

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF)
OKLAHOMA GAS AND ELECTRIC COMPANY)
FOR AN ORDER OF THE COMMISSION) CAUSE NO. PUD 201500273
AUTHORIZING APPLICANT TO MODIFY ITS)
RATES, CHARGES, AND TARIFFS FOR RETAIL)
ELECTRIC SERVICE IN OKLAHOMA)

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CORPORATION COMMISSION
OF OKLAHOMA

Direct Testimony

of

David Smith

on behalf of

Oklahoma Gas and Electric Company

December 18, 2015

David Smith
Direct Testimony

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

2 A. My name is David Smith. My business address is 321 N. Harvey, Oklahoma City,
3 Oklahoma 73102.

4
5 Q. **By whom are you employed and in what capacity?**

6 A. I am employed by Oklahoma Gas and Electric Company (“OG&E” or “Company”) as
7 Senior Costing Analyst.

8
9 Q. **What is your educational background and professional experience?**

10 A. I graduated with a bachelor’s degree in economics from the University of Central
11 Oklahoma. I am pursuing further education at the graduate level in areas of both Finance
12 and Economics at Oklahoma City University and the University of Oklahoma. In
13 addition, I worked approximately five and a half years as a public utility regulatory
14 analyst for the Oklahoma Corporation Commission (“OCC”). While at the OCC, I
15 testified to numerous rate filings and cost trackers. I joined OG&E in 2010 as a Senior
16 Costing Analyst.

17
18 Q. **What is the purpose of your testimony?**

19 A. My testimony presents and supports OG&E’s jurisdictional and class cost of service
20 studies (“COSS”) and the development of the jurisdictional and class allocations and
21 related schedules. The Company’s cost of service studies are based upon a test year
22 ending June 30, 2015.

23
24 I. COST OF SERVICE STUDIES

25 A. General Explanation of a Cost of Service Study

26 Q. **What is the primary purpose of a cost of service study?**

27 A. A COSS is used to determine the portion of the overall revenue requirement to be
28 recovered from each of the Company’s jurisdictional and/or customer classes. In a COSS,

1 particular costs are either allocated or directly assigned to jurisdictions and/or customer
2 classes. Because costs are generally determined from historical accounting records, this
3 type of analysis is referred to as an accounting or embedded COSS. Costs are allocated
4 on a cost causation basis; and when the COSS is prepared and all costs are allocated, the
5 result is a fully allocated embedded COSS that establishes cost responsibility and makes
6 it possible to determine the cost of providing service to each jurisdiction and customer
7 class. National Association of Regulatory Utility Commissioners (“NARUC”) cost
8 allocation manual notes that “While opinions vary on the appropriate methodologies to be
9 used to perform cost studies, few analysts seriously question the standard that service
10 should be provided at cost.”¹

11
12 B. Data and Accounting Sources Utilized

13 **Q. What sources are used in a cost of service study?**

14 **A.** Cost of service studies rely on the utility company’s historic, or embedded, statements of
15 revenue, number of customers, energy sales, accounting reports, engineering records,
16 customer billing records and load survey data. Investor-owned electric utilities in
17 Oklahoma are required by the Federal Energy Regulatory Commission (“FERC”) to keep
18 their accounting records according to the “Uniform System of Accounts for Public
19 Utilities and Licensees” (“USOA”), CFR Title 18, Part 101. The OCC adopted the USOA
20 requirements as well (see OAC 165:35-27-4(a)). The USOA sets the guidelines for
21 recording assets, liabilities, income, and expenses into various accounts. Embedded costs
22 are used as the basis for FERC Form 1 annual reports prescribed by FERC. For purposes
23 of a rate case, the costs recorded in each FERC account are typically adjusted to reflect
24 applicable OCC policies and for known and measurable changes to the test year level of
25 expenditures.

¹ National Association of Regulatory Utility Commissioners (“NARUC”) Electric Utility Cost Allocation Manual, January 1992, page 12.

1 Q. **What type of costs and cost components are included in the cost of service studies**
2 **you are sponsoring?**

3 A. For example, the following broad categories of costs are included in cost of service
4 studies: 1) Fixed Costs – costs that do not vary with output, remain constant in the short
5 run and include capital costs, return, depreciation expense, income taxes, property taxes,
6 and some operation and maintenance (“O&M”) expense; and 2) Variable Costs—costs
7 that vary with output which include fuel costs, purchased power and some O&M
8 expense.

9 Additionally, there are sub components of the fixed and variable costs. These
10 include directly assigned costs that are incurred to serve a particular customer or class of
11 service (street lighting, dedicated substation circuits, etc.) and what are called joint or
12 common costs. Joint or common costs are those costs that are shared by all customers
13 because they are incurred to produce jointly beneficial products.

14
15 Q. **How are joint and common costs allocated?**

16 A. In an embedded cost study, the joint and common costs identified in the test year are
17 allocated either on the basis of the overall ratios of those costs that have been directly
18 assigned, or by a series of allocators that best reflect “cost causation” principles such as
19 labor, wages or plant ratios, or by a detailed analysis of each account to determine
20 whether it is beneficial. As noted in the NARUC manual, “The classification and
21 treatment of joint and common costs requires considerable judgment in an embedded cost
22 study.”²

23
24 Q. **What do you mean by cost causation?**

25 A. Cost causation is the determination as to what, or who, is causing costs to be incurred by
26 the utility in providing service to its customers. Examples of cost causation may include:
27 1) a customer’s request for service at a new location causes the Company to incur costs
28 such as investment in line transformation, a service drop and metering facilities and
29 establishes a commitment on the part of the Company to provide, among other things,

² NARUC Manual, page 15

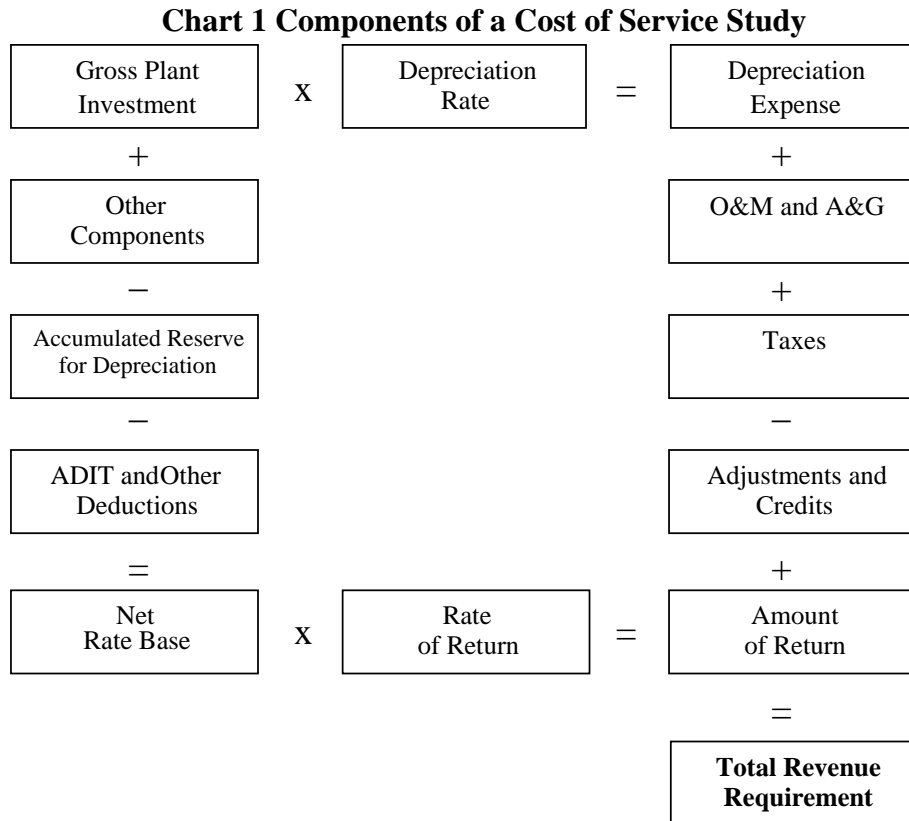
1 answers to questions and a monthly billing; or 2) a customer’s energy use or usage,
 2 usually expressed in kilowatt-hours (“kWh”), causes OG&E to incur costs related to
 3 capacity and energy in order to meet customer’s demand.
 4

5 **Q. How are a utility’s costs reflected in a cost of service study?**

6 A. In aggregate, the costs are normally expressed in terms of a revenue requirement. The
 7 COSS consists of O&M, depreciation expense, taxes (including income taxes) and return
 8 on rate base. “The total of these four components produces the test period cost of service
 9 which equals the total revenue requirements upon which rates are designed.”³ On a
 10 customer class basis, revenue requirement is the revenue required from each customer
 11 class to provide service to that customer class.
 12

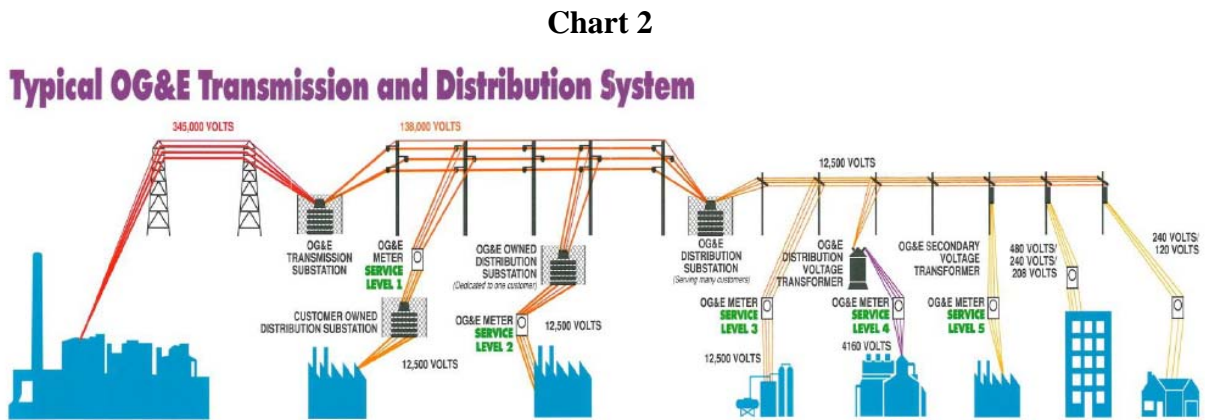
13 **Q. Please describe how a cost of service study is structured.**

14 A. Chart 1 below summarizes the revenue requirement model.



³ Accounting for Public Utilities, §7.08

- 1 Q. Please describe the physical characteristics of the electric industry that cause costs
 2 to be incurred.
- 3 A. Generation, transmission and distribution are the three main components of a vertically
 4 integrated utility.⁴ Chart 2 illustrates how power flows from the power plant to ultimate
 5 consumers on the OG&E system.



- 6 Q. How is this information separated to determine the cost of serving the various
 7 classes of utility customers?
- 8 A. Costs are allocated to customer classes using a three-step process: functionalization,
 9 classification, and finally, allocation. Below I explain each of these steps.

C. Functionalization Process

- 12 Q. Would you please describe the functionalization process?
- 13 A. Once the relevant data is gathered, the costs are separated by function. Typically,
 14 functions in a fully integrated electric utility are:
- 15 1. Production and Purchased Power;
 - 16 2. Transmission;
 - 17 3. Distribution;
 - 18 4. Customer Service; and
 - 19 5. Administrative and General (“A&G”).

⁴ NARUC Manual, page 4

1 The production function captures the costs associated with power generating facilities
2 and power purchase agreements. The transmission function captures the costs associated
3 with the high voltage lines and stations that deliver power to the distribution system and
4 connects with other utilities, generators, and some large customers. The distribution
5 function includes facilities and costs associated with distribution stations, primary and
6 secondary lines, transformers, service drops and meters that connect most customers to
7 the utility network. The customer service function encompasses the services and costs
8 associated with providing meter reading, billing, collection, customer information and
9 related services such as advice and assistance. The A&G function is a general service
10 category that captures the costs associated with management of the business and general
11 services such as staffing, accounting, legal, regulatory, communications, general purpose
12 buildings, maintenance of such facilities, and other costs that may not be directly
13 assignable to the other functions.

14
15 D. Classification Process

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

17 A. Classification is a refinement of functionalized costs. Functionalized costs are further
18 separated into three classifications: (1) demand-related costs (costs associated with the
19 maximum rate of energy use by the customer, also referred to as kW demand); (2) energy
20 costs (costs that vary with the amount of energy produced, e.g., kWh consumption); and
21 (3) customer costs (costs that are directly related to the number of customers served).
22 Typical cost classifications used in cost studies are shown in Chart 3.

Chart 3

FUNCTIONALIZATION	CLASSIFICATION
Production	Demand, Energy
Transmission	Demand
Distribution	Demand, Customer
Customer Service	Customer

1 As seen above, production plant costs, such as depreciation expense and return on
2 investment, are generally considered to be demand-related costs. Fuel costs and certain
3 production O&M expenses are energy-related because they vary with the quantity of
4 energy produced. Transmission costs are typically considered as demand-related because
5 they are mainly fixed and do not vary with energy usage. Distribution system costs are
6 driven by the need to deliver the peak demand of customers served from each facility and
7 by the number of customers served. Distribution costs for stations, primary lines and
8 transformers tend to vary with the size of the load served, while service drop and meter
9 costs vary based on the number of customers receiving the service. Customer service
10 costs vary with the number of customers and the complexity of meeting their needs. The
11 classification process provides a basis on which to allocate different categories of costs
12 (demand, energy, or customer) to the Company's jurisdictions, and ultimately to the
13 customer classes through the allocation process.

14 E. Allocation Processes

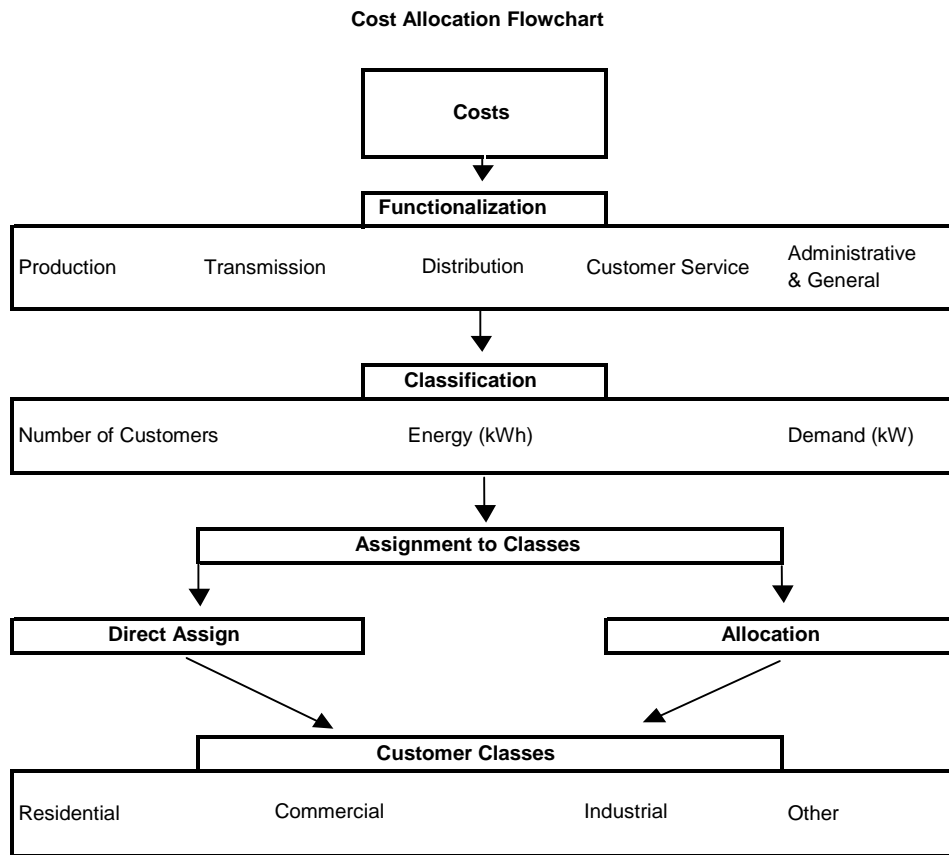
15
16 **Q. Please describe the allocation processes.**

17 **A.** After costs are functionalized and classified, they are allocated or directly assigned
18 among jurisdictions (Oklahoma retail, Arkansas retail and FERC). Within the Oklahoma
19 retail jurisdiction, the functionally classified costs are then further allocated or assigned
20 among classes of customers, based on the factors that most influence cost incurrence for
21 each cost item. OG&E's customer classes have been determined and grouped according
22 to the nature of service provided and the load characteristics. OG&E's major customer
23 classes are generally grouped as Residential, General Service, Power and Light, Large
24 Power and Light, and Other.

25 The objective of this process is to assign costs in a reasonable and understandable
26 way. As discussed earlier, some costs are directly assigned and others are allocated
27 among the classes; directly assigned costs are costs that can be readily identified as
28 belonging to a jurisdiction, a single class or even a single customer. For instance, the
29 costs associated with the poles and luminaries used for street lighting in Oklahoma are
30 directly assigned to the Oklahoma jurisdiction and then to the street lighting class in that

1 jurisdiction. Most costs, however, are attributable to more than one type of customer.
 2 These joint costs must be allocated to jurisdictions and then to the Oklahoma
 3 jurisdictional retail customer classes by an allocation methodology that recognizes each
 4 class's contribution to the cost driver that ultimately determines the overall level of cost
 5 for each sub-category of utility service. Chart 4 is a flowchart that provides an overview
 6 of the steps used to allocate costs to jurisdictional customer classes.

Chart 4



7 The process described above is applied to each cost category in the cost of service study.

8

9 **Q. What is the end result of the functionalization, classification and allocation process?**

10 **A.** When the process is completed and all of the costs are allocated to the jurisdictions and
 11 customer classes, the result is a fully allocated embedded cost of service study that
 12 establishes the cost responsibility for each jurisdiction and customer class of service.

1 II. OG&E'S JURISDICTIONAL COST OF SERVICE STUDY

2 Q. Did OG&E submit a jurisdictional cost of service study as required by the
3 Commission's minimum standard filing requirements?

4 A. Yes. The Company submitted its COSS as required in OAC 165:70-5-1 *et. seq.*

5 Q. What criteria have been established to ensure that the allocation of costs to the
6 customers is reasonable?

7 A. The Company uses the following criteria to judge the appropriateness of its allocation
8 methodology:

- 9 1. The method should reflect the planning and operating characteristics of the
10 utility's system.
- 11 2. The method should recognize individual customer class characteristics such as
12 energy use, peak demand on the relevant portion of the system, service
13 diversity characteristics or the number of customers.
- 14 3. The method should produce reliable results that are relatively stable from
15 year-to-year.
- 16 4. Customers who benefit from the use of the system should also bear
17 appropriate cost responsibility for the system.

18
19 Q. Briefly describe the contents of Section K.

20 A. Section K sets forth the Company's Cost of Service and jurisdictional calculations; and
21 the schedules in Section K and supporting work papers in the supplemental package
22 provide the support for those calculations.

23 Schedule K-1, shows the pro forma adjusted Total Company cost of service.
24 Each of the supporting schedules details, by account, the associated allocation basis for
25 the amounts shown on Schedule K-1. Chart 7 lists such supporting schedules.

Chart 7

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

1 **III. CHANGES TO THE JURISDICTIONAL COST OF SERVICE STUDY**

2 **A. Functional Changes**

3 **Q. Is OG&E proposing functional allocation changes to the jurisdictional cost of**
4 **service study?**

5 A. Yes, OG&E is proposing a functional allocation change for both Generation Step-up
6 Transformers (“GSUs”) and generation radial ties.

7
8 **Q. Please explain the purpose of GSUs.**

9 A. GSUs convert lower voltages provided by the power plants to higher voltages in order to
10 allow electricity to be transported over miles of transmission lines more efficiently.

11
12 **Q. Please explain the purpose of generation radial ties.**

13 A. Currently, generation radial ties are the poles and wires needed to transfer power from the
14 generator to the nearest transmission system. In practical terms, generation facilities are
15 built as close as possible to existing transmission facilities but sometimes require a radial
16 tie to connect to the transmission system.

17
18 **Q. Has OG&E allocated GSUs and generation radial ties differently in this case versus**
19 **the previous rate case?**

20 A. Yes. OG&E proposes in this case to allocate these costs as generation assets using a
21 production demand allocator as opposed to a transmission demand allocator. Previously,
22 these costs were booked and functionalized as transmission costs based on FERC

1 accounting guidelines and were allocated as such in OG&E's previous rate case using a
2 transmission demand allocator. However, both of these assets provide the transition
3 phase of transferring electricity produced from generation sources to the transmission
4 system. The FERC transmission formula rate does not consider GSUs or generation
5 radial ties as transmission assets for cost recovery purposes at the FERC. In addition,
6 OG&E's recently expired wholesale sales contract classified these assets as production
7 assets and as discussed by OG&E witness Rowlett, OG&E's wholesale contracts no
8 longer exist.

9
10 **B. Classification Changes and Additions**

11 **Q. How does OG&E propose to classify certain environmental as well as community
12 solar production plant and associated costs for recovery in this case?**

13 A. OG&E proposes to recover the environmental costs as demand-related and using the
14 production demand allocator, which is the same as all other production plant. In addition,
15 because of the localized nature of the community solar project and its interconnection to
16 the distribution system, the solar project's costs are allocated 100 percent to the
17 Oklahoma jurisdiction and then allocated to Oklahoma customer classes using the
18 production demand allocator.

19
20 **C. Explanation of Demand Allocation Changes**

21 **Q. What are the primary demand allocators used in the COSS you are sponsoring?**

22 A. There are three primary demand allocators used in OG&E's COSS that support how costs
23 should be allocated for the three main functions: production demand; transmission
24 demand; and distribution demand.

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

27 A. Each of the three functional categories of production, transmission, and distribution have
28 different cost drivers that require different allocation methods to most accurately match
29 costs to the cost causers. Therefore, the demands imposed on OG&E's generating units

1 utilize coincident peak demands at the time of the system peak for the production demand
2 allocator, while the distribution demand allocator utilizes non-coincident peak demands
3 that do not occur at the same time as the system peak.
4

5 **Q. Is OG&E using the same jurisdictional production demand allocation methodology**
6 **as approved in its previous rate case?**

7 A. The Average and Excess (“A&E”) methodology is the same, however, in this case
8 OG&E proposes to change the jurisdictional demand inputs used to determine the excess
9 component by using an average of the four summer coincident peaks (“4CP”) instead of
10 using only the jurisdictional loads at the time of the system peak (“1CP”).⁵
11

12 **Q. Why does OG&E believe this production demand allocation methodology is**
13 **appropriate?**

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

- 16 1. The use of an average of 4CPs for the jurisdictional demand input creates a
17 more normalizing or smoothing effect from year to year;
- 18 2. The 4CP A&E provides reliable results and consistency to OG&E’s methods
19 utilized in the past;
- 20 3. The 4CP A&E reflects cost-causation by recognizing that OG&E is a
21 summer-peaking utility, and is consistent with system planning principles;
- 22 4. Resulting rates under the 4CP A&E are just and reasonable; and
- 23 5. 4CP A&E has been approved in multiple states including Oklahoma.
24

25 **Q. Please describe how OG&E calculates the production demand allocator that is used**
26 **in this case.**

27 A. The 4CP A&E demand method utilizes two types of demand components in the
28 allocation of production demand-related costs, the “average” component and “excess”

⁵ Joint Stipulation and Settlement Agreement of Cost of Service and Rate Design Issues in Cause No. PUD 201100087.

1 component. These are derived using average and peak demands. Average demand is
2 determined using the annual kilowatt hours (“kWhs”) consumed during the test year
3 divided by 8760 hours. The peak demand reflects the average of the peak demand loads
4 of the four summer months of all customer classes at the time of the Company’s highest
5 measured one-hour demands for the system in each of the four summer months. The
6 “excess demand” is determined by subtracting the average demands from the peak
7 demands. The system load factor is calculated by dividing the annual average demand by
8 the annual system peak demand. The average component is weighted by calculating the
9 average demand times the system load factor. The excess component is weighted by
10 calculating the excess demand times one minus the system load factor. The allocation
11 factors are derived by adding the average component to the excess component for each
12 customer class.

13 14 D. Modifications to Demand Allocators

15 1. Generation

16 Q. **What adjustments did OG&E make to the jurisdictional load data in its production
17 demand allocator calculations?**

18 A. The load data adjustments for the production demand allocator have not changed since
19 OG&E’s last general rate case. The Company modified the demand and energy input
20 components of the allocator by crediting the Oklahoma jurisdiction for the direct
21 assignment of 440 MW peak demand related to cogeneration contracts, as well as the
22 energy provided by cogeneration and the Sooner wind farm.

23
24 Q. **Why did OG&E make these modifications to the production demand allocator?**

25 A. The costs of OG&E’s cogeneration contracts and the Sooner wind farm are assigned to
26 Oklahoma retail customers in accordance with prior OCC Orders. Because the
27 Oklahoma retail jurisdiction is responsible for all of the cogeneration costs, an adjustment
28 is made to the jurisdictional allocator so these costs are not allocated to other
29 jurisdictions. The cogeneration contracts provide a 440 MW capacity contribution to the
30 Company’s overall generation resources and, along with the associated energy kWhs

1 provided by both the cogeneration and Sooner wind farm, should be considered in
2 developing the production demand allocation for OG&E's generation fleet. The result is
3 to have a joint cost allocator to allocate production costs that do not include cogeneration
4 or the Sooner wind farm costs that are directly assigned to only the Oklahoma
5 jurisdiction.

6
7 **Q. What was the change in the production demand allocator from modifying the**
8 **Oklahoma retail jurisdiction for the 440 MW demand supplied by cogeneration**
9 **contracts and the associated cogeneration and Sooner wind farm energy kWhs?**

10 A. As a result of the change, the production demand allocator decreased for the Oklahoma
11 retail jurisdiction. This change resulted in an Oklahoma production demand allocator of
12 90.9169% instead of 91.5327% without the adjustment. This allocation methodology is
13 supported by the cost causation principle discussed previously in my testimony and
14 regulatory normalization practice.

15
16 **Q. Are there any wholesale customer loads included in your jurisdictional production**
17 **demand allocation in this case?**

18 A. No. Since OG&E's last general rate case, all wholesale contracts have expired, leaving
19 only OG&E's two retail jurisdictions.

20
21 2. Transmission and Distribution Allocation

22 **Q. How has the Company classified and allocated transmission costs in this case?**

23 A. The Company classifies transmission on demand and has historically, and in this case,
24 allocated its transmission costs to its retail and wholesale jurisdictions by using an
25 average of twelve monthly coincident peak demands ("12-CP").

26
27 **Q. Generally, how does OG&E classify distribution plant costs in its COSS?**

28 A. OG&E classifies distribution plant costs as either demand related or customer related
29 depending on the FERC account. FERC accounts 360-363 are considered as demand
30 related. Accounts 364-368 are considered both demand and customer related and are

1 classified based on the zero-intercept methodology as supported by the NARUC Cost
2 Allocation Manual. This zero-intercept methodology was approved in Cause No. PUD
3 200800398 and is consistent with OG&E's previous rate case. The rest of the
4 distribution plant accounts are considered customer related. Additionally, distribution
5 O&M accounts are classified in the same manner as the underlying plant accounts.
6

7 **Q. How has the Company allocated demand related distribution plant costs in this**
8 **case?**

9 A. Demand-related distribution costs were allocated based on class non-coincident peak
10 demands ("NCPs"), as opposed to CPs. The reason for using NCPs is that local
11 distribution demand costs are incurred to serve area load, rather than a system load.
12 Using NCPs instead of CPs in this methodology also recognizes that little or no diversity
13 exists at this level except within each class.
14

15 **Q. What allocation methodologies did you use for customer-related distribution plant**
16 **costs?**

17 A. The customer-related distribution plant costs and certain associated expenses are
18 allocated to the customers who require such facilities by using the weighted customer
19 methodology. Customer-related distribution costs are limited to the costs that vary
20 directly with the number of customers (except for meters and lighting costs which are
21 direct assigned). These costs include poles, conductors, underground conduit, service
22 drops, transformers, and associated expenses.
23

24 **Q. Please explain the weighted customer methodology of allocating the customer-**
25 **related distribution costs described above.**

26 A. The number of customers by tariff class and average costs for each are obtained from the
27 records of the company. A weighting factor is derived by using the costs of one class as
28 a base, residential in this case, and dividing the cost of the other classes by this base. A
29 weighted allocation factor is then determined by multiplying the number of customers in
30 each class by each class's weight. This weighted factor is then compared to other classes

1 within the Oklahoma jurisdiction to arrive at percentages to use for allocation purposes
2 for the class cost of service.

3
4 **Q. Is there a change in the allocation methodology of distribution-related customer
5 costs in this case that is different than OG&E's previous case?**

6 A. Yes, meter costs are allocated differently in this case. In OG&E's previous case, PUD
7 201100087, meter costs were allocated using the weighted customer methodology as
8 described above. Due to the installation of SmartGrid meters in OG&E's service territory
9 and the ability to capture current meter costs by customer class, the meter costs in this
10 case are now directly assigned to each applicable class. This is similar to the direct
11 assignment of costs for the lighting classes to more accurately reflect cost-causation.

12
13 **Q. Please describe the allocation of the other O&M expenses that are identifiable as
14 customer-related.**

15 A. Customer accounting expenses, customer information expenses, and customer services
16 expenses were allocated to each jurisdiction using a combination of adjusted test year end
17 number of customers and various other customer-based allocators. This is the same
18 method that was used in OG&E's previous rate cases.

19
20 **IV. CLASS COST OF SERVICE STUDY**

21 **Q. Please describe the Section L as it relates to the class cost of service study you are
22 sponsoring.**

23 A. The class cost of service study for Section L is the same fully allocated, embedded cost-
24 based study, consistent with Section K and OG&E's previous filings before the
25 Commission. Section L provides the revenue, revenue deductions, income taxes, rate
26 base components and return on rate base for each Oklahoma customer class.

27
28 **Q. Please generally describe the contents and organization of Section L.**

29 A. Schedule L-1 is the Rate Design Cost of Service for the test year. It shows the Oklahoma
30 jurisdictional pro forma adjusted cost of service by customer class under rates placed in

1 effect as of August 2, 2012. Revenue, revenue deductions and rate base are organized in
2 the same manner as on Schedule K-1. Line 31 shows the percentage rates of return earned
3 from each class under current rates.

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

8 Schedule L-3 presents the change in sales revenue for each class if a rate of return
9 on rate base was to be applied equally to all classes of service. Line 13 is the total class
10 revenue requirement needed to achieve the Company's proposed return on rate base.
11 Line 14 is the pro forma class revenue based on existing rates for the test year. Line 15 is
12 the difference between the class revenue requirement and the current tariff revenue. This
13 deficiency or excess represents the class change needed in current tariffs for rate design.
14 Line 16 shows the class revenues received from current tariffs.

15 Schedule L-4 indicates the percent increases necessary to recover the revenue
16 deficiency through sales revenue for each class. Line 12 indicates the return on rate base
17 by class of service adjusted for the deficiency at these levels of revenue.

18
19 **Q. Was the class cost of service study developed in a manner consistent with the study**
20 **previously filed by OG&E with the Commission?**

21 **A.** Yes. The methodologies employed by OG&E in the development of the class cost of
22 service study filed in Cause No. PUD 201100087 were used in the current class cost of
23 service study.

24
25 **Q. Does the class cost of service study use the same allocation methods to allocate**
26 **similar costs as is used in the jurisdictional cost of service study?**

27 **A.** Yes, primarily the same methodologies for allocating costs are used in both the
28 jurisdictional and class study; however, different inputs were utilized in this case for the
29 transmission demand costs.

1 Q. **How is the class transmission demand allocation determined in this case?**

2 A. The inputs utilized for allocating jurisdictional transmission costs to the customer classes
3 were the average of the four summer peak demands. This is consistent with the class
4 allocator used in OG&E's last base rate case.

5
6 Q. **How are the results of the class cost of service study used in this proceeding?**

7 A. The results of the class cost of service submitted in this proceeding are primarily used to:
8 (1) provide embedded cost information that can be used as one tool in developing the
9 pricing structures for each customer class; (2) provide information with which present
10 and proposed relative rates of return by customer class can be compared and reviewed;
11 and; (3) comply with Commission filing requirements. See the attached Direct Exhibit
12 DWS-1 (Schedule L-3 in the Application Package) that shows the increase in revenues by
13 class at the equalized rate of return of 8.088 percent.

14
15 VI. CONCLUSION

16 Q. **Would you please summarize your testimony regarding the cost of service studies
17 you are supporting?**

18 A. The jurisdictional cost of service study identifies the embedded cost of service for the
19 Oklahoma retail, Arkansas retail and FERC jurisdictions. This embedded cost of service
20 study is based upon sound cost allocation principles, reflects all of the test year
21 adjustments, and establishes the cost responsibility for the provision of electric service to
22 each jurisdiction.

23 The class cost of service study quantifies the embedded cost of service for the
24 Oklahoma retail individual customer classes that make up the Oklahoma retail
25 jurisdiction. In addition, the class cost of service study provides information necessary to
26 develop cost based rates for OG&E's retail customers.

27
28 Q. **Are the cost of service studies in this filing transparent and verifiable?**

29 A. Yes, I believe that the jurisdictional and class cost of service studies are transparent and

1 verifiable. They provide complete detail as to each allocation made on an account-by-
2 account basis. In addition, cross-references to supporting schedules are provided on all
3 summary pages. Every calculation made in the model can be readily verified by
4 Commission Staff and other parties to the case.

5

6 **Q. Does this conclude your direct testimony?**

7 **A. Yes, it does.**

SECTION L - RATE DESIGN COST OF SERVICE
SCHEDULE L-3

OKLAHOMA GAS AND ELECTRIC COMPANY
EQUAL RATE OF RETURN
CHANGE IN SALES REVENUE
TEST YEAR ENDING JUNE 30, 2015
CAUSE NO. PUD 201500273

Direct Exhibit DWS-1

LINE NO.	DESCRIPTION	1 TOTAL RESIDENTIAL SERVICE S/L-5 Cols. 2 thru 6	2 RESIDENTIAL STANDARD S/L-5	3 RESIDENTIAL TOU S/L-5	4 RESIDENTIAL VPP S/L-5	5 RESIDENTIAL CPP S/L-5	6 RESIDENTIAL DG S/L-5	7 TOTAL GENERAL SERVICE Cols. 8, 13, 17, 18, 19, & 20	8 TOTAL GENERAL SVC STANDARD Cols. 9 thru 12	9 GENERAL SVC STANDARD S/L-2	10 GENERAL SVC STANDARD S/L-3	11 GENERAL SVC STANDARD S/L-4	12 GENERAL SVC STANDARD S/L-5
SCHEDULE L-3 COS AT CLAIMED ROR													
<u>EXPENSES</u>													
1	OPERATING EXPENSES	\$430,982,362	\$369,292,133	\$2,298,836	\$58,794,961	\$497,679	\$98,753	\$85,163,128	\$75,757,371	\$4,262	\$186,972	\$63,635	\$75,502,501
2	UNCOLLECTIBLE ACCOUNTS	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3	TOTAL EXPENSES	\$430,982,362	\$369,292,133	\$2,298,836	\$58,794,961	\$497,679	\$98,753	\$85,163,128	\$75,757,371	\$4,262	\$186,972	\$63,635	\$75,502,501
<u>INCOME TAXES</u>													
4	EXISTING RATES	\$31,924,869	\$25,663,925	\$134,298	\$6,065,978	\$48,366	\$12,304	\$6,189,310	\$5,018,346	\$1,641	\$67,481	\$2,730	\$4,946,494
5	INCREASE	\$35,793,557	\$32,334,489	\$212,090	\$3,219,708	\$24,864	\$2,406	\$8,060,364	\$7,680,845	(\$779)	(\$36,737)	\$8,885	\$7,709,476
6	TOTAL INCOME TAXES	\$67,718,426	\$57,998,414	\$346,388	\$9,285,686	\$73,229	\$14,710	\$14,249,674	\$12,699,191	\$862	\$30,745	\$11,615	\$12,655,970
<u>RETURN</u>													
7	EXISTING RATES	\$109,316,532	\$90,975,028	\$513,370	\$17,655,839	\$140,072	\$32,224	\$22,168,420	\$18,970,680	\$3,341	\$133,303	\$14,414	\$18,819,621
8	INCREASE (DECREASE)	\$56,522,152	\$51,059,885	\$334,914	\$5,084,290	\$39,263	\$3,800	\$12,728,244	\$12,128,939	(\$1,230)	(\$58,012)	\$14,030	\$12,174,151
9	TOTAL RETURN	\$165,838,684	\$142,034,912	\$848,284	\$22,740,129	\$179,335	\$36,024	\$34,896,664	\$31,099,619	\$2,111	\$75,292	\$28,444	\$30,993,772
10	TOTAL REVENUE REQUIREMENT (L3, L6 and L9)	\$664,539,473	\$569,325,459	\$3,493,508	\$90,820,775	\$750,244	\$149,486	\$134,309,466	\$119,556,181	\$7,235	\$293,008	\$103,695	\$119,152,243
11	RATE BASE	\$2,050,428,835	\$1,756,119,094	\$10,488,184	\$281,158,863	\$2,217,296	\$445,398	\$431,462,212	\$384,515,566	\$26,099	\$930,904	\$351,686	\$383,206,876
12	REQUESTED RATE OF RETURN	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%
13	TOTAL REVENUE REQUIREMENT	\$664,539,473	\$569,325,459	\$3,493,508	\$90,820,775	\$750,244	\$149,486	\$134,309,466	\$119,556,181	\$7,235	\$293,008	\$103,695	\$119,152,243
14	OPERATING REVENUE	\$572,223,764	\$485,931,086	\$2,946,504	\$82,516,777	\$686,117	\$143,280	\$113,520,858	\$99,746,397	\$9,244	\$387,757	\$80,780	\$99,268,616
15	DEFICIENCY or (EXCESS)	\$92,315,709	\$83,394,373	\$547,004	\$8,303,998	\$64,127	\$6,206	\$20,788,608	\$19,809,784	(\$2,009)	(\$94,749)	\$22,915	\$19,883,627
16	SALES REVENUE (EXCLUDES MISC REVENUE)	\$556,982,413	\$472,184,681	\$2,901,055	\$81,075,343	\$678,271	\$143,063	\$112,566,802	\$98,867,030	\$8,949	\$386,199	\$80,511	\$98,391,371
17	PERCENT INCREASE IN SALES OF ELECTRICITY REVENUE	16.13%	17.16%	18.56%	10.06%	9.35%	4.33%	18.31%	19.86%	-21.74%	-24.44%	28.37%	20.03%

SECTION L - RATE DESIGN COST OF SERVICE
SCHEDULE L-3

OKLAHOMA GAS AND ELECTRIC COMPANY
EQUAL RATE OF RETURN
CHANGE IN SALES REVENUE
TEST YEAR ENDING JUNE 30, 2015
CAUSE NO. PUD 201500273

Direct Exhibit DWS-1

LINE NO.	DESCRIPTION	13	14	15	16	17	18	19	20	21	22	23	24
		TOTAL GENERAL SVC TOU	GENERAL SVC TOU S/L-3	GENERAL SVC TOU S/L-4	GENERAL SVC TOU S/L-5	GENERAL SVC VPP S/L-5	GENERAL SVC CPP S/L-5	GENERAL SVC DG S/L-5	TOTAL GENERAL SVC STANDARD-SCI	GENERAL SVC STANDARD-SCI S/L-3	GENERAL SVC STANDARD-SCI S/L-5	TOTAL OIL & GAS PRODUCTION	TOTAL OIL & GAS PROD STANDARD
		Cols. 14 thru 16							Cols. 21 & 22			Cols. 24 & 28	Cols. 25 thru 27
SCHEDULE L-3 COS AT CLAIMED ROR													
<u>EXPENSES</u>													
1	OPERATING EXPENSES	\$2,916,782	\$32,108	\$40,178	\$2,844,496	\$5,710,552	\$247,591	\$41,159	\$489,674	\$0	\$489,674	\$6,126,543	\$5,510,356
2	UNCOLLECTIBLE ACCOUNTS	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3	TOTAL EXPENSES	\$2,916,782	\$32,108	\$40,178	\$2,844,496	\$5,710,552	\$247,591	\$41,159	\$489,674	\$0	\$489,674	\$6,126,543	\$5,510,356
<u>INCOME TAXES</u>													
4	EXISTING RATES	\$396,058	\$3,569	\$4,221	\$388,268	\$825,544	\$19,844	\$1,251	(\$71,734)	\$1	(\$71,735)	\$2,060,448	\$1,843,562
5	INCREASE	\$107,543	\$2,303	\$2,820	\$102,420	\$96,762	\$19,168	\$5,526	\$150,520	(\$1)	\$150,521	(\$1,068,554)	(\$951,221)
6	TOTAL INCOME TAXES	\$503,601	\$5,872	\$7,042	\$490,688	\$922,305	\$39,012	\$6,778	\$78,786	\$0	\$78,786	\$991,894	\$892,341
<u>RETURN</u>													
7	EXISTING RATES	\$1,063,468	\$10,743	\$12,791	\$1,039,934	\$2,105,876	\$65,270	\$7,872	(\$44,745)	\$2	(\$44,747)	\$4,116,461	\$3,687,380
8	INCREASE (DECREASE)	\$169,823	\$3,637	\$4,454	\$161,733	\$152,798	\$30,268	\$8,727	\$237,688	(\$2)	\$237,690	(\$1,687,370)	(\$1,502,088)
9	TOTAL RETURN	\$1,233,291	\$14,380	\$17,244	\$1,201,667	\$2,258,674	\$95,538	\$16,599	\$192,942	\$0	\$192,942	\$2,429,091	\$2,185,292
10	TOTAL REVENUE REQUIREMENT (L3, L6 and L9)	\$4,653,674	\$52,359	\$64,464	\$4,536,851	\$8,891,532	\$382,141	\$64,535	\$761,402	\$0	\$761,402	\$9,547,527	\$8,587,988
11	RATE BASE	\$15,248,405	\$177,791	\$213,210	\$14,857,404	\$27,926,240	\$1,181,236	\$205,225	\$2,385,540	\$0	\$2,385,540	\$30,033,271	\$27,018,936
12	REQUESTED RATE OF RETURN	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%
13	TOTAL REVENUE REQUIREMENT	\$4,653,674	\$52,359	\$64,464	\$4,536,851	\$8,891,532	\$382,141	\$64,535	\$761,402	\$0	\$761,402	\$9,547,527	\$8,587,988
14	OPERATING REVENUE	\$4,376,307	\$46,419	\$57,190	\$4,272,698	\$8,641,972	\$332,705	\$50,282	\$373,195	\$3	\$373,192	\$12,303,451	\$11,041,298
15	DEFICIENCY or (EXCESS)	\$277,367	\$5,940	\$7,274	\$264,153	\$249,560	\$49,436	\$14,253	\$388,207	(\$3)	\$388,210	(\$2,755,924)	(\$2,453,310)
16	SALES REVENUE (EXCLUDES MISC REVENUE)	\$4,361,306	\$46,222	\$56,927	\$4,258,157	\$8,585,268	\$331,124	\$50,187	\$371,887	\$3	\$371,884	\$12,259,681	\$10,999,167
17	PERCENT INCREASE IN SALES OF ELECTRICITY REVENUE	6.34%	12.80%	12.72%	6.18%	2.89%	14.86%	28.35%	104.02%	0.00%	104.02%	-22.40%	-22.22%

OKLAHOMA GAS AND ELECTRIC COMPANY
EQUAL RATE OF RETURN
CHANGE IN SALES REVENUE
TEST YEAR ENDING JUNE 30, 2015
CAUSE NO. PUD 201500273

LINE NO.	DESCRIPTION	25 OIL & GAS PROD STANDARD S/L-3	26 OIL & GAS PROD STANDARD S/L-4	27 OIL & GAS PROD STANDARD S/L-5	28 TOTAL OIL & GAS PROD TOU Cols. 29 thru 31	29 OIL & GAS PROD TOU S/L-3	30 OIL & GAS PROD TOU S/L-4	31 OIL & GAS PROD TOU S/L-5	32 TOTAL SCHOOLS NON-DEMAND Cols. 33, 37, & 41	33 TOTAL SCHOOLS ND - STANDARD Cols. 34 thru 36	34 SCHOOLS ND-STANDARD S/L-3	35 SCHOOLS ND-STANDARD S/L-4	36 SCHOOLS ND-STANDARD S/L-5
SCHEDULE L-3 COS AT CLAIMED ROR													
<u>EXPENSES</u>													
1	OPERATING EXPENSES	\$1,589,241	\$59,238	\$3,861,877	\$616,187	\$220,824	\$23,413	\$371,950	\$10,426,958	\$3,748,181	\$59,315	\$51,595	\$3,637,271
2	UNCOLLECTIBLE ACCOUNTS	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3	TOTAL EXPENSES	\$1,589,241	\$59,238	\$3,861,877	\$616,187	\$220,824	\$23,413	\$371,950	\$10,426,958	\$3,748,181	\$59,315	\$51,595	\$3,637,271
<u>INCOME TAXES</u>													
4	EXISTING RATES	\$631,835	\$14,152	\$1,197,575	\$216,885	\$115,859	\$9,218	\$91,809	(\$368,960)	\$111,239	\$11,157	\$2,189	\$97,893
5	INCREASE	(\$373,431)	(\$3,262)	(\$574,529)	(\$117,332)	(\$80,310)	(\$5,072)	(\$31,951)	\$2,621,726	\$659,947	(\$962)	\$6,922	\$653,986
6	TOTAL INCOME TAXES	\$258,405	\$10,890	\$623,046	\$99,553	\$35,549	\$4,146	\$59,858	\$2,252,766	\$771,186	\$10,195	\$9,112	\$751,879
<u>RETURN</u>													
7	EXISTING RATES	\$1,222,508	\$31,820	\$2,433,051	\$429,081	\$213,875	\$18,163	\$197,042	\$1,376,895	\$846,460	\$26,487	\$11,383	\$808,591
8	INCREASE (DECREASE)	(\$589,690)	(\$5,151)	(\$907,247)	(\$185,281)	(\$126,818)	(\$8,009)	(\$50,455)	\$4,140,008	\$1,042,132	(\$1,519)	\$10,931	\$1,032,719
9	TOTAL RETURN	\$632,818	\$26,670	\$1,525,804	\$243,799	\$87,057	\$10,154	\$146,588	\$5,516,903	\$1,888,592	\$24,968	\$22,314	\$1,841,310
10	TOTAL REVENUE REQUIREMENT (L3, L6 and L9)	\$2,480,463	\$96,798	\$6,010,727	\$959,539	\$343,430	\$37,713	\$578,395	\$18,196,628	\$6,407,958	\$94,479	\$83,021	\$6,230,459
11	RATE BASE	\$7,824,155	\$329,742	\$18,865,039	\$3,014,334	\$1,076,376	\$125,547	\$1,812,412	\$68,210,963	\$23,350,544	\$308,706	\$275,892	\$22,765,947
12	REQUESTED RATE OF RETURN	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%
13	TOTAL REVENUE REQUIREMENT	\$2,480,463	\$96,798	\$6,010,727	\$959,539	\$343,430	\$37,713	\$578,395	\$18,196,628	\$6,407,958	\$94,479	\$83,021	\$6,230,459
14	OPERATING REVENUE	\$3,443,584	\$105,211	\$7,492,503	\$1,262,153	\$550,558	\$50,794	\$660,801	\$11,434,894	\$4,705,880	\$96,959	\$65,167	\$4,543,754
15	DEFICIENCY or (EXCESS)	(\$963,121)	(\$8,413)	(\$1,481,776)	(\$302,614)	(\$207,128)	(\$13,081)	(\$82,406)	\$6,761,734	\$1,702,078	(\$2,480)	\$17,854	\$1,686,705
16	SALES REVENUE (EXCLUDES MISC REVENUE)	\$3,429,938	\$104,888	\$7,464,341	\$1,260,514	\$550,054	\$50,746	\$659,714	\$11,403,179	\$4,693,830	\$96,754	\$65,007	\$4,532,069
17	PERCENT INCREASE IN SALES OF ELECTRICITY REVENUE	-27.97%	-8.00%	-19.78%	-23.98%	-37.62%	-25.75%	-12.47%	59.13%	36.17%	-2.56%	27.40%	37.12%

SECTION L - RATE DESIGN COST OF SERVICE
SCHEDULE L-3

OKLAHOMA GAS AND ELECTRIC COMPANY
EQUAL RATE OF RETURN
CHANGE IN SALES REVENUE
TEST YEAR ENDING JUNE 30, 2015
CAUSE NO. PUD 201500273

Direct Exhibit DWS-1

LINE NO.	DESCRIPTION	37	38	39	40	41	42	43	44	45	46	47	48
		TOTAL SCHOOLS ND-TOU	SCHOOLS ND-TOU	SCHOOLS ND-TOU	SCHOOLS ND-TOU	SCHOOLS ND-VPP	TOTAL SCHOOLS DEMAND	TOTAL SCHOOLS D-STANDARD	SCHOOLS D-STANDARD	SCHOOLS D-STANDARD	SCHOOLS D-STANDARD	TOTAL SCHOOLS D-TOU	SCHOOLS D-TOU
		Cols. 38 thru 40	S/L-3	S/L-4	S/L-5	S/L-5	Cols. 43 & 47	Cols. 44 thru 46	S/L-3	S/L-4	S/L-5	Cols. 48 thru 50	S/L-3
SCHEDULE L-3													
COS AT CLAIMED ROR													
<u>EXPENSES</u>													
1	OPERATING EXPENSES	\$3,456,917	\$152,688	\$77,810	\$3,226,419	\$3,221,861	\$5,836,032	\$2,591,186	\$38,875	\$133,114	\$2,419,197	\$3,244,846	\$145,308
2	UNCOLLECTIBLE ACCOUNTS	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3	TOTAL EXPENSES	\$3,456,917	\$152,688	\$77,810	\$3,226,419	\$3,221,861	\$5,836,032	\$2,591,186	\$38,875	\$133,114	\$2,419,197	\$3,244,846	\$145,308
<u>INCOME TAXES</u>													
4	EXISTING RATES	(\$369,192)	\$9,052	(\$2,369)	(\$375,875)	(\$111,007)	\$180,378	\$165,551	\$7,788	\$32,184	\$125,580	\$14,827	\$19,217
5	INCREASE	\$1,212,282	\$16,623	\$15,874	\$1,179,785	\$749,497	\$1,048,784	\$384,924	(\$1,314)	(\$9,090)	\$395,328	\$663,860	\$4,813
6	TOTAL INCOME TAXES	\$843,090	\$25,675	\$13,505	\$803,910	\$638,490	\$1,229,162	\$550,475	\$6,474	\$23,094	\$520,908	\$678,687	\$24,030
<u>RETURN</u>													
7	EXISTING RATES	\$150,350	\$36,626	\$8,007	\$105,717	\$380,085	\$1,353,999	\$740,245	\$17,929	\$70,909	\$651,406	\$613,755	\$51,248
8	INCREASE (DECREASE)	\$1,914,333	\$26,250	\$25,066	\$1,863,017	\$1,183,543	\$1,656,151	\$607,840	(\$2,075)	(\$14,355)	\$624,269	\$1,048,311	\$7,600
9	TOTAL RETURN	\$2,064,683	\$62,877	\$33,073	\$1,968,733	\$1,563,628	\$3,010,150	\$1,348,084	\$15,854	\$56,555	\$1,275,675	\$1,662,066	\$58,848
10	TOTAL REVENUE REQUIREMENT (L3, L6 and L9)	\$6,364,690	\$241,240	\$124,388	\$5,999,063	\$5,423,979	\$10,075,344	\$4,489,746	\$61,203	\$212,762	\$4,215,781	\$5,585,599	\$228,185
11	RATE BASE	\$25,527,729	\$777,408	\$408,912	\$24,341,409	\$19,332,689	\$37,217,488	\$16,667,707	\$196,021	\$699,243	\$15,772,443	\$20,549,782	\$727,591
12	REQUESTED RATE OF RETURN	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%
13	TOTAL REVENUE REQUIREMENT	\$6,364,690	\$241,240	\$124,388	\$5,999,063	\$5,423,979	\$10,075,344	\$4,489,746	\$61,203	\$212,762	\$4,215,781	\$5,585,599	\$228,185
14	OPERATING REVENUE	\$3,238,075	\$198,366	\$83,448	\$2,956,261	\$3,490,939	\$7,370,409	\$3,496,982	\$64,592	\$236,207	\$3,196,183	\$3,873,427	\$215,773
15	DEFICIENCY or (EXCESS)	\$3,126,615	\$42,874	\$40,940	\$3,042,802	\$1,933,040	\$2,704,935	\$992,764	(\$3,389)	(\$23,445)	\$1,019,598	\$1,712,172	\$12,412
16	SALES REVENUE (EXCLUDES MISC REVENUE)	\$3,228,080	\$197,771	\$83,163	\$2,947,146	\$3,481,269	\$7,355,351	\$3,490,124	\$64,449	\$235,682	\$3,189,993	\$3,865,227	\$215,262
17	PERCENT INCREASE IN SALES OF ELECTRICITY REVENUE	96.56%	21.61%	49.06%	102.93%	55.37%	36.70%	28.39%	-5.25%	-9.93%	31.90%	44.20%	5.75%

SECTION L - RATE DESIGN COST OF SERVICE
SCHEDULE L-3

OKLAHOMA GAS AND ELECTRIC COMPANY
EQUAL RATE OF RETURN
CHANGE IN SALES REVENUE
TEST YEAR ENDING JUNE 30, 2015
CAUSE NO. PUD 201500273

Direct Exhibit DWS-1

LINE NO.	DESCRIPTION	49 SCHOOLS D-TOU S/L-4	50 SCHOOLS D-TOU S/L-5	51 TOTAL POWER & LIGHT Cols. 52, 58, & 64	52 TOTAL PWR & LGHT STANDARD Cols. 53 thru 57	53 PWR & LGHT STANDARD S/L-1	54 PWR & LGHT STANDARD S/L-2	55 PWR & LGHT STANDARD S/L-3	56 PWR & LGHT STANDARD S/L-4	57 PWR & LGHT STANDARD S/L-5	58 TOTAL PWR & LGHT TOU Cols. 59 thru 63	59 PWR & LGHT TOU S/L-1	60 PWR & LGHT TOU S/L-2
SCHEDULE L-3 COS AT CLAIMED ROR													
<u>EXPENSES</u>													
1	OPERATING EXPENSES	\$276,114	\$2,823,424	\$178,459,995	\$112,092,964	\$30,346	\$324,314	\$5,795,134	\$1,771,442	\$104,171,728	\$64,945,480	\$584,188	\$779,308
2	UNCOLLECTIBLE ACCOUNTS	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3	TOTAL EXPENSES	\$276,114	\$2,823,424	\$178,459,995	\$112,092,964	\$30,346	\$324,314	\$5,795,134	\$1,771,442	\$104,171,728	\$64,945,480	\$584,188	\$779,308
<u>INCOME TAXES</u>													
4	EXISTING RATES	\$28,667	(\$33,058)	\$24,163,357	\$12,051,316	\$16,627	\$162,556	\$2,093,644	\$558,866	\$9,219,622	\$12,129,688	\$306,261	\$328,263
5	INCREASE	\$17,922	\$641,125	\$7,943,473	\$8,091,489	(\$12,893)	(\$73,333)	(\$1,176,434)	(\$251,059)	\$9,605,209	(\$402,773)	(\$222,676)	(\$182,903)
6	TOTAL INCOME TAXES	\$46,589	\$608,068	\$32,106,830	\$20,142,805	\$3,734	\$89,223	\$917,210	\$307,807	\$18,824,832	\$11,726,915	\$83,585	\$145,360
<u>RETURN</u>													
7	EXISTING RATES	\$85,793	\$476,714	\$66,084,180	\$36,551,218	\$29,505	\$334,304	\$4,103,918	\$1,150,253	\$30,933,239	\$29,354,583	\$556,326	\$644,803
8	INCREASE (DECREASE)	\$28,301	\$1,012,410	\$12,543,660	\$12,777,394	(\$20,360)	(\$115,802)	(\$1,857,725)	(\$396,451)	\$15,167,733	(\$636,024)	(\$351,630)	(\$288,825)
9	TOTAL RETURN	\$114,094	\$1,489,124	\$78,627,839	\$49,328,612	\$9,145	\$218,502	\$2,246,193	\$753,801	\$46,100,972	\$28,718,558	\$204,696	\$355,978
10	TOTAL REVENUE REQUIREMENT (L3, L6 and L9)	\$436,798	\$4,920,616	\$289,194,665	\$181,564,382	\$43,225	\$632,039	\$8,958,537	\$2,833,050	\$169,097,531	\$105,390,954	\$872,469	\$1,280,645
11	RATE BASE	\$1,410,663	\$18,411,527	\$972,154,295	\$609,898,769	\$113,068	\$2,701,553	\$27,771,923	\$9,319,995	\$569,992,230	\$355,076,143	\$2,530,855	\$4,401,306
12	REQUESTED RATE OF RETURN	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%
13	TOTAL REVENUE REQUIREMENT	\$436,798	\$4,920,616	\$289,194,665	\$181,564,382	\$43,225	\$632,039	\$8,958,537	\$2,833,050	\$169,097,531	\$105,390,954	\$872,469	\$1,280,645
14	OPERATING REVENUE	\$390,574	\$3,267,080	\$268,707,532	\$160,695,498	\$76,478	\$821,174	\$11,992,696	\$3,480,561	\$144,324,589	\$106,429,751	\$1,446,775	\$1,752,373
15	DEFICIENCY or (EXCESS)	\$46,224	\$1,653,536	\$20,487,133	\$20,868,884	(\$33,253)	(\$189,135)	(\$3,034,159)	(\$647,511)	\$24,772,942	(\$1,038,797)	(\$574,306)	(\$471,728)
16	SALES REVENUE (EXCLUDES MISC REVENUE)	\$389,665	\$3,260,300	\$267,923,080	\$160,165,353	\$76,155	\$820,303	\$11,963,589	\$3,471,927	\$143,833,379	\$106,178,965	\$1,443,566	\$1,750,244
17	PERCENT INCREASE IN SALES OF ELECTRICITY REVENUE	11.83%	50.61%	7.62%	12.99%	-43.48%	-23.03%	-25.30%	-18.60%	17.16%	-0.98%	-39.70%	-26.92%

OKLAHOMA GAS AND ELECTRIC COMPANY
EQUAL RATE OF RETURN
CHANGE IN SALES REVENUE
TEST YEAR ENDING JUNE 30, 2015
CAUSE NO. PUD 201500273

LINE NO.	DESCRIPTION	61	62	63	64	65	66	67	68	69	70	71	72	
		PWR & LGHT TOU S/L-3	PWR & LGHT TOU S/L-4	PWR & LGHT TOU S/L-5	TOTAL PWR & LGHT STANDARD-SCI	PWR & LGHT STANDARD-SCI S/L-3	PWR & LGHT STANDARD-SCI S/L-5	TOTAL LRG. PWR & LGHT TOU	LRG. PWR & LGHT TOU S/L-1	LRG. PWR & LGHT TOU S/L-2	LRG. PWR & LGHT TOU S/L-3	LRG. PWR & LGHT TOU S/L-4	LRG. PWR & LGHT TOU S/L-5	
					Cols. 65 & 66								Cols. 68 thru 72	
SCHEDULE L-3 COS AT CLAIMED ROR														
<u>EXPENSES</u>														
1	OPERATING EXPENSES	\$8,898,348	\$3,405,261	\$51,278,375	\$1,421,551	\$42,677	\$1,378,874	\$86,283,448	\$9,636,920	\$49,788,420	\$13,667,846	\$3,900,748	\$9,289,513	
2	UNCOLLECTIBLE ACCOUNTS	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
3	TOTAL EXPENSES	\$8,898,348	\$3,405,261	\$51,278,375	\$1,421,551	\$42,677	\$1,378,874	\$86,283,448	\$9,636,920	\$49,788,420	\$13,667,846	\$3,900,748	\$9,289,513	
<u>INCOME TAXES</u>														
4	EXISTING RATES	\$3,550,996	\$841,417	\$7,102,752	(\$17,647)	(\$4,656)	(\$12,991)	\$12,813,391	\$816,896	\$8,389,538	\$2,690,850	\$752,436	\$163,671	
5	INCREASE	(\$2,118,437)	(\$255,050)	\$2,376,293	\$254,756	\$12,929	\$241,828	\$1,643,208	\$621,491	(\$261,976)	(\$486,662)	(\$103,747)	\$1,874,101	
6	TOTAL INCOME TAXES	\$1,432,559	\$586,367	\$9,479,045	\$237,110	\$8,273	\$228,837	\$14,456,599	\$1,438,387	\$8,127,562	\$2,204,188	\$648,690	\$2,037,772	
<u>RETURN</u>														
7	EXISTING RATES	\$6,853,510	\$1,838,732	\$19,461,212	\$178,379	(\$156)	\$178,535	\$32,808,589	\$2,541,125	\$20,317,634	\$6,166,427	\$1,752,432	\$2,030,971	
8	INCREASE (DECREASE)	(\$3,345,256)	(\$402,753)	\$3,752,441	\$402,290	\$20,416	\$381,874	\$2,594,815	\$981,406	(\$413,690)	(\$768,495)	(\$163,828)	\$2,959,422	
9	TOTAL RETURN	\$3,508,253	\$1,435,979	\$23,213,653	\$580,669	\$20,260	\$560,409	\$35,403,404	\$3,522,530	\$19,903,944	\$5,397,932	\$1,588,605	\$4,990,392	
10	TOTAL REVENUE REQUIREMENT (L3, L6 and L9)	\$13,839,160	\$5,427,607	\$83,971,073	\$2,239,329	\$71,210	\$2,168,119	\$136,143,450	\$14,597,838	\$77,819,927	\$21,269,966	\$6,138,043	\$16,317,678	
11	RATE BASE	\$43,376,030	\$17,754,442	\$287,013,510	\$7,179,383	\$250,495	\$6,928,889	\$437,727,541	\$43,552,551	\$246,092,287	\$66,740,011	\$19,641,501	\$61,701,190	
12	REQUESTED RATE OF RETURN	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	
13	TOTAL REVENUE REQUIREMENT	\$13,839,160	\$5,427,607	\$83,971,073	\$2,239,329	\$71,210	\$2,168,119	\$136,143,450	\$14,597,838	\$77,819,927	\$21,269,966	\$6,138,043	\$16,317,678	
14	OPERATING REVENUE	\$19,302,854	\$6,085,410	\$77,842,339	\$1,582,283	\$37,865	\$1,544,418	\$131,905,428	\$12,994,941	\$78,495,593	\$22,525,122	\$6,405,617	\$11,484,155	
15	DEFICIENCY or (EXCESS)	(\$5,463,694)	(\$657,803)	\$6,128,734	\$657,046	\$33,345	\$623,701	\$4,238,022	\$1,602,897	(\$675,666)	(\$1,255,156)	(\$267,574)	\$4,833,523	
16	SALES REVENUE (EXCLUDES MISC REVENUE)	\$19,264,807	\$6,071,749	\$77,648,599	\$1,578,762	\$37,530	\$1,541,232	\$131,710,923	\$12,975,161	\$78,396,692	\$22,482,906	\$6,394,304	\$11,461,860	
17	PERCENT INCREASE IN SALES OF ELECTRICITY REVENUE	-28.31%	-10.81%	7.87%	41.53%	88.06%	40.38%	3.21%	12.33%	-0.86%	-5.57%	-4.18%	42.09%	

SECTION L - RATE DESIGN COST OF SERVICE
SCHEDULE L-3

OKLAHOMA GAS AND ELECTRIC COMPANY
EQUAL RATE OF RETURN
CHANGE IN SALES REVENUE
TEST YEAR ENDING JUNE 30, 2015
CAUSE NO. PUD 201500273

Direct Exhibit DWS-1

LINE NO.	DESCRIPTION	73 TOTAL MUNICIPAL PUMPING	74 MUNICIPAL PUMPING S/L-3	75 MUNICIPAL PUMPING S/L-4	76 MUNICIPAL PUMPING S/L-5	77 MUNICIPAL PUMPING - TOU S/L-5	78 TOTAL LIGHTING SERVICE	79 MUNICIPAL LIGHTING S/L-5	80 SECURITY LIGHTING S/L-5	81 TOTAL OKLA RETAIL JURISDICTION	
		Cols. 74 thru 77					Cols. 79 & 80		Cols. 1, 7, 23, 32, 42, 51, 67, 73, & 78		
	SCHEDULE L-3 COS AT CLAIMED ROR										
	<u>EXPENSES</u>										
1	OPERATING EXPENSES	\$2,600,427	\$11,065	\$192,943	\$2,378,055	\$18,363	\$21,064,901	\$9,844,612	\$11,220,289	\$826,943,795	
2	UNCOLLECTIBLE ACCOUNTS	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
3	TOTAL EXPENSES	\$2,600,427	\$11,065	\$192,943	\$2,378,055	\$18,363	\$21,064,901	\$9,844,612	\$11,220,289	\$826,943,795	
	<u>INCOME TAXES</u>										
4	EXISTING RATES	\$564,847	(\$129)	\$44,882	\$515,749	\$4,345	\$1,625,527	\$105,091	\$1,520,436	\$79,153,167	
5	INCREASE	(\$108,672)	\$2,167	(\$10,966)	(\$98,606)	(\$1,268)	\$2,049,738	\$1,621,856	\$427,882	\$57,983,624	
6	TOTAL INCOME TAXES	\$456,175	\$2,038	\$33,916	\$417,143	\$3,078	\$3,675,265	\$1,726,947	\$1,948,318	\$137,136,791	
	<u>RETURN</u>										
7	EXISTING RATES	\$1,288,752	\$1,568	\$100,375	\$1,177,271	\$9,538	\$5,763,749	\$1,668,100	\$4,095,648	\$244,277,577	
8	INCREASE (DECREASE)	(\$171,606)	\$3,422	(\$17,316)	(\$155,710)	(\$2,002)	\$3,236,773	\$2,561,098	\$675,675	\$91,562,826	
9	TOTAL RETURN	\$1,117,146	\$4,990	\$83,059	\$1,021,561	\$7,537	\$9,000,521	\$4,229,198	\$4,771,323	\$335,840,402	
10	TOTAL REVENUE REQUIREMENT (L3, L6 and L9)	\$4,173,748	\$18,093	\$309,918	\$3,816,759	\$28,978	\$33,740,688	\$15,800,757	\$17,939,931	\$1,299,920,989	
11	RATE BASE	\$13,812,393	\$61,695	\$1,026,938	\$12,630,574	\$93,185	\$111,282,410	\$52,289,789	\$58,992,621	\$4,152,329,407	
12	REQUESTED RATE OF RETURN	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	8.088%	
13	TOTAL REVENUE REQUIREMENT	\$4,173,748	\$18,093	\$309,918	\$3,816,759	\$28,978	\$33,740,688	\$15,800,757	\$17,939,931	\$1,299,920,989	
14	OPERATING REVENUE	\$4,454,026	\$12,504	\$338,200	\$4,071,075	\$32,247	\$28,454,177	\$11,617,803	\$16,836,374	\$1,150,374,539	
15	DEFICIENCY or (EXCESS)	(\$280,278)	\$5,589	(\$28,282)	(\$254,316)	(\$3,269)	\$5,286,511	\$4,182,954	\$1,103,557	\$149,546,450	
16	SALES REVENUE (EXCLUDES MISC REVENUE)	\$4,447,795	\$12,445	\$337,450	\$4,065,703	\$32,197	\$28,424,512	\$11,611,242	\$16,813,270	\$1,133,073,736	
17	PERCENT INCREASE IN SALES OF ELECTRICITY REVENUE	-6.29%	44.70%	-8.36%	-6.25%	-10.14%	18.58%	36.00%	6.55%	13.00%	