**DIRECT TESTIMONY OF**

**LAWRENCE J. VOGT**

**ON BEHALF OF**

**GEORGIA POWER COMPANY**

**DOCKET NO. 42516**

1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. Lawrence J. Vogt, 21093 Pineville Road, Long Beach, Mississippi 39560. I am the President and Principal Consultant of Vogtage Engineering Corporation.

**Q. MR. VOGT, PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.**

1. I am a graduate of the University of Louisville with Bachelor of Science and Master of Engineering degrees in Electrical Engineering. Over the last 43 years, I have held various positions including Distribution Engineer, Senior Industrial Marketing Engineer, and Rate Engineer at Public Service Indiana (now known as Duke Energy – Indiana) in Plainfield, IN; Senior Rate Design Engineer and Principal Engineer – Rates & Regulation at Southern Company Services (“SCS”) in Atlanta, GA; Manager, Distribution Technologies Center at ABB Power T&D Company in Raleigh, NC; Lead Product Manager at Louisville Gas & Electric Company in Louisville, KY; and Manager, Pricing Planning and Implementation, and Director, Rates at Mississippi Power Company. I have participated in numerous regulatory filings throughout my career in Mississippi, Indiana, Kentucky, and before the Federal Energy Regulatory Commission (“FERC”). This includes providing sponsored testimony and appearances as an expert witness in Commission hearings. In 2010, I established Vogtage Engineering Corporation. Additional details are found in my curriculum vitae attached as Appendix 1.

I have been active in a variety of industry functions throughout my career. I have conducted numerous industry lectures and workshops under the sponsorships of EUCI, the Electric League of Indiana, Inc., and the University of South Alabama. I have served as an Adjunct Professor in Pennsylvania State University’s International Power Engineering Program. I served as a representative on the Rate & Regulatory Affairs Committee of the Edison Electric Institute, where I also served as Committee Chairman (2012 – 2014). I have also served as a Principal Instructor in the Committee-sponsored E-Forum Rate College and Electric Rate Advanced Course. I also served as a representative on the Rates & Regulation Section of the Southeastern Electric Exchange. I am a Senior Life Member of the Institute of Electrical and Electronics Engineers, and I am a Member of the Association of Energy Engineers. I am a registered Professional Engineer in several states, including Georgia. In addition, I am the coauthor of several technical papers and reports as well as the textbook Electrical Energy Management (Lexington Books, 1977). I am also the author of the textbook Electricity Pricing: Engineering Principles and Methodologies (CRC Press, 2009) and of the “Engineering Principles of Electricity Pricing,” Chapter 21 in Power Systems, 3rd ed. of The Electric Power Engineering Handbook, CRC Press, 2012.

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

1. The purpose of my testimony is to present and explain the cost-of-service studies filed by Georgia Power Company (“Company”) in this proceeding, and which are contained in Exhibit\_\_\_(LJV-1) through Exhibit\_\_\_(LJV-9).

Q. Please describe the contents of your exhibitS.

1. The first two exhibits, Exhibit\_\_\_(LJV-1) and Exhibit\_\_\_(LJV-2), are projected Period II cost-of-service studies for the 12-month period ending July 31, 2020 based on the Company’s recommended allocation methodologies. In one Period II study, Exhibit\_\_\_(LJV-1), the customer categories are rate groupings, and in the other Period II study, Exhibit\_\_\_(LJV-2), the customer categories are individual rates. The next two exhibits, Exhibit\_\_\_(LJV-3) and Exhibit\_\_\_(LJV-4), are historical Period I cost-of-service studies, for the 12-month period ending December 31, 2018 based on the Company’s recommended allocation methodologies. In one Period I study, Exhibit\_\_\_(LJV-3), the customer categories are rate groupings, and in the other Period I study, Exhibit\_\_\_(LJV-4), the customer categories are individual rates. The next two exhibits, Exhibit\_\_\_(LJV-5) and Exhibit\_\_\_(LJV-6), are Period II cost-of-service studies for the period ending July 31, 2020, but these two studies use an alternative 4-CP Production function allocation advocated by some customer groups in previous cases with this Commission. The next two exhibits, Exhibit\_\_\_(LJV-7) and Exhibit\_\_\_(LJV-8), are Period I cost-of-service studies for the period ending December 31, 2018, but these two studies use an alternative 4-CP Production function allocation as advocated by some customer groups in previous cases. We have filed these 4-CP study results simply for informational purposes. Each of these eight exhibits contain 13 schedules, which set out the results of the cost-of-service study along with the supporting analyses.

I have included only the summary pages of each of these first eight exhibits in hard copy due to the voluminous size of the exhibits. The exhibits may be found in their entirety in electronic pdf format on the disk attached to this filing. Those files are designated as Exhibit\_\_\_(LJV-1).pdf through Exhibit\_\_\_(LJV-8).pdf.

Exhibit\_\_\_(LJV-9) is a summary of the customer-related costs calculated from Exhibit\_\_\_(LJV-4). These costs are shown for the Company’s rate schedules supporting Exhibit\_\_\_(LTL-1) in Mr. Legg’s testimony.

Q. Who prepared the cost-of-service studies that you are sponsoring in this filing?

1. The cost-of-service studies being presented in this filing were prepared by the Costing and Energy Analysis section of SCS at the request of the Company. These studies were prepared under my direction.
2. Do you believe that the Company’s recommended allocation methodologies Reflect the most relevant cost of service to be used by this Commission?
3. Yes, I do. The overall methodology used in this filing is consistent with the methodology used in numerous prior cases of the Company. It continues to be reflective of cost causation, it is objective and fair to the different groups of customers, and it provides accurate and stable results.

**COST OF SERVICE PRINCIPLES AND APPLICATIONS**

1. What is a cost-of-service study and WHAT IS ITS PURPOSE?

A. A cost-of-service study separates a utility’s total electric investments, revenues, and expenses among the jurisdictions an electric utility serves and then among the rate classes or groups within each jurisdiction. For a regulatory commission to review a utility’s jurisdictional earnings and to evaluate the contribution made by rates within its jurisdiction, it is necessary to analyze the costs to serve the respective rate classes or groups. Like other electric utilities, Georgia Power maintains its books and records in accordance with the Uniform System of Accounts as directed by FERC and this Commission. Although this system of accounting records company-wide information, it does not separate the Company’s investments or expenses by jurisdiction or by rate classes or groups within jurisdiction. The cost-of-service study that has been performed for the Company accomplishes this objective of separating costs by jurisdiction, rate groupings, and rates using generally accepted methodologies and practices consistent with past filings.

1. How are cost-of-service studies used in the regulatory process?
2. A cost-of-service study typically is used as a tool to determine earnings and how well costs are being recovered from each regulatory jurisdiction, and from the customers or customer groups within the different jurisdictions. The respective regulatory body can use these jurisdictional cost-of-service results to ascertain the utility’s overall revenue requirement as well as judge the adequacy of rates within that jurisdiction. The National Association of Regulatory Utility Commissioners (“NARUC”) identifies the cost-of-service study among the basic tools of ratemaking, and it is used to attribute costs to different categories of customers based on how those customers cause costs to be incurred.

**Q. How were the studies used by Georgia Power in this rate filing?**

1. The jurisdictional separation of rate base and net operating income developed in the various schedules of Exhibit\_\_\_(LJV-1) was used to determine the proposed jurisdictional revenue increase needed to achieve the requested rate of return. These jurisdictional separations were calculated according to accepted cost-of-service principles and followed the methodologies previously filed with this Commission. In addition, information from the Company’s proposed cost-of-service study was considered in the design of proposed rates for the retail customers in this docket as described in Mr. Legg’s testimony.
2. Where did you get the financial data used in the cost-of-service studies?
3. The Company provided the financial information for all the cost-of-service studies filed in this proceeding. The Company’s investment, revenue, and expense items were then (a) directly assigned to specific jurisdiction and rate group where these costs were explicitly known to be caused by a specific rate group and (b) allocated to jurisdiction and rate groups and specific rates where the costs were determined to be jointly caused by the different groups of customers.
4. How were wholesale customers treated for cost-of-service purposes?
5. Investment, revenues, and expenses associated with non-full requirements wholesale customers were identified and removed from the Total Electric System before most allocations were made. The remaining investment, revenue, and expense items were then assigned or allocated to the retail rate groups within the retail jurisdiction. This method is consistent with the methodology filed by the Company and accepted by this Commission in previous cases.
6. In preparing a cost-of-service study, is there some overall guiding principle or concept that should be followed?
7. The overall objective of a cost-of-service study is to assign or allocate costs fairly and equitably to all customers. This objective is accomplished when the resulting cost-of-service study reflects “cost causation,” i.e., those customers who caused a particular cost item to be incurred by the Company in providing them service should be responsible for those particular costs.

When certain costs are readily identified with a specific customer group, the assignment of those costs to that group clearly reflects cost causation and is fair and equitable to all customers. However, it must be recognized that most parts of an electric system are planned, designed, constructed, operated, and maintained to jointly serve all customers. These costs are referred to as joint or common costs. Joint or common costs must be allocated to customer groups based on the nature of the costs incurred and the aggregate requirements and service characteristics of the customers that caused the costs to be incurred. By adhering to this fundamental and essential principle of cost causation, the results of the cost-of-service study will be fair and equitable to all customers.

1. Please Describe the steps that are required TO PREPARE A cost-of-service study.
2. (1) *Functionalization* separates the investment and expenses of the Company into specified functional categories based on the operations involved in providing electric service. The Company follows the functional categories set forth by the FERC Uniform System of Accounts, which are production, transmission, distribution, customer services (customer accounting, customer assistance, sales), and administrative and general.

(2) *Levelization* further separates the functionalized investment and expenses into voltage-based service levels of the system. The service level designations are a means of identifying and associating investment and expenses with customers and their loads at established points of electrical service. In general, the lower the voltage level of service required by the customer, the greater the cost of providing service since additional equipment is necessary to deliver lower voltage service. The following table describes each service level of the system.

|  |  |
| --- | --- |
| **Voltage Level** | **Level Description** |
| A | Generation |
| B-1 | Step-up Substation |
| B-2 | High Voltage Transmission Lines (>115 kV) |
| C-1 | Substations Transforming from High Voltage Transmission Line (>115 kV) to Subtransmission Voltage (<69 kV) |
| D | Subtransmission Voltage Lines (<69 kV) |
| C-2 | Substations Transforming from High Voltage Transmission Line (>115 kV) to Primary Distribution Voltage (<25 kV) |
| E | Substations Transforming from Subtransmission Voltage Lines (<69 kV) to Primary Distribution Lines (4-25 kV) |
| F | Primary Distribution Lines (4-25 kV) |
| G | Secondary Distribution (<1 kV) |

(3) *Classification* differentiates the levelized functional investment and expenses based on three primary cost drivers: demand related, energy related, and customer related. These are identified by the characteristics of the investment and expenses within each function and level. Each of these three cost drivers has its own separate and appropriate allocation methodology to apportion respective costs to the associated jurisdiction, customer class, and rate group.

(a) *Demand related*: Costs that are incurred to serve customers’ peak requirements for electricity. This generally refers to costs incurred by the utility to provide the capacity necessary to serve the customers’ peak kilowatt (kW) loads (demands) throughout the year. Demand-related costs are classified at Levels A through G.

(b) *Energy related*: Costs that vary with the amount of energy utilized by the customer. These costs are comprised primarily of production fuel and variable operations and maintenance (VO&M) expenses, which vary with the kilowatt-hours (kWh) consumed by the customers. Energy-related costs are classified at Level A.

(c) *Customer related*: Costs that are independent of customers’ kW and kWh consumption. Many of these costs vary with the number of customers on the system. This generally refers to the basic costs incurred by the utility to attach a customer to the distribution system, which includes metering, service lines, a portion of the system known as the Minimum Distribution System, along with customer billing and certain administrative costs. The Minimum Distribution System is discussed below. Customer-related costs are classified at Levels F and G.

(4) *Direct assignment* associates specific costs and revenues with specific customers or rate groups.

(5) *Allocation* apportions the common costs of service among rate groups.

**COST CLASSIFICATION OF THE DISTRIBUTION SYSTEM**

1. PLEASE DESCRIBE WHAT IS MEANT BY A MINIMUM DISTRIBUTION SYSTEM?
2. The Minimum Distribution System (“MDS”) is that portion of the total costs of facilities that make up the primary voltage lines, the line transformers, and the secondary voltage lines, which is independent of customers’ load requirements. An MDS study separates the costs of these distribution facilities into their respective demand-related cost components and customer-related cost components on the basis of cost causation.

MDS represents the readiness to serve a customer, not the capacity needed to meet a customer’s peak demand requirements. MDS is only about providing an appropriate utilization voltage at the point at which a customer connects to the distribution system, and costs are incurred to provide a customer with such access. The readiness to serve costs are independent of how much electricity a customer consumes; thus, MDS costs are classified as customer-related cost components. MDS does not represent the costs of capacity necessary to meet a customer’s peak load requirements. That portion of the total costs of facilities that make up the primary voltage lines, the line transformers, and the secondary voltage lines that provide capacity to meet customers’ peak load requirements is classified as a demand-related cost component.

1. How is an MDS study performed?
2. Quantifying the costs of MDS is accomplished by evaluating the cost causation aspects of all distribution system facilities, including the primary and secondary lines, line transformers, and other distribution equipment. This approach requires an understanding of the functional application of each distribution item. In so doing, some items are found to be related to peak load requirements (100% demand related), some items are found to be independent of peak load requirements (100% customer related), and other items are found to be functionally associated with both readiness to serve and capacity.  The costs of items having attributes of both customer-related and demand-related functions must be analyzed in order to separate the total item cost into the two cost components. These items include overhead conductors and poles, underground conductors and conduit, and overhead and padmount line transformers. They all provide both a readiness to serve function and a capacity function.

To accomplish this cost separation, the Company applies a zero-intercept cost analysis for each of these distribution items. The zero-intercept method is a linear regression analysis that relates a distribution item’s unit costs (dependent variable) to its associated capacity values (independent variable). An example is shown below for single-phase overhead line transformers. The data plots represent the unit costs of transformers having standard size capacity ratings, i.e., 15, 25, 37.5, 50, 75, and 100 kVA. The resulting regression line intersects the unit cost axis where the value of capacity is equal to zero, thus defining the per unit customer component cost, which is $635.16. This zero-intercept value is multiplied by the total number of single-phase overhead transformers booked in FERC Account 368 in order to determine that amount of the total cost of single-phase overhead transformers that is classified as customer related. The difference between the total cost of the transformers and the customer-related cost amount represents the demand-related transformer cost amount.

Separate regression analyses are also conducted for single-phase padmount transformers, three-phase padmount transformers, overhead conductors, underground conductors, and distribution poles to separate the total costs of these items into their respective customer and demand cost components.

1. ASIDE FROM THE MDS EQUIPMENT YOU DISCUSSED, HOW ARE OTHER DISTRIBUTION EQUIPMENT AND FACILITIES CLASSIFIED?
2. Distribution property that is classified as 100% demand-related components include voltage regulators and capacitors. This equipment is installed on the primary voltage lines and is utilized to maintain circuit voltages within an acceptable operating range during heavy loading conditions. If there was no load connected to the energized system, line voltage would not sag, and voltage regulation equipment would not be required. Thus, these devices are classified as demand related. Distribution property that is independent of load and is thus classified as 100% customer-related components include reclosers, sectionalizers, and fused cutouts. This equipment is installed on the primary voltage lines and function together to provide distribution system protection under fault (short circuit) conditions. These devices work in a coordinated fashion to isolate a fault location and maintain a voltage connection to as many customers as possible during the fault event. Without their intended intervention during a fault, line conductors and equipment would be damaged from the fault current flows that occur and many, if not all, customers on the affected circuit could experience a major power outage. The protection equipment functions the same with or without load connected to the energized circuit because it responds to the severe overcurrent situation caused by a fault. Thus, these devices are classified as customer related. In addition, lightning arresters are installed on the primary lines to abate damaging overvoltage conditions that occur during electrical storms. These lightning arresters function the same with or without load connected to the circuit. Thus, these devices are classified as customer related.

While cutouts and arresters are utilized for line protection, they are also applied to provide protection from overcurrent and overvoltage conditions for specific equipment, e.g., each overhead transformer. Cutouts and arresters used for this purpose are classified in the same manner as the equipment they protect was classified.

1. IS the MDS methodology accepted by the National Association of Regulatory Utility Commissioners (NARUC) as a reasonable methodology?
2. Yes, it is described in the NARUC Electric Utility Cost Allocation Manual.
3. Is MDS commonly used by other utilities?
4. Yes. Examples of U.S. and Canadian utilities where MDS has been used in cost of service include Alabama Power (AL), ATCO (CAN), Carolina Power & Light (NC), Central Hudson Electric & Gas (NY), Central Maine Power (ME), Choctawhatchee Electric Cooperative (FL), Connecticut Light & Power (CT), Duke Energy Progress (NC), Gulf Power (FL), Hydro One (CAN), Jackson County REMC (IN), Kentucky Utilities (KY), LG&E (KY), Madison Gas & Electric (WI), Mississippi Power (MS), New Brunswick Power Corporation (CAN), Newfoundland Power (CAN), Northern States Power (MN), Rochester Gas & Electric (NY), and Tampa Electric (FL).
5. has Georgia Power previously filed a cost-of-service study including an MDS analysis?
6. Yes. Georgia Power has filed cost-of-service studies that include an MDS analysis for several decades. As such, the MDS analysis has been included in the parity calculation among rates and rate groups and subsequently considered in any corresponding rate adjustments for over 30 years.

**COST ALLOCATORS**

1. WHAT ARE COST ALLOCATORS, AND WHAT ARE THEY USED FOR?
2. Cost allocators are per unit ratios, or percentages, that are based on cost-causation characteristics, and these ratios are applied to total common cost items (e.g., a production asset) to apportion their costs to the customer groups or rates. These ratios represent the fair share proportion of the costs of service for each customer group or rate. To best reflect cost causation across all of the assets used to provide electric service, a series of ratios are developed for the allocations of the various energy, demand, and customer cost component items.
3. How were the COST allocators developed?
4. The development began with the collection and analysis of load research data. The number of customers and their respective demand and energy sales by voltage level of service were collected and analyzed as was territorial supply and system energy and demand losses. These demands by rate group occurred at the times of the company’s monthly coincident peaks (CP) and the non-coincident peaks (NCP). System power flows were modeled through the various voltage levels of the system. This analysis produced the “12-CP,” “4-CP,” and “NCP” demand allocators, the kWh “energy” allocators, and the “number of customers” allocator.
5. Please explain further how you developed ENERGY AND demand allocators for the various voltage levels of service.
6. Balanced system power flows for demand and energy were developed through a model, which computes total system losses for each voltage level. The power flow process began by taking the total energy sales at secondary distribution, Level G, and multiplying these sales by the loss percentage at Level G, and then combining these calculated losses and sales. This amount was then added to the sales at primary distribution, Level F, and this new total was in turn multiplied by the loss percentage at Level F. This procedure was continued up through the transmission system to generation, Level A. The cumulative level sales and losses were then compared to the actual generation output. To the extent that there was a mismatch between the total loss adjusted sales and generation output, the model then adjusted the loss percentages at each level and then iterated the above process until the sum of the losses at each level matched the total system losses, and a balanced power flow was achieved.

These total system loss percentages were then applied to the energy sales of each rate group in order to compute each group’s loss adjusted sales at each voltage level. The aggregation of each group’s energy sales and losses up through the system to Level A provided the basis for developing the energy allocator for VO&M costs. Since the VO&M costs occur at the generation (territorial input) level, basing the energy allocator on the groups’ loss adjusted sales at Level A results in a fair and equitable allocation of the energy-related costs.

A similar process was used to calculate the 12-CP and 4-CP demand allocators. The NCP demand allocators for Levels F and G were developed using the loss percentages calculated by the monthly coincident peak demand flow since there is no territorial input for NCP with which to balance.

1. Please expand on the 12-CP and NCP Allocator concepts.
2. The demand of customers can be described in many ways. A 12-CP demand is used as an allocator in the cost-of-service study where capacity is built to support the common or coincident load of customers in every month of the year. A 12-CP demand is defined as the sum of the highest kW load for the Company in each month of the 12-month period divided by twelve. At the jurisdictional, class or rate group level, 12-CP is the respective coincident demands at the time of the monthly system peaks. Using this allocator ensures that the coincident load burden placed on the system by a jurisdiction, class or rate group is allocated an appropriate share of the costs of the system. Since the last filed study, the use of this concept has been strengthened by the fact that the company is now planning for both summer and winter reliability constraints. The summer and winter reliability planning of the company further underscores that no one month or season is adequate at representing the coincident impact of customers on system capacity.

The NCP demand is the highest hourly demand occurring for each rate group during the entire test period. The NCP allocator is applied at the distribution levels, where customer peak loads have much less diversity with each other than they do at the upper voltage levels of the system. The NCP allocators more accurately reflects the characteristics of customer loads at the primary and secondary distribution levels and more closely approximates how the Company plans and operates these functional areas of the distribution system. This method was used to allocate distribution demand costs at Level F (primary distribution) and Level G (line transformers and secondary distribution).

1. Has the 12-CP method been used in previous proceedings before this Commission or BEFORE THE FERC?
2. Yes. The 12-CP allocation methodology was used in GPSC Docket No. 3840 (filed in April 1989) where it was accepted by the Commission and reflected in its order. Furthermore, the 12-CP allocation methodology has been used in all subsequent filings before this Commission where a cost-of-service study has been required.

In addition, 12-CP has been one of FERC’s preferred allocation techniques for determining wholesale jurisdictional obligations, and it has been used by the Company in its filings before the FERC. It has proven to be a common and popular allocation technique employed in numerous retail filings before many state commissions throughout the United States. It is a straight-forward methodology, has a strong cost causative relationship, and has a history of providing stable and sound results. In addition, the load tests, utilized by FERC to evaluate the feasibility of the 12-CP method for production and bulk transmission cost allocation, supports a 12-CP approach when applied to the test period loads in this filing.

1. Where is the 12-CP allocator APPLIED in the studies?

A. A major application of the 12-CP is to allocate Production capital cost, and a portion of Transmission capital cost.

1. How were production-related Operations and maintenance costs allocated?
2. Production-related O&M demand costs were allocated using the 12-CP methodology. Production-related operations and maintenance running costs (i.e., variable O&M) were allocated on the basis of the customer's annual energy consumption, adjusted for losses. Fuel costs were directly identified on a rate basis and were directly offset by fuel revenue since the costs and revenues associated with fuel are handled in proceedings outside of a general rate case proceeding.
3. please explain How transmission-related capital costs were allocated?
4. Transmission-related capital costs, just as production-related and other costs, were allocated in the manner in which they are incurred. With the exception of step-up substations, which are linked to and allocated in the same manner as production-related costs, transmission costs are incurred based upon the need for transmission capacity. Transmission capacity requirements are a function of system load requirements along with a consideration of ambient temperatures, and the bulk power flow needs.
5. how do ambient temperatures affect capacity?
6. The load carrying capability of the transmission system is inversely related to ambient temperatures. Thus, the higher the temperature, the less the load carrying capability of a given line conductor, substation breaker, etc. The converse is also true, i.e., the lower the temperature, the higher the load carrying capability. Temperatures across Georgia Power's transmission system are distinctly seasonal. Given sufficient transmission capacity during the hot summer months, the transmission system will effectively realize a significantly greater transmission capability during the colder winter months. Furthermore, load growth during the summer period will have a greater influence on the need for additional transmission capacity than would a comparable load growth in the winter months. Consequently, to reflect the seasonal nature of transmission costs, some form of a summer peak period allocator is appropriate. In this study, as in prior cost-of service studies filed with the Commission, the summer peak period allocator is based on an average of the coincident peak loads for the four summer months of June, July, August, and September. This is referred to as the 4-CP allocation method.
7. Do all transmission-related costs have this temperature sensitivity thereby justifying a sole use of the 4-CP concept?
8. No, not all transmission costs are this temperature sensitive. The 4-CP method is not applicable to step-up substation facilities, and the 4-CP method is only partially applicable to bulk power transmission-related capital costs.
9. Why is the 4-CP method not applicable to step-up substations?
10. Power is generated at low voltage and high current, but it is transmitted most efficiently at a higher voltage and lower current. The step-up substations provide this voltage transformation function. The step-up substations do not provide for the transfer of power from one geographical area to another. Step-up substations exist only at generating plant sites, and all generating plants have step-up substations. Consequently, it is appropriate to allocate the capital costs associated with step-up substations in the same manner as the capital costs associated with the generating plants, which these substations directly support. Thus, the Company utilizes the 12-CP allocation method for allocating the cost of step-up substations.
11. Why is the 4-CP method applicable only in part for the allocation of bulk power transmission-related capital costs?
12. To simply use the 4-CP method exclusively to allocate these costs would not give appropriate consideration to the planning and operating interrelationship that exists between the bulk power transmission system and the generating plants. In general, the bulk power transmission carries the generated power to the load centers through a network system. To this end, production plant generation helps support bulk power flows, provides voltage support and frequency maintenance, and imparts a certain inertial stability to the power flows across the transmission system. The transmission system helps support generation by tying generating units together for reliability and stability purposes and provides a dynamic medium for the delivery of power across the system through a grid connected to many alternate power sources and paths. While peak loads may have the greater impact on transmission planning, it is also important to recognize this very real relationship between generation and bulk power transmission facilities. Consistent with prior cost-of-service studies, the Company has filed with the Commission, the bulk power transmission system costs have been allocated using a 20 percent / 80 percent weighted average of the 12-CP / 4-CP allocators. Lower voltage service levels of the transmission function are allocated upon the 4-CP or NCP allocators depending upon specific voltage service level.
13. How were the distribution-related capital costs allocated within the cost-of-service STUDY?
    1. Distribution-related costs were first segregated between those costs which are directly related to the requirements to simply set up a customer to be served (customer costs) and those costs which are directly related to the customers’ load requirements (demand costs), as previously discussed. As in prior proceedings before this Commission, customer-related costs were allocated based on the average number of customers. Depending upon the voltage level of service, distribution demand-related capital costs were allocated on either the 4-CP methodology, or the rate group’s NCP demands, depending upon the particular functions of the facilities within the distribution system.

Q. Why is the NCP method appropriate to allocate distribution costs at lower distribution levels?

1. The NCP method is based on determining cost responsibility to each rate group on the basis of the rate groups’ maximum NCP demands rather than their contribution to the system peak. This allocator is particularly appropriate at the lower service levels of distribution service, which is comprised of primary line, line transformers, and secondary lines, since the capital costs at these levels are essentially designed to serve the rates’ maximum non-coincident peak loads.
2. Has this NCP allocation method been used previously?
3. Yes, it has been used in the Company’s filings since the 1990’s and is still appropriate for this filing.
4. Does the degree of load accuracy for the compilation of these various allocators adhere to the level required of previous cost-of-service studies?
5. Yes.
6. How have you allocated costs for Georgia Power’s real-time pricing (“RTP”) customers and load in this cost-of-service study?
7. The RTP rates are different from the other electric service rates in that the RTP rates consist of an embedded rate portion, which is priced under a standard rate schedule, plus a marginal or incremental portion, which is priced on the basis of particular hourly production and transmission costs. RTP load has been treated for the purposes of developing load allocators in the same manner as the 2004, 2007, 2010 and 2013 Rate Cases. The Customer Baseline Load (“CBL”), which is priced using embedded rates, was included in the load allocators. The revenues and expenses associated with incremental RTP sales were directly assigned to the RTP customers.

Because we are specifically identifying the RTP rates, it is necessary to allocate and assign all appropriate embedded and marginal costs and revenues to the RTP rates to ensure a clear measure of the rate of return on investment. We have done this by allocating embedded Production and Transmission costs to the RTP customers based on their CBL load. We allocated embedded Distribution costs on their total load just as we do all embedded firm service load. We then assigned total RTP revenue as well as the marginal costs of Production and Transmission to the RTP customers, which was identified through system lambda costs, marginal reliability costs, marginal transmission costs, and marginal cost of system losses. This assignment of marginal cost to RTP customers creates a commensurate reduction in embedded cost to serve non-RTP rates. This gives an accurate accounting for the costs associated with serving RTP customers and the revenue collected from serving that load.

**Q.** **DO YOU BELIEVE THIS IS THE CORRECT COST TREATMENT FOR RTP?**

1. Yes. Since RTP prices are based upon marginal cost, embedded Production and Transmission costs should not be allocated to incremental RTP load.

**COST-OF-SERVICE STUDY OUTLINE**

**Q.** **PLEASE EXPLAIN THE GENERAL MAKE-UP OF EACH COST-OF-SERVICE STUDY.**

A. Page (i), the index, provides a listing of schedules that designates the three major sections of the cost-of-service study. Section 1 presents the summary of the results of the cost-of-service study by the rate groups. Section 2 presents the detailed allocation of investment, revenues, and expenses to the two jurisdictions (retail and wholesale) and to the rate groups within the retail jurisdiction. Section 3 shows the Company’s power flow diagram and the service level designations used throughout the study.

**Q. PLEASE ELABORATE ON THE INFORMATION PRESENTED IN SECTION 1 OF THE COST-OF-SERVICE STUDY.**

A. Section 1 presents, in summary form, the results of the cost-of-service study for Georgia Power for the designated period. Schedule 1.00, also known as the Summary Page, shows the Company’s total rate base, revenues, expenses, and net income separated between regulatory jurisdictions; and within the retail jurisdiction between the rate groups. Schedule 1.00 presents the Company’s earnings position under present rates, Schedule 1.02 shows the allocation of cash working capital, and Schedule 1.05 develops the allocation of income taxes.

**Q. WHAT PORTION OF THIS STUDY DESCRIBES THE INVESTMENT ALLOCATION?**

1. In Section 2, Schedules 2.00 through 2.03 present the investment allocations. On Schedules 2.00 and 2.01, gross plant investment and accumulated provision for depreciation are analyzed and allocated to the respective rate groups identified in the heading at the top of the page. Schedules 2.02 and 2.03 set forth other items that must be considered in developing the Company’s total rate base. These items are analyzed and allocated to the various rates and rate groups as indicated by the notes contained within each schedule.

**Q. WHAT PORTION OF THIS STUDY PRESENTS THE ANALYSIS OF REVENUES AND THE ALLOCATION OF EXPENSES?**

1. Schedule 2.10 presents the analysis of revenues from sales and other operating revenues. Schedules 2.20 through 2.40 contain the expense allocations and are presented in a format similar to the schedules describing the investment allocation. Schedule 2.60 presents a listing of the allocators used in and referenced throughout the cost-of-service study.

**Q. WHAT IS SHOWN IN SECTION 3?**

1. This is a power flow diagram which shows the designation of electric service levels. The power flow diagram illustrates the various paths on which electricity flows through the Georgia Power system. These are indicated on the chart by vertical lines. The horizontal lines represent various points within the system established for the purpose of classifying investment and expenses and for identifying the various types of facilities used in providing electric service. The letter designations of service levels on the left side are a means of identifying the investment and expenses with customers and customers’ loads at these established points. These levels are referred to in the study on numerous occasions. Through the use of these service levels, one is able to identify the service location of customers and their relative use of the Georgia Power system. This, in turn, allows for the proper identification and association of system cost responsibility with customer service requirements at the respective service levels.
   1. **PLEASE DESCRIBE EXHIBIT\_\_\_(LJV-9).**
2. This Exhibit summarizes by rate, the customer-related costs from the historical Period I cost-of-service study, Exhibit\_\_\_(LJV-4), using the Company’s recommended allocation methodologies. The exhibit shows the customer-related cost portion of each rate’s revenue requirement, the associated numbers of customers taking service under each rate, and the calculated unit cost per customer per month. This data is provided as an input to the rate design process, which is discussed in Mr. Legg’s testimony.

**CONCLUSIONS**

**Q. ARE THE ALLOCATED COST-OF-SERVICE STUDIES FILED IN THIS PROCEEDING SIMILAR TO THE ALLOCATED COST-OF-SERVICE STUDIES FILED IN PRIOR PROCEEDINGS AND APPROPRIATE FOR USE BY THIS COMMISSION?**

1. Yes. I have thoroughly reviewed each of the filed studies. I find that these studies are similar to and consistent with the allocated cost-of-service studies the Company has previously filed with this Commission. They accurately reflect cost causation and can be used to judge the adequacy of rates with respect to the costs to serve and be used for rate design purposes.
   1. **DOES THIS COMPLETE YOUR DIRECT TESTIMONY?**
   2. Yes, it does.

Appendix – 1

**Lawrence J. Vogt**

President and Principal Consultant

Vogtage Engineering Corporation

**Summary Of Utility Industry Experience**

* B.S. & M.Eng Degrees in EE
* Licensed Professional Engineer
* Expert Witness
* Published Author
* Professional Instructor
* Project Manager
* Business Unit Manager
* Utility Consultant

**WORK EXPERIENCE**

**Rates Engineering**

Pricing Strategy – Development and implementation of long-term plans for retail tariff restructuring and rate structure modifications based on projected industry contingencies.

Cost-of-Service Studies – Design and construction of a comprehensive Excel-based electric cost-of-service model; development of a GIS-based minimum distribution system methodology for customer–demand cost classification; design of a comprehensive system electric loss study methodology for use in energy and demand allocation factor development; development of rate schedule functional cost components for use in rate design.

Rate Design Studies – Development of coincidence factor–load factor curves using interval data and hours use of demand based bill frequency distributions for intra-rate electric cost allocation and production of rate schedule cost curves for supporting demand-based rate structures; development of alternative rate structures for all customer classes, including block energy, demand, hours use of demand, and time of use; development of outdoor lighting and facilities lease rates; development of special electric rates, including economic development, generation standby, purchase of excess customer generation energy, and interruptible rates; development of various cost recovery clauses; administration of rates and associated policies.

Rate Analysis – Development of mathematical and graphical techniques for evaluation of electric rates and rate relationships; development of unique rate analysis methodologies, e.g., contour-based differential rate charts; conceptual outline of a rate design and analysis tool (*RateManager*, coded and commercialized by Good¢ents Solutions).

Electric Service Revenue Forecasting – Development of historical and projected billing determinant databases using average rate and ogive forecasting methodologies for residential and small commercial customer classes and a discrete bill forecasting methodology for large commercial and industrial customers; development of projected customer rate class revenues based on projected billing determinants.

Regulatory Support – Preparation of retail and wholesale regulatory filing documents, including testimony, exhibits, and responses to interrogatories; appearance as an expert witness in regulatory docket proceedings; participation in special regulatory meetings, such as collaborative interest groups; design and implementation of formulary performance-based ratemaking methods. Development and presentation of instructional courses in ratemaking principles and methodologies.

**Power Distribution Engineering**

Distribution Planning – Development of load-bearing land use databases calibrated to substation peak loads and service areas; spatial allocation of projected customer class loads; optimization of substation capacity sizing and siting; forecasting and outage contingency analyses.

Integrated Resource Planning – Development of DSM-based customer class load models; spatial analysis of DSM impacts on T&D loads and substation capacity expansion using distribution planning software.

Distribution Design and Analysis – Routing and specification of primary feeder lines and equipment; specification of electric service facilities; feeder protection coordination studies; capacitor sizing and siting studies.

Distribution System Restoration – Field engineering support of distribution system restoration efforts due to tornados and hurricanes.

**Marketing**

Industrial Marketing – Engineering assistance to commercial and industrial customers for new load additions, demand and energy management project evaluations, power factor correction projects, electric service invoices, and rate schedule selection; development and presentation of customer education programs.

Products and Services Marketing – Development of optional products and services proposals for large C&I customers, including distribution engineering, line construction, and maintenance services; coal procurement; development of a standard service criterion.

**Business Unit Management**

Electric Rates Function – Management of a team of engineers, accountants, economists, and computer scientists responsible for:

* Development of jurisdictional and customer and rate class cost-of-service studies;
* Design of electric rates for all categories of retail and wholesale electric services; and
* Application and governance of the electric tariff.

Power Distribution Function – Management of a team of engineers and geographers responsible for:

* Digitizing distribution electric circuit maps and construction of geographical load databases for use in distribution system planning and analysis;
* Production of spatial electric load forecasts; and
* Development of least-cost distribution system expansion plans, including the effects of demand-side management and energy efficiency programs.

**COMPANY AND POSITION HISTORY**

**Vogtage Engineering Corporation July 2010 – Present**

Long Beach, Mississippi

Position: President and Principal Consultant

**Mississippi Power Company, A Southern Company April 1997 – May 2018**

Gulfport, Mississippi

Positions: Director, Rates August 2014 – May 2018

Manager, Rates August 2005 – July 2014

Manager, Pricing Planning & Implementation June 1998 – July 2005

Principal Rate Research Analyst March 1997 – June 1998

**Louisville Gas and Electric Company September 1994 – March 1997**

Louisville, Kentucky

Positions: Lead Product Manager November 1996 – March 1997

Rates and Regulatory Coordinator September 1994 – October 1996

**ABB Power T&D Company August 1989 - September 1994**

Pittsburgh, Pennsylvania and Raleigh, North Carolina

Positions: Manager, Distribution Technologies Center January 1994 - September 1994

Manager, Consulting Studies June 1992 - December 1993

Consulting Engineer August 1989 - May 1992

**Southern Company Services, Inc., A Southern Company March 1980 – July 1989**

Atlanta, Georgia

Positions: Principal Engineer – Rates & Regulation June 1987 – July 1989

Assistant to the Assistant Vice President May 1984 – May 1987

Senior Rate Design Engineer April 1983 – April 1984

Rate Design Engineer March 1980 – March 1983

**Public Service Company of Indiana, Inc. May 1976 – February 1980**

(Now known as Duke Energy – Indiana)

Plainfield, Indiana

Positions: Rate Engineer February 1979 – February 1980

Senior Industrial Marketing Engineer May 1977 – January 1979

Engineer May 1976 – April 1977

Student Engineer (Co-op and Part Time) Prior to May 1976

**EDUCATION**

**University of Louisville**, Louisville, Kentucky

Bachelor of Science (Electrical Engineering) May 1975

Master of Engineering (Electrical Engineering) May 1976 Thesis: “Electrical Energy Management”

**PROFESSIONAL AFFILIATIONS**

**Institute of Electrical and Electronics Engineers** Senior Member, ID: 07062771 (Since 1974)

* Power Engineering Society: Customer Products and Services Subcommittee

Power Systems Planning and Implementation Subcommittee

* Industry Applications Society

**Association of Energy Engineers** Member, ID: 01969 (Since 1978)

**Edison Electric Institute** Member, Rate Committee (2005 - 2018)

* Committee Chairman, 2012 - 2014
* Committee Vice Chairman, 2010 - 2012

**Southeastern Electric Exchange** Member, Rates & Regulation Section (2010 - 2018)

**Registered Professional Engineer:**

Alabama, ID: 13650-PE, December 1981 Georgia, ID: PE012852, April 1981

Indiana, ID: PE60018668, January 1980 Mississippi, ID: 08429, September 1981

Vogtage Engineering Corporate License: Mississippi Certificate of Authority: E-2258

**REGULATORY FILINGS AND TESTIMONY**

**Mississippi Public Service Commission**

Testimony and appearances on behalf of Mississippi Power Company.

* Docket 2017-AD-112, 2017: Encouraging Stipulation of Matters in Connection with the Kemper County IGCC Project; prefiled testimony on test period rate revenues; public hearing held; order issued.
* Docket 2016-UA-230, 2016: Jurisdictional Cost-of-Service Study as of December 31, 2015; prefiled testimony on cost assignment methodologies; order issued without a hearing.
* Docket 2015-UN-80, 2015: A Change in Rates Related to the Kemper County IGCC Project; prefiled testimony on cost recovery methodology and rate schedule revisions; public hearing held; order issued.
* Docket 2014-UN-10, 2014: Establishment of an Energy Efficiency Quick Start Plan and Cost Recovery Rate; prefiled testimony on cost recovery methodology; order issued without a hearing.
* Docket 2013-UN-14, 2013: A Change in Rates Related to the Kemper County IGCC Project; prefiled testimony on cost recovery methodology and rate schedule revisions; public hearing held; order issued.
* Docket 2011-UN-0135, 2011: Establishment of a Certificated New Plant Rate Schedule; prefiled testimony on cost recovery methodology and rate schedule revisions; public hearing held; order issued.
* Docket 2011-AD-2, 2011: Investigation of the Development and Implementation of Net Metering Programs and Standards; prefiled comments on specific issues that should be addressed in a possible rule; public hearing held; order issued.
* Docket 1992-UN-0059, 2011: Environmental Compliance Overview Plan; prefiled testimony on modification of the cost recovery mechanism and change in billing factors; public hearing held: order issued.
* Docket 2010-AD-2, 2010: Investigation of the Development and Implementation of Energy Efficiency Programs and Standards; prefiled comments on decoupling and lost sales, incentives, and program cost recovery; collaborative meetings; prefiled testimony on cost recovery; rulemaking order issued without a hearing.
* Docket 1992-UN-0059, 2010: Environmental Compliance Overview Plan; prefiled testimony on change in billing factors; public hearing held: order issued.
* Docket 1992-UN-0059, 2009: Environmental Compliance Overview Plan; prefiled testimony on change in billing factors; public hearing held.
* Docket 2008-AD-0477, 2008: Energy Independence and Security Act of 2007; prefiled comments on “Rate Design Modifications to Promote Energy Efficiency Investments”; public hearing held: order issued.
* Docket 2007-UN-0398. 2007: Establishment of a Formulary Lighting Charge Rate Schedule; order issued without a hearing.
* Docket 2007-UN-0395. 2007: Revision of the Cogeneration and Small Power Purchase Rate Schedule; order issued without a hearing.
* Docket 2007-AD-0201, 2007: Energy Policy Act of 2005 -- Proposed PURPA Standards; prefiled comments on "Net Metering;" public hearing held: order issued.
* Docket 2006-UN-0511, 2006: Establishment of a System Restoration Rider Schedule; prefiled testimony on cost recovery methodology; order issued without a hearing.
* Docket 2005-UA-0555, 2006: Hurricane Katrina System Restoration Cost Recovery; pre-filed testimony on cost recovery methodology; public hearing held: order issued.
* Docket 2006-AD-0362, 2006: Energy Policy Act of 2005 -- Proposed PURPA Standards; prefiled comments on "Smart Metering and Interconnection"; public hearing held: order issued.
* Docket 2003-UN-0898, 2005: Performance Evaluation Plan General Increase in Rates; prefiled testimony on rate schedule revisions; public hearing held: order issued.

**Kentucky Public Service Commission**

Filings on behalf of Louisville Gas & Electric Company.

* Case 95-239, 1995: Small Power Production and Cogeneration Purchase Schedule; filed revised schedule SPPC-II; order issued without a hearing.
* Case 95-276, 1995: Establishment of an Excess Facilities Rider; filed new schedule; order issued without a hearing.
* Case 93-150, 1995 and 1996: Quarterly filing of exhibits and rates for Demand-Side Management Cost Recovery Mechanism; orders issued without a hearing.
* Case 73-146, 1995 and 1996: Annual filing of exhibit and rate for Differential Underground Charge for New Residential Subdivisions; orders issued without a hearing.

**Indiana Utility Regulatory Commission**

Testimony and appearances on behalf of Public Service Indiana.

* Cause No. 35755, 1979: Joint Petition of Public Service Company of Indiana, Inc. and United Rural Electric Membership Corporation; prefiled testimony addressing the rate impacts associated with the exchange of properties and customers; public hearing held; order issued.
* Cause No. 35756, 1979: Joint Petition of Public Service Company of Indiana, Inc. and Morgan County Rural Electric Membership Corporation; prefiled testimony addressing the rate impacts associated with the exchange of properties and customers; public hearing held; order issued.
* Cause No. 35954, 1979: Joint Petition of Public Service Company of Indiana, Inc. and Parke County Rural Electric Membership Corporation; prefiled testimony addressing the rate impacts associated with the exchange of properties and customers; public hearing held; order issued.

**Federal Energy Regulatory Commission**

Testimony on behalf of Mississippi Power Company.

* Docket ER11-1871, 2010: Wholesale Rate Case

Prefiled testimony on rate design; case settled and order issued without a hearing.

* Docket ER08-1467, 2008: Wholesale Rate Case

Prefiled testimony on rate design; case settled and order issued without a hearing.

**PUBLICATIONS**

**Books**

Lawrence J. Vogt, “Engineering Principles of Electricity Pricing,” Chapter 21 in *Power Systems*, 3rd ed. Edited by Leonard L. Grigsby, CRC Press, 2012.

Lawrence J. Vogt, *Electricity Pricing: Engineering Principles and Methodologies*, CRC Press, 2009.

Lawrence J. Vogt and David A. Conner, *Electrical Energy Management*, Lexington Books, 1977.

**Reports and Papers**

H. L. Willis, L. J. Vogt, R. G. Huff, and W. R. Pettyjohn, "DSM: Transmission and Distribution Impacts, Volume 1: Analysis Framework and Test Case," EPRI Final Report CU-6924, Vol. 1, August 1990.

H. L. Willis, L. J. Vogt, H. N. Tram, and J. M. Fredley, "DSM: Transmission and Distribution Impacts, Volume 2: Application on Spatial Frequency Analysis," EPRI Final Report CU-6924, Vol. 2, August 1990.

J. Flory, J. Peters, L. Vogt, K. Keating, B. Hopkins, and N. R. Friedman, "Evaluating DSM: Can An Engineer Count On It?" IEEE Transactions on Power Systems, Vol. 9, No. 4, pp. 1752 – 1758, February 1994.

Lawrence J. Vogt and H. Lee Willis, "Optimizing the Power System Impacts of Demand-Side Management,” IEE Conference Publication No. 373, CIRED 12th International Conference on Electricity Distribution, Birmingham, UK, pp. 6.4.1 – 6.4.5, May 1993.

Lawrence J. Vogt, H. Lee Willis, and Lynn C. Ribar, "DSM and the T&D System: A Complicated Interaction," EPRI CU-7394; Proceedings of the 5th National Demand-Side Management Conference, Boston, MA, pp. 305 - 309, August 1991.

Lawrence J. Vogt, H. Lee Willis, and Michael J. Buri, “Distribution Planning and DSM Assessment Using Satellite Imagery and Pattern Recognition,” Proceedings of the Pennsylvania Electric Association’s System Planning Committee Meeting, Wilkes-Barre, PA; May 1991.

Timothy S. Yau, William M. Smith, R. Gary Huff, Lawrence J. Vogt, and H. Lee Willis, "Demand-Side Management Impact on the Transmission and Distribution System," IEEE Transactions on Power Systems, Vol. 5, No. 2, pp. 506 – 512, May 1990.

**INDUSTRY PRESENTATIONS**

**Institute of Electrical and Electronics Engineers**

“Engineering in Customer Service Planning – Utility Products and Services,” IEEE Power Engineering Society Meeting, Seattle, WA; July 2000.

"Evaluating DSM: Can an Engineer Count On It? – Verifying DSM Load Reduction: T&D Engineering Perspectives," IEEE Power Engineering Society Meeting, Seattle, WA; July 1992.

**Edison Electric Institute**

“Formulary Methodology for Pricing Lighting Facilities,” EEI Rate and Regulatory Affairs Committee Meeting, Chicago, IL; September 2013.

“Minimum Distribution System: Concepts and Applications,” EEI Rate and Regulatory Affairs Committee Meeting, Louisville, KY; March 2013.

“Trends in Riders: What's Out There?” EEI Rate and Regulatory Affairs Committee Meeting, Clearwater, FL; March 2012.

“Transition to Forecast Test Years: Mississippi Power Perspective” and “Performance-Based Ratemaking for New Generation,” EEI Rate and Regulatory Affairs Committee Meeting, Alexandria, VA; September 2011.

“Mississippi Power’s Retail Pricing Mechanisms,” EEI Rate and Regulatory Affairs Committee Meeting, Jersey City, NJ; March 2010.

“Rate Design Transition at Mississippi Power,” EEI Rate and Regulatory Affairs Committee Meeting, New Orleans, LA; March 2009.

“Ratemaking With Bary Curves,” EEI Rate Analysts Meeting, Louisville, KY; April 2008.

“Ratemaking With Bary Curves,” EEI Rate and Regulatory Affairs Committee Meeting, San Francisco, CA; September 2007.

“Hurricane Katrina: Impacts and Cost Recovery Issues” and “Mississippi Power’s Performance Evaluation Plan,” EEI Rate and Regulatory Affairs Committee Meeting, Savannah, GA; March 2006.

**Southeastern Electric Exchange**

“Impacts of PV on Distribution Systems,” S.E.E. Rates and Regulation Section Meeting, Lexington, KY; April 2019.

“Demand and Energy Loss Factors Used in the Cost-of-Service Study,” S.E.E. Rates and Regulation Section Meeting, Charlotte, NC; April 2018.

“Model-Based Approach to Rate Design: Exploring Rate Relationships,” S.E.E. Rates and Regulation Section Meeting, Williamsburg, VA; April 2016.

“Cost-Based Rate Design: A Deeper Dive,” S.E.E. Rates and Regulation Section Meeting, Mobile, AL, April 2015.

“Straight Fixed–Variable Rate Design,” S.E.E. Rates and Regulation Section Meeting, Atlanta, GA; October 2014.

“Update on Kemper County IGCC Energy Facility,” S.E.E. Rates and Regulation Section Meeting, Charleston, SC; October 2013.

“Minimum Distribution System: Concepts and Applications,” S.E.E. Rates and Regulation Section Meeting, Savannah, GA; October 2012.

“Formulary Lighting Pricing,” S.E.E. Rates and Regulation Section Meeting, New Orleans, LA; November 2011.

“Mississippi Power’s Revenue Neutral Adjustment Clause,” S.E.E. Rates and Regulation Section Meeting, Atlanta, GA; May 2011.

“Fundamentals of Rate Design Workshop,” S.E.E., Rates and Regulation Section Meeting, St. Petersburg, FL; May 8, 2003.

"Cost Analysis and Rate Design: Outdoor Lighting,” S.E.E. Rates and Regulation Section Meeting, Richmond, VA; October 1981.

**EUCI Conferences**

“Experiences With Formulary Ratemaking,” EUCI’s 10th Annual Electricity Pricing Conference, New Orleans, LA; September, 2012.

“Mississippi Power’s Success: Hurricane Katrina Impacts and Response” and “Hurricane Katrina: Cost Recovery Issues,” EUCI’s Disaster Management and Cost Recovery for Utilities and Energy Companies Conference, New Orleans, LA; June 2006.

“Planning DSM to Optimize T&D Benefits,” EUCI’s Integrated Resource Planning Conference, Denver, CO; March 1993; Co-presenter – Lee Willis

**Other Industry Conferences**

“Employing a Minimum Distribution System Methodology for the Cost-of-Service Study,” Marcus Evans Electric Utility Ratemaking Conference, Atlanta, GA; July 2013.

“Bridging the Gap Between Cost of Service and Rate Design Structure,” The Prime Group’s Electric Cooperative Rate Conference, Louisville, KY; September 2007.

“Developing Pricing Structures to Market Reliability-Based Service Options” (pre-conference workshop), The Center for Business Intelligence’s “Electric Distribution Reliability” Conference, Houston, TX; February 2001; Co instructor – Arlan W. Chenault.

“Spatially Differentiated Pricing,” INFOCAST’s “Pricing Strategies for the Competitive Era” Seminar, Chicago, IL; January 1997.

"DSM and the T&D System: A Complicated Interaction," The 5th National Demand-Side Management Conference, Boston, MA, August 1991.

“Distribution Planning and DSM Assessment Using Satellite Imagery and Pattern Recognition,” Pennsylvania Electric Association’s System Planning Committee Meeting, Wilkes-Barre, PA; May 1991.

"DSM: Transmission and Distribution Impacts," Electric Power Research Institute Workshops, Hartford, CT, November 1987; San Diego, CA, December 1987; Chattanooga, TN, March 1988; Minneapolis, MN, March 1988; Denver, CO, March 1988.

"Purchased Energy Analysis and Energy Accounting," Open Pit Mining Association Meeting, New Orleans, LA; June 1979.

**The Energy Council**

“Ratemaking 101,” Oklahoma City, OK, September 2018

**Mississippi State Legislature Committee Sessions**

“Net Metering: Issues and Solutions,” Joint Legislative Hearing on Energy Efficient Homes and Buildings, Jackson, MS; November 16, 2009.

“Net Metering Concerns,” House Agricultural Committee, Jackson, MS; November 12, 2008.

**AFFILIATED TRAINING PROGRAMS: Power Systems and Utility Ratemaking Programs**

**Webinar Courses**

**EUCI Electric Cost of Service and Rate Design Series, Instructor**

Session 1: "Electric Cost of Service Concepts and Methodologies," March 21, 2012.

Session 2: "Electric Rate Design Concepts and Methodologies," March 28, 2012.

Session 3: "Risk Mitigation in Electric Rate Design," April 4, 2012.

**Edison Electric Institute E-Forum Lecture Series, Instructor**

Sponsored by the EEI Rate and Regulatory Affairs Committee:

Introduction to Alternative Regulation Series:

Session I: “Rate Design to Ensure Fixed Cost Recovery: Rate Reform,” March 30, 2010.

Rate College Series:

Session 16: “Managing Risk Through Rate Schedule Billing and Service Provisions,” September 22, 2009.

Session 13: “Rate Design for the Rate Case,” May 13, 2009.

Session 11: “Rate Design: Translating Costs to Rates,” February 25, 2009.

Session 8: “The Embedded Cost-of-Service Study: Allocation Methodologies and Results,” August 26, 2008.

Session 7: “The Embedded Cost-of-Service Study: Functionalization and Classification Methodologies,” June 18, 2008.

**Classroom Courses**

**EUCI, Instructor**

“An Introduction to Electric Utility Systems” (1½ day course).

Open Enrollment Courses: Multiple venues, 2013 - Present.

In-House Courses:

* Southern California Public Power Association, Glendora, CA, September 2018
* Belize Electricity Limited, Belize City, November 2016.
* California Public Service Commission, San Francisco, August 2014.

**Wisconsin Public Utility Institute, Instructor**

Sponsored Programs:

Annual EEI Advanced Rate Design Course:

* “An In-depth View of the Customer Charge,” July 2016 – Present.
* “A Distribution Engineer’s View of a Minimum Distribution System Methodology,” 2013 -2015.
* “Demand Rate Design Methodology,” July 2012.

Market Inflection Drivers for Service Utilities: Tracking the Trends Series:

* “Economics and Engineering in a New Partnership: Cost of Service,” June 2017.
* “Roll of Engineering in Distribution System Cost Recovery,” August 2016.

Large Public Power Council Roundtable:

* “Impact of Distributed Resources on Cost-of-Service and Rate Design,” August 2016.
* “Minimum Distribution System Methodology,” May 2013.

California Public Utility Commission Staff:

“Minimum Distribution System Methodology,” October 2014.

**Penn State University, Adjunct Professor**

Sponsored Programs:

Electric Cost-of-Service and Rate Design Courses; 1989 - 2011

* Advanced School of Power Engineering, Pittsburgh, PA; (Annual 4 day course).

In-House Courses:

* Provincial Electric Authority, Bangkok, Thailand; February 2005 (2 week course).
* Panamanian Public Service Commission Staff, Panama City, Panama; April 2001 (1 week course).
* Power Finance Corporation/State Electric Boards, New Delhi, India; February - March 1996 (3 week course).
* Empressas Publicas de Medillin, Medillin, Colombia; November 1993 (1 week course).
* Jamaica Public Service Company, Kingston, Jamaica; June 1993 (2 week course).

**University of South Alabama, Instructor**

Sponsored Programs:

Electric Cost-of-Service and Rate Design Courses; Mobile, AL, 1989 – 1996.

* Utility Rate Fundamentals Course (2½ day course).
* Strategic Utility Pricing Course (1½ day course).

In-House Courses:

* Oklahoma Gas & Electric Co., Public Service of Oklahoma, and Oklahoma Public Service Commission, Oklahoma City, OK; April 1990 (1 week course).

**Electric League of Indiana, Inc., Instructor**

Sponsored Programs:

The Electrification Council Series:

* “Energy Management Action Course,” Indianapolis, IN; April - May 1979 (6 session course).
* “Electric Power Distribution for Industrial Plants and Commercial Buildings Course,” Clarksville, Indianapolis, and Wabash IN; September - November 1978 (10 session course).

**Professional Development Seminars, Inc., Instructor**

“Fossil-Fired Power Plant Technologies,” New Orleans, LA, September 2015 and Birmingham, AL, October 2015.