BEFORE THE
CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF **OKLAHOMA GAS AND ELECTRIC COMPANY** FOR AN ORDER OF THE COMMMISSION AUTHORIZING APPLICANT TO MODIFY ITS RATES, CHARGES, AND TARIFFS FOR RETAIL ELECTRIC SERVICE IN OKLAHOMA	))))))	Cause No. PUD 200800398

Direct Testimony

of

Greg Veitch

on behalf of

Oklahoma Gas and Electric Company

February 27, 2009

Q. **Please state your name and business address.**

A. My name is Greg Veitch. My business address is 321 N. Harvey, Oklahoma City, Oklahoma 73102.

Q. **By whom are you employed and in what capacity?**

A: I am employed by the Oklahoma Gas and Electric Company (OG&E) as Manager Cost of Service.

Q. **What is your educational background and experience with OG&E?**

A. I earned a Bachelor of Science degree in Accounting from Central State University in 1988. In 1991, I became a Certified Public Accountant, licensed to practice in Oklahoma, and a member of the Oklahoma Society of Certified Public Accountants. I have been employed by OG&E for thirty-six years. Except for my earlier experience at OG&E in utility operations (1973-1988), my corporate experience has been in the areas of accounting, tax and regulation. I have worked in various job positions covering several accounting functions, including a manager's position in accounting for four years. My experience in accounting included Securities and Exchange Commission filings, Federal Energy Regulatory Commission Form 1 filings, internal and external financial accounting, and preparation and filing of the fuel adjustment clauses for all jurisdictions. My seven years experience in tax was primarily property tax related that required working closely with the Oklahoma Tax Commission and county officials and being

involved with legislative issues. My regulatory experience in the Cost of Service department (2005 to present) has been primarily in cost of service studies, rate case support and administration of fuel adjustment clauses for all jurisdictions. I was promoted to Manager Cost of Service in September 2008. I have attended various courses and seminars on cost of service, rate design and utility industry related issues.

Q. **Have you previously filed testimony before any regulatory body?**

A. Yes. I filed testimony on behalf of Oklahoma Gas and Electric Company before the Arkansas Public Service Commission in Docket No. 08-103-U.

Q. **Have your credentials been accepted by this Commission?**

A. No. I respectfully request the Commission to accept my credentials to testify in this cause.

Q. **What is the scope of your testimony?**

A. My testimony describes how OG&E calculates its total cost of providing service ("cost-of-service") and allocates costs between jurisdictions and to Oklahoma customer classes. The test year used in the study is the twelve months ending September 30, 2008. I am sponsoring schedules in Section K and Section L of the Company's Application Package. These schedules represent the Company's cost-of-service outputs which are used as inputs to establish the jurisdictional allocations in Sections B, H and J of the Company's Application Package. I am also responsible for the calculation of these jurisdictional allocations.

Q. **Would you briefly describe how your testimony is organized?**

A. My testimony is divided into three parts: (i) the contents and organization of the schedules that I am sponsoring; (ii) the procedures OG&E followed in developing its cost-of-service study; and (iii) the development of the demand allocation factors used in the study.

PART I

Q. **Briefly describe the contents of Section K of the Company's Application Package.**

A: Section K sets forth the Company's Cost of Service and jurisdictional calculations; the schedules in Section K provide the support for those calculations.

Schedule K-1, column one, shows the pro forma adjusted Total Company cost of service under existing rates. Columns two and three show the Oklahoma and Not-At-Issue (Arkansas Retail and Federal Energy Regulatory Commission Wholesale) jurisdictional cost of service. The revenues, operating expenses, and rate base for the Oklahoma jurisdiction are indicated on lines 1, 12, and 33 respectively. Line 34 shows an earned rate of return of 7.28 percent for the Oklahoma jurisdiction under rates currently in effect. Each of the supporting schedules details by account and the associated allocation basis for the amounts shown on Schedule K-1. Table 1 lists such supporting schedules:

Table 1

Schedule Name	Description
Schedule K-2.1	Pro forma electric revenues based on current rates
Schedule K-2.2	Operation and maintenance expenses
Schedule K-2.3	Depreciation expense
Schedule K-2.4	Taxes other than income
Schedule K-2.5	Plant in service
Schedule K-2.6	Accumulated depreciation
Schedule K-2.7	Construction work in progress
Schedule K-2.8	Plant held for future use
Schedule K-2.9	Working capital
Schedule K-2.10	Other rate base adjustments

Q. **Mr. Veitch, please proceed with your description of the contents and organization of Section L of the Company's Application Package, which presents the Company's Rate Design Cost of Service information.**

A. Section L provides the revenue, revenue deductions, income taxes, return, rate base components and return on rate base for each Oklahoma customer class.

Schedule L-1 is the Rate Design Cost of Service for the test year. It shows the Oklahoma jurisdictional pro forma adjusted cost of service by customer class under rates placed in effect as of January 1, 2006. Revenue, revenue deductions and rate base are organized in the same manner as on Schedule K-1. Line 34 shows the percentage rates of return earned from each class under current rates.

Supporting Schedules L-2.1 through L-2.10, show in detail, the allocation of costs and rate base components to each Oklahoma customer class. These schedules provide the same information as the schedules in Section K, except that the information is provided by Oklahoma customer class.

Schedule L-3 presents the revenue requirement for each class, if a rate of return on rate base of 9.64 percent, the return that Dr. Murry testifies is reasonable for OG&E, were to be applied equally to all classes of service. Line 13 is the total class revenue requirement needed to achieve a 9.64 percent return on rate base. Line 14 is the pro forma class revenue based on existing rates for the test year. Line 15 is the difference between the class revenue requirement and the current tariff revenue. This deficiency or excess represents the change needed in current tariffs for rate design. Line 16 shows the revenues received from current tariffs.

Schedule L-4 indicates the percent increases necessary to recover the revenue deficiency through sales revenue for each class advocated by Company witness, Bryan Scott, in his testimony. Line 12 indicates the return on rate base by class of service adjusted for the deficiency at these levels of revenue.

Q. **Are you sponsoring these schedules for inclusion in the record in this proceeding?**

A. Yes. These schedules were prepared by me or under my supervision.

PART II

Q. **What is the purpose or nature of a cost-of-service study?**

A. The cost-of-service study is used to determine a utility's total revenue requirement and to allocate the cost-of-service components to determine the revenue requirements for the Oklahoma customer classes. The cost-of-service study is also used as a tool to determine rates of return for each customer class. In a cost-of-service study, particular costs are either allocated or directly assigned to customer classes to determine the cost-of-service for each class. Because costs are generally determined from historical accounting records, this type of analysis is referred to as an "accounting" or "embedded" cost-of-service study. Costs are allocated to customer classes on a cost causation basis; referred to as a "fully distributed" or "fully allocated" cost-of-service study. When the cost-of-service study is prepared and all costs are allocated to the various jurisdictions, the result is a fully allocated embedded cost-of-service study that establishes cost responsibility and makes it possible to determine the cost of providing service to each customer class.

Q. **What are the "cost" components of the cost-of-service study you are sponsoring?**

A. The cost components used in the cost-of-service study are: (i) Operation and Maintenance Expenses, (ii) Depreciation Expenses, (iii) Federal and State Income Taxes, (iv) Taxes Other Than Income Taxes, and (v) Costs of Capital (Return).

Q. **What are the major steps required in the development of a fully allocated cost-of-service study?**

A. The development of a fully allocated cost-of-service study consists of three major steps: (i) functionalization, (ii) classification, and (iii) allocation or assignment. First, functionalization is the process of categorizing embedded costs by the operating function with which the costs are primarily associated. The functional categories used in ratemaking are:

- Production
- Transmission
- Distribution
- Customer Service
- Administrative and General (A&G).

The Production function captures the costs associated with facilities used for generating electricity. The Transmission function captures the costs associated with high voltage power lines and stations that deliver power to the distribution system. The Distribution function includes costs associated with facilities not classified as "transmission," including distribution stations, primary and secondary power lines, transformers, service drops and meters that connect customers to the utility system. The Customer Service

function deals with services and costs associated with providing meter reading, billing, bill collection, customer information and other services. The A&G function captures the costs associated with management of the business and general services of the utility such as staffing, accounting, legal, regulatory, communications, general purpose buildings/facilities, maintenance of such buildings/facilities, and other costs that may not be assignable to other functions.

Q. **Please describe the classification process.**

A. The second step is to classify the functionalized costs in order to reflect the manner in which the costs were incurred. Classification further defines functional costs into demand-related (*i.e.*, costs associated with being able to serve customers at maximum demand), energy-related (*i.e.*, costs that vary with the amount of energy used by customers), and customer-related (*i.e.*, costs that are directly related to the number of customers served).

The typical cost classifications associated with each functional category are summarized below in Table 2:

Table 2

Cost Function	Cost Classification
Production	Demand-Related Energy-Related
Transmission	Demand-Related
Distribution	Demand-Related Customer-Related
Customer Service	Customer-Related

Demand-related costs are fixed in nature, and tend not to vary with the use of electric plant facilities. Thus, demand-related costs are allocated to customer classes based on their respective megawatt (MW) load or demand characteristics.

Energy-related costs vary with use of electric plant facilities. Fuel and variable operation and maintenance expenses are primarily energy-related costs. These costs are allocated to customer classes based on an analysis of class energy consumption, including losses in delivery.

Customer-related costs are those expenses that are a function of the number and size of customers. Customer-related plant investment includes facilities needed to give customers access to OG&E's system. Other customer-related costs include expense items such as customer accounts, customer service and information, meter operation and plant-associated O&M expenses.

Q. **Did OG&E update any major studies that affect the classification process?**

A. Yes. OG&E hired a consulting firm, B & B Consulting International, L.L.C., to conduct updated "minimum-size method" (minimum system) and "minimum-intercept method" (zero intercept) studies. OG&E believed that such an analysis was necessary because the previously conducted analysis was outdated.

Q. **What is the purpose of doing such an analysis of the minimum system or zero intercept methods?**

A. The purpose of this analysis is to determine that portion of certain distribution costs that should be classified as customer-related. The distribution FERC Accounts 364 through 368 are considered in the analysis and are described in the table below:

Table 3

Account	Description
364	Poles, Towers and Fixtures
365	Overhead Conductors and Devices
366	Underground Conduit
367	Underground Conductors and Devices
368	Line Transformers

The minimum system method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The zero intercept method seeks to identify that portion of plant related to a hypothetical no-load use situation. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component.

Q. **What method is OG&E proposing?**

A. On the recommendation of B & B Consulting International, L.L.C., OG&E is adopting the "zero-intercept" method for classification of the customer-related component for distribution FERC Accounts 364 through 368. See Table 4 below showing the historical and proposed customer-related percentages:

Table 4

Account	Description	% Customer - Historical	% Customer - Zero Intercept Proposed
364	Poles, Towers and Fixtures	55.00%	54.94%
365	Overhead Conductors and Devices	30.00%	54.94%
366	Underground Conduit	90.00%	37.57%
367	Underground Conductors and Devices	90.00%	37.57%
368	Line Transformers	100.00%	71.67%

Q. **What does the third step - allocation or assignment - involve?**

A. The third step in the process is allocation, which involves dividing functionalized and classified costs to jurisdictions and customer classes of service. Most costs are attributable to more than one jurisdiction or customer class and must be allocated based on each jurisdiction's or customer class' contribution to the costs. At the same time, some costs can be directly assigned to a certain jurisdiction, a single customer class or a certain customer when those costs can be identified as being wholly attributable to such a jurisdiction, customer class, or customer. Investment in a substation used solely by a particular customer is one example of a cost that should be directly assigned to a specific class. After all costs have been allocated or assigned, a cost to serve is calculated for each jurisdiction and customer class.

Q. **What criteria did OG&E use in the development of appropriate allocation factors?**

A. The following criteria, although not an exhaustive list, provides an objective basis upon which to judge the appropriateness of an allocation methodology:

1. The method should reflect the operating and planning characteristics of the utility system;

2. The method should recognize the various customer class characteristics such as peak demand, energy usage, load factor, diversity characteristics, number and size of customers, points of delivery, etc.;

3. The method should produce stable results from year-to-year; and

4. Customers who benefit from the use of plant and equipment should bear the costs in a proportional manner.

Q. **Were any allocators changed in this cost-of-service study as compared to the cost-of-service study performed in the last Oklahoma rate case?**

A. Yes. Some allocators were changed while others were eliminated or added. It is normal for allocators to be changed, eliminated or added over time or from case to case as circumstances change.

Q. **Can you describe the allocators that were changed from the allocators used in the last rate case?**

A: The allocators listed below have been changed:

Line Description	Previous	Revised
Acct 556-System Control & Dispatch	**CAP3SY**	**CAP1SY**
Regulatory Assets	**GROSSPLT**	**SUP_OM**
Other (Accrued Pension Benefit Obligation)	**GROSSPLT**	**SUP_OM**
Accts 583.1 & 584.1 – Overhead Lines	**CAP5TC&CUS7TC**	**PLT364365TC**
Acct 904-Bad Debts	**CUSDEP**	**BADDEBT**
Amortization of Regulatory Asset	**CAP2OR**	**OKLA_OM**
Acct 924.3-Prop. Insurance-Dist Plant	**CAP5TC**	**DISTPLT**
Acct 408.1–Misc Taxes	**CAP5TC**	**SUP_OM**
Income Tax Adjustments/Credits	**Various**	**RATEBASE**

Account 556, System Control & Dispatch, was changed from a transmission demand allocator to a production demand allocator to reflect the Southwest Power Pool, Inc. ("SPP") policy regarding this account. The SPP considers Account 556 costs production-related because such costs are charged to load-serving entities that are responsible for scheduling and dispatching generation to meet load. Regulatory Assets, Amortization of Regulatory Asset and Other (Accrued Pension Benefit Obligation) required switching from a gross plant or demand allocator to labor and O&M related allocators. The Company believes that the new allocators better reflect the underlying nature of these costs. Accts 583.1 & 584.1 – Overhead Lines and Acct 924.3-Prop. Insurance-Dist. Plant were changed because these expenses should follow the underlying plant accounts. Acct 904-Bad Debts was changed because better information is available to provide a more appropriate allocator. Acct 408.1-Misc Taxes was changed from a demand allocator to a more appropriate labor allocator since most of these taxes are payroll related. Income Tax Adjustments/Credits used in the calculation of income tax was changed to a more appropriate allocator based on rate base.

Q. **What allocators have been eliminated?**

A. Certain jurisdictional allocators used for direct assignments of functional costs that were embedded in other functions were eliminated because they are no longer needed. For example, some distribution substations in the past may have been accounted for as transmission substations and vice versa. Because of better definitions of what constitutes the appropriate function for a substation, our embedded accounting records now reflect more accurately the proper function. Additionally, some energy allocators were

eliminated because they were no longer necessary. The energy allocators ENR1SY, ENR4VE and ENR2WC utilized the same factors so we eliminated the last two allocators and kept ENR1SY as the only energy allocator.

Q. **What allocators were added?**

A. A "WNDFRM" allocator was added to allocate costs associated with the Centennial wind farm. This wind farm and the Oklahoma jurisdiction allocator of 88.7185% was approved in Cause No. PUD 200500177, Order No. 524078.

PART III

Q. **Please describe the development of the demand allocation factors used in the cost-of-service study you are sponsoring.**

A. I will begin with a description of the production demand allocation factor. Next, I will describe the transmission demand allocation factor. Finally, I will describe the distribution demand-related allocation factor. It should be noted that demand load data used in the development of these allocators in this case were "weather normalized" as testified by Company witness Philip Bartholomew.

Q. **Why is it appropriate to use different demand allocation factors for production, transmission and distribution?**

A. The purpose of the allocation process is to assign costs to the cost causer in the most accurate way possible. As explained below, each of the production, transmission, and

distribution categories have different cost drivers that require different allocation methods to most accurately match costs to cost causers.

Q. **Please describe the method of cost allocation used to determine the jurisdictional and customer class production demand responsibilities.**

A. The 1 CP Average and Excess demand (1CP & Excess) method utilizes two types of demand measurements in the allocation of demand-related costs. The first measurement, the coincident peak demand ("1CP"), is the load of all customer classes at the time of the Company's highest measured one-hour demand for the system in the test year. The second measurement, energy, is the total mega-watt hours used during the test year to determine the average demand ("Average"). The 1CP & Excess demand method recognizes not only the class loads at the time of the system maximum peak, but also the amount of energy usage that classes utilize during all hours of the test year. A distinction is made between the cost of facilities to serve the average requirements and the cost of facilities to serve the excess, or additional load-following requirements. The determination of the factor for allocation to a jurisdiction or customer class on the basis of average demands utilizes the system annual load factor. The excess factor is based on the difference between the jurisdiction's or customer class' coincident peak demands incurred at the time of system peak and the jurisdiction's or customer class' average demands.

Q. **Did your production demand allocator change since OG&E's last rate case?**

A: Yes. OG&E previously used an average and excess method using a non-coincidental peak (NCP) instead of 1CP in this case.

Q. **Why did OG&E change the production demand allocator?**

A. The Joint Stipulation approved in Cause No. PUD 200800086 (Order No. 559892) contained provisions that read as follows: "The Stipulating Parties further agree that in OG&E's next general rate review the Stipulating Parties will recommend utilization of a measure of peak load based on a 2-CP, a 4-CP, or some measure of a normal 1-CP in the allocation method used for production plant....The Stipulating Parties further agree that in OG&E's next general rate case review the Stipulating Parties will recommend utilization of a Coincident Peak (CP) Average and Excess allocation methodology for OG&E's production costs."

Q. **Why does OG&E believe a 1CP & Excess production allocator is appropriate?**

A. This method is appropriate for the allocation of OG&E's production capacity costs for the following reasons:

1. The method recognizes the annual net system peak load used for resource planning in the Company and by the Southwest Power Pool, Inc. in its reserve capacity margin requirements;
2. The utilization of Company facilities by the classes of service throughout the year is considered in the method;

3. The benefits of load diversity are shared among the jurisdictions and customer classes of service;

4. All customers who benefit from the use of the facilities are allocated a portion of the costs at least equal to their annual load factors;

5. The methodology does not penalize classes of service or individual customers for incurring peak demands during the off-peak months; and

6. The average and excess method has been accepted by many public utility commissions, including the Oklahoma Corporation Commission.

Q. **Why did OG&E not use multiple CPs in its production demand allocator?**

A. Multiple CPs are used when a smoothing effect or normalization is required. Weather is the main driver for fluctuations in production on OG&E's system. Since OG&E, in this filing, is already using demand load data that is "weather normalized," normalization is already considered without the need for multiple CPs and there is no benefit from using a multiple CP.

Q. **Please proceed with a discussion of the transmission allocation factor development.**

A. Investment and expenses functionalized to transmission are classified as demand-related. The Company has used an average of twelve (12) monthly coincident peak demands (12CP) allocation method for allocating these costs. Under this method, transmission demand costs are allocated in proportion to the average of the coincident monthly peak demands of the customer classes (adjusted for losses) at the time of the monthly net system peak demands. Also, the 12CP allocation method is consistent with the pricing

strategy being used by the Federal Energy Regulatory Commission (FERC). The FERC Order No. 888[1], *the Final Transmission Open Access Rule*, proposes interstate transmission pricing be based on a twelve coincident peak demand method.

Q. **What allocation methodology did you use for demand-related distribution costs?**

A. Demand-related distribution costs were allocated based on class maximum non-coincident peak demands (NCPs), as opposed to coincident peak demands (CPs). The reason for using NCPs is that local distribution demand costs are incurred to serve area load, rather than a system load. Using NCPs instead of CPs in this methodology also recognizes that little or no diversity exists at this level except within each class.

Q. **Please summarize your testimony.**

A. First, I am sponsoring schedules in Section K and Section L of the Company's Application Package. Section K sets forth the Company's Cost of Service and jurisdictional calculations and Section L presents the Oklahoma jurisdiction class amounts to be used as a basis for rate design. Second, my testimony describes the development of the Company's cost-of-service study. The cost-of-service study is used to determine OG&E's total revenue requirement and to allocate the cost of service components to determine the revenue requirements for the Oklahoma customer classes, and subsequently is used as a tool to develop rates of return for each such customer class. Third, I discussed the development of demand-related allocators.

I request the Commission accept the cost-of-service study submitted in this case for the setting of new rates for the Company.

[1] Order No. 888, FERC Stats. & Regs. ¶ 31,048 (1006).

Q. **Does this conclude your testimony at this time?**

A: Yes, it does.