associated with a declining-block rate structure is cost justified due to his perception that I&M is entitled to a guaranteed recovery of fixed costs.[19] To this end, I will note that the Company will have every reasonable opportunity to recover its authorized revenue requirement under the existing rate structure and under lower fixed monthly customer charges. While there is no denying the fact that higher customer charges along with declining-block rates reduce the risk to a utility through more guaranteed revenue recovery, the reality is, Mr. Nollenberger's Rate RS rate design proposals are nothing more than an attempt to further reduce the Company's risk of revenue collection.

Mr. Nollenberger's third opinion in support of his Residential rate design proposals is that "a rate design that recovers a disparate amount of fixed costs through volumetric energy charges has the potential to introduce intra-class subsidies paid by high energy users to low energy users." I strongly disagree with Mr. Nollenberger's opinion for two reasons.

[18] Direct testimony of Mr. Nollenberger, page 16, lines 12 through 19.

[19] Because Residential energy (KWH) usage tends to be weather sensitive, a declining-block rate reduces the risk to a utility because more revenue is collected from the higher priced first usage block (that is not weather sensitive) than the remaining lower priced usage blocks.

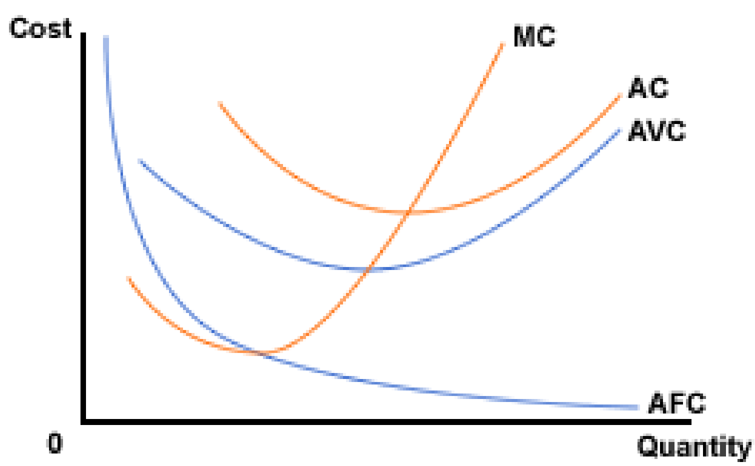
First, it should be remembered that I&M's system is constructed to serve all customers. I&M's system has been in place for generations and with its poles and wires installed along virtually every street and road in its service area. When a new customer applies for service, but for the incremental investment required to connect that customer (e.g., service drop and meter), that customer will utilize the existing system. If the new customer is a low usage customer, this does not mean that he is being subsidized by other large volume customers, but rather, is contributing to the overall cost of I&M's system. Indeed, Mr. Nollenberger characterizes any customer that uses less energy and contributes less revenue than the average is somehow being subsidized. This is incorrect in that an economic subsidy only exists if the customer in question is not contributing at least the short-run marginal cost to serve that customer. The second reason for my disagreement relates to I&M's current approved Tariff as it relates to new customer connections. Paragraph 14 of Petitioner's Tariff relating to Terms and Conditions states as follows:

> The Company shall, upon proper application for service from overhead and/or underground distribution facilities, provide necessary facilities for rendering adequate service, without charge for such facilities, when the estimated total revenue for a period of two and one-half years to be realized by the Company from permanent and continuing customers on such extension is at least equal to the estimated cost of such extension. If the estimated cost of the extension required to furnish adequate service is greater than the total estimated revenue from such extension, such an extension shall be made by the Company under the following conditions:
>
> (a) Upon proper applications for such extension and adequate provision for payment to the Company by such applicants of that part of the estimated cost of such extension over and above the amount which would have qualified as provided for above, the Company shall proceed with such extension . . . .

As indicated, Petitioner's own Tariff already contains a provision to prevent inequities that might accrue as a result of low volume customers utilizing the system. That is, new low volume customers that do not generate enough revenue to justify the investment required to connect a new customer are required to make a Contribution in Aid of Construction in order to be connected and obtain service from I&M.

Q. IS THERE AN ECONOMIC REASON WHY MR. NOLLENBERGER'S ASSERTION THAT LARGE USAGE CUSTOMERS SUBSIDIZE SMALL USAGE CUSTOMERS IS INCORRECT AND BEARS NO RESEMBLANCE TO INTRA-CLASS COST INCIDENCE?

A. While there is no doubt that the vast majority of I&M's non-fuel costs are sunk, or fixed costs in the short-run, all costs are variable in the long-run. Simply because customers that use more electricity contribute more revenue than do smaller volume customers, and hence, provide more recovery of the Company's total costs (which are largely fixed in nature) tells us nothing about the cost incurrence between small and large customers. To illustrate these points, consider the classical cost curves that are used as a foundation in economic price theory:



As can be seen in the above graph, as quantity (volume) increases, average fixed costs per unit ("AFC") decline. This is exactly what Mr. Nollenberger implies. That is, as customers' sales volumes increase, they contribute more to fixed costs such that their contribution to average fixed costs are lower than those of smaller volume customers. What is most important is to observe the marginal cost ("MC") curve. Marginal costs are incremental costs in that they measure the change in costs relative to a change in quantity. As shown in the above graph, as quantity (volume) increases, the marginal (incremental) cost per unit of providing service also increases.

Indeed, these classical cost curves serve as the foundation not only for price theory but also as the cornerstone for various Demand-Side Management ("DSM") programs in place throughout the country. That is, by implementing programs to reduce peak demand (which costs are generally fixed in the short-run but variable in the long-run), long-run marginal costs are reduced as are long-run total costs. As a parallel, to accept Mr. Nollenberger's assertion that as consumers use more electricity, average total fixed costs decline, would necessarily mean there is no economic or public policy need for any DSM programs for any utility in the country.

Q. ARE I&M'S PROPOSED RATE RS FIXED CUSTOMER CHARGES AND PROPOSED IMPLEMENTATION OF A DECLINING-BLOCK ENERGY RATE CONTRARY TO EFFECTIVE CONSERVATION EFFORTS?

A. Yes. High fixed charge and declining-block 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 SFV pricing method[20] 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 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.[21] 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… .[22]

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

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

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

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.[23]

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 coupled with a declining-block volumetric energy charge sends an even stronger price signal to consumers to use more energy.

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. AS IT RELATES TO PUBLIC POLICY, DO YOU HAVE ANY GENERAL COMMENTS CONCERNING THE ESTABLISHMENT OF FIXED MONTHLY CUSTOMER CHARGES?

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

A. Yes. Several Commissions in the Country have a policy of maintaining relatively low fixed monthly customer charges primarily due to the reasoning that customers should have greater flexibility in controlling their energy bills with revenues collected primarily through volumetric rates as well as concerns over the affordability of energy by low income and low usage customers. Examples of States with this policy include: Maryland, Washington State, Virginia, Montana, Oregon, and South Carolina. Other State Commissions have allowed and established very high fixed monthly customer charges primarily due to the reasoning that fixed costs should be recovered from fixed charges and that fixed charges promote a greater level of revenue stability to utilities. Examples of this high customer charge policy States include: Ohio and New York.

My philosophy and opinions align with those States that have a policy of maintaining relatively low fixed monthly customer charges. I&M is in the business of providing electricity to its customers such that the most equitable method of collecting revenues from its customers should be based upon the utilization of the Company's facilities and resources. Furthermore, as a matter of conservation as well as equity, the establishment of relatively low fixed charges enables customers to more easily control their energy bills. In these regards, the ratemaking process is such that rates are developed with the best expectation that the company will have an opportunity to recover its costs and collects its authorized revenue requirement. This is true even with relatively low customer charges.

My philosophy is particularly relevant within Indiana's ratemaking process given the fact that I&M is entitled to use a fully projected future test year for ratemaking as well as the numerous guaranteed cost recovery riders that are in place within I&M's tariff.

Q. HAVE YOU CONDUCTED ANY STUDIES OR ANALYSES TO INDICATE THE LEVELS AT WHICH I&M'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 A DIRECT CUSTOMER COST ANALYSIS APPLICABLE TO I&M'S RESIDENTIAL CLASS?

A. Yes. I conducted a direct customer cost analysis of I&M's Residential class. The details of this analysis are provided in my Attachment GAW-7. As indicated in this Attachment, the Residential direct customer cost is calculated to be between $8.77 and $9.27 per month. The lower cost of $8.77 is based on a 9.10% return on equity as recommended by OUCC witness David Garrett, while the higher cost of $9.27 is based on the Company's requested return on equity of 10.50%. In this regard, a cost of equity of even 9.10% overstates the risks associated with fixed monthly customer charges. This is because customer charges are "fixed" charges such that there is virtually no risk associated with this charge.

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

A. Like all electric utilities, I&M 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 I&M's services simply to be "connected," overhead and indirect costs are most appropriately recovered through volumetric energy charges.

Q. BASED ON YOUR OVERALL EXPERIENCE AS WELL AS THE STUDIES AND ANALYSES YOU HAVE CONDUCTED FOR THIS CASE, WHAT ARE YOUR RECOMMENDATIONS REGARDING RESIDENTIAL RATE DESIGN FOR THIS CASE?

A. Although my customer cost analysis indicates that a customer charge of no more than $8.77 to $9.27 is warranted, I recommend that the current Residential monthly customer charges ($10.50 for Rate RS, $11.50 for Rate RS-TOD and $10.50 RS-TOD2) be maintained at their current levels. This maintaining of the current Residential customer charges will promote rate continuity as well as promoting conservation as any increase authorized in this case will be collected from the Residential energy charges thereby, sending a more appropriate price signal for customers to conserve and use energy more efficiently.

With regard to Rate RS energy charges, I recommend the rejection of the Company's proposed declining-block rate structure and maintaining the current flat energy charge per KWH.

Q. PLEASE BRIEFLY SUMMARIZE WHY YOUR RECOMMENDED RESIDENTIAL RATE DESIGN IS APPROPRIATE.

A. It must be remembered that my proposed rate design will allow I&M a reasonable opportunity to recover all of its costs and earn a fair rate of return. Utilities advocate higher Residential fixed customer charges and declining-block rates structures in order to minimize their risks by guaranteeing revenue recovery through fixed or largely unavoidable charges. Whether electricity rates are largely volumetric priced or largely based on fixed charges, the reality is that the utility will collect its required revenues. This is particularly relevant in this case since the Company is using a forecasted test year that incorporates energy usage (KWH) under normal weather conditions. Rate designs structured largely based on flat volumetric charges promote conservation, are efficient, and allow customers to better manage their total electric bills by varying their energy usage. Rate designs structured with large fixed monthly customer charges or declining-block energy charges are contrary to conservation, are inefficient, and stifle customers' abilities to manage their electric bills.

Q. DO YOU HAVE ANY COMMENTS OR RECOMMENDATIONS RELATING TO THE COMPANY'S PROPOSED OPTIONAL RESIDENTIAL DEMAND METERED TARIFF?

A. Yes. I&M is proposing an optional pilot rate entitled "Residential Service – Demand Metered (Tariff RSD). This experimental rate will be limited to 4,000 customers and can be referred to as a three-part rate schedule which consists of a fixed monthly customer charge, a demand charge (per KW) and a flat energy charge (per KWH). Because this proposed rate schedule is optional in that it will provide customers with another service alternative, I do not object to this proposed pilot rate. However, the purpose of every pilot, or experimental, program is to gather and obtain information. As such, if the Pilot Rate RSD is approved, I recommend that the Commission direct I&M to keep and maintain specific records on a customer by customer basis that compares each customer's actual RSD bills (and billing determinants) to those that would have resulted under Rate RS and Rate RS-TOD. Furthermore, the Company should be required to submit detailed reports, data, and workpapers to the Commission, OUCC, and other interested parties on at least an annual basis.

VI. BILLING DETERMINANTS

Q. HAVE YOU EXAMINED THE COMPANY'S FORECASTED TEST YEAR BILLING DETERMINANTS BY RATE SCHEDULE?

A. Yes.

Q. DID YOUR EXAMINATION REVEAL APPARENT ANOMALIES?

A. Yes. As part of my investigation, I compared the Company's customer and energy forecasts sponsored by Chad Burnett (summarized in Attachment CMB-1) to the customer and energy billing determinants used to project forecasted test year revenues at current rates as well as to design rates (provided in Attachment JCD-2). In conducting my investigation, I determined that Mr. Burnett's forecasted energy (KWH) sales were consistent with the energy billing determinants contained in Attachment JCD-2. However, there was a significant difference in the number of customers (and corresponding bills) between Mr. Burnett's forecast and those used to estimate forecasted test year revenues and design rates. Based on informal discussions with the Company, it was determined there was an error in developing the forecasted test year billing determinants as it relates to number of customers and number of bills. As a result, OUCC propounded data request number OUCC-36-01 that inquired about this apparent discrepancy. The Company's response (with attachment) is provided in my Attachment GAW-8.

In response to OUCC-36-01, the Company corrected its forecasted billing determinants by rate schedule which has the effect of increasing the number of customer bills for most rate schedules, which in turn, increases customer charge revenue at current rates. As a result, I have applied the Company's corrected number of customer bills by rate schedule originally provided in Attachment JCD-2. My corrected revenues are provided by rate schedule in my Attachment GAW-9 which results in an increase to forecasted test year revenues at current rates of $3,758,305.[24]

VI. FUTURE SDI CONTRACT NEGOTIATIONS

Q. DOES I&M HAVE ANY SPECIAL OR NEGOTIATED CONTRACT RATES?

A. I&M has one special contract customer which is Steel Dynamics, Incorporated ("SDI"). This special contract was approved by the Commission in Cause No. 45120, which was the Fourth Amendment to the existing contract between I&M and SDI.

Q. WAS THERE A SIGNIFICANT CHANGE IN THE TERMS OF SERVICE AS A RESULT OF THE FOURTH AMENDMENT TO THE SDI CONTRACT?

A. Yes. Prior to the Fourth Amendment to the SDI contract approved in Cause No. 45120, SDI's service was considered **[BEGIN CONFIDENTIAL]** [redacted]. [redacted][25] **[END CONFIDENTIAL]**.

Q. IS I&M PROPOSING ANY CHANGES OR INCREASES TO SDI'S RATE IN THIS RATE CASE?

A. No. The Commission approved the contract rates for SDI in Cause No. 45120 such that no increase is proposed as a result of I&M's application in this case.

Q. ARE YOU PROPOSING OR RECOMMENDING ANY CHANGE IN SDI'S RATES AS A DIRECT RESULT OF THIS RATE CASE?

A. No. This portion of my testimony is to assist the Commission in evaluating any future proposed contracts between I&M and SDI. This information is particularly relevant because in prior applications for a special contract with SDI, there has been little to no cost information available to the Commission or parties in evaluating the reasonableness of the proposed contracts. As a result, I have conducted studies of the cost to serve SDI that can then be used by the Commission and other parties in evaluating the reasonableness of future proposed special contracts applicable to SDI.

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[24] The details supporting my Attachment GAW-8 are provided in my Confidential workpapers.

[25] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. HOW DID YOU DEVELOP YOUR ESTIMATES OF THE COST TO SERVE SDI?

A. Because SDI is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** As a result of discovery, I obtained forecasted test year load and energy data specific to SDI in response to OUCC-23-08, OUCC-23-13, and OUCC-23-17. With this information I was able to develop allocation factors associated with SDI.

Once SDI's allocation factors were developed, I then applied these factors to I&M's jurisdictional overall requested future test year cost of service and allocated costs to SDI in the same manner as all other classes.

Q. WHAT METHODS DID YOU USE TO ALLOCATE COSTS TO SDI?

A. I have estimated SDI's cost of service utilizing the 6-CP approach proposed by I&M in this case as well as using the 12-CP to allocate generation and transmission-related costs. As a note, I have not conducted studies of the cost to serve SDI under the P&A and BIP methods in order to minimize unnecessary detail. Rather, the 6-CP and 12-CP methods provide a reasonable range of the "costs" to serve SDI.

Q. WHAT ARE THE RESULTS OF YOUR STUDIES TO ESTIMATE THE COST TO SERVE SDI?

A. A summary of SDI's revenue requirement is provided in the following two tables. Table 13 utilizes a required return on equity of 9.10% while Table 14 utilizes a required return on equity of 10.50%.

[BEGIN CONFIDENTIAL]

TABLE 13
SDI Indiana Revenue Requirement[26]
ROE @ 9.10%

	Current Revenue	Required Increase	Revenue Requirement
6-CP	$[redacted]	$[redacted]	$[redacted]
12-CP	$[redacted]	$[redacted]	$[redacted]

[26] Reflects the Indiana jurisdictional portion of total SDI which is 69.4520% per Attachment JCD-1.

TABLE 14
SDI Indiana Revenue Requirement[26]
ROE @ 10.50%

	Current Revenue	Required Increase	Revenue Requirement
6-CP	$[redacted]	$[redacted]	$[redacted]
12-CP	$[redacted]	$[redacted]	$[redacted]

[END CONFIDENTIAL]

A summary of my cost of service studies applicable to SDI is provided in my Confidential Attachment GAW-10, while the details of my studies are provided in my filed workpapers.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

BACKGROUND & EXPERIENCE PROFILE

GLENN A. WATKINS

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

Jan. 2017-Present	President/Senior Economist, Technical Associates, Inc.
Mar. 1993-Dec. 2016	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.

GLENN A. WATKINS

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 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

INDIANA MICHIGAN POWER COMPANY
I&M Generation Characteristics

Actual 2018

	Total	Rockport (I&M Share) 1	Rockport (I&M Share) 2	Cook 1	Cook 2		Hydro	Solar
Max Output MW	[redacted]						[redacted]	
Total Energy MWH						2/		
Pct. of Generation								
Operational Capacity Factors [1]						2/		

Actual 2017

	Total	Rockport (I&M Share) 1	Rockport (I&M Share) 2	Cook 1		Cook 2	Hydro	Solar
Max Output MW	[redacted]					[redacted]		
Total Energy MWH					3/			
Pct. of Generation								
Operational Capacity Factors [1]					3/			

2-Year Average:

	Total	Rockport (I&M Share) 1	Rockport (I&M Share) 2	Cook 1	Cook 2	Hydro	Solar
Pct. of Generation	[redacted]						
Operational Capacity Factors [1]							

[1] Calculated as: annual MWH divided by number of hours in the year divided by maximum hourly output.
[2] Reflects 7,027 hours instead of 8,760 hours due to refueling from March 1 through May 11, 2018.
[3] Reflects 6,811 hours instead of 8,760 hours due to refueling from September 11 through December 1, 2017.

Sources: Confidential responses to OUCC-26-03, 26-04, and 26-05.

INDIANA MICHIGAN POWER COMPANY
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PEAK AND AVERAGE COST OF SERVICE STUDY

	Total Retail	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRAN	IP-SEC	IP-PRI
Operating Income											
Revenue:											
Firm Sales	$ 1,148,678,098	$ 500,722,762	$ 147,099,807	$ 2,501,480	$ 59,066	$ 222,373,945	$ 11,029,146	$ 391,131	$ 17,288	$ 43,408,192	$ 122,932,643
Interruptible	$ 94,345,014	$ 35,159,699	$ 10,353,868	$ 178,642	$ 3,287	$ 20,439,001	$ 1,064,828	$ 40,178	$ 1,973	$ 4,119,590	$ 12,614,108
Sales for Resale	$ 124,696,131	$ 42,956,925	$ 12,686,092	$ 232,251	$ 6,218	$ 27,467,570	$ 1,459,632	$ 59,682	$ 2,377	$ 5,825,867	$ 18,108,786
Other Operating Revenues	$ 129,987,221	$ 57,399,104	$ 15,600,535	$ 276,395	$ 9,232	$ 24,819,615	$ 1,304,298	$ 68,623	$ 1,428	$ 4,913,860	$ 14,151,513
Gain on Disp of Emission Const. Allow.	$ 35,671	$ 12,288	$ 3,629	$ 66	$ 2	$ 7,857	$ 418	$ 17	$ 1	$ 1,667	$ 5,180
Total Operating Revenue	$ 1,497,742,135	$ 636,250,779	$ 185,743,931	$ 3,188,835	$ 77,806	$ 295,107,989	$ 14,858,322	$ 559,631	$ 23,068	$ 58,269,176	$ 167,812,230
Expenses:											
Operating & Maintenance	$ 932,962,529	$ 360,905,687	$ 100,471,341	$ 1,688,295	$ 39,443	$ 195,864,679	$ 10,133,207	$ 386,549	$ 18,012	$ 40,076,722	$ 121,414,451
Depreciation & Amortization	$ 322,482,905	$ 137,695,005	$ 37,002,236	$ 559,616	$ 12,595	$ 65,110,696	$ 3,179,201	$ 109,014	$ 5,517	$ 12,922,179	$ 36,593,577
Regulatory Debits/Credits	$ 1,310,661	$ 488,446	$ 143,838	$ 2,482	$ 46	$ 283,943	$ 14,793	$ 558	$ 27	$ 57,230	$ 175,238
Taxes Other Than Income	$ 83,988,863	$ 36,913,570	$ 10,037,829	$ 155,011	$ 3,744	$ 16,500,644	$ 801,545	$ 27,750	$ 1,318	$ 3,249,868	$ 9,072,165
Other O&M Expenses	$ 8,458,095	$ 3,664,445	$ 1,073,301	$ 18,190	$ 426	$ 1,647,350	$ 81,815	$ 2,906	$ 130	$ 322,204	$ 915,460
State Income Taxes	$ (1,295,866)	$ 1,044,549	$ 877,532	$ 24,491	$ 767	$ (975,381)	$ (52,545)	$ (1,221)	$ (249)	$ (266,728)	$ (995,900)
Total Federal Income Taxes (Current + Deferred)	$ (19,081,043)	$ (1,924,350)	$ 1,717,594	$ 68,107	$ 2,238	$ (6,600,218)	$ (340,487)	$ (9,649)	$ (1,164)	$ (1,599,685)	$ (5,428,172)
Total Expenses	$ 1,328,826,145	$ 538,787,351	$ 151,323,672	$ 2,516,192	$ 59,258	$ 271,831,713	$ 13,817,527	$ 515,906	$ 23,591	$ 54,761,791	$ 161,746,819
Net Operating Income	$ 168,915,990	$ 97,463,427	$ 34,420,259	$ 672,643	$ 18,548	$ 23,276,276	$ 1,040,795	$ 43,725	$ (523)	$ 3,507,386	$ 6,065,411
Rate Base:											
Gross Plant	$ 7,247,120,442	$ 3,168,816,406	$ 844,331,072	$ 12,517,197	$ 304,643	$ 1,444,531,300	$ 69,530,736	$ 2,386,674	$ 115,272	$ 285,523,050	$ 791,141,599
Accum. Depreciation and Amortization	$ (2,525,787,876)	$ (1,072,017,986)	$ (290,903,660)	$ (4,455,094)	$ (103,491)	$ (511,877,850)	$ (25,097,295)	$ (886,140)	$ (42,586)	$ (101,605,321)	$ (288,109,451)
Net Plant	$ 4,721,332,565	$ 2,096,798,420	$ 553,427,411	$ 8,062,103	$ 201,152	$ 932,653,449	$ 44,433,441	$ 1,500,534	$ 72,686	$ 183,917,729	$ 503,032,148
Working Capital	$ 157,001,138	$ 59,431,644	$ 17,136,369	$ 291,081	$ 6,336	$ 33,611,925	$ 1,735,071	$ 66,027	$ 3,042	$ 6,842,730	$ 20,666,014
Rate Base Offsets	$ 68,628,497	$ 25,525,207	$ 7,205,749	$ 128,880	$ 2,339	$ 14,526,205	$ 786,019	$ 31,117	$ 1,581	$ 2,947,228	$ 9,448,163
Total Rate Base	$ 4,946,962,201	$ 2,181,755,271	$ 577,769,529	$ 8,482,064	$ 209,828	$ 980,791,580	$ 46,954,532	$ 1,597,678	$ 77,310	$ 193,707,687	$ 533,146,325
Rate of Return	3.41%	4.47%	5.96%	7.93%	8.84%	2.37%	2.22%	2.74%	-0.68%	1.81%	1.14%
INDEX ROR		131%	174%	232%	259%	70%	65%	80%	-20%	53%	33%

INDIANA MICHIGAN POWER COMPANY
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PEAK AND AVERAGE COST OF SERVICE STUDY

	Total Retail	IP-SUB	IP-TRA	MS	WSS_SEC	WSS_PRI	WSS_SUB	EHG	IS	OL	SL
Operating Income											
Revenue:											
Firm Sales	$ 1,148,678,098	$ 42,746,124	$ 30,664,651	$ 3,058,727	$ 5,579,327	$ 3,006,878	$ 636,376	$ 701,451	$ 137,952	$ 6,169,229	$ 5,441,923
Interruptible	$ 94,345,014	$ 4,963,583	$ 3,741,370	$ 232,376	$ 526,621	$ 315,227	$ 70,888	$ 44,708	$ 4,030	$ 181,145	$ 289,890
Sales for Resale	$ 124,696,131	$ 7,383,070	$ 5,751,746	$ 305,441	$ 800,331	$ 474,077	$ 108,126	$ 60,064	$ 7,681	$ 384,642	$ 615,552
Other Operating Revenues	$ 129,987,221	$ 7,116,463	$ 2,562,313	$ 333,514	$ 592,319	$ 339,665	$ 99,051	$ 69,661	$ 5,368	$ 169,194	$ 155,071
Gain on Disp of Emission Const. Allow.	$ 35,671	$ 2,112	$ 1,645	$ 87	$ 229	$ 136	$ 31	$ 17	$ 2	$ 110	$ 176
Total Operating Revenue	$ 1,497,742,135	$ 62,211,353	$ 42,721,725	$ 3,930,145	$ 7,498,827	$ 4,135,983	$ 914,472	$ 875,901	$ 155,033	$ 6,904,319	$ 6,502,612
Expenses:											
Operating & Maintenance	$ 932,962,529	$ 47,382,135	$ 35,820,153	$ 2,266,298	$ 5,343,005	$ 3,102,976	$ 685,806	$ 449,100	$ 57,467	$ 3,217,987	$ 3,639,216
Depreciation & Amortization	$ 322,482,905	$ 12,993,374	$ 9,053,727	$ 807,899	$ 1,706,748	$ 921,880	$ 186,287	$ 163,650	$ 26,946	$ 1,778,272	$ 1,654,487
Regulatory Debits/Credits	$ 1,310,661	$ 68,955	$ 51,976	$ 3,228	$ 7,316	$ 4,379	$ 985	$ 621	$ 56	$ 2,516	$ 4,027
Taxes Other Than Income	$ 83,988,863	$ 3,180,243	$ 2,138,711	$ 214,935	$ 427,579	$ 226,720	$ 46,074	$ 45,642	$ 8,364	$ 501,204	$ 435,948
Other O&M Expenses	$ 8,458,095	$ 320,494	$ 230,108	$ 22,414	$ 41,449	$ 22,440	$ 4,754	$ 5,090	$ 980	$ 44,419	$ 39,718
State Income Taxes	$ (1,295,866)	$ (434,385)	$ (459,977)	$ 9,333	$ (47,626)	$ (31,865)	$ (5,383)	$ 6,433	$ 2,421	$ 17,658	$ (7,789)
Total Federal Income Taxes (Current + Deferred)	$ (19,081,043)	$ (2,238,612)	$ (2,151,259)	$ (975)	$ (260,863)	$ (163,424)	$ (29,012)	$ 16,915	$ 7,764	$ (23,309)	$ (122,481)
Total Expenses	$ 1,328,826,145	$ 61,272,204	$ 44,683,438	$ 3,323,132	$ 7,217,609	$ 4,083,106	$ 889,512	$ 687,453	$ 103,997	$ 5,538,748	$ 5,643,126
Net Operating Income	$ 168,915,990	$ 939,148	$ (1,961,713)	$ 607,013	$ 281,218	$ 52,877	$ 24,960	$ 188,448	$ 51,036	$ 1,365,571	$ 859,486
Rate Base:											
Gross Plant	$ 7,247,120,442	$ 278,469,970	$ 180,774,135	$ 18,405,620	$ 37,812,271	$ 19,921,144	$ 3,986,192	$ 3,765,872	$ 662,964	$ 44,283,863	$ 39,840,462
Accum. Depreciation and Amortization	$ (2,525,787,876)	$ (104,713,094)	$ (70,300,497)	$ (6,377,211)	$ (13,343,435)	$ (7,238,710)	$ (1,497,501)	$ (1,289,679)	$ (205,115)	$ (13,207,998)	$ (12,515,763)
Net Plant	$ 4,721,332,565	$ 173,756,876	$ 110,473,638	$ 12,028,409	$ 24,468,836	$ 12,682,434	$ 2,488,691	$ 2,476,193	$ 457,849	$ 31,075,865	$ 27,324,699
Working Capital	$ 157,001,138	$ 8,080,356	$ 6,003,127	$ 389,018	$ 898,091	$ 523,947	$ 116,285	$ 76,262	$ 9,022	$ 480,431	$ 634,360
Rate Base Offsets	$ 68,628,497	$ 3,898,542	$ 3,066,229	$ 158,126	$ 375,863	$ 236,168	$ 55,844	$ 30,117	$ 1,515	$ 92,861	$ 110,745
Total Rate Base	$ 4,946,962,201	$ 185,735,774	$ 119,542,994	$ 12,575,553	$ 25,742,790	$ 13,442,549	$ 2,660,819	$ 2,582,571	$ 468,386	$ 31,649,157	$ 28,069,805
Rate of Return	3.41%	0.51%	-1.64%	4.83%	1.09%	0.39%	0.94%	7.30%	10.90%	4.31%	3.06%
INDEX ROR		15%	-48%	141%	32%	12%	27%	214%	319%	126%	90%

INDIANA MICHIGAN POWER COMPANY
OUCC
12-CP GENERATION AND TRANSMISSION COST OF SERVICE STUDY

	Total Retail	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRAN	IP-SEC	IP-PRI
Operating Income											
Revenue:											
Firm Sales	$ 1,148,678,098	$ 500,722,762	$ 147,099,807	$ 2,501,480	$ 59,066	$ 222,373,945	$ 11,029,146	$ 391,131	$ 17,288	$ 43,408,192	$ 122,932,643
Interruptible	$ 94,345,014	$ 32,564,018	$ 9,632,001	$ 176,349	$ 4,719	$ 20,765,844	$ 1,103,540	$ 45,119	$ 1,798	$ 4,401,270	$ 13,670,506
Sales for Resale	$ 124,696,131	$ 42,956,925	$ 12,686,092	$ 232,251	$ 6,218	$ 27,467,570	$ 1,459,632	$ 59,682	$ 2,377	$ 5,825,867	$ 18,108,786
Other Operating Revenues	$ 129,987,221	$ 57,362,764	$ 15,566,350	$ 275,515	$ 9,179	$ 24,836,337	$ 1,304,663	$ 68,569	$ 1,433	$ 4,917,445	$ 14,173,743
Gain on Disp of Emission Const. Allow.	$ 35,671	$ 12,288	$ 3,629	$ 66	$ 2	$ 7,857	$ 418	$ 17	$ 1	$ 1,667	$ 5,180
Total Operating Revenue	$ 1,497,742,135	$ 633,618,757	$ 184,987,880	$ 3,185,662	$ 79,184	$ 295,451,553	$ 14,897,398	$ 564,518	$ 22,897	$ 58,554,441	$ 168,890,858
Expenses:											
Operating & Maintenance	$ 932,962,529	$ 369,373,772	$ 108,437,082	$ 1,893,372	$ 51,918	$ 191,968,204	$ 10,048,250	$ 398,964	$ 16,831	$ 39,241,270	$ 116,234,273
Depreciation & Amortization	$ 322,482,905	$ 141,351,787	$ 40,442,091	$ 648,174	$ 17,982	$ 63,428,077	$ 3,142,513	$ 114,375	$ 5,007	$ 12,561,405	$ 34,356,615
Regulatory Debits/Credits	$ 1,310,661	$ 511,502	$ 165,526	$ 3,040	$ 80	$ 273,334	$ 14,562	$ 592	$ 24	$ 54,956	$ 161,134
Taxes Other Than Income	$ 83,988,863	$ 37,466,119	$ 10,557,599	$ 168,392	$ 4,558	$ 16,246,396	$ 796,001	$ 28,560	$ 1,241	$ 3,195,355	$ 8,734,155
Other O&M Expenses	$ 8,458,095	$ 3,673,429	$ 1,081,753	$ 18,408	$ 439	$ 1,643,216	$ 81,725	$ 2,919	$ 128	$ 321,318	$ 909,964
State Income Taxes	$ (1,295,866)	$ 131,914	$ 109,431	$ 5,573	$ (301)	$ (601,041)	$ (42,723)	$ (2,099)	$ (150)	$ (175,343)	$ (465,548)
Total Federal Income Taxes (Current + Deferred)	$ (19,081,043)	$ (5,417,812)	$ (1,226,447)	$ (4,446)	$ (1,863)	$ (5,165,353)	$ (302,918)	$ (13,031)	$ (783)	$ (1,249,932)	$ (3,396,857)
Total Expenses	$ 1,328,826,145	$ 547,090,711	$ 159,567,036	$ 2,732,513	$ 72,812	$ 267,792,832	$ 13,737,410	$ 530,280	$ 22,298	$ 53,949,028	$ 156,533,735
Net Operating Income	$ 168,915,990	$ 86,528,046	$ 25,420,843	$ 453,149	$ 6,372	$ 27,658,721	$ 1,159,989	$ 34,239	$ 599	$ 4,605,413	$ 12,357,123
Rate Base:											
Gross Plant	$ 7,247,120,442	$ 3,236,132,107	$ 907,653,468	$ 14,147,420	$ 403,813	$ 1,413,556,889	$ 68,855,383	$ 2,485,367	$ 105,885	$ 278,881,762	$ 749,962,597
Accum. Depreciation and Amortization	$ (2,525,787,876)	$ (1,099,369,004)	$ (316,632,161)	$ (5,117,469)	$ (143,785)	$ (499,292,649)	$ (24,822,892)	$ (926,240)	$ (38,772)	$ (98,906,902)	$ (271,378,025)
Net Plant	$ 4,721,332,565	$ 2,136,763,103	$ 591,021,307	$ 9,029,951	$ 260,028	$ 914,264,241	$ 44,032,491	$ 1,559,127	$ 67,113	$ 179,974,860	$ 478,584,572
Working Capital	$ 157,001,138	$ 61,208,867	$ 18,808,163	$ 334,121	$ 8,955	$ 32,794,160	$ 1,717,241	$ 68,632	$ 2,795	$ 6,667,391	$ 19,578,834
Rate Base Offsets	$ 68,628,497	$ 26,875,146	$ 8,475,606	$ 161,572	$ 4,328	$ 13,905,049	$ 772,476	$ 33,096	$ 1,393	$ 2,814,045	$ 8,622,366
Total Rate Base	$ 4,946,962,201	$ 2,224,847,115	$ 618,305,076	$ 9,525,644	$ 273,311	$ 960,963,450	$ 46,522,208	$ 1,660,855	$ 71,300	$ 189,456,296	$ 506,785,772
Rate of Return	3.41%	3.89%	4.11%	4.76%	2.33%	2.88%	2.49%	2.06%	0.84%	2.43%	2.44%

INDIANA MICHIGAN POWER COMPANY
OUCC
12-CP GENERATION AND TRANSMISSION COST OF SERVICE STUDY

	Total Retail	IP-SUB	IP-TRA	MS	WSS_SEC	WSS_PRI	WSS_SUB	EHG	IS	OL	SL
Operating Income											
Revenue:											
Firm Sales	$ 1,148,678,098	$ 42,746,124	$ 30,664,651	$ 3,058,727	$ 5,579,327	$ 3,006,878	$ 636,376	$ 701,451	$ 137,952	$ 6,169,229	$ 5,441,923
Interruptible	$ 94,345,014	$ 5,572,220	$ 4,336,119	$ 231,777	$ 603,394	$ 357,427	$ 81,519	$ 45,564	$ 5,773	$ 286,907	$ 459,152
Sales for Resale	$ 124,696,131	$ 7,383,070	$ 5,751,746	$ 305,441	$ 800,331	$ 474,077	$ 108,126	$ 60,064	$ 7,681	$ 384,642	$ 615,552
Other Operating Revenues	$ 129,987,221	$ 7,123,609	$ 2,572,493	$ 332,518	$ 593,806	$ 340,609	$ 99,247	$ 69,464	$ 5,387	$ 172,976	$ 161,113
Gain on Disp of Emission Const. Allow.	$ 35,671	$ 2,112	$ 1,645	$ 87	$ 229	$ 136	$ 31	$ 17	$ 2	$ 110	$ 176
Total Operating Revenue	$ 1,497,742,135	$ 62,827,135	$ 43,326,655	$ 3,928,551	$ 7,577,087	$ 4,179,126	$ 925,298	$ 876,560	$ 156,795	$ 7,013,864	$ 6,677,916
Expenses:											
Operating & Maintenance	$ 932,962,529	$ 45,716,875	$ 33,447,824	$ 2,498,306	$ 4,996,435	$ 2,883,050	$ 640,152	$ 494,959	$ 53,114	$ 2,336,558	$ 2,231,320
Depreciation & Amortization	$ 322,482,905	$ 12,274,263	$ 8,029,281	$ 908,087	$ 1,557,089	$ 826,909	$ 166,572	$ 183,453	$ 25,066	$ 1,397,643	$ 1,046,514
Regulatory Debits/Credits	$ 1,310,661	$ 64,421	$ 45,517	$ 3,860	$ 6,372	$ 3,780	$ 860	$ 746	$ 44	$ 117	$ 194
Taxes Other Than Income	$ 83,988,863	$ 3,071,584	$ 1,983,915	$ 230,073	$ 404,965	$ 212,369	$ 43,095	$ 48,634	$ 8,080	$ 443,690	$ 344,082
Other O&M Expenses	$ 8,458,095	$ 318,727	$ 227,591	$ 22,661	$ 41,082	$ 22,207	$ 4,706	$ 5,139	$ 976	$ 43,484	$ 38,224
State Income Taxes	$ (1,295,866)	$ (249,754)	$ (211,264)	$ (11,965)	$ (11,823)	$ (9,488)	$ (639)	$ 2,275	$ 2,911	$ 104,011	$ 130,158
Total Federal Income Taxes (Current + Deferred)	$ (19,081,043)	$ (1,532,082)	$ (1,198,916)	$ (82,658)	$ (123,749)	$ (77,711)	$ (10,847)	$ 964	$ 9,640	$ 307,607	$ 406,153
Total Expenses	$ 1,328,826,145	$ 59,664,036	$ 42,323,948	$ 3,568,364	$ 6,870,371	$ 3,861,115	$ 843,900	$ 736,170	$ 99,833	$ 4,633,110	$ 4,196,644
Net Operating Income	$ 168,915,990	$ 3,163,100	$ 1,002,707	$ 360,187	$ 706,716	$ 318,011	$ 81,398	$ 140,390	$ 56,962	$ 2,380,754	$ 2,481,273
Rate Base:											
Gross Plant	$ 7,247,120,442	$ 265,232,252	$ 161,915,683	$ 20,249,930	$ 35,057,267	$ 18,172,872	$ 3,623,271	$ 4,130,417	$ 628,367	$ 37,277,082	$ 28,648,611
Accum. Depreciation and Amortization	$ (2,525,787,876)	$ (99,334,482)	$ (62,638,126)	$ (7,126,572)	$ (12,224,050)	$ (6,528,370)	$ (1,350,043)	$ (1,437,797)	$ (191,058)	$ (10,361,075)	$ (7,968,406)
Net Plant	$ 4,721,332,565	$ 165,897,770	$ 99,277,557	$ 13,123,359	$ 22,833,217	$ 11,644,502	$ 2,273,228	$ 2,692,620	$ 437,309	$ 26,916,006	$ 20,680,206
Working Capital	$ 157,001,138	$ 7,730,863	$ 5,505,240	$ 437,711	$ 825,355	$ 477,791	$ 106,703	$ 85,886	$ 8,109	$ 295,442	$ 338,881
Rate Base Offsets	$ 68,628,497	$ 3,633,075	$ 2,688,044	$ 195,111	$ 320,615	$ 201,108	$ 48,566	$ 37,427	$ 821	$ (47,652)	$ (113,695)
Total Rate Base	$ 4,946,962,201	$ 177,261,708	$ 107,470,841	$ 13,756,180	$ 23,979,186	$ 12,323,401	$ 2,428,497	$ 2,815,933	$ 446,239	$ 27,163,797	$ 20,905,392
Rate of Return	3.41%	1.78%	0.93%	2.62%	2.95%	2.58%	3.35%	4.99%	12.76%	8.76%	11.87%

INDIANA MICHIGAN POWER COMPANY
OUCC
BASE-INTERMEDIATE-PEAK COST OF SERVICE STUDY

	Total Retail	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRAN	IP-SEC	IP-PRI
Operating Income											
Revenue:											
Firm Sales	$ 1,148,678,098	$ 500,722,762	$ 147,099,807	$ 2,501,480	$ 59,066	$ 222,373,945	$ 11,029,146	$ 391,131	$ 17,288	$ 43,408,192	$ 122,932,643
Interruptible	$ 94,345,014	$ 34,786,404	$ 10,303,708	$ 185,004	$ 4,887	$ 20,293,734	$ 1,071,787	$ 45,924	$ 1,693	$ 4,167,092	$ 12,726,201
Sales for Resale	$ 124,696,131	$ 42,956,925	$ 12,686,092	$ 232,251	$ 6,218	$ 27,467,570	$ 1,459,632	$ 59,682	$ 2,377	$ 5,825,867	$ 18,108,786
Other Operating Revenues	$ 129,987,221	$ 57,430,766	$ 15,609,534	$ 276,430	$ 9,216	$ 24,815,531	$ 1,303,827	$ 68,563	$ 1,430	$ 4,910,427	$ 14,138,567
Gain on Disp of Emission Const. Allow.	$ 35,671	$ 12,288	$ 3,629	$ 66	$ 2	$ 7,857	$ 418	$ 17	$ 1	$ 1,667	$ 5,180
Total Operating Revenue	$ 1,497,742,135	$ 635,909,146	$ 185,702,769	$ 3,195,232	$ 79,389	$ 294,958,637	$ 14,864,810	$ 565,318	$ 22,790	$ 58,313,245	$ 167,911,377
Expenses:											
Operating & Maintenance	$ 932,962,529	$ 355,854,319	$ 99,035,689	$ 1,682,746	$ 42,136	$ 196,516,298	$ 10,208,314	$ 396,008	$ 17,680	$ 40,624,430	$ 123,479,804
Depreciation & Amortization	$ 322,482,905	$ 135,369,966	$ 36,341,436	$ 557,061	$ 13,834	$ 65,410,623	$ 3,213,771	$ 113,367	$ 5,364	$ 13,174,278	$ 37,544,216
Regulatory Debits/Credits	$ 1,310,661	$ 459,220	$ 135,532	$ 2,450	$ 61	$ 287,713	$ 15,227	$ 613	$ 25	$ 60,399	$ 187,188
Taxes Other Than Income	$ 83,988,863	$ 36,428,896	$ 9,900,079	$ 154,478	$ 4,002	$ 16,563,166	$ 808,751	$ 28,657	$ 1,286	$ 3,302,421	$ 9,270,334
Other O&M Expenses	$ 8,458,095	$ 3,656,596	$ 1,071,070	$ 18,182	$ 430	$ 1,648,363	$ 81,931	$ 2,921	$ 129	$ 323,055	$ 918,669
State Income Taxes	$ (1,295,866)	$ 1,536,244	$ 1,020,217	$ 25,388	$ 578	$ (1,048,975)	$ (59,782)	$ (1,877)	$ (230)	$ (319,672)	$ (1,199,070)
Total Federal Income Taxes (Current + Deferred)	$ (19,081,043)	$ (29,099)	$ 2,267,374	$ 71,536	$ 1,506	$ (6,883,186)	$ (368,387)	$ (12,194)	$ (1,090)	$ (1,803,785)	$ (6,211,148)
Total Expenses	$ 1,328,826,145	$ 533,276,142	$ 149,771,397	$ 2,511,840	$ 62,548	$ 272,494,001	$ 13,899,826	$ 527,495	$ 23,164	$ 55,361,126	$ 163,989,992
Net Operating Income	$ 168,915,990	$ 102,633,004	$ 35,931,373	$ 683,392	$ 16,840	$ 22,464,636	$ 964,984	$ 37,823	$ (374)	$ 2,952,119	$ 3,921,385
Rate Base:											
Gross Plant	$ 7,247,120,442	$ 3,110,165,733	$ 827,661,925	$ 12,452,765	$ 335,910	$ 1,452,097,152	$ 70,402,794	$ 2,496,496	$ 111,415	$ 291,882,409	$ 815,122,111
Accum. Depreciation and Amortization	$ (2,525,787,876)	$ (1,048,495,254)	$ (284,218,249)	$ (4,429,253)	$ (116,031)	$ (514,912,249)	$ (25,447,047)	$ (930,186)	$ (41,039)	$ (104,155,837)	$ (297,727,195)
Net Plant	$ 4,721,332,565	$ 2,061,670,479	$ 543,443,676	$ 8,023,512	$ 219,879	$ 937,184,903	$ 44,955,747	$ 1,566,311	$ 70,376	$ 187,726,571	$ 517,394,916
Working Capital	$ 157,001,138	$ 57,883,190	$ 16,696,282	$ 289,380	$ 7,162	$ 33,811,674	$ 1,758,095	$ 68,926	$ 2,941	$ 7,010,625	$ 21,299,131
Rate Base Offsets	$ 68,628,497	$ 24,178,591	$ 6,823,026	$ 127,401	$ 3,057	$ 14,699,917	$ 806,042	$ 33,638	$ 1,492	$ 3,093,239	$ 9,998,754
Total Rate Base	$ 4,946,962,201	$ 2,143,732,260	$ 566,962,984	$ 8,440,292	$ 230,098	$ 985,696,494	$ 47,519,884	$ 1,668,875	$ 74,809	$ 197,830,435	$ 548,692,801
Rate of Return	3.41%	4.79%	6.34%	8.10%	7.32%	2.28%	2.03%	2.27%	-0.50%	1.49%	0.71%
INDEX ROR		140%	186%	237%	214%	67%	59%	66%	-15%	44%	21%

INDIANA MICHIGAN POWER COMPANY
OUCC
BASE-INTERMEDIATE-PEAK COST OF SERVICE STUDY

Label	Total Retail	IP-SUB	IP-TRA	MS	WSS_SEC	WSS_PRI	WSS_SUB	EHG	IS	OL	SL
Operating Income											
Revenue:											
Firm Sales	$ 1,148,678,098	$ 42,746,124	$ 30,664,651	$ 3,058,727	$ 5,579,327	$ 3,006,878	$ 636,376	$ 701,451	$ 137,952	$ 6,169,229	$ 5,441,923
Interruptible	$ 94,345,014	$ 5,447,015	$ 3,589,989	$ 238,653	$ 541,146	$ 321,843	$ 78,058	$ 46,788	$ 4,542	$ 188,575	$ 301,969
Sales for Resale	$ 124,696,131	$ 7,383,070	$ 5,751,746	$ 305,441	$ 800,331	$ 474,077	$ 108,126	$ 60,064	$ 7,681	$ 384,642	$ 615,552
Other Operating Revenues	$ 129,987,221	$ 7,109,050	$ 2,555,043	$ 333,529	$ 591,379	$ 339,148	$ 98,921	$ 69,652	$ 5,347	$ 167,885	$ 152,977
Gain on Disp of Emission Const. Allow.	$ 35,671	$ 2,112	$ 1,645	$ 87	$ 229	$ 136	$ 31	$ 17	$ 2	$ 110	$ 176
Total Operating Revenue	$ 1,497,742,135	$ 62,687,371	$ 42,563,074	$ 3,936,438	$ 7,512,412	$ 4,142,081	$ 921,512	$ 877,972	$ 155,524	$ 6,910,441	$ 6,512,597
Expenses:											
Operating & Maintenance	$ 932,962,529	$ 48,564,820	$ 36,979,950	$ 2,263,868	$ 5,492,937	$ 3,185,551	$ 706,554	$ 450,499	$ 60,851	$ 3,426,758	$ 3,973,317
Depreciation & Amortization	$ 322,482,905	$ 13,537,739	$ 9,587,557	$ 806,780	$ 1,775,759	$ 959,888	$ 195,837	$ 164,294	$ 28,504	$ 1,874,365	$ 1,808,267
Regulatory Debits/Credits	$ 1,310,661	$ 75,798	$ 58,686	$ 3,214	$ 8,183	$ 4,857	$ 1,105	$ 629	$ 76	$ 3,724	$ 5,960
Taxes Other Than Income	$ 83,988,863	$ 3,293,721	$ 2,249,992	$ 214,701	$ 441,965	$ 234,643	$ 48,065	$ 45,776	$ 8,689	$ 521,235	$ 468,004
Other O&M Expenses	$ 8,458,095	$ 322,332	$ 231,910	$ 22,411	$ 41,682	$ 22,569	$ 4,786	$ 5,093	$ 986	$ 44,744	$ 40,237
State Income Taxes	$ (1,295,866)	$ (528,691)	$ (585,333)	$ 9,909	$ (62,039)	$ (39,876)	$ (7,106)	$ 6,401	$ 2,105	$ (3,084)	$ (40,973)
Total Federal Income Taxes (Current + Deferred)	$ (19,081,043)	$ (2,603,555)	$ (2,633,582)	$ 1,221	$ (316,431)	$ (194,304)	$ (35,675)	$ 16,784	$ 6,546	$ (103,230)	$ (250,343)
Total Expenses	$ 1,328,826,145	$ 62,662,163	$ 45,889,182	$ 3,322,105	$ 7,382,056	$ 4,173,327	$ 913,566	$ 689,476	$ 107,756	$ 5,764,512	$ 6,004,469
Net Operating Income	$ 168,915,990	$ 25,208	$ (3,326,108)	$ 614,333	$ 130,356	$ (31,246)	$ 7,945	$ 188,496	$ 47,768	$ 1,145,928	$ 508,128
Rate Base:											
Gross Plant	$ 7,247,120,442	$ 292,201,945	$ 194,240,369	$ 18,377,403	$ 39,553,110	$ 20,879,912	$ 4,227,091	$ 3,782,115	$ 702,265	$ 46,707,866	$ 43,719,656
Accum. Depreciation and Amortization	$ (2,525,787,876)	$ (110,220,509)	$ (75,701,332)	$ (6,365,894)	$ (14,041,624)	$ (7,623,238)	$ (1,594,117)	$ (1,296,193)	$ (220,877)	$ (14,180,181)	$ (14,071,572)
Net Plant	$ 4,721,332,565	$ 181,981,436	$ 118,539,037	$ 12,011,509	$ 25,511,486	$ 13,256,674	$ 2,632,974	$ 2,485,922	$ 481,388	$ 32,527,685	$ 29,648,085
Working Capital	$ 157,001,138	$ 8,442,898	$ 6,358,653	$ 388,274	$ 944,051	$ 549,260	$ 122,645	$ 76,690	$ 10,060	$ 544,428	$ 736,776
Rate Base Offsets	$ 68,628,497	$ 4,213,828	$ 3,375,413	$ 157,478	$ 415,833	$ 258,181	$ 61,375	$ 30,490	$ 2,417	$ 148,516	$ 199,811
Total Rate Base	$ 4,946,962,201	$ 194,638,162	$ 128,273,103	$ 12,557,260	$ 26,871,369	$ 14,064,114	$ 2,816,993	$ 2,593,102	$ 493,865	$ 33,220,629	$ 30,584,672
Rate of Return	3.41%	0.01%	-2.59%	4.89%	0.49%	-0.22%	0.28%	7.27%	9.67%	3.45%	1.66%
INDEX ROR		0%	-76%	143%	14%	-7%	8%	213%	283%	101%	49%

INDIANA MICHIGAN POWER COMPANY
OUCC Base Rate Revenue Distribution

Class	OUCC Indexed ROR P&A Gen 12-CP Trans.	OUCC Indexed ROR 12-CP Gen 12-CP Trans.	OUCC Indexed ROR BIP Gen 12-CP Trans.	OUCC Indexed ROR Average All Methods	IMP Base Rate Percent Increase 1/	IMP Percent of Firm % Increase	Present Base Revenue 1/	OUCC Percent of Firm % Increase	OUCC Revenue Increase	OUCC Proposed Base Revenue	OUCC Percent Increase
RS	131%	114%	140%	128%	27.31%	103%	$500,723	86%	$62,827	$563,550	12.55%
GS-SEC	174%	120%	186%	160%	27.07%	102%	$147,100	80%	$17,260	$164,360	11.73%
GS-PRI	232%	139%	237%	203%	15.63%	59%	$2,501	75%	$275	$2,777	11.00%
GS-SUB	259%	68%	214%	180%	70.77%	267%	$59	75%	$6	$66	11.00%
LGS-SEC	70%	84%	67%	74%	26.24%	99%	$222,374	110%	$35,878	$258,252	16.13%
LGS-PRI	65%	73%	59%	66%	20.15%	76%	$11,029	115%	$1,860	$12,889	16.87%
LGS-SUB	80%	60%	66%	69%	29.95%	113%	$391	115%	$66	$457	16.87%
LGS-TRAN	-20%	25%	-15%	-3%	29.15%	110%	$17	150%	$4	$21	22.00%
IP-SEC	53%	71%	44%	56%	24.99%	94%	$43,408	125%	$7,959	$51,367	18.33%
IP-PRI	33%	71%	21%	42%	26.64%	100%	$122,933	125%	$22,539	$145,471	18.33%
IP-SUB	15%	52%	0%	22%	24.99%	94%	$42,746	150%	$9,405	$52,151	22.00%
IP-TRA	-48%	27%	-76%	-32%	25.83%	97%	$30,665	150%	$6,747	$37,411	22.00%
MS	141%	77%	143%	120%	30.00%	113%	$3,059	90%	$404	$3,462	13.20%
WSS_SEC	32%	86%	14%	44%	24.24%	91%	$5,579	125%	$1,023	$6,602	18.33%
WSS_PRI	12%	76%	-7%	27%	20.94%	79%	$3,007	150%	$662	$3,668	22.00%
WSS_SUB	27%	98%	8%	44%	13.79%	52%	$636	125%	$117	$753	18.33%
EHG	214%	146%	213%	191%	23.07%	87%	$701	75%	$77	$779	11.00%
IS	319%	374%	283%	325%	30.00%	113%	$138	50%	$10	$148	7.33%
OL	126%	257%	101%	161%	12.02%	45%	$6,169	80%	$724	$6,893	11.73%
SL	90%	348%	49%	162%	23.73%	89%	$5,442	80%	$639	$6,080	11.73%
TOTAL FIRM	100%	100%	100%	100%	26.55%	100%	$1,148,678		$168,480	$1,317,158	14.67%

1/ Per MWN-2, page 1 workpaper.

INDIANA MICHIGAN POWER
Residenial Customer Cost Analysis

		ROE @ 9.10%	ROE @ 10.50%
Gross Plant			
369	Services	$155,440,720	$155,440,720
370	Meters	$47,155,470	$47,155,470
	Total Gross Plant	$202,596,190	$202,596,190
Depreciation Reserve			
	Services 1/	$54,095,162	$54,095,162
	Meters 1/	$21,946,473	$21,946,473
	Total Depreciation Reserve	$76,041,634	$76,041,634
Total Net Plant		$278,637,824	$278,637,824
Operation & Maintenance Expenses			
586	Dist Oper - Meter	$1,386,241	$1,386,241
597	Maintenance of Meters	$37,383	$37,383
902	Meter Reading	$822,614	$822,614
903	Customer Records	$7,432,310	$7,432,310
	Total O & M Expenses	$9,678,548	$9,678,548
Depreciation Expense			
	Services 2/	$4,616,589	$4,616,589
	Meters 3/	$4,371,312	$4,371,312
	Total Depreciation Expense	$8,987,901	$8,987,901
Revenue Requirement			
	Interest	$6,826,627	$6,826,627
	Equity return	$11,630,816	$13,420,173
	State Income Taxes	$645,255	$744,525
	Income Tax	$2,920,213	$3,369,476
	Revenue For Return	22,022,911	24,360,800
	O & M Expenses	$9,678,548	$9,678,548
	Depreciation Expense	$8,987,901	$8,987,901
	Subtotal Customer Revenue Requirement	$40,689,360	$43,027,250
	Total Revenue Requirement	$40,689,360	$43,027,250
	Number of Bills	4,723,320	4,723,320
	Monthly Cost Before Bad Debts & Utility Receipts Tax	$8.61	$9.11
	Bad Debts + Utility Receipts Tax Rate	1.7634%	1.7634%
	TOTAL MONTHLY CUSTOMER COST	**$8.77**	**$9.27**

1/ Calculated based on the relationship of total Company reserve to total gross plant per testimony of Company witness Cash, Attachment JAC-1, page 26.
2/ Calculated based on an accrual rate of 2.97% per testimony of Company witness Cash, Attachment JAC-1, page 26.
3/ Calculated based on an accrual rate of 9.27% per testimony of Company witness Cash, Attachment JAC-1 page 26.

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 36
IURC CAUSE NO. 45235

DATA REQUEST NO OUCC 36-01

REQUEST

There appears to be significant discrepancies between the forecasted test year Residential customer charge billing determinants utilized in Attachment JCD-2 (Revenue Proof) and Mr. Burnett's forecasted test year Residential number of customers. The Residential customer charge billing determinants in Attachment JCD-2 are as follows:

Rate Schedule	No. of Bills	Bills ÷ 12
RS	4,648,110	387,343
RS-TOD	17,012	1,418
RS-TOD-2	1,558	130
Total Residential	4,666,680	388,890

The forecasted test year Residential number of customers per Attachment CMB-1 are 407,911 (EOY) and 407,109 (average year). Note, it is understood that there is a slight difference between number of customers and bills as shown in the Attachment JCD-2.

Please provide a reconciliation of test year Residential class customer counts (bills) found in Attachment JCD-2 and Attachment CMB-1.

RESPONSE

In responding to this data request, I&M determined that during the development of test year billing determinants, the total forecasted level of customers provided in Attachment CMB-1 was allocated to the Company's outdoor lighting (OL) class, as well as to all non-lighting classes. However, the total forecasted level of customers should have been allocated only to non-OL classes since the Company's records do not recognize OL accounts as unique "customers". Instead, OL accounts are most often associated with other non-OL accounts (e.g. RS, GS, LGS, etc.). The Company's allocation of forecasted customers to the OL class resulted in an understatement of the number of customers for the test period in the Company's non-outdoor lighting rate classes, including residential. Updated test year customer count and number of bill values for the Company's residential rate schedules are shown in Table OUCC 36-01 below and in "OUCC 36-01.xlsx."

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 36
IURC CAUSE NO. 45235

TABLE OUCC 36-01

	Attachment JCD-2		Corrected		Attachment CMB-1 *
	Customer Count	Bills	Customer Count	Bills	Customer Count
RS-TOD	17,147	17,012	17,735	17,595	
Residential	4,704,596	4,648,110	4,865,952	4,807,530	
RS-TOD2	1,575	1,558	1,629	1,611	
Total RS	4,723,318	4,666,680	4,885,316	4,826,736	4,885,310

* Sum of twelve monthly values.

	Att. JCD-2		Updated - OUCC 36-01	
	Customer Count	Bills	Customer Count	Bills
RS-TOD	17,147	17,012	17,735	17,595
RS-TOD - Emp	464	464	480	480
Residential	4,704,596	4,648,110	4,865,952	4,807,530
Residential - Emp	13,819	13,779	14,293	14,251
RS-TOD2	1,575	1,558	1,629	1,611
RS-TOD2 - Emp	14	14	15	15
GS NM	2,139	2,587	2,384	2,858
GS-TOD2	48	48	55	55
GS Secondary	516,969	514,542	598,569	595,758
GS Primary	462	460	567	563
GS Sub	33	33	41	41
LGS Secondary	45,432	45,361	53,520	53,437
LGS Primary	773	771	953	951
LGS Sub	18	18	23	23
LGS Tran	9	9	10	10
GS-LMTOD	1,170	1,168	1,358	1,355
GS-TOD Sec	14,488	14,455	16,707	16,669
GS-TOD Pri	10	10	12	12
LGS-LMTOD Sec	433	431	504	502
LGS-TOD Sec	5,299	5,294	6,122	6,117
LGS-TOD Pri	16	16	20	20
IP Primary	1,370	1,368	1,693	1,691
IP Secondary	894	893	1,099	1,098
IP Sub	195	195	248	248
IP Transmission	56	56	72	72
EHG	1,471	1,471	1,705	1,705
IS	344	344	397	397
MS	3,427	3,427	3,915	3,914
WSS Sec	4,173	4,169	4,824	4,819
WSS Pri	146	146	169	169
WSS Sub	52	52	60	60
WSS-TOD Sec	48	48	56	56
OL	258,834			
SLCM-240	6,955	6,948	7,722	7,714
SLCM-3PHS	12	12	12	12
SLCM - 480	1,473	1,473	1,592	1,592
FW-SL	12	12	12	12
ECLS	1,310		1,382	
SLC	1,227		1,383	
SLS	455		478	
IP-IRP	24	12	24	12
IP-Firm	72	72	72	72
Total	5,593,071	5,272,581	5,593,076	5,528,750
Total Residential	4,723,318	4,666,680	4,885,316	4,826,736

Note: Residential employee billing data is included in non-employee RS totals

INDIANA MICHIGAN POWER COMPANY - INDIANA
TEST YEAR ENDED DECEMBER 31, 2020
PROFORMA RATE SUMMARY

Tariff	Test Year Base + Fuel Revenue	Proposed Base Revenue	Difference	% Difference	Total Test Year Revenue
RS (011,012,013,014,015,016,017,038,039,051,052,053,054, 063)	$ 470,364,394	$ 580,931,764	$ 110,567,370	23.51%	$ 593,794,451
RS TOD/OPES (030, 032, 034, 036)	$ 2,656,741	$ 3,268,558	$ 611,818	23.03%	$ 3,476,082
RS TOD2 (021)	$ 132,982	$ 164,701	$ 31,719	23.85%	$ 167,163
GS Sec (211, 212, 215, 218, 281)	$ 132,494,559	$ 160,717,662	$ 28,223,104	21.30%	$ 174,440,251
GS LMTOD (223, 225)	$ 354,528	$ 426,406	$ 71,878	20.27%	$ 500,464
GS TOD 2 (221, 282)	$ 12,119	$ 13,716	$ 1,597	13.18%	$ 14,262
GS Unmetered (204, 214)	$ 64,882	$ 76,589	$ 11,707	18.04%	$ 75,354
GS TOD Sec (229)	$ 4,228,513	$ 5,083,841	$ 855,328	20.23%	$ 5,786,360
GS TOD Pri (227)	$ 3,349	$ 4,103	$ 754	22.50%	$ 4,495
GS Pri (217)	$ 2,241,181	$ 2,707,811	$ 466,631	20.82%	$ 3,186,773
GS Sub (236)	$ 52,215	$ 64,095	$ 11,881	22.75%	$ 79,051
LGS Sec (240, 242)	$ 204,124,263	$ 244,288,223	$ 40,163,960	19.68%	$ 251,429,812
LGS LMTOD (251)	$ 802,606	$ 974,202	$ 171,595	21.38%	$ 993,491
LGS TOD Sec (253)	$ 7,180,360	$ 8,397,765	$ 1,217,405	16.95%	$ 8,423,680
LGS TOD Pri (255)	$ 207,255	$ 255,661	$ 48,406	23.36%	$ 243,845
LGS Pri (244, 246)	$ 10,272,998	$ 12,415,251	$ 2,142,252	20.85%	$ 12,884,008
LGS Sub (248)	$ 370,110	$ 452,445	$ 82,335	22.25%	$ 466,261
LGS Tran (250)	$ 16,393	$ 19,960	$ 3,567	21.76%	$ 21,377
IP Sec (327)	$ 41,346,364	$ 49,618,168	$ 8,271,804	20.01%	$ 51,241,182
IP Pri (322)	$ 115,859,164	$ 140,066,179	$ 24,207,015	20.89%	$ 146,288,616
IP Sub (323)	$ 40,242,145	$ 48,910,923	$ 8,668,779	21.54%	$ 51,729,228
IP Tran (324)	$ 13,447,627	$ 16,413,085	$ 2,965,458	22.05%	$ 18,069,645
FW SL (525)	$ 724,717	$ 935,549	$ 210,832	29.09%	$ 908,356
ECLS (530)	$ 3,538,292	$ 3,714,647	$ 176,355	4.98%	$ 3,682,107
SLC (531)	$ 159,474	$ 185,933	$ 26,459	16.59%	$ 181,358
SLS (533)	$ 461,637	$ 483,038	$ 21,401	4.64%	$ 487,841
SLCM (733, 734, 735)	$ 427,649	$ 510,134	$ 82,485	19.29%	$ 499,177
OL (090 - 121)	$ 6,093,601	$ 6,580,063	$ 486,462	7.98%	$ 6,363,649
WSS Sec (545)	$ 4,847,210	$ 5,796,325	$ 949,115	19.58%	$ 5,908,083
WSS TOD (547)	$ 468,843	$ 550,673	$ 81,830	17.45%	$ 581,966
WSS Pri (546)	$ 2,843,439	$ 3,323,499	$ 480,060	16.88%	$ 3,553,254
WSS Sub (542)	$ 598,856	$ 692,831	$ 93,975	15.69%	$ 762,823
EHG (208)	$ 656,706	$ 772,015	$ 115,309	17.56%	$ 852,640
IS (213)	$ 130,044	$ 150,154	$ 20,110	15.46%	$ 162,445
MS (543, 544)	$ 2,917,657	$ 3,500,603	$ 582,947	19.98%	$ 3,667,870
Interruptible - Firm Portion	$ 15,974,029	$ 19,178,715	$ 3,204,686	20.06%	$ 19,888,417
Total Indiana Firm Revenues	$ 1,086,316,899	$ 1,321,645,289	$ 235,328,390	21.66%	$ 1,370,815,836
Interruptible - Jurisdictional	$ 93,234,072	$ 97,615,768	$ 4,381,697	4.70%	$ 97,358,899
Total	$ 1,179,550,971	$ 1,419,261,057	$ 239,710,086	20.32%	$ 1,468,174,735
Revenue Verification Difference		$ (4,486,819)			
Total	$ 1,179,550,971	$ 1,414,774,238	$ 235,223,267	19.94%	$ 1,468,174,735
As Filed	$1,175,792,666				$1,464,416,431
Adjustment	**$ 3,758,305**				**$ 3,758,304**

STEEL DYNAMICS, INC - AS A SEPARATE CLASS
6-CP CCOSS

	Total Retail	SDI
Operating Income		
Revenue:	[redacted]	[redacted]
Firm Sales	[redacted]	[redacted]
Interruptible	[redacted]	[redacted]
Sales for Resale	[redacted]	[redacted]
Other Operating Revenues	[redacted]	[redacted]
Gain on Disp of Emission Const. Allow.	[redacted]	[redacted]
Total Operating Revenue	[redacted]	[redacted]
Expenses:	[redacted]	[redacted]
Operating & Maintenance	[redacted]	[redacted]
Depreciation & Amortization	[redacted]	[redacted]
Regulatory Debits/Credits	[redacted]	[redacted]
Taxes Other Than Income	[redacted]	[redacted]
Other O&M Expenses	[redacted]	[redacted]
State Income Taxes	[redacted]	[redacted]
Total Federal Income Taxes (Current + Deferred)	[redacted]	[redacted]
Total Expenses	[redacted]	[redacted]
Net Operating Income	[redacted]	[redacted]
Rate Base:	[redacted]	[redacted]
Gross Plant	[redacted]	[redacted]
Accum. Depreciation and Amortization	[redacted]	[redacted]
Net Plant	[redacted]	[redacted]
Working Capital	[redacted]	[redacted]
Rate Base Offsets	[redacted]	[redacted]
Total Rate Base	[redacted]	[redacted]
Rate of Return	[redacted]	[redacted]
Required Rate of Return	[redacted]	[redacted]
Required Income	[redacted]	[redacted]
Less Current Operating Income	[redacted]	[redacted]
Income Deficiency	[redacted]	[redacted]
Revenue Conversion Factor	[redacted]	[redacted]
Revenue Deficiency Before Transmission Owner Cost (per Exhibit A-1).	[redacted]	[redacted]
Transmission Owner Costs, Revenues	[redacted]	[redacted]
Total Required Rate Increase	[redacted]	[redacted]

STEEL DYNAMICS, INC - AS A SEPARATE CLASS
12-CP CCOSS

	Total Retail	SDI
Operating Income		
Revenue:	[redacted]	
Firm Sales		
Interruptible		
Sales for Resale		
Other Operating Revenues		
Gain on Disp of Emission Const. Allow.		
Total Operating Revenue		
Expenses:		
Operating & Maintenance		
Depreciation & Amortization		
Regulatory Debits/Credits		
Taxes Other Than Income		
Other O&M Expenses		
State Income Taxes		
Total Federal Income Taxes (Current + Deferred)		
Total Expenses		
Net Operating Income		
Rate Base:		
Gross Plant		
Accum. Depreciation and Amortization		
Net Plant		
Working Capital		
Rate Base Offsets		
Total Rate Base		
Rate of Return		
Required Rate of Return		
Required Income		
Less Current Operating Income		
Income Deficiency		
Revenue Conversion Factor		
Revenue Deficiency Before Transmission Owner Cost (per Exhibit A-1).		
Transmission Owner Costs, Revenues		
Total Required Rate Increase		

AFFIRMATION

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

Glenn A. Watkins
President & Senior Economist of Technical Associates, Inc.
Indiana Office of Utility Consumer Counselor
Cause No. 45235
Indiana Michigan Power Company

August 19, 2019
Date

CERTIFICATE OF SERVICE

Indiana Office of Utility Consumer Counselor Public's Exhibit No. 12 Public (Redacted) Testimony of OUCC Witness Glenn A. Watkins has been served upon the following parties of record in the captioned proceeding by electronic service on August 20, 2019.

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