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 RATES, CHARGES, AND TARIFFS FOR RETAIL ELECTRIC SERVICE IN OKLAHOMA	PUD 2023-000087

REDACTED
RATE DESIGN AND COST OF SERVICE TESTIMONY OF FRANK J. BELING
ON BEHALF OF
GENTNER F. DRUMMOND, OKLAHOMA ATTORNEY GENERAL

Gentner F. Drummond, the Attorney General of Oklahoma, on behalf of the utility customers of this State, hereby submits the Rate Design and Cost of Service Testimony of Frank J. Beling in the proceeding referenced above. The Attorney General urges close consideration of the testimony.

Respectfully submitted,

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CERTIFICATE OF SERVICE

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REDACTED

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OF

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ON BEHALF OF

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OKLAHOMA ATTORNEY GENERAL

May 3, 2024

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I. Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Frank J. Beling, and my business address is 5555 North Grand Boulevard, Oklahoma City, Oklahoma 73112.

Q. BY WHOM ARE YOU EMPLOYED, WHAT IS YOUR POSITION, AND WHAT ARE YOUR GENERAL AREAS OF RESPONSIBILITY?

A. I am employed by Guernsey Engineers, Architects, and Consultants in its Analytical Solutions Group, and my current title is Senior Vice President. My primary areas of responsibility involve rate analysis, power supply planning, and risk management.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science degree in Mechanical Engineering and a Master of Science degree in Mechanical Engineering. Please refer to Exhibit FJB-1 for a summary of my experience.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE STATE OR FEDERAL REGULATORY COMMISSIONS?

A. Yes. I have previously appeared before the Oklahoma Corporation Commission. My credentials were accepted at that time.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am appearing on behalf of the Oklahoma Attorney General.

Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY AND WERE THE EXHIBITS PREPARED EITHER BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, I have prepared exhibits that I will reference in my testimony. The exhibits were prepared by me or under my direct supervision.

Q. WHAT IS THE PURPOSE OF THE TESTIMONY YOU ARE PRESENTING IN THIS PROCEEDING?

A. The purpose of this testimony is to discuss cost allocation methods proposed by Oklahoma Gas and Electric Company ("OGE" or "Company"). My testimony supports the Company's proposed change in transmission cost allocation from a 4 Coincident Peak ("CP") method to a 12 CP method and also supports a change in the allocation of owned wind resource costs from a 4 CP method to an energy-focused allocation. My testimony then recommends that the Company consider alternatives to the production demand allocation in future rate cases as resource adequacy requirement changes occur at the Southwest Power Pool ("SPP"). Finally, my testimony addresses a comparative analysis that the Company used to support a proposed increase to its customer charge. I discuss why the Company's comparative analysis was not appropriate, and I provide an updated set of references.

II. Transmission Allocation

Q. HOW DOES THE COMPANY INCUR TRANSMISSION COSTS?

A. The transmission-related costs shown in the Company's Cost of Service model can generally be described as falling into two categories: costs related to Company-owned transmission facilities and costs related to SPP transmission charges.

Q. WHAT ARE TYPICAL METHODS FOR ALLOCATING TRANSMISSION COSTS?

A. Transmission costs can be directly assigned or spread using an allocation method. Directly assigned transmission costs are appropriated if those facilities are exclusively used by a customer. Other transmission costs are typically allocated based on usage of the transmission facilities as measured during certain points in time. Peak demand of a customer class irrespective of when the peak occurs is a Non-coincident Peak. Measuring the demand of the customer class at the time of the system peak is called the Coincident Peak, or "CP". The CP can be measured at different time periods throughout the year. Common types of CP measurements include a 1 CP (single system coincident peak) that measures the highest single peak hour for the entire year, a summer 4 CP that considers the peak for each of the four summer months, and a 12 CP that considers the system peak in each of the 12 months of the calendar year.

Q. HOW DOES THE COMPANY PROPOSE TO ALLOCATE TRANSMISSION COSTS?

A. The Company currently uses a 4 CP allocator to allocate transmission costs in Oklahoma and is proposing the use of a 12 CP allocator.

Q. WHY DOES THE COMPANY PROPOSE USING A 12 CP ALLOCATION FOR TRANSMISSION COSTS?

A. The Company offers two primary arguments to support the change: consistency and cost causation. Company witness Lauren E. Maxey indicates that applying the 12 CP allocation would be consistent with how the Company allocates transmission costs in both Federal Energy Regulatory Commission ("FERC") and Arkansas jurisdictions and is currently and historically used through FERC approved formula rates.[1] Ms. Maxey further identifies that a 12 CP is appropriate based on how "SPP plans for and operates the transmission grid in order to provide access to the most cost-effective power to all customers throughout the SPP footprint across all twelve months of a year; not just in the summer months."[2] Finally, Ms. Maxey adds that, in addition to a planning perspective, SPP also assigns costs to the Company based on a 12 CP by "utiliz[ing] a 12-CP allocator when assigning costs across its SPP footprint."[3]

Q. IS COMPANY WITNESS MAXEY CORRECT IN INDICATING THAT USING A 12 CP TO ALLOCATE TRANSMISSION COSTS FOLLOWS COST CAUSATION PRINCIPLES?

A. Yes. I agree with Ms. Maxey's arguments that a 12 CP allocation follows cost causation principles for both general categories of Company transmission expense (i.e., Company-owned transmission facilities and SPP transmission charges).

Q. HOW DOES THE COMPANY PLAN ITS TRANSMISSION SYSTEM FACILITIES?

A. The Company's 2021 Integrated Resource Plan ("IRP") states:

> OG&E is a member of and provides input to SPP [Southwest Power Pool] who is ultimately responsible for the planning of the OG&E system. SPP evaluates system adequacy and develops a transmission expansion plan to determine what improvements are necessary to ensure reliable transmission service.[4]

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[1] Direct Testimony of Lauren E. Maxey for Oklahoma Gas and Electric Company 18:11–13 (Dec. 29, 2023) [hereinafter "Maxey Direct"].
[2] Maxey Direct 18:22–24.
[3] Maxey Direct 18:29–30.
[4] OGE's Response to AG-OGE-1-17.

Q. WHAT TYPE OF STUDIES ARE INVOLVED IN THE SPP TRANSMISSION EXPANSION PLAN?

A. The SPP transmission expansion plan[5] provides an overview of several types of studies such as the Generation Interconnection studies and Integrated Transmission Planning ("ITP"). The Generator Interconnection Study Process, as defined by the SPP OATT Business Practices[6] studies, base reliability time periods such as summer, winter, light loading and non-coincident peaks. Likewise, SPP's ITP Manual[7] uses the same base reliability time periods in determining potential future transmission expansions. Additionally, the SPP ITP manual outlines criteria for evaluating persistent operation needs which can occur throughout a year and are not tied to a specific month or season.

Q. DO EITHER THE SPP TRANSMISSION PLANNING PROCESS OR THE SPP TRANSMISSION COST ALLOCATION PRIMARILY FOCUS ON A 4 CP?

A. No. As previously described, the SPP transmission planning process includes a focus on loads in seasons other the 4 CP months. Company witness Maxey describes SPP cost allocation methodology in that "the SPP utilizes a 12-CP allocator when assigning costs across its SPP footprint . . . [.]"[8]

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[5] 2024 SPP Transmission Expansion Plan Report, Southwest Power Pool, Inc., Version 1, Feb. 6, 2024, https://www.spp.org/documents/56611/2024%20spp%20transmission%20expansion%20plan%20report.pdf.
[6] Open Access Transmission Tariff Business Practices, Southwest Power Pool, Inc. Feb. 2, 2001 (updated January 12, 2024), https://www.spp.org/documents/64300/spp%20oatt%20business%20practices.pdf.
[7] Integrated Transmission Planning Manual, Southwest Power Pool, Inc., Version 2.16, Jan. 30, 2024, https://www.spp.org/documents/71013/itp%20manual%20version%202.16.pdf.
[8] Maxey Direct 18:29–30.

Q. WHAT IS YOUR RECOMMENDATION FOR THE ALLOCATION OF TRANSMISSION EXPENSES?

A. Based on my previous discussion of the fact that from both a planning perspective and a SPP cost perspective, the Company's transmission costs are driven by year-round peaks rather than by a 4 CP, I recommend that the Commission approve the Company-proposed 12 CP allocation for transmission plant and costs.

III. Wind Cost Allocation

Q. DOES THE COMPANY PROPOSE RECOVERY OF WIND RESOURCE COSTS IN THE SAME MANNER AS ITS OTHER GENERATING RESOURCES?

A. No. As discussed by Ms. Maxey, the Company proposes to allocate the cost of owned wind resources based on an allocator of 16 percent demand and 84 percent energy, which is different from how the Company handles the costs of its other generating resources under both its current and proposed allocation methodology.[9]

Q. PLEASE DESCRIBE THE ROLE WIND RESOURCES PLAY IN A RESOURCE PORTFOLIO AND HOW IT DIFFERS FROM THE ROLE OF TRADITIONAL THERMAL RESOURCES.

A. Traditional thermal resources are commonly used to satisfy a capacity planning obligation such as the one the Company has in the SPP. Because traditional thermal resources are commonly assigned accredited planning capacity at a value close to the total size of the resource, they are a predictable tool in meeting planning capacity requirements.

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[9] Maxey Direct 14:14–15.

Wind resources, on the other hand, are commonly assigned much lower values of accredited planning capacity and the accredited planning capacity assigned to wind resources has been historically more volatile than that of traditional thermal resources.

The difference in capacity benefits does not mean that wind resources cannot provide benefits to utilities; it simply means that the wind resources play a different role in resource portfolios and create value in a different way compared to traditional thermal resources. In other words, the primary value of wind resources is an energy benefit rather than a capacity benefit.

Q. PLEASE CHARACTERIZE THE GENERAL RELATIONSHIP BETWEEN FIXED AND VARIABLE COSTS OF WIND RESOURCES.

A. In general, the costs associated with owned wind resources are largely fixed costs. Although wind resources have no fuel cost, they have a high upfront capital cost.

Q. DOES THE COMPANY-PROPOSED ALLOCATION OF 16/84 FOR OWNED WIND RESOURCES FOLLOW A STRICT COST-OF-SERVICE APPROACH TO RECOVERY?

A. No. As I previously indicated, the costs of owned wind resources are often mostly fixed cost and, under a strict cost-of-service-based allocation, would be allocated using a demand allocator. Therefore, the Company-proposed 16/84 split between demand and energy allocation does not follow a strict cost-of-service-based allocation.

Q. IS THE COMPANY CORRECT TO PROPOSE AN APPROACH TO RECOVERY OTHER THAN A STRICT COST-OF-SERVICE-BASED APPROACH FOR THE OWNED WIND RESOURCES?

A. Yes. As I previously indicated, the primary value that wind resources bring to a utility resource portfolio are energy-related benefits. However, under a strict cost-of-service-based allocation, most of the owned wind resource costs would be allocated to demand. This mismatch would create a misalignment between costs and benefits and can shift costs between customer classes with different load factors.

Under a strict cost-of-service-based allocation, customer classes with lower load factors (i.e., less energy per demand) would be assigned a higher share of owned wind resource costs, while customer classes with higher load factors (i.e., more energy per demand) would be assigned a higher share of the project benefits.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE TYPE OF COST SHIFT YOU DESCRIBE THAT COULD OCCUR IF OWNED WIND RESOURCES WERE TO BE ALLOCATED USING A STRICT COST-OF-SERVICE-BASED APPROACH?

A. Yes. Take, for example, two hypothetical customer classes that both contribute to the Company CP at a level of 10 MW. The first customer class is a collection of residential consumers, where its usage over the year varies greatly over the course of a day and also over the course of a year. The result of this variance in load levels results in a low CP Load Factor for the load (i.e., low level of energy per CP demand). The second example customer class is a collection of customers that use high levels of energy at all times. Because its usage is at almost the same level for every hour of the year, the class has a high CP Load Factor (i.e., high level of energy per CP demand).

Under a strict cost-of-service-based approach, both customer classes would participate in the costs of the owned wind resources at the same level because their contribution to Company demand is each 10 MW.

However, the two customer classes have different participation in the benefits of the owned wind projects. Because the benefits of the owned wind projects are realized as a reduction in fuel cost, those benefits are assigned to production energy, and customer classes participate in those benefits based on energy consumption of the class. The first example customer class (residential, low load factor consumers) receives a smaller portion of owned wind resource benefits because they purchase a lower level of energy from the Company. The second example customer class (high load factor using lots of energy every hour) receives a higher level of the owned wind resource benefits because they purchase a higher level of energy from the Company.

This example of customer classes with differing load factors illustrates the importance of aligning the costs and benefits of the owned resources, and the potential cost shift that can occur if there is a misalignment.

Q. HAVE YOU ESTIMATED AN EQUITABLE ALLOCATION BETWEEN DEMAND AND ENERGY FOR THE COMPANY'S OWNED WIND RESOURCES?

A. Yes. Based on the principles discussed above, I performed an estimate-level analysis to estimate a fair allocation of Company wind costs between demand and energy. The results of my analysis indicate a 10/90 split between demand and energy.

Q. ON WHAT IS YOUR ESTIMATED ALLOCATION BASED?

A. My estimate is based on the concept of identifying a portion of the owned wind resource costs as providing capacity value to the Company and allocating those costs to demand. All other owned wind resource costs would be allocated to energy.

Q. HOW DOES YOUR ALLOCATION METHOD DIFFER FROM THE COMPANY PROPOSAL?

A. The Company appears to begin with the capacity accreditation as a percentage of project size. This is an important first step in understanding how the resource contributes to Company resource planning. However, the Company appears to use this percentage as the percentage of owned wind resource costs that should be allocated to demand.

My estimated allocation also starts with the capacity accreditation of the owned wind resources. However, I then use the accredited planning capacity for the owned wind resources to estimate a value of capacity (in dollars) that the owned resources provide to the Company as a basis for determining how much of the owned wind resources should be allocated to demand.

Q. HOW DO THE OWNED WIND RESOURCES PROVIDE CAPACITY VALUE TO THE COMPANY?

A. The owned wind resources provide capacity value to the Company by satisfying a portion of its planning capacity obligation to the SPP. The Company indicates the level of accredited planning capacity it receives for each of its resources,[10] with the total for all three of its owned wind resources as 61 megawatts ("MW") in 2024. Each resource's capacity value is provided in Table 1 below.

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[10] OGE's Response to OIEC-OGE-07-14.

Table 1 – Summary of Company Wind Resource Capacity

Resource	Nameplate Capacity (MW)	Accredited Capacity (MW)
Centennial	120	19
OU Spirit	101	9
Crossroads	228	33

Q. WHAT IS THE ECONOMIC VALUE OF THE PLANNING CAPACITY CREDIT THAT THE RENEWABLE RESOURCES WILL PROVIDE?

A. It is difficult to place an exact economic value on the planning capacity that the Company's owned wind resources will provide in the future. The market value of capacity can vary over time, and the SPP does not currently have a formal capacity trading market. However, many markets develop a Cost of New Entry ("CONE") metric based on the costs of constructing and owning a low-capital-cost resource, and the CONE is commonly used to approximate the cost of satisfying a capacity obligation. In many cases, the CONE is developed based on the price of a simple-cycle combustion turbine.

As further discussed below, the CONE is not necessarily indicative of the market value or cost of capacity, but it can provide an estimate-level proxy value for the upper ranges of the market value of capacity.

Q. DOES A COST OF NEW ENTRY ("CONE") VALUE REPRESENT THE VALUE OF CAPACITY IN A MARKET?

A. The CONE is not necessarily predictive of the price or value of capacity in a market. Many times, the market value of capacity is lower than the CONE, and there are also occasions when it can be higher. The CONE is sometimes viewed as a long-term soft cap on the price of capacity because, if a utility is forced to pay for capacity at a price higher than the CONE, the utility could instead construct new capacity, presumably at a price similar to the CONE itself. For these reasons, I used the CONE as a starting point for a proxy value of capacity in my estimate.

Q. PLEASE INDICATE HOW YOU ARRIVED AT YOUR ESTIMATES FOR A FAIR COST ALLOCATION FOR OWNED WIND RESOURCES.

A. I started by identifying basic information about the owned wind resources, such as remaining plant balances and operations and maintenance ("O&M") expense.[11] I also considered the level of planning capacity credit the Company receives for each of its owned wind resources, which I used for the remaining life of each owned wind resource.[12] Next, I estimated a remaining cost for owned wind resources using information provided by the Company, such as O&M costs,[13] capital expenditures,[14] and remaining plant balances.[15] I used the simplifying assumption that Production Tax Credit ("PTC") values were spread evenly across the resource life based on resource depreciation and remaining plant balance. Using these assumptions, I started with remaining plant balance of around $493 million, added planned and estimated capital investments, credited an estimated portion of previous PTC value, and added an assumed level of future O&M expenses to arrive at a normalized estimated remaining resource cost of around $511 million on a Net Present Value ("NPV") Basis.

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[11] OGE's Response to AG-OGE-25-1.
[12] OGE's Response to OIEC-OGE-7-14.
[13] OGE's Response to AG-OGE-25-1.
[14] OGE's Response to AG-OGE-25-1.
[15] OGE's Response to AG-OGE-25-1.

Next, I escalated the previously-discussed CONE value by 2.5 percent each year to estimate a CONE for future years; the estimated 2025 CONE value was around $89.94 per kW-yr. I used this escalated CONE value to estimate the value of the capacity provided by the Renewable Resources in each future year using the Company assumptions for the level of planning capacity provided by each of the owned wind resources.[16]

Finally, I identified that this estimated capacity value of the owned wind resources should be allocated to demand, and the remainder of the costs of the owned wind resources should be allocated to energy.

The results of my calculation were about a 10/90 split between demand and energy for the owned wind resources. My calculations are provided in Confidential Exhibit FJB-3.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED AN ALLOCATOR FOR OWNED WIND RESOURCES SIMILAR TO THAT REQUESTED BY THE COMPANY IN THIS PROCEEDING?

A. Yes. The Commission previously approved a similar allocator with a 16/84 split between demand and energy for the allocation of costs for PSO's Sundance wind facility in Case PUD 2022-000093.[17]

Q. IS THE COMPANY-PROPOSED 16/84 SPLIT A REASONABLE ALLOCATION OF OWNED WIND RESOURCE COSTS?

A. Yes. My estimate-level analysis indicates a 10/90 split between demand and energy for allocation of owned wind resource costs would be equitable, which is similar to the Company-proposed 16/84 split. However, as previously described, the basis for

[16] OGE's Response to OIEC-OGE-7-14.
[17] Order Modifying Final Order No. 738,226, Order No. 738,571, at 16, *Pub. Serv. Co. of Okla. Rates & Charges for Elec. Serv.*, No. PUD 2022-00093 (Okla. Corp. Comm'n Nov. 21, 2023).

determining the allocation should be rooted in costing principles as provided in my testimony, and not simply using the accredited capacity as a percentage of project sizes.

IV. Demand Allocation

Q. IS THE COMPANY'S CURRENT ALLOCATION OF PRODUCTION DEMAND COSTS AFFECTED BY BOTH PEAK DEMANDS AND ENERGY?

A. Yes. The Company's current allocation methodology for production demand expenses is affected by class energy usage (average demand) and is also affected by the coincident peak in certain months of the year.

Q. DOES THE PORTION OF THE COMPANY'S PRODUCTION DEMAND COST ALLOCATOR THAT IS AFFECTED BY PEAK DEMANDS HAVE A SEASONAL FOCUS?

A. Yes. A portion of the Company's proposed production demand allocator is affected by the coincident peaks in June, July, August, and September. This seasonal focus means that coincident peak demands of customer classes outside of these four months do not affect the allocation of production demand costs between customer classes.

Q. SHOULD THE COMPANY CONSIDER MODIFYING ITS CURRENT SEASONAL FOCUS OF THE PRODUCTION DEMAND ALLOCATOR IN FUTURE RATE DESIGNS?

A. Yes. Historically, the SPP planning requirement has focused on the Company peak that occurs in the summer period. However, due to upcoming changes in SPP seasonal adequacy requirements,[18] the Company may soon also face a planning capacity requirement in winter months that could also drive its capacity costs.

Because those future requirements could include months outside the four summer months, the Company should consider revising its production demand allocator. The Company should carefully consider any future planning requirement and ensure that its class allocation methodology closely aligns with the drivers of its capacity costs.

V. Customer Charge

Q. HAS THE COMPANY PROPOSED A CHANGE TO THE MONTHLY CUSTOMER CHARGE

A. Yes. Company witness Gwin Cash provides direct testimony showing customer charge increases under the Company's request.[19] As summary of rates and the percent increase requested is shown below in Table 2.

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[18] SPP Supply Adequacy Working Group December 6-7, 2023 Meeting Minutes and Materials, https://spp.org/documents/71422/sawg%20minutes%2020231206-07.pdf; https://spp.org/Documents/70647/SAWG%20Meeting%20Materials%2020231206-07.zip.

[19] *See* Direct Testimony of Gwin Cash for Oklahoma Gas and Electric Company (Dec. 29, 2023) [hereinafter "Cash Direct"].

Table 2 – Company-proposed Changes to Customer Charge

Rate	Current	Proposed	Change
Residential	$ 13.00	$ 21.00	62%
Residential - TOU	$ 13.00	$ 21.00	62%
Residential - VPP	$ 13.00	$ 21.00	62%
General Service	$ 28.51	$ 56.00	96%
General Service - TOU	$ 28.51	$ 56.00	96%
General Service - VPP	$ 28.51	$ 56.00	96%
Oil and Gas Producers - TOU	$ 29.37	$ 40.25	37%
Oil and Gas Producers - VPP	$ 29.37	$ 40.25	37%
Public Schools Small	$ 20.95	$ 56.00	167%
Public Schools Small - TOU	$ 20.95	$ 56.00	167%
Public Schools Small - VPP	$ 20.95	$ 56.00	167%
Public Schools Large - SL-3	$ 135.00	$ 125.00	-7%
Public Schools Large - SL-4	$ 95.00	$ 120.00	26%
Public Schools Large - SL-5	$ 70.00	$ 119.00	70%
Municipal Water Pumping - TOU	$ 29.35	$ 43.00	47%
Municipal Water Pumping - VPP	$ 29.35	$ 43.00	47%
Power and Light	$ 79.00	$ 119.00	51%
Power and Light - TOU	$ 79.00	$ 119.00	51%
Large Power and Light - TOU - SL-1	$ 300.00	$ 400.00	33%
Large Power and Light - TOU - SL-2	$ 350.00	$ 400.00	14%
Large Power and Light - TOU - SL-3	$ 135.00	$ 160.00	19%
Large Power and Light - TOU - SL-4	$ 135.00	$ 150.00	11%
Large Power and Light - TOU - SL-5	$ 77.00	$ 120.00	56%

Q. DID THE COMPANY PROVIDE COMPARITIVE INFORMATION ABOUT OTHER SURROUNDING UTILITIES TO JUSTIFY ITS PROPOSED INCREASE IN CUSTOMER CHARGE?

A. Yes. Company witness Cash provided Direct Exhibit GC-2 which "provides a list of customer charges in Oklahoma for electric utilities that are investor owned, regulated cooperatives, and un-regulated cooperatives."[20]

Q. DOES DIRECT EXHIBIT GC-2 CONTAIN A LIST OF UTILITIES THAT ARE MOSTLY RURAL ELECRIC COOPERATIVES?

A. Yes. A majority of the utilities listed in Direct Exhibit GC-2 are rural electric cooperatives.

Q. ARE RURAL ELECTRIC COOPERATIVES A REASONABLE COMPARISON FOR THE COMPANY?

A. No. Rural electric cooperatives are not a reasonable comparison for OGE, an Investor-owned utility with a 2022 test-year revenue requirement of over $3 billion and whose service territory includes a metropolitan area with a population of over 1 million.

Many rural electric cooperatives have much lower consumer densities compared to investor-owned utilities. For example, the Oklahoma Association of Electric Cooperatives ("OAEC") reports an average number of active meters per mile of line as 5.82[21] for Oklahoma rural electric cooperatives. Conversely, the Company has a meter per mile rate of 17.99.[22] The customer density of the Company per mile of line is more than three times

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[20] Cash Direct 10:28–11:1; Direct Exhibits of Gwin Cash for Oklahoma Gas and Electric Company, Direct Exhibit GC-2 (Jan. 4, 2024).
[21] OAEC Key Facts (OAEC_KeyFacts_8.5x11_2024.pdf), Oklahoma Association of Electric Cooperatives, https://www.dropbox.com/scl/fi/oa6jm4wyd1wbw77d66cjk/OAEC_KeyFacts_8.5x11_2024.pdf?rlkey=rm9f3hdmou0nuplv96c51bnla&e=2&dl=0 (last visited May 2, 2024).
[22] Based on total customer count divided by total miles as provided in OGE's Response to PUD-OGE-2-4.

that of the average Oklahoma rural electric cooperative in the state and is clearly not a good comparison for customer charges.

Q. HAVE YOU PREPARED A REVISED COMPARISON TABLE WITH OTHER INVESTOR-OWNED UTILITIES INSTEAD OF RURAL ELECTRIC COOPERATIVES?

A. Yes. Table 3 below includes Investor-owned utilities as opposed to rural electric cooperatives.

Table 3 – Sample of Investor-owned Utilities and Fixed Charges

Investor Owned Utility	State	Fixed Charge
Ameren	MO	$ 9.00
Cleco Power LLC	LA	$ 9.00
Empire District Electric Co	MO	$ 13.00
Empire District Electric Co	OK	$ 14.11
Entergy Arkansas LLC	AR	$ 8.40
Evergy	KS	$ 14.25
Evergy	MO	$ 12.00
Oklahoma Gas & Electric Co	OK	$ 13.00
Public Service Co of Oklahoma	OK	$ 17.00
Southwestern Electric Power Co	AR	$ 11.97
Southwestern Public Service Co	NM	$ 11.20
Southwestern Public Service Co	TX	$ 12.45

Q. WHAT IS THE SOURCE OF DATA USED TO DEVELOP THE COMPARISONS IN YOUR TABLE 3?

A. Please refer to Exhibit FJB-2.

Q. WOULD THE COMPANY-PROPOSED INCREASE IN RESIDENTIAL CUSTOMER CHARGE TO $21.00 MAKE IT THE HIGHEST CUSTOMER CHARGE ON TABLE 3?

A. Yes.

VI. Conclusion

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. The Company proposes to update its allocation methodology for transmission expenses from a 4 CP demand to a 12 CP demand. I explained why this change is reasonable and follows cost causation principles for both Company-owned facilities and for SPP transmission charges.

Next, I discussed the Company's proposed allocator for owned wind resource costs. I discussed the importance of alignment in allocation of costs and benefits of owned wind resources. I pointed out that under a strict cost-of-service-based allocation method, most of the wind costs would be allocated to demand while most of the wind benefits would be allocated to energy, creating an imbalance between costs and benefits for customer classes with different load factors. I described a calculation I performed to determine that an allocation more heavily weighted toward energy would be appropriate for the owned wind resources. I therefore agreed with the Company that for these owned wind resource costs it is appropriate to use an allocation methodology that is heavily weighted toward energy instead of demand.

I also discussed the changes in planning requirements in the SPP and noted that the Company may soon face significant capacity planning requirements in winter months that could drive a portion of its capacity costs. I suggested that in future rate designs the

Company should consider a change in its production demand allocator because, under its current allocation methodology, the only months in which coincident peaks contribute to cost allocation are in the four summer months.

Finally, I commented on the Company's proposed increase in its customer charge on the residential class. The Company used a comparative analysis to support its proposed increase to the customer charge and compared its proposed customer charge to that of several other surrounding utilities, most of which were rural electric cooperatives. I indicated that rural electric cooperatives are not a reasonable reference point for comparison, and I provided an alternate table with more appropriate references to other surrounding investor-owned utilities. I pointed out that the Company's proposed increase in customer charge would make it the highest customer charge among utilities compared in the table.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS?

A. Yes. My testimony is limited to the express statements contained within. My testimony does not address every potential issue; therefore, my recommendations should not be construed as the only recommendations or requests that I may support in the record. Other recommended courses of action may be presented in the record of which I may support. In addition, the fact that I do not express an opinion on a particular issue should not be interpreted as agreement with or support for the Company's position on that issue.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

AFFIDAVIT OF FRANK J. BELING

STATE OF OK)
) **ss**
COUNTY OF OK)

I, Frank J. Beling, do hereby swear/affirm that the foregoing testimony is true and correct to the best of my knowledge and belief.

Frank J. Beling

Subscribed and sworn to/affirmed before me this 3rd day of May, 2024.

KATHLEEN TANKSLEY
NOTARY PUBLIC
COMM # 04000797
EXPIRES 1-28-2028
STATE OF OKLAHOMA

Kathleen Tanksley
Notary Public

My Commission expires on 1-28-28 ~~#0~~ 4000797

EDUCATION:

M.S., Mechanical Engineering, Washington University, St. Louis, 2009
B.S., Mechanical Engineering, Washington University, St. Louis, 2008

EXPERIENCE:

2007-Present: C. H. Guernsey & Company, Oklahoma City, Oklahoma

2023-Present:	Senior Vice President
2013-2022:	Vice President, Analytical Solutions Group
2008-2013:	Consultant
2007-2008:	Analytical Intern

Mr. Beling provides services to utility systems, specializing in wholesale rate design, power supply planning, and risk management. Mr. Beling has appeared before the Oklahoma Corporation Commission.

Rates

Mr. Beling provides wholesale rate design expertise utilities around the country, including to G&T cooperative and municipal clients. Mr. Beling assists in rate reviews to build consensus among participants and to identify relevant issues in rate design, then designs and recommends rate structures to meet client needs.

Mr. Beling provides expertise in areas such as rate unbundling, allocation of margin, alignment of rates with structured markets, cost of service analysis, tiered rate structures, interruptible / demand side management rates, market-based rates, standby/backup rates, etc.

Power Supply

Mr. Beling provides wholesale power supply analysis, including the evaluation and integration of thermal and renewable resources. Mr. Beling performs resource valuations in both bilateral and integrated markets; he also provides analysis of regulatory and environmental requirements.

Mr. Beling provides production cost modeling for system optimization and for regular budgeting processes.

Risk Management

Mr. Beling creates and implements risk management strategies for clients to understand and reduce exposure to markets. Mr. Beling works in power markets, gas markets, capacity markets, etc., and has helped implement risk management strategies for clients using physical and financial hedges to protect against potential unfavorable changes in market conditions.

Mr. Beling applies the principle of diversity in purchases and utilizes fundamental market analysis to assist clients in the formation of purchasing and hedging strategies.

SPECIFIC CONSULTING EXPERIENCE:

Wholesale Rate Design, Cost of Service, and Rate-Related Analysis

- 1803 Electric Cooperative, Baton Rouge, Louisiana
- Associated Electric Cooperative Inc, Springfield, Missouri
- Arizona Electric Power Cooperative, Benson, Arizona
- Basin Electric Power Cooperative, Bismarck, North Dakota
- Brazos Electric Power Cooperative, Waco, Texas
- Central Iowa Power Cooperative, Cedar Rapids, Iowa
- Corn Belt Electric Power Cooperative, Humboldt, Iowa
- Cooperative Energy, Hattiesburg, Mississippi
- East Texas Electric Cooperative, Nacogdoches, Texas
- Golden Spread Electric Cooperative, Amarillo, Texas
- Grand River Dam Authority, Vinita, Oklahoma
- Great River Energy, Maple Grove, Minnesota
- Hoosier Energy REC, Bloomington, Indiana
- Kansas Electric Power Cooperative, Topeka, Kansas
- Northwest Iowa Power Cooperative, Le Mars, Iowa
- Oklahoma Municipal Power Authority, Edmond, Oklahoma
- PNGC Power, Clackamas, Oregon
- South Texas Electric Cooperative, Nursery, Texas
- Upper Missouri Power Cooperative, Sidney, Montana
- Western Farmers Electric Cooperative, Anadarko, Oklahoma
- Wabash Valley Power Alliance, Indianapolis, Indiana

Power Supply / System Resource Planning

- Diverse Power (Georgia: SERC)
- Golden Spread Electric Cooperative (Texas: SPP & ERCOT)
- Grand River Dam Authority (Oklahoma: SPP)
- Greystone Power Corporation (Georgia: SERC)
- High Plains Power (Wyoming: WECC)
- Jackson Electric Membership Cooperative (Georgia: SERC)
- Mohave Electric Cooperative (Arizona: SRSG)
- Navopache Electric Cooperative (Arizona: SRSG)
- Poudre Valley Rural Electric Association (Colorado: WECC)
- Rayburn Electric Cooperative (Texas: ERCOT)
- South Texas Electric Cooperative (Texas: ERCOT)
- Trico Electric Cooperative (Arizona: SRSG)

Expert Witness / Regulatory Support

- Expert Witness / support for Oklahoma Attorney General:
    - OCC Case No. PUD 2017-267
    - OCC Case No. PUD 2022-121
    - OCC Case No. PUD 2023-086
    - OCC Case No. PUD 2023-087

- Independent Evaluator on behalf of Public Utility Division of Oklahoma Corporation Commission:
    - OCC Case No. PUD 2018-138
    - OCC Case No. PUD 2021-166
    - OCC Case No. PUD 2021-165
    - OCC Case No. PUD 2022-013
    - OCC Case No. PUD 2022-049

PUD 2023-000087
Exhibit FJB-2

Investor Owned Utility	State	Fixed Charge	Reference	Date Accessed
Ameren	MO	$ 9.00	ameren.com	4/11/24
Cleco Power LLC	LA	$ 9.00	cleco.com	4/11/24
Empire District Electric Co	MO	$ 13.00	libertyutilities.com	4/11/24
Empire District Electric Co	OK	$ 14.11	libertyutilities.com	4/11/24
Entergy Arkansas LLC	AR	$ 8.40	entergy-arkansas.com	4/11/24
Evergy	KS	$ 14.25	evergy.com	4/11/24
Evergy	MO	$ 12.00	evergy.com	4/11/24
Oklahoma Gas & Electric Co	OK	$ 13.00	oge.com	4/11/24
Public Service Co of Oklahoma	OK	$ 17.00	psoklahoma.com	4/11/24
Southwestern Electric Power Co	AR	$ 11.97	swepco.com	4/11/24
Southwestern Public Service Co	NM	$ 11.20	xcelenergy.com	4/11/24
Southwestern Public Service Co	TX	$ 12.45	xcelenergy.com	4/11/24

[redacted]