BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR AN ORDER OF THE COMMISSION	)	
AUTHORIZING APPLICANT TO MODIFY ITS	)	CASE NO. PUD 2023-000087
RATES, CHARGES, AND TARIFFS FOR RETAIL	)	
ELECTRIC SERVICE IN OKLAHOMA	)	

Rebuttal Testimony

of

Lauren E. Maxey

on behalf of

Oklahoma Gas and Electric Company

May 17, 2024

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

A. My name is Lauren E. Maxey. My business address is 321 N. Harvey Ave., Oklahoma City, Oklahoma 73102.

Q. **Are you the same Lauren E. Maxey that filed Direct Testimony in this Case on December 29, 2023?**

A. Yes.

Q. **Please state the purpose of your Rebuttal Testimony.**

A. The purpose of my Rebuttal Testimony is to respond to recommendations made by Public Utilities Division ("PUD") witness David Scalf, Attorney's General ("AG") witness Frank J. Beling, AARP witness Patrick Sullivan, Oklahoma Industrial Energy Consumers ("OIEC") witnesses Mark Garrett and Larry Blank, Walmart witness Eric Austin, CMC Steel Oklahoma witness Justin Bieber, Federal Executive Agencies ("FEA") witness Michael P. Gorman, and The Oklahoma Association of Electric Cooperatives ("OAEC") witness David W. Hedrick regarding areas of the Company's request for a change in allocation of wind production costs and the allocation of transmission costs. Further, I will address AARP witness Patrick Sullivan's theory on the use of a basic customer approach to allocate distribution plant costs. I am also responding to recommendations made regarding the 1MW Cost of Service Study ("COSS").

PROPER ALLOCATION OF WIND PRODUCTION COSTS

Q. **What is the position regarding the change in allocation of wind production costs of PUD, AG, and AARP?**

A. The PUD, AG, and AARP all support the allocation of wind production costs on the proposed blended demand and energy allocation methodology. However, PUD Staff witness Scalf proposes to allocate 50% of OG&E's wind based on the blended methodology to mitigate effects on customers.[1]

[1] Responsive Testimony David Scalf, p. 13, lines 10-13.

Q. **What is the position regarding the change in allocation of wind production costs of OIEC, Walmart, CMC Steel, and FEA?**

A. The OIEC, Walmart, CMC Steel, and FEA all support the same position of rejecting these allocation changes and continue using the 4 Coincident Peak (4CP) Average and Excess production demand allocator for wind production costs for historical reasons and due to the fact that OG&E allocates all production resources in the exact same manner.

Q. **Why does OG&E believe that continued use of a production demand allocator is inappropriate for wind production assets?**

A. The main benefit of producing wind energy is the fuel savings related to any production. These energy benefits are then captured by customers through their kWh consumption through fuel cost savings. As a result, high volume users retain a greater proportion of fuel offsets compared to the amount these same customers contribute to wind facility costs when using the production demand allocator. Moreover, the significant financial benefits derived from production tax credits associated with wind generation are provided to customers on an energy basis through the Rider for Tax Credits. This means the current methodology allocates costs on a demand basis while providing the unique and significant financial benefits of wind generation on an energy basis. Therefore, high-volume users reap the disproportionate benefits due to the unique nature of wind generation versus traditional generation resources.

Q. **OIEC witness Garrett states that OG&E is attempting to relitigate an issue that has been resolved. Is this true?**

A. No. Allocators can be updated as needed to ensure that customers who cause costs to be incurred pay for those system costs. Further, Order 738226 in Case No. PUD 2022-000093 states that "The Commission recognizes a need to further assess and evaluate whether current cost allocations for transmission remain appropriate…"[2], which shows not only that allocators can be updated as needed, but that the Commission recognizes that historical methodologies are not always an appropriate way to continue to allocate costs to customers. Mr. Garrett's continued insistence that OG&E is attempting to relitigate issues that have

[2] Order No. 738226, Case No. PUD 2022-000093, p. 15, item 23.

been resolved is not only inappropriate but in direct opposition to a very recent Commission finding on cost allocation issues.

Q. **OIEC witness Garrett refers to a finding of the Commission related to PSO's wind energy purchase agreements. Explain why this treatment is inappropriate for OG&E's wind generation assets.**

A. OIEC witness Garrett cites the order from Cause No. PUD 201300188 which states "…the cost of Renewable Energy Purchase agreements should be recovered through the Fuel Cost Adjustment Rider using PSO's Production Demand Allocator."[3] The referenced Renewable Energy Purchase agreements are an agreement to purchase energy, not generate energy from Company owned resources. The use of the blended wind allocator is being applied to assets that are owned by the Company.

Q. **Was the blended allocator recently approved for use for PSO's company-owned wind generation assets?**

A. Yes, Order No. 738226 in Case No. PUD 2022-000093 approved the use of the blended allocator for the Sundance Wind Facility.

Q. **Witnesses Garrett and Bieber state that this allocation was approved based on specific circumstances. Please explain.**

A. Witness Garrett explains that blended allocation methodology was approved as a pilot project but left other company wind projects to be allocated on the legacy 4CP methodology. CMC witness Bieber also points to this ruling for Sundance being a pilot project to *further evaluate proper allocations.*[4]

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3 Responsive Testimony Mark Garrett, p. 13, lines 1-3.
4 Responsive Testimony Justin Bieber, p. 20, line 5.

Q. Are there reasons why the Sundance facility is unique?

A. Yes. It is unique because it is one of the first three wind projects that PSO added to its fleet of Company owned generation resources. The Sundance facility was a part of the North Central Energy Facilities which were completed in 2021-2022.[5]

The Sundance Wind Facility was included in base rates for the first time in Cause No. PUD 202100055.[6] The settlement agreement approving the North Central Energy Facilities permits PSO to change the allocation methodology in the case following the original filed case where the facilities were placed into base rates.[7]. Since the Sundance wind facility was the only facility that was previously placed into base rates, it was the only company owned facility for which the allocation methodology could be changed in Case No. PUD 2022-000093.

Q. How does the Sundance facility differ from the previous PSO Renewable Energy Purchase agreements?

A. As discussed above, the PSO wind facilities prior to this time were Renewable Energy Purchase agreements. Mr. Garrett's mischaracterization of these assets is important to note as these purchased power agreements are for the energy purchased from wind farms that PSO does not own. They include no amount of wind generation plant in their base rates from these agreements.

Q. What was ordered by the Commission for the other two wind facilities that were a part of the North Central Wind Energy Facilities?

A. The Maverick and Traverse facilities are the other two facilities that make up the North Central Wind Energy Facilities and included in the Wind Facility Asset Rider.[8] PSO has also requested that all wind be allocated on this approved blended methodology to ensure proper cost allocation in their current case which moves all three of these company owned wind production facilities and the Rock Falls facility to base rates[9]. As noted by Jacob

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5 2023 AEP 10-K, Item 2 PROPERTIES, PSO Table.

6 Case No. PUD 2022-000093, Direct Testimony Matthew Horeled, p. 4, lines 19-20.

7 Order No. 708933, Case No. PUD 2019-000048, Section II, p. 10, Testimony Summary John O. Aaron, Allocation of Revenue Requirement to Customer Classes.

8 Order No. 708933, Case No. PUD 2019-000048, Section II, p. 9-12, Testimony Summary John O. Aaron.

9 Direct Testimony Jacob Miller, PSO Case No. PUD 2023-000086, p. 17, lines 11-13.

Miller, the proper allocation of these resources will become increasingly important as renewable generation becomes a larger portion of their production fleet.[10]

Q. **Are wind generation resources functionally different than other generation resources?**

A. Yes. As discussed in my Direct Testimony, the capacity factor for wind resources is much lower than traditional generation, and the main benefit of wind generation is created by the fuel savings from wind energy production provided to customers. Additionally, the FERC recently issued Order No. 898 in Docket No. RM21-11-000, which, in part, creates new subfunctions and accounts to track plant costs and expenses for renewables resources, including wind generation, separately from other generation resources. These rules will become effective January 1, 2025.[11] This addition to FERC Uniform System of Accounts is indicative of the acknowledgement by the FERC that renewable generating resources are functionally different than traditional thermal resources.

Q. **Did OIEC discuss the treatment of the PTCs generated by wind energy resources?**

A. Yes, Witness Norwood addressed this. He claims PTCs should move to the fuel cost adjustment rider and be passed to customers in a manner in which they are earned.[12]

Q. **Does this conflict with the OIEC support of continuing to use a production demand allocator to allocate costs to retail customer classes?**

A. Yes. As discussed in my Direct Testimony, the main benefit of wind resources are the fuel costs savings. OG&E proposed a blended demand and energy allocator which recognizes the amount of capacity that is allowed for by the ELCC but could have elected to allocate these costs based on energy usage only. This suggested allocation of PTCs shows that OIEC recognizes the value of the fuel cost savings that they are receiving from the energy provided by wind resources, but OIEC continues to support the claim that the cost to

10 Direct Testimony Jacob Miller, PSO Case No. PUD 2023-000086, p. 18, lines 3-5.
11 https://www.ferc.gov/media/order-no-898
12 Responsive Testimony Scott Norwood, p. 12, lines 13-14.

provide that energy to customers should not be allocated in the same manner, which creates a further benefit to large energy consuming customers only.

Q. **Does the change in this wind allocation methodology result in the promotion of one industry of business over another?**

A. No. To treat all customers fairly, it is crucial that costs that are charged to customers be allocated in the COSS based on cost causation principles. By continuing to treat wind production costs the same as other sources of production and allocate the costs of these assets in the same way, the inequity continues. This inequity favors high volume users and harms low use customers such as residential customers.

Q. **Do large customers benefit from the continued use of the 4CP production demand allocator?**

A. Yes, and in fact, OIEC points out this fact in their testimony. OIEC witness Blank explains that this allocator change would shift over $5 million to the residential class. This demonstrates the inequity of continuing an allocation that does not properly align with cost causation.

Q. **Do you agree with the continued use of the 4CP production demand allocator due to the energy component of the Average and Excess part of its calculation?**

A. No. FEA witness Gorman, OIEC witness Blank, Walmart witness Austin, and CMC witness Bieber support the continued use of the 4CP A&E due to the fact that energy is considered as part of the calculation for this allocator. This argument is a red herring to distract from the fact that basing the majority of allocation on energy is more reasonable from a cost causation perspective.

PROPER ALLOCATION OF TRANSMISSION COSTS

Q. **What is the position regarding the change in allocation of transmission costs of PUD, AG, and AARP?**

A. The PUD, AG, and AARP all support the allocation of transmission costs on the proposed 12 Coincident Peak ("12CP") allocation methodology. However, PUD Staff witness Scalf proposes to allocate 50% of OG&E's transmission on the 12CP to mitigate effects on customers and allocate the remainder on the historical 4CP allocator.[13]

Q. **Are any other recommendations made by these witnesses?**

A. Yes, AG witness Beling notes that recent changes to the SPP adequacy requirements could result in the need to look at not only the traditional summer peak for capacity requirements, but to also consider the capacity requirements in the winter months. This could result in changes to allocations to customers. OG&E will continue to monitor these issues and will study the need to change allocators as needed to properly assign costs to customers using methods that align the method in which those costs are incurred.

Q. **What is the position regarding the change in allocation of transmission costs of OIEC, Walmart, CMC Steel, and FEA?**

A. The OIEC, Walmart, CMC Steel, and FEA all support the same position of rejecting the use of the 12CP allocator and support continuing to use the 4CP. These parties support this recommendation due to OG&E being a summer peaking utility and the historical usage of the 4CP allocator within the Oklahoma jurisdiction.

Q. **OIEC witness Garrett states that OG&E is attempting to relitigate an issue that has been resolved. Is this true?**

A. No. As discussed above, allocators can and should be updated as needed to ensure that customers who cause costs to be incurred pay for those system costs. Mr. Garrett's continued insistence that OG&E is attempting to relitigate issues that have been resolved is not only inappropriate but in direct opposition to previous Commission decisions.

Q. **Did PSO recently request to use a 12CP allocator for transmission costs?**

A. Yes, PSO requested to use a 12CP allocator for transmission costs in both of its recent filings, Case Nos. PUD2022-000093 and PUD 2023-000086.

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13 Responsive Testimony David Scalf, p. 17, lines 15-17.

Q. **What was the result of these filings?**

A. The stipulating parties in Case No. PUD 2022-000093 agreed to the use of the 12CP allocator for transmission costs and asked the Commission to approve this allocation. However, in Commission Order 738226, the Commission states "The Commission recognizes a need to further assess and evaluate whether the current cost allocations for transmission remain appropriate in light of the arguments raised…"[14] [15] Case No. PUD 2023-000086 is currently pending. PSO has requested that transmission costs be allocated to retail customers on a 12CP allocator in that filing.[16]

Q. **Witness Blank states that "Transmission capacity costs to serve the retail customer loads of OG&E greatly follow total generation capacity needs at system peaks."[17] Do you agree with this statement?**

A. No. OIEC's position that transmission capacity costs are driven by the retail customer peak load on the system is true, but it is only one factor in the transmission system usage. As explained in my Direct Testimony, "A cost allocation method that allocates transmission costs based on customer contributions to each of the 12 coincident peaks reflects the OG&E customers and their usage of the transmission system across the year. Transmission is not built to only meet peak demand in certain seasons, but to transmit electric energy from generating facilities to load during all months of the year."[18] This is also supported by Commission Staff witness Scalf, who states "Transmission and the associated transmission plant costs are not built and incurred for just four months of the year; they are built to serve load all twelve months."[19]

Additionally, the transmission system is designed to serve more than OG&E's retail load, such as transmitting energy produced by wind farms to customer loads within the entire SPP footprint. This energy might be transmitted across the OG&E territory to another customer. OG&E's customers benefit from any use of the OG&E transmission as needed by the SPP through the market transactions.

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[14] PSO Final Order No. 738226, Case No. PUD2022-000093, p. 15, Item 23 Transmission Cost Allocation.
[15] Responsive Testimony David Scalf, p. 16-17.
[16] PSO Case No. PUD 2023-000086, Direct Testimony Jacob Miller, p.10-14
[17] Responsive Testimony Larry Blank, p. 14, lines 4-5.
[18] Direct Testimony Lauren Maxey, p. 18, lines 24-28.
[19] Responsive Testimony David Scalf, p. 15, lies 13-15.

Q. **Does the NARUC Cost Allocation Manual discuss transmission cost allocation?**

A. Yes. Witness Blank also provides a citation to the NARUC manual, saying "The 12 CP demand allocation is based on the principle that a utility installs facilities to maintain a reasonably constant level of reliability throughout the year…"[20]. Since the OG&E transmission system is designed to not only support the OG&E retail load, but also to maintain reliability throughout the year, the 12CP allocation of transmission costs is appropriate. This is supported by the NARUC Cost Allocation Manual directly, stating "the transmission system is designed to reliably and economically deliver bulk power supply throughout the system, even under adverse operating conditions."[21]

Q. **Does the NARUC Cost Allocation Manual provide tests related to the use of the 12CP allocator for transmission costs?**

A. Yes. Both OIEC witnesses Blank and CMC witness Bieber both present tests that they claim are applied to determine the appropriate use of a 12CP allocator. However, they misrepresent how these tests are used.

The NARUC Cost Allocation manual actually provides a total of seven tests that can be used to analyze transmission cost allocation methods. It makes no determination on which method is correct for all utilities or any transmission system. One of the seven methods of allocating transmission plant is, in fact, the 12CP methodology as proposed by OG&E in this case.

Q. **Please explain why the test presented in OIEC witness Blank's Responsive Testimony is inappropriate.**

A. The test that was presented in Table 1[22] in OIEC witness Blank's Responsive Testimony is being represented as the way to determine if use of a 4CP allocator is appropriate for transmission system costs. However, this data is used under the Average Seasonal System Coincident Peak Method as a way to determine **when** the utility season peak is, **not** to decide if this is an appropriate way to allocate system costs. Therefore, OIEC's witness

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20 Responsive Testimony Larry Blank, p. 12, lines 18-19.

21 NARUC Cost Allocation Manual, p. 75.

22 Responsive Testimony of Larry Blank, p. 13

Blank's use of the test to determine cost causers or the appropriate allocation of transmission costs is misplaced.

Q. **How does OG&E assign transmission costs across its jurisdictions?**

A. OG&E assigns transmission costs to customers using a 12CP allocation to determine what portion of costs to assign to each jurisdiction. No intervenor witness explains why it is appropriate and reasonable to use a 12 CP allocator to assign transmission costs across jurisdictions, but it is not appropriate to use 12 CP to allocate those same costs to classes in Oklahoma.

Q. **What allocator does the FERC jurisdiction use for allocating transmission plant?**

A. The FERC jurisdiction currently and historically uses a 12CP when setting rates for transmission service through the FERC approved formula rates. The SPP also uses a 12 CP allocator when assigning costs across the SPP on a load ratio share basis. No intervenor witness explains why it is appropriate and reasonable to use a 12 CP allocator at FERC and SPP for allocating transmission costs, but it is not appropriate to use 12 CP to allocate those same costs to classes in Oklahoma.

Q. **How does OG&E allocate transmission costs in its Arkansas retail jurisdiction?**

A. OG&E uses a 12CP allocator to assign costs within the Arkansas retail jurisdiction, both to determine the jurisdictional portion of costs Arkansas customers will pay and to assign costs to each customer class. No intervenor witness explains why it is appropriate and reasonable to use a 12 CP allocator in Arkansas for allocating transmission costs, but it is not appropriate to use 12 CP to allocate those same costs to classes in Oklahoma.

<u>BASIC CUSTOMER APPROACH</u>

Q. **What does AARP witness Sullivan recommend to the Commission with respect to the allocation of distribution costs within the COSS?**

A. Witness Sullivan recommends the Commission consider applying the basic customer approach to distribution FERC accounts 364 – 368 (referred to generally as "distribution system") to be classified as 100 percent demand-related for determining reasonable allocation of costs to customer classes.[23]

Q. **Do you agree with witness Sullivan's recommendation?**

A. No. Mr. Sullivan's recommendation to use the basic customer approach fails to show that there is a minimum level of distribution cost that scales as customers are added to the system. A zero-intercept study quantifies this relationship, and the Company utilizes this methodology in its COSS, which Mr. Sullivan's refers to as a "OG&E's minimum system study"[24].

Q. **What is a zero-intercept study?**

A. The zero-intercept study is a technique that assesses the relationship between asset cost and carrying capacity by using regression to identify a curve demonstrating that relationship. The curve crosses where the y-intercept is the cost related to no-load or minimum system investment to serve customers regardless of size.[25]

Q. **Is the zero-intercept method of distribution cost classification new to OG&E's COSS?**

A. No. OG&E has filed its COSS utilizing a zero-intercept study in each of its last six general rate case proceedings, Cause Nos. PUD 2021000164, PUD 201800140, PUD 201700496, PUD 201500273, PUD 201100087, and PUD 200800398. The current version of the study is the result of the Commission Final Order from Cause No. PUD 201500273. In that ruling, the Commission ordered OG&E to update its zero-intercept study to be used in its next rate case filing.[26]

Q. **Did OG&E comply with the order of the Commission?**

A. Yes. In 2017, the Company conducted a new zero-intercept study that was first used in Cause No. PUD 201700496. In that Cause, PUD recommended approval of the Company's

[23] Responsive Testimony Patrick Sullivan p. 17, Lines 4-7.
[24] Responsive Testimony Patrick Sullivan, p. 33, line 2.
[25] National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual p. 92
[26] Cause No. 201500273, Order No. 662059, Report of the Administrative Law Judge, p. 81

zero-intercept study.[27] This study was used again in Cause No. PUD 201800140, Case No. PUD 2021000164 and again in this current case.

Q. **What does the NARUC Cost Allocation Manual say about the use of a zero-intercept study?**

A. In the embedded cost section, the NARUC Manual states "To insure that (distribution) costs are properly allocated, the analyst must first classify each account as demand-related, customer-related or a combination of both."[28] The NARUC Manual goes on to recommend one of two approaches, either a minimum-size method or the minimum-intercept (zero-intercept) method.[29] Both methods seek to identify a minimum level of system investment to serve customers regardless of their size. The NARUC Manual describes the zero-intercept method as using more data than the minimum-size method and being generally considered a more accurate approach in the industry.[30]

Q. **What is witness Sullivan's basic customer approach?**

A. Witness Sullivan's basic customer approach is a simple classification of 100% of cost of distribution FERC accounts 364 – 368 as being demand-related. In practice, witness Sullivan's approach has the effect of substantially reducing the cost allocated to residential customers at the expense of the other rate classes. This basic customer approach inappropriately shifts costs to commercial and industrial customers and to public schools.

Q. **Did the Company follow the NARUC Cost Allocation Manual when it performed its zero-intercept study?**

A. Yes, the Company did follow the NARUC Cost Allocation Manual in the process of updating its zero-intercept study The NARUC Manual states that each utility's choice of methodologies will depend on the unique circumstances of each utility.[31]

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[27] Cause No. 201700496, Chaplin Rate Design and Cost of Service Responsive, p. 20 lines 7-10
[28] NARUC Manual p. 89
[29] Id. at p. 90
[30] Id. at p. 92
[31] Id. at p. 22

1MW COSS

Q. Did the 1MW COSS that the Company filed with the original application comply with Commission Order 728277 in Case No PUD 2021-000164?

A. Yes. This order required the Company to perform a 1MW COSS to "verify the accuracy of the decision of the Company in this Case to treat the 1 MW customer class's coincident peak as their own customer class." PUD witness Scalf agrees that the filed COSS complied with the settlement in that Case.[32]

Q. Does OG&E generally support the direct assignment of costs to individual customers as they are added to the system?

A. No. Generally, all plant costs for each FERC account are spread to all customer classes according to appropriate allocation methodologies utilizing customer load characteristics and customer counts.

Q. Please explain the allocation of transmission radial costs to customers as shown in this 1MW COSS.

A. OG&E does not track transmission radials by customer. OG&E used property accounting records and engineering records to identify the length of each transmission radial that is dedicated to a single customer, and the average cost per mile of the gross plant balance of transmission radials was assigned to these customers.

Q. Why did OG&E use the average cost per mile of transmission radials to assign costs for these assets?

A. The Company follows cost allocation principles that support average rate making. Therefore, using the average cost per mile of transmission radials is an appropriate way to assign costs to assets that are not tracked individually nor are they depreciated individually. The result allows average ratemaking principles to be combined with the allocation of costs that was included in the 1MW COSS.

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32 Responsive Testimony David Scalf, p. 18

Q. **Please provide another example of the application of average ratemaking principles.**

A. The 1MW customers were brought onto the OG&E system as any other customer would be. For example, as the Company extends the distribution system to serve new residential customers, that subset of customers is not charged higher rates by direct assigning their newer vintage assets that were installed to them. They are charged an average rate based on their class's usage and demand characteristics. It would be inappropriate to deviate from this use of average rates that is applied throughout the regulated industry. Company witness Jeremy Schwartz will also discuss how OG&E ensures that all customers pay for their portion of line extension costs.

Q. **OAEC witness David Hedrick suggests that OG&E has deviated from this system average ratemaking practice by direct assignment of substations to SL2 customers. Why do these assets differ from transmission radials?**

A. OG&E has previously agreed to direct assign Service Level 2 ("SL2") substations to SL2 customers. As shown in Figure 3 of my Direct Testimony in this Case, SL2 customers are served directly from a substation, which can either be dedicated to a single customer or have one dedicated circuit from the substation to serve a customer.

OG&E's population of substations are tracked individually by station number, which allows their costs to be identified and directly assigned to the customers they are serving. These assets are the exception in OG&E's property accounting records and the Company's use of mass property accounting. By contrast, transmission radials are not tracked individually. The tracking of each individual asset on OG&E's system would be voluminous and extremely costly. This is common in the utility industry and another reason why average rate making has been accepted as an industry practice for many years. The practice of using average rate making principles would be the consistent and appropriate way to treat these radial assets. OG&E continues to support the allocation of system costs to all customers based on average ratemaking principles.

RECOMMENDATIONS

Q. **Please summarize your recommendations to the Commission.**

A. I recommend the Commission approve the use of a blended wind allocator for company-owned wind generation assets and approve the use of the 12CP allocator for transmission costs within the Oklahoma retail jurisdiction to align these allocations with cost causation principles. Further, I recommend that the Commission reject the basic customer approach for classification of distribution plant costs and approve the Company's COSS which uses a zero-intercept approach to classify these costs. Finally, I recommend that the Commission affirm that OG&E performed the required COSS analysis for the 1MW customers that are already served on legacy rates and accept the use of average rate making principles for all customers that OG&E serves.

Q. **Does this conclude your Rebuttal Testimony?**

A. Yes.