BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS & ELECTRIC COMPANY	)	
FOR AN ORDER OF THE COMMISSION	)	CAUSE NO. PUD 201700496
AUTHORIZING APPLICANT TO MODIFY ITS	)	
RATES, CHARGES, AND TARIFFS FOR RETAIL	)	
ELECTRIC SERVICE IN OKLAHOMA	)	

Responsive Cost of Service Testimony of Ron Nelson

On behalf of

AARP

FILED
MAY 16 2018
COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

May 16, 2018

I. Background and Qualifications

Q. Please state you name, occupation, and business address.

A. My name is Ron Nelson. I am a Senior Consultant with Strategen Consulting. My business address is Suite 210, 2150 Allston Way, Berkeley, California 94704.

Q. Who are you testifying on behalf in this proceeding?

A. I am testifying on behalf of AARP.

Q. What is your educational and professional background?

A. Currently, I am a Senior Consultant at Strategen Consulting. The Strategen team is nationally recognized for its thought leadership and deep expertise in rate design, renewable program development, grid modernization and new grid technologies including distributed and centralized renewable energy, energy storage, smart grid technologies, and electric vehicles. During my time at Strategen, I have worked with numerous consumer advocates on issues related to cost of service modeling and theory as well as making recommendations for how to translate costs studies into efficient rate designs.

Before joining Strategen in early 2018, I worked for the Minnesota Attorney General's Office for almost five years, where I led the Office's work on cost of service, rate design, and utility business model issues. Before that, I worked for two universities and the United States Geological Survey as an economic researcher. I have a Master of Science from Colorado State University in Agriculture and Resource Economics, and a

Bachelor of Arts and Minor in Environmental Economics and Mathematics, respectively, from Western Washington University.

Q. Have you testified in similar regulatory proceedings previously?

A. Yes. I have testified in Minnesota in nine separate rate case proceedings on issues related to cost of service modeling, revenue apportionment, rate design, renewable program development, tariff analysis, fuel clause structure, multi-year rate plans, performance metrics, performance incentive mechanisms, decoupling, and the utility business model. A full resume is attached as Exhibit AARP-RN-1.

Q. Have you previously testified in Oklahoma?

A. No.

Q. How is your testimony organized?

A. My testimony is organized into five sections and a conclusion:

I. Background and Qualifications

II. Purpose of Testimony

III. Economic Incentives

IV. Class Cost of Service Study: Objectives and Background

V. Class Cost of Service Study: Analysis

Conclusion

II. Purpose of Testimony

Q. What is the purpose of your testimony?

A. I am testifying on issues regarding Oklahoma Gas and Electric's ("OG&E" or "Company") embedded Class Cost of Service Study ("CCOSS").

Q. What is your role as a consumer advocate in this rate case proceeding?

A. AARP advocates for fair and affordable utility rates for residential customers. Personally, as a consumer advocate for clients in rate cases and similar proceedings, my role is to identify issues within a utility's CCOSS model and recommendations where the utility's business objectives may not align with societal or state policy objectives and provide recommendations on how to remove the bias so that commissions can set just and reasonable rates. As I will explain in my testimony, utilities have an incentive to assign and collect revenue in ways that will maximize profit for their shareholders. My recommendations for revisions to OG&E's proposed CCOSS will remove biases from the Company's model in order to better align them with economic theory and cost causation.

Q. How is your testimony organized?

A. In the following section, Section III, I discuss the economic incentives relating to CCOSS modeling and rate design. In Section IV, I describe and discuss the objectives of the CCOSS. In Section V, I provide an in-depth discussion and analysis of OG&E's proposed CCOSS with the primary focus being its use of the minimum system approach.

Q. Could you summarize your recommendations regarding the CCOSS models relied upon by OG&E in this case?

A. The analysis below demonstrates that OG&E's CCOSS relies on an extremely flawed minimum system study to classify hundreds of millions of dollars in distribution system costs. OG&E's minimum system studies do not appear to rely on the correct data, ran regressions incorrectly, follow the method outlined in the National Association of Regulatory Utility Consumers ("NARUC") Electric Manual, or estimate the cost of the minimum system correctly. For these reasons, I recommend the Oklahoma Corporation Commission (Commission) rely on a CCOSS utilizing another common distribution system classification method, referred to as the basic customer approach, for this case.

III. Economic Incentives

Q. What incentives related to the CCOSS and rate design should decision makers consider when evaluating utilities proposals?

A. The regulatory framework that investor-owned utilities operate within give them important, and sometimes perverse, incentives related to maximizing profit. These powerful incentives can influence the proposals that utilities make regarding the CCOSS and rate design. For example, utilities can maximize profits for shareholders by shifting cost responsibility, and then revenue apportionment, onto the residential class because of the economic concept of price elasticity of demand. The objectives of these proposals can be to maximize expected profits for shareholders minimizing business risk and

increase profits for the Company, even though those objectives may result in inefficient rates.

Q. Why is the CCOSS important to utilities?

A. The CCOSS is important to utilities because commissions traditionally rely on the CCOSS when apportioning revenue responsibility and designing rates. As a result, changes to the way that costs are allocated in the CCOSS can lead to millions of dollars being shifted between classes when it comes to revenue apportionment. In addition, results from the CCOSS can be used as justification for altering the magnitude and structure of a given customer class's rate design components, such as the customer charge.

Q. Why do utilities care about which class pays for its costs?

A. Introducing bias into the CCOSS will not increase a utility's revenue requirement. Despite this fact, utilities have an economic incentive to push costs onto different classes in a way that will allow it to maximize its actual earnings potential over the long-run. Dr. Harry M. Trebing, founder of the Institute of Public Utilities at Michigan State University, discussed this problem in "Market Failure and Regulatory Reform: Energy and Telecommunication Networks as a Case Study":

> Energy and telecommunications utilities serve markets that are clearly differentiated along the lines of (1) large business customers, (2) public sector customers, (3) commercial customers, and (4) residential/small business customers. *Each market has distinctive demand characteristics, and the greater the inelasticity of demand, the more vulnerable that market will be to arbitrary cost allocations*, the assignment of write-offs or accelerated depreciation charges, and different target levels of profit. . . .

> There are numerous recent examples of cost shifting and cross subsidization in the utility industries.[1]

Utilities thus have an economic incentive to shift costs onto certain classes of customers because of a basic economic concept—the price elasticity of demand.

Q. What is the price elasticity of demand?

A. The price elasticity of demand for electricity is the sensitivity, or elasticity, associated with the quantity of electricity demanded given a change in the price of electricity. Specifically, the price elasticity of demand measures how much a person reduces their consumption of a good given a one percent increase in price. When the price elasticity of demand is small—between negative one and zero—customers do not greatly change consumption when prices increase, and customer are said to have inelastic demand. A high price elasticity of demand—less than negative one—means that a customer is more responsive to price changes. For example, a customer with high price elasticity, or, simply, elastic demand, will make significant changes in consumption in response to price changes. A customer with inelastic demand will make a comparatively smaller change in consumption in response to the same price change.

This presents the utility with an incentive to shift subjective cost allocations (and there are many in the CCOSS) to classes with more inelastic demand by increasing their rates. For two utilities with identical revenue requirements and identical customer classes, the utility that can allocate more costs to its more inelastic customer classes

[1] Harry M. Trebing, *Market Failure and Regulatory Reform: Energy and Telecommunication Networks as a Case Study, in Institutional Economics and the Theory of Social Value: Essays in Honor of Marc R. Tool*, 228 (1995) (emphasis added).

will, in the long-run, have a higher earnings potential than its counterpart that has more costs assigned to customers with more elastic demand.

Q. Do residential customers have a different price elasticity of demand than other classes?

A. Yes. Economic theory and empirical research clearly supports the concept that residential customers have a different price elasticity of demand for electricity when compared to industrial customers. The different price elasticities stem partially from the differences in how electricity is used between the two customers. For residential customers, electricity is a necessity, with few substitutes, while for industrial customers, electricity is simply an input to production, with multiple substitutes and opportunities to invest in ways to optimize or alter their consumption.

Q. Why is the price elasticity of demand important?

A. When different customer classes have different price elasticities of demand, they will react to price changes differently. This nuance is very important to utilities, because it indicates that the residential class will react *less* to a price increase than other classes, leading to higher sustained revenues over time, all else constant. The differences in price sensitivity creates an incentive for utilities to shift costs onto certain customer classes and design rates in ways that are beneficial to the utility.

Q. What is the intent of discussing the economic incentives related to the CCOSS and rate design in this section of testimony?

A. My intent is to connect the seemingly subjective assumptions made within a cost of service analysis to the utility's revenue apportionment, rate design, business model and

ultimately its financial position. While I do not have any specific recommendation regarding these incentives, I do recommend that the Commission keep OG&E's economic incentives in mind when considering cost of service and rate design issues. The Commission should be aware that the Company may have an incentive to promote costs of service models and rate designs that benefit it financially.

IV. Class Cost of Service Study: Objectives and Background

Q. What is the purpose of a CCOSS?

A. The purpose of a CCOSS is to decipher, with as much detail and accuracy as possible, which customer class caused the utility's various embedded costs associated with providing service.

Q. How is a CCOSS performed?

A. A CCOSS has three general steps. First, costs are functionalized into various categories. Second, costs are classified as energy, demand/capacity, or customer. Lastly, the costs are allocated to the various customer classes using allocators related to energy, demand/capacity, or customer characteristics.

Q. How are costs functionalized?

A. Public utilities are required to maintain records in accordance with the Uniform System of Accounts as designated by the Federal Energy Regulatory Commission ("FERC"). These accounts assign costs by various functions, such as generation, transmission,

and distribution. The purpose of functionalizing costs is to aid in determining which customers are jointly or solely responsible for various costs.

Many utilities also subfunctionalize costs by voltage level. For example, distribution costs can be subfunctionalized into primary and secondary voltages. Subfunctionalizing by voltage level adds more detail to the CCOSS and improves the accuracy of assigning costs when done properly.

Q. How are costs classified?

A. After a utility's costs are functionalized, they are then classified as either energy, demand, or customer costs based on cost causation. Costs classified as energy costs are those that fluctuate on a customer class's energy usage, measured in kilowatt-hours ("kWh"). Demand costs are those costs that fluctuate based on a customer class's contribution to peak demand, measured in kilowatts ("kW"). Finally, customer costs are those required to provide service to customers, regardless of whether the customers consume electricity or not. Specifically, the NARUC Electric Manual defines a customer cost as "costs that are directly related to the number of customers served."[2] In other words, the utility incurs customer costs based directly on the *number* of customers on its system, rather than on the amount of energy they consume or when they consume it.

Q. How are costs allocated once they have been classified?

A. Costs are allocated to customer classes based on each class's contribution to the particular cost. For example, if the company spends the same amount of time and

[2] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, at 20 (1992) (hereinafter "NARUC Electric Manual").

money on each customer location, regardless of class, then it is appropriate to allocate that cost based on the number of customer locations. This result stems from the fact that the number of customer locations cause these costs to be incurred, rather than a customer's electricity consumption or any other factor.

Q. How are the appropriate approaches to classification and allocation determined?

A. Classifications and allocations are informed by cost causation. Cost causation is based on the notion that the customer, or set of customers, that caused a certain cost should pay for the cost. To determine cost causation, analysts often rely on economic theory and power system engineering considerations.

Q. Can you describe the methods that you will focus on in this testimony?

A. Yes. In this testimony I will discuss three different methods for classifying and allocating the costs of the distribution system: the basic customer approach, the minimum system approach, and an energy related classification approach.

Q. What is the basic customer approach?

A. According to the basic customer approach, only costs that can be traced to a specific customer should be assigned as customer costs, because those are the only costs that vary based on the number of customers in a class. Under this theory, the costs of the conductors and transformers cannot be attributed directly to a customer, because adding one customer to the system would not increase these costs. Instead, the basic customer approach recognizes that the distribution system is built to serve peak demand, and so its costs should be classified as demand.

Q. What is the minimum system approach?

A. The minimum system approach reasons that the costs of the capacity in the distribution system are caused by peak demand and should be classified as a demand cost. Some of the costs, however, are related to connecting a customer to the "minimum system," a distribution system with little or no capacity. Because this minimum system has no capacity, the cost to connect a customer should be the same and would vary based on the number of customers in a class and should be classified as a customer cost. The cost of the minimum system can be estimated in several ways, including the minimum size and zero intercept methods.

Q. Are there any other approaches to classifying and allocating distribution system costs?

A. Yes. As indicated in the NARUC Electric Manual, the distribution system can be classified and allocated as partially energy related.[3] For example, the peak-and-average approach could be used to classify and/or allocate distribution system cost. The peak-and-average approach reasons that some part of the distribution system is built to provide the regular amount of energy that is used all the time—represented by the system's load factor. These costs are classified as energy because they are related to how much energy is sold. The rest of the costs of the distribution system are installed to serve peak demand, and so are classified as demand costs.

[3] NARUC Electric Manual at 21, 34, and 134. While the NARUC Electric Manual indicates that classifying the distribution system as energy is appropriate, it does not explicitly discuss a method for determining the portion related to energy.

Q. Are there any current industry trends impacting traditional methods used within the CCOSS?

A. Yes. Technology is changing rapidly to meet evolving customer service demands, such as increased reliability, and to further state policy goals, such as integrating distributed and large scale renewable energies. The new and expanding service requirements and policy goals require a cost analyst to re-evaluate cost causation issues that may previously have been considered settled. For example, many states are in the process of exploring grid modernization. This process of modernizing the electric grid will impact the cost causation associated with grid investments in new ways.

Q. Which distribution classification approach do you think should be considered by the Commission in this case?

A. While there are arguments that support each of the approaches discussed above, I believe that the basic customer approach most accurately reflects cost causation. For this reason, I recommend that the Commission considered a CCOSS model that utilizes the basic customer approach. I discuss the basic customer, minimum system and energy related approaches in more detail below.

V. Class Cost of Service Study: Analysis

Q. In general, how does the basic customer approach differ from the minimum system approach proposed by OG&E?

A. The basic customer approach classifies and allocates the cost of OG&E's distribution system in a different manner than OG&E's proposed minimum system approach.

Q. Please explain why classifying and allocating distribution system costs can differ between CCOSS models.

A. As stated by renowned regulatory economist Charles Phillips, "[w]hen the same plant or equipment is used to provide several types of service, there is no one correct way to allocate these costs among the different units of service. Any method of apportionment is subject to dispute."[4] This statement is true for classifying and allocating distribution system costs as well. Therefore, various models incorporate different mechanisms to determine how the costs of the distribution system are classified and allocated.

Q. Do other regulatory commissions in the United States use the basic customer and energy related approaches?

A. Yes. In 2000, the Regulatory Assistance Project (RAP) estimated that approximately 30 electric utilities use methods that do not classify any portion of the distribution system as a customer cost.[5] I have also testified in a proceeding where a natural gas utility claimed

[4] *See* Charles R. Phillips Jr., *The Regulation of Public Utilities* 438 (1993).
[5] *See* Fredrick Weston, The Regulatory Assistance Project, *Charging for Distribution Utility Services: Issues in Rate Design* at 29 (2000).

that 19 states utilize the basic customer or peak-and-average approaches.[6] This demonstrates that many Commissions have used these methods to classify and allocate both electric and natural gas distribution systems throughout the country.

Q. Does OG&E use the minimum system approach in each of the jurisdictions that it operates?

A. No. The CCOSS filed by OG&E in this case indicates that the Company uses the basic customer approach in Arkansas.[7]

Q. Are the basic customer and energy related approaches commonly used and supported by reliable references?

A. Yes. The National Association of Regulatory Utility Commissioners ("NARUC") has two references that mention one or both approaches.[8] In addition, Dr. James Bonbright discusses the basic customer approach in *Principles of Public Utility Rates*.

Q. Please explain how this section of your testimony is organized.

A. I begin, in Section V.A, I provide an in-depth discussion of the basic customer approach. In Section V.B, I analyze the minimum system approach.

---

[6] *In the Matter of the Application of CenterPoint Energy Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-15-424, Rebuttal Testimony of Russell A. Feingold, at Schedule 3 (Dec. 18, 2015). Due to the time intensive nature associated with a review of these estimates, I have not verified either of these estimates by assessing each Commission's order on the subject. I believe that it is reasonable to rely on CenterPoint Energy's survey as demonstrative that a minimum of 19 regulatory commissions use the Basic Customer or Peak-and-Average approaches, given that it was provided by a utility in opposition to those methods.

[7] Along with the CCOSS, OG&E Witness Smith Direct Testimony in Docket No. 16-052-U supports this assertion.

[8] *See* National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* (1992) [hereinafter NARUC Electric Manual]; *see also* National Association of Regulatory Utility Commissioners, *Gas Distribution Rate Design Manual* (1989) [hereinafter NARUC Gas Manual]. The NARUC Electric Manual methods the Peak-and-Average approach on page 41 and discusses a method similar to the Basic Customer in the marginal cost section on pages 136–146. The NARUC Gas Manual discusses the Basic Customer approach on page 23.

A. Basic Customer Approach

Q. How would a CCOSS utilizing the basic customer approach differ from OG&E's proposed CCOSS in this case?

A. A basic customer CCOSS would differ in only one way from OG&E's minimum system CCOSS—it classifies distribution system costs differently. Specifically, the basic customer approach classifies FERC account 364-368 (referred to generally as "distribution system") as 100 percent demand related and FERC accounts 369-370 (referred to as "customer-specific distribution equipment") as customer related, while the minimum system approach most commonly classifies FERC accounts 364-369 as both demand and customer related. OG&E's minimum system CCOSS classifies meters and service lines, FERC accounts 369 and 370, as 100 percent customer related and classifies transformers, poles, conductors and cables, FERC accounts 364-368, as 27 to 75 percent customer and 25 to 63 percent demand related.[9] It is important to note that OG&E's minimum system study differs from the NARUC Electric Manual's methodology and most utilities application of the minimum system approach, by classifying service lines, FERC account 369, as 100 percent customer as opposed to including a demand component. This increases the percentage of customer related costs in OG&E's CCOSS.

Q. Why might it be appropriate to classify distribution system costs as 100 percent demand?

[9] Satterwhite, Direct at 11.

A. There are at least two reasons that cost analysts find it reasonable to classify the distribution system as 100 percent demand costs. First, distribution system equipment will not be designed or installed if it is incapable of serving peak demand reliably and safely. This indicates that the cost of distribution equipment is caused by the requirement to meet peak demand. As one analysis of cost of service methods put it: "The theoretical basis for (the Basic Customer) approach is that the distribution system is sized to a certain capacity, that capacity is available to the total population of customers served by a system, and any capacity used by one customer is generally not available to another."[10] That is, from an engineering perspective, the distribution system is designed to meet localized peak demand of a group of customers, and from an economic perspective demand reflects how the system is utilized by customers.

A second, similar explanation is that demand costs are the fixed costs that the utility incurs to be ready to provide service. According to Alfred Kahn, a distinguished regulatory economist, demand costs are those caused by "the utility's readiness to serve, on demand. This readiness to serve is made possible by the installation of *capacity* . . . the fixed, capital costs . . . . And the proper measure of that responsibility is the proportionate share of each customer in the total demand placed on the system at its peak."[11] Said another way, it is a customer's demand that causes the fixed costs of the distribution system, not simply the numerical addition of that customer on the system.

[10] Jim Lazar, *Cost Elements and Study Organization For Embedded Cost of Service Analysis: Applicable to the Tucson Electric Power Company* 19 (1992).
[11] Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions* 95 (1988) Vol. I.

Q. How much would utilizing the basic customer approach change the results of the CCOSS?

A. Table 1 displays the results of a basic customer CCOSS compared to OG&E's proposed CCOSS. To obtain the results in Table 1, I altered OG&E's proposed CCOSS and reran the CCOSS model using the basic customer approach.

Table 1

CCOSS Approach	Total Residential	Total General	Total Oil and Gas Production	Total Public Schools - Small	Total Public Schools- Large	Total Power and Light	Total Power and Light - TOU	Large Power and Light - TOU	Total Municipal Pumping	Total Lighting
OG&E Proposed	4.28%	-4.45%	-23.24%	15.94%	8.19%	-4.38%	-2.33%	-5.51%	-5.58%	6.91%
Basic Customer	2.49%	-14.87%	-27.42%	36.03%	27.32%	1.14%	8.77%	-2.22%	-4.10%	6.37%

Q. Please explain Table 1.

A. Table 1, above, displays the CCOSS results using OG&E's proposed minimum system CCOSS and the CCOSS results utilizing the basic customer approach. The columns represent major customer classes. The number under each class represents how close or far away each class is from paying its respective cost of service. Specifically, positive numbers represent deficiencies and negative number represent sufficiencies. Said another way, a positive number indicates that the class is providing less revenue than that required to meet a levelized return on equity across classes. For example, under OG&E's proposed minimum system CCOSS, the Power and Light class is paying *over* its cost of service by approximately 4.5 percent. However, under the basic customer CCOSS the same class is paying *under* its cost of service by over 1 percent.

Q. What are some takeaways from Table 1?

A. The main take away is that one assumption—how to classify distribution system costs—can drastically impact the results of a CCOSS. It is also important to note that OG&E's proposed minimum system CCOSS assigns more costs to the residential class than any other common approach.

B. OG&E's Minimum System Study

Q. What is the minimum system approach?

A. The minimum system approach is a way to separate the costs of the distribution system into customer related costs and demand related costs.

Q. What does a minimum system do mechanically?

A. The minimum system approach estimates how much it costs to connect a customer to a minimum or zero capacity distribution system. It then classifies the costs of the minimum system as customer costs.

Q. How is the cost of a minimum system estimated?

A. There are two common methods to estimate the minimum system: the minimum size and zero intercept methods.

At a high level, the minimum size method creates a minimum system using the average book unit installed cost of the smallest distribution equipment installed and multiplies this unit cost by the total number of distribution equipment on the system. Take transformers for example. The first step of the minimum size method is to determine the average book unit installed cost of the smallest transformer on the distribution system. The second

step is to determine how many transformers are installed on the distribution system. The third step is to multiply these two numbers together—this number is the cost of the minimum system. Lastly, the cost of the minimum system is compared to the total cost of transformers on the distribution system—creating a ratio of customer and demand related transformer costs.[12]

The zero intercept method can also be used to estimate the minimum system associated with transformers. At a high-level, the zero intercept method utilizes econometric regression analysis to estimate the "zero or no load" unit cost of each type of distribution system equipment. The first general step of the zero intercept method requires gathering and cleaning cost data. Second, a regression is run on the data. Third, the constant coefficient estimated in the regression is assumed to be the unit cost of a no load transformer. Lastly and like the minimum size method, the no load transformer cost is multiplied by the total number of transformers to come to the customer related portion of transformer costs.

It is important to understand that, while methodologically distinct, at their core, the minimum size and zero intercept methods are simply approaches to do the same thing; that is, to estimate the cost of the minimum system.[13] However, because the minimum size method estimates the minimum system using distribution equipment with some load (i.e. because the smallest equipment still serves load) and the zero intercept theoretically estimates a no load scenario, the minimum size method should result in a higher, over-estimated percentage of customer costs.

[12] The NARUC Electric Manual discusses the minimum size method on pages 90-92.
[13] The NARUC Electric Manual discusses the zero intercept method on pages 92-94.

1. Reasonableness of the Minimum System Approach

Q. Do you believe that the minimum system approach is a reasonable way to classify distribution system costs?

A. There are many recognized approaches to classify distribution system costs, and each approach has a logical argument to support it. Across the country, regulators have coalesced around three general methods to classify distribution system costs.[14] Approximately half of the commissions in the country do not use the minimum system approach, and do not classify any portion of the distribution system as customer costs. These commissions classify the distribution system as either 100 percent demand or a portion as demand and the remainder as commodity costs. The other half of the commissions use a form of the minimum system approach to classify some portion of distribution system costs as customer and demand. With this said, I find the minimum system approach to be the *least* reasonable way to classify distribution system costs.

Q. Why do you find the minimum system approach the least reasonable way to classify distribution system costs?

A. While the minimum system approach is based on a "certain intuitive appeal," the method requires the analyst to create a hypothetical, no-capacity system—something that is not real and not directly based on system characteristics.[15] To create this imaginary minimum distribution system, analysts must make numerous subjective assumptions that oversimplify system engineering and assign costs based on questionable cost

[14] *See* Jim Lazar and Wilson Gonzalez, Regulatory Assistance Project, *Smart Rate Design for a Smart Future*, A-4 (2015) (describing the minimum system/zero intercept, basic customer, and peak-and-average methods).
[15] *See* Fredrick Weston, The Regulatory Assistance Project, *Charging for Distribution Utility Services: Issues in Rate Design* at 30 (2000).

causative principles. This is different than the basic customer approach, which relies more heavily on actual system data. Since utilities have an economic incentive to over-classify customer costs, the subjective decisions made by utilities can lead to increased customer cost classification. Because of this reliance on actual system data, the basic customer CCOSS is less subjective.

Q. Can you provide more details about the subjective decisions that analysts make when using the minimum system approach?

A. Yes. When using the minimum system approach, the first decision is simply whether or not to use the minimum size or zero intercept method. Because minimum sized distribution equipment contains some capacity, the minimum size method theoretically classifies more costs as customer costs than the zero intercept. For this reason, the first decision can swing millions of dollars in the CCOSS. After the first decision, others follow that can have a significant impact on the results of the minimum system approach. These decisions can include:

1. Whether to use booked or current costs when calculating the cost of the minimum system;
2. Whether to select the minimum size equipment based on current safety standards, historical installations, current installations, an industry standard, or the most commonly installed equipment;
3. Whether to make a demand adjustment when using the minimum size method;
4. If a demand adjustment is made, how to do so; and,

5. How to prepare and clean data for either method.

Q. Why are these subjective decisions problematic?

A. It is important to understand that, while the minimum system approach has a basic intuitive appeal, many of the decisions it requires analysts to make have no clear support one way or the other. Different utilities, therefore, make different strategic choices at these decision points, and then present arguments to justify a methodology that, for instance, squarely contradict another utility's argument for its methodology. That is not to say that one utility's argument is correct and the other is wrong; both arguments can appear equally plausible. But, when you investigate how the decisions impact the results of the CCOSS, it becomes apparent that the utilities are not merely using "judgment" by indifferently making objective assumptions about a real system. Instead, in my experience, utilities have consistently created methodologies and made assumptions that inflate the proportion of costs that are classified and allocated as customer costs.

Q. Has any credible authority analyzed the different approaches of classifying and allocating the distribution system?

A. Yes. I have identified four significant analyses that evaluated the Minimum System approach to some extent. The analyses, and controversy associated with the minimum system approach, goes back at least to Bonbright's seminal work, *Principles of Public Utility Rates*, in 1961. The other analyses were conducted by research consultants or the Regulatory Assistance Project ("RAP").[16]

[16] *See* Fredrick Weston, The Regulatory Assistance Project, *Charging for Distribution Utility Services: Issues in*

Q. What conclusion did Bonbright come to 1961?

A. Bonbright did not oppose the theory of developing a hypothetical minimum system. He recognized that it was appropriate to classify any distribution costs *above* the hypothetical minimum system as demand costs. But Bonbright rejected the notion that the costs of this hypothetical minimum system should be classified as customer costs, concluding that doing so is "clearly indefensible."[17] Bonbright's primary concern was that the minimum system analysis does not consider population density of a service territory, even though population density is vital in determining the cost of providing service to additional customers:

> What the (minimum system) imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor . . . Indeed, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.[18]

Bonbright simply observed that if a person is added to an existing minimum distribution system, for reasons such as urban infill, there would be no increase in minimum distribution system costs. Therefore, the minimum distribution system is not caused by the number of customers.

Rate Design (2000); Jim Lazar, *Cost Elements and Study Organization For Embedded Cost of Service Analysis: Applicable to the Tucson Electric Power Company* (1992); and Jim Lazar and Wilson Gonzalez, Regulatory Assistance Project, *Smart Rate Design For a Smart Future* (2015).

[17] James C. Bonbright, *Principles of Public Utility Rates* 348 (1st ed. 1961).

[18] James C. Bonbright, *Principles of Public Utility Rates* 348 (1st ed. 1961).

2. OG&E's Minimum System Studies

Q. Have you analyzed OG&E's minimum system studies?

A. Yes.

Q. Does OG&E's minimum system studies suffer from the general shortcomings you described above?

A. Yes. Obviously OG&E's minimum system studies suffer from the same theoretical shortcomings that plague all minimum system studies. I will note that OG&E does classify primary distribution equipment as 100 percent demand, which differentiates it from many minimum system studies. However, OG&E's application of the minimum system methodology is almost unrecognizable from the methodologies discussed in the NARUC Electric Manual and other references on the subject. Said another way, OG&E's minimum size and zero intercept methods are poorly executed and do not follow best practices. I detail the issues with OG&E's analyzes below.

Q. At a high-level, does OG&E provide clear justification for classifying power lines, transformers, and poles within the distribution system as customer related?

A. No. In fact, OG&E witness Satterwhite states that "Distribution costs for substations, primary lines, and transformers tend to vary with the size of load served."[19] I agreed with this statement. The statement indicates that this distribution equipment should be classified as 100 percent demand, but OG&E does not do so for each type of distribution equipment.

[19] Satterwhite Direct, at 7-8.

OG&E classifies transformers as approximately 75 percent customer related. Witness Satterwhite's statement does not align with this classification nor does OG&E's witness provide any explanation as to why the cost of transformers specifically vary with the number of customers. In fact, one transformer often serves multiple residential customers and is sized to meet the peak demand of the customers served. It is not clear why OG&E classifies transformers as customer related.

On the other hand, OG&E classifies both primary lines and substations as 100 percent demand related. This fact begs the question—why is OG&E using the same logic and support for transformers why they employ a different classification approach? OG&E did not provide any engineering related information to justify using the minimum system study in Witness Satterwhite's direct testimony.

Q. What method does OG&E use to estimate the minimum system in this case?

A. OG&E updated its zero intercept study for this case.[20] OG&E used essentially same methodology that was used in its 2008 zero intercept study.[21] The 2008 study transitioned OG&E from using the minimum size method to the zero intercept method.[22] My analysis relies on the information provided in OG&E Response to Data Request OCC-KJC-1-4 Att. because, to my knowledge, this is the only written description of the method, Witness Satterwhite's direct testimony, and Witness Satterwhite's zero intercept study provided in OG&E Response to Data Request AG-1-3 Att. I analyzed both the

[20] Satterwhite, Direct at 11.
[21] In OG&E Response to Data Request OCC-KJC 1-5, it noted some changes to its approach, but these changes appear unrelated to the methodological concerns I address in this testimony.
[22] See OG&E Response to Data Request OCC-KJC-1-4 Att.

minimum size and zero intercept methods to provide a comprehensive perspective on the methods used to estimate the costs associated with an imaginary minimum system.

Q. Did you review the methodology and analysis that supports OG&E's recommendation to use the zero intercept method?

A. Yes.

a. OG&E's Zero Intercept Method

Q. Did you identify any issues with OG&E's zero intercept method?

A. I identified numerous issues with the zero intercept analysis that OG&E uses to support its classification of distribution system equipment. First, the cost data created by the Company is not reliable nor is the form of the data used commonly utilized in a minimum system study. Second, the Company appears to have ran the regressions on the wrong data. Third, the Company's actual regressions are flawed. Fourth, the Company did not follow the NARUC Electric Manual or any other reference that I am aware of. Finally, the Company did not calculate the minimum system correctly.

Q. Before diving into the specific problems with OG&E's analysis, are there any general problems with the zero intercept method that you would like to note?

A. Yes. The zero intercept involves estimating the value of the constant term in the following equation:

$$y = a + bx + e$$

Where y is the dependent variable, x is the independent variable, a is the constant (i.e. zero intercept), b is the slope coefficient, and e is the error term.

The problem with the zero intercept is, that from a statistical standpoint, its entire premise is false. The intercept, or constant, term should not be used for interpretation purposes. "(T)here are at least two reasons that suggest that the intercept should *not* be relied on for purposes of analysis or inference."[23] First, because of the technical procedure for estimating numbers within a regression, "the constant term acts as a garbage collector, with an unknown amount of (garbage) being dumped into it."[24] Second, the constant term "often lies *outside* the range of sample observations."[25] Said another way, when you are making estimates based on data that is clustered, the farther away from the cluster you get, the less accurate your estimate becomes.

Simply said, from a technical standpoint, the zero intercept is not based on sound statistics.

Q. Why do you think that the NARUC Electric Manual provides the zero intercept method as an option for estimating the minimum system?

A. The NARUC Electric Manual was written in 1992. Statistical theory and methods have advanced considerably since that time. For this reason, the NARUC Electric Manual's discussion of the econometrics associated with the zero intercept method may be outdated.

---

[23] A. H. Studenmund, "*Using Econometrics: A Practical Guide,*" at 206-208, Fifth Edition, (2006).
[24] *Ibid.*
[25] *Ibid.*

Q. Getting back to the specifics of OG&E's zero intercept method, what data did OG&E use for the study?

A. For both the zero intercept and minimum sized methods, the Company appears to rely on "Construction costs ... estimated by OG&E engineering personnel."[26]

Q. Is it common to use cost estimates from a utility's "engineering personnel" to conduct a minimum system study?

A. While it is not completely clear what this means, I can say that the costs that should be used are average book values.[27] Relying on engineering personnel would not be the appropriate source for unit cost data. If that is the case, it does not appear that the Company relied on the correct data. In any case, the Company does not provide a detailed accounting of how it arrived at unit cost data in its minimum system study.

Q. What are some of the impacts that relying on incorrect cost data could have on the results of the minimum system study?

A. If the underlying data is not representative of the investment history of the utility, the entire purpose of the study is defeated. The results are only as good as the data and method used to estimate the results. In this case, it appears that OG&E relied on data that is not recommended by the NARUC Electric Manual or any other reference that I am aware of.

[26] *See* OG&E Response to Data Request OCC-KJC-1-4 Att.
[27] See NARUC Electric Manual, at 90-94.

Q. Please discuss the data that the Company used to run the regressions.

A. The Company created a weighted nit cost associated with each size and type of distribution equipment. However, the Company ran its regressions on its own unit costs created by "engineering personnel." According to the NARUC Electric Manual, this is not the correct data to use for the regressions. Take transformers, for example, the NARUC Electric Manual states "Determine zero intercept of transformer cost using cost per transformer by type, *weighted by number of each category*."[28] This is important because the cost estimates from OG&E's "engineering personnel" are quite linear, but whether the costs of transformers are weighted the largest transformers are cheapest per unit. This outcome is opposite of the theory that the zero intercept is based on and, again, calls the entire method into question.

Q. Are the regressions used for the zero-intercept method statistically valid?

A. No. OG&E ran ordinary least squares (OLS) regressions to obtain the zero intercept values. For an OLS regression to be valid, it must pass the Gauss Markov assumptions. The Gauss Markov assumptions are a set of assumptions related to underlying data and must be met for the coefficients in the model to be correctly and accurately estimated. Given the numerous issues with OG&E's zero intercept analyses, I did not find it meaningful to run the statistical tests to indicate whether these assumptions are met. However, I will provide a few observations related to the assumptions.

First and foremost, to be a valid regression, the equation must be specified correctly. The zero intercept equation attempting to explain the unit cost of each respective

[28] *See* NARUC Electric Manual, at 94.

distribution equipment (i.e. y the dependent variable). The regression uses a demand related variable (i.e. x the independent variable) to predict this. However, the unit cost of distribution equipment is related to the number of customers, according to the vary theory the method is the application for. By not including this variable, the regression is mis-specified and the results are likely biased.[29]

Second, a regression needs to have a sufficient number of observations (i.e. data points). OG&E's regressions all had four to thirteen observations; this is far too few. The reason the number of observations is important is because the purpose of a regression is to determine a statistical relationship between two variables. In order to determine whether two variables are related with accuracy, their interaction has to be observed numerous times. When there are too few observations, the regression is too sensitive to one observation (which could be biased or unlike other "normal" observations—an outlier). For this reason, accurate regressions require more observations than four or even thirteen.

Q. What methodology did OG&E follow?

A. It is not clear that the Company followed any recommended methodology. It is certain that the Company did not follow the NARUC Electric Manual. First, the Company did not calculate a demand component related to service lines (i.e. FERC account 369). Second, they did not follow the NARUC Electric Manual for estimating the customer costs associated with poles. These are two examples among many other where the Company did not follow the NARUC Electric Manual.

[29] A. H. Studenmund, *"Using Econometrics: A Practical Guide,"* at 163, Fifth Edition, (2006).

Q. Why is it important to follow the method outlined in the NARUC Electric Manual or another reputable reference?

A. The minimum system study is easy to manipulate when following a rigid methodology, but without a clear methodology an analyst can essentially arrive at any result desired.

Q. Were there any other significant problems with OG&E's zero intercept analysis?

A. Yes. For both the zero intercept and minimum size methods, *the minimum system was calculated incorrectly*. The NARUC Electric Manual explicitly states, repeatedly, that the minimum system is the unit cost of the zero or minimum sized distribution equipment times the total number of unit of that type of distribution equipment. For example, the NARUC Electric Manual states on page 94 to "Multiply zero intercept cost by total number of line transformers to get customer component," and again on page 92 "Multiply minimum intercept cost by total number of distribution poles to get customer component." OG&E followed neither of these instructions. Instead, OG&E explains its calculation as follows:

> The imputed investment based on the regression at zero electrical capacity was then compared to the weighted average installation for these items in order to arrive at the customer related percentage. Since no electrical capacity exists for poles and conduit, poles were assigned the percentage ascribed to overhead conductor and conduit was assigned the percentage ascribed to underground conductor.[30]

Said more simply, OG&E summed the average weighted cost of each distribution equipment type and compared it to the estimated zero intercept cost estimate—

[30] See OG&E Response to Data Request No OCC-KJC-1-4 Att. While this calculation involves the number of the distribution equipment sampled, it does not use the total number of distribution system equipment and is compared to the summation of the weighted sizes.

this is not the correct method for estimating the cost of a minimum system. OG&E's method is not recommended by the NARUC Electric Manual and results in an incorrect calculation of minimum system costs.

Q. Please summarize your analysis of the zero intercept method.

A. OG&E's zero intercept method does not follow best practices, it is based on unreliable data, and simply does not follow any recommended methodology. I recommend that OG&E's zero intercept method be rejected.

b. OG&E's Minimum Size Method

Q. What reference do utilities commonly use to support their execution of the minimum size method?

A. The NARUC Electric Manual.

Q. What reference did OG&E use when conducting its minimum size method?

A. As with the zero intercept method, it is not clear that OG&E used any reference. The Company did not provide any citations, nor did they discuss the methodology employed in any detail.

Q. What general concerns do you have with OG&E's Minimum Size method?

A. The minimum size method was conducted incorrectly. I found many of the same errors with OG&E's minimum size method as I did with their zero intercept, along with additional errors. First, the Company did not appear to use the correct cost data to conduct the minimum size method. Second, the Company did not follow the NARUC Electric Manual. Third, the Company does not use the smallest sized distribution

equipment installed on the system for every type, instead the Company used the minimum cost installed. Fourth, the Company does not make a demand adjustment to the minimum system created with the minimum size method—resulting in an over-estimate of customer costs. Finally, the Company did not do the correct math to estimate the minimum system cost.

Q. Could you please summarize your analysis on the minimum size method?

A. Yes. Given the tremendous overlap with the issues and errors between the zero intercept and minimum size method, I provide a high-level discussion of the minimum size method.

OG&E's minimum size analysis is plagued by the same and additional issues and errors as its zero intercept method. These two analyses are supposed to be based on average book value so that the investment cycle of the utility can be accurately classified and allocated to customer classes. Cost of service analyses are based on cost causation, so the results are only as good as the data underlying the analysis. OG&E's analysis does not rely on accurate cost records that demonstrate how costs are incurred, rendering the results of the Company's minimum system study completely unreliable.

Conclusion

Q. Please summarize your analysis of the CCOSS that OG&E relied on in this case.

A. OG&E's CCOSS model relies on a highly flawed minimum system study to classify distribution system costs occurring in FERC accounts 364-368. The analysis I provided in this testimony demonstrates that OG&E's CCOSS relies on an extremely flawed minimum system study to classify and allocated distribution system costs. Furthermore, my analysis has demonstrated that OG&E's minimum size and zero intercept methods appear to rely on incorrect data, runs regressions on incorrect data, do not follow the methodology outlined in the NARUC Electric Manual, and do not estimate the cost of the minimum system correctly.

Q. Please summarize your primary recommendation.

A. I strongly recommend that the Commission reject OG&E's proposed minimum system studies for use in Oklahoma and instead rely on a CCOSS that utilizes the basic customer approach in this case.

Q. Does this conclude your direct testimony?

A. Yes.

Exhibit AARP-RN-1: Resume of Ron Nelson

PROFESSIONAL BACKGROUND AND EDUCATION

EDUCATION

M.S. **Agricultural and Resource Economics**
Colorado State University, Fort Collins, CO, 2013

Minor **Mathematics**
Western Washington University, Bellingham, WA, 2011

B.A. **Environmental Economics**
Western Washington University, Bellingham, WA, 2006

EMPLOYMENT

2017 - Present	Senior Consultant, Strategen Consulting
2013 – 2017	Utilities Economist, Antitrust and Utilities Division, Office of the Minnesota Attorney General
2012 – 2013	Consulting Economist, United States Geological Survey
2011 – 2013	Economic Research Assistant, Colorado State University

PREVIOUS TESTIMONY

Company	Docket No.	Subject
Minnesota Power	E-002/GR-16-664	CCOSS, Rate Design, and th Utility Business Model
Otter Tail Power	E-002/GR-15-1033	Marginal and Embedded CC and Rate Design
Xcel Energy	E-002/GR-15-826	CCOSS, Rate Design, PBR
Minnesota Energy Resources Corp.	G-011/GR-15-736	CCOSS and Rate Design
CenterPoint Energy	E-002/GR-15-424	CCOSS and Rate Design
Dakota Energy Association	E-002/GR-14-482	CCOSS and Rate Design
Xcel Energy	E-002/GR-13-868	CCOSS and Rate Design
Minnesota Energy Resources Corp.	G-011/GR-13-617	CCOSS
CenterPoint Energy	G-008/GR-13-316	CCOSS

Affidavit of Ron Nelson
Cause No. PUD 2018-496

County of Ramsey)
) ss
State of Minnesota)

I, Ron Nelson, state under penalty of perjury under the laws of Minnesota, that the foregoing Responsive Testimony dated May 16, 2018, is true and correct to the best of my knowledge and belief.

Ron Nelson

Subscribed and sworn to before me this 15 day of May 2018.

My Commission Expires: January 31, 2019

Notary Public:

JOHN J. DELUCA
NOTARY PUBLIC - MINNESOTA
My Commission Expires Jan. 31, 2019

1