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	)	**CASE NO. PUD 2023-000087**
AUTHORIZING APPLICANT TO MODIFY ITS	)	
RATES, CHARGES, AND TARIFFS FOR RETAIL	)	
ELECTRIC SERVICE IN OKLAHOMA	)	

RESPONSIVE TESTIMONY

OF

MARK E. GARRETT

COST OF SERVICE AND RATE DESIGN ISSUES

ON BEHALF OF

OKLAHOMA INDUSTRIAL ENERGY CONSUMERS ("OIEC")

May 3, 2024

TABLE OF CONTENTS

I. WITNESS IDENTIFICATION AND PURPOSE OF TESTIMONY

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Mark E. Garrett. My business address is 4028 Oakdale Farm Circle, Edmond, Oklahoma 73013.

Q: WHAT IS YOUR PRESENT OCCUPATION?

A: I am the President of Garrett Group Consulting, Inc., a firm specializing in public utility regulation, litigation and consulting services.

Q: DID YOU PROVIDE TESTIMONY ON REVENUE REQUIREMENT ISSUES IN THIS CASE ON APRIL 26, 2024?

A: Yes.

Q: HAVE YOUR QUALIFICATIONS BEEN ACCEPTED BY THIS COMMISSION IN PROCEEDINGS DEALING WITH COST OF SERVICE AND RATE DESIGN ISSUES?

A: Yes, they have. A description of my qualifications and a list of the proceedings in which I have been involved are attached to my testimony filed April 26, 2024 as *Exhibit MG-1*.

Q: ON WHOSE BEHALF ARE YOU APPEARING IN THESE PROCEEDINGS?

A: I am appearing on behalf of Oklahoma Industrial Energy Consumers ("OIEC"). A description of OIEC and OIEC's interest in this proceeding was provided with my April

26, 2024 testimony.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: The purpose of my testimony is to address several important cost-of-service allocation and rate design issues. These issues include:

1. The allocation of transmission system costs;
2. The allocation of wind production costs;
3. The allocation of 1MW Customer Costs; and
4. OG&E's proposed Vegetation Management Tracker.

Regarding the first two issues, the Company is attempting to overturn two long-standing Commission-approved cost allocation methodologies for transmission and wind. Electric utility transmission costs have been allocated using a 4 Coincident Peak ("4CP") allocation since the mid-1990s. Wind generation has been allocated by this Commission using a 4CP allocation since 2008 when wind first came on Oklahoma's electric utility systems. A change in these allocators would move significant costs to the industrial customers, making their rates far less competitive. Such an arbitrary shift of costs onto many of the job-providers in the state would diminish the Commission efforts to foster economic development and promote job growth in our state. Further, it would raise questions as to the consistency and dependability of Commission regulatory policy by authorizing such a watershed change. It would also impose real harm to the customers that have relied on the Commission's sound cost allocation methods for many years.

Regarding the third issue, the allocation of costs to customers located outside of

OG&E's service territory, the Company apparently enticed these customers onto its system by paying their line extension costs and is now improperly allocating those costs to the captive customers inside the service territory for cost recovery. The under-recovered line extension costs for these customers should be paid by OG&E's shareholders as the Company has elected not to collect the line extension costs from such customers The costs clearly cannot be recovered from other customers already on the system. The Company's cost recovery scheme is anti-competitive and contrary to Oklahoma law.

Regarding the fourth issue, OG&E's proposed Vegetation Management Tracker meets none of the criteria for tracker recovery. Moreover, the proposed tracker is a classic example of objectionable piecemeal ratemaking. The tracker should be rejected.

II. ALLOCATION OF TRANSMISSION SYSTEM COSTS

Q: WHAT IS THE ISSUE REGARDING OG&E'S PROPOSED TRANSMISSION COST ALLOCATION?

A: OG&E proposes to change the allocation of transmission costs from a 4CP method to a 12CP method. OG&E's proposed change has been rejected by the Commission in prior litigated cases, as discussed below. The 4CP allocation has been used by OG&E and other electric utilities to allocate transmission costs in Oklahoma since 1996. and a departure from this method would require significant new rationale and support. The Company provides no such rationale or support in this case. OG&E is a summer peaking system and its generation costs are allocated on a 4CP basis; the delivery system for these costs – the transmission lines – should continue to be allocated in the same manner.

Q: PLEASE DESCRIBE THE COMMISSION'S DECISIONS ON THIS ISSUE IN PRIOR LITIGATED CASES.

A: On two separate occasions, Public Service Company of Oklahoma ("PSO") attempted to change its transmission cost allocation method to a 12CP allocation for transmission costs, and both of those attempts were rejected by this Commission. In Order No. 657877, in Cause No. PUD 201500208, the Commission specifically found that PSO's system is a summer peaking system, and that it is appropriate to use a 4CP method for transmission cost allocation.

> **Transmission Allocation (ALJ Initial Report at p. 156)**
>
> The Commission does not adopt the AL's recommendation that a 12 coincident peak (12CP) method to allocate PSO's transmission costs be used. Instead, the Commission finds that a 4CP method is appropriate for transmission cost allocation. The Commission finds that PSO's system is a summer peaking system, and that it is appropriate to reflect the cost to use the transmission system during the four peak periods of the year, rather than all twelve months.

Again, in Cause No. PUD 201700151, the Commission rejected the 12CP and made the following findings regarding this issue:[1]

> 140. THE COMMISSION FURTHER FINDS that in its retail cost of service study, PSO proposed to change its allocation of transmission costs for retail customers from a 4CP allocation to a 12CP allocation. (Exhibit 24, pp. 13-14.)
>
> 141. THE COMMISSION FURTHER FINDS that OIEC recommends PSO's class cost of service study be modified to retain the four Coincident Peak (4 CP) methodology for allocation of transmission costs to PSO's retail customers, rather than changing to a 12 Coincident Peak (12 CP)

[1] *See* Report and Recommendation of the Administrative Law Judge (Dec. 11, 2017), Cause No. PUD 201700151, accepted by the Commission in Order No. 672864.

> methodology. (Exhibit 124, pp. 4-9.) PUD also rejects PSO's proposed 12CP method for transmission cost allocation and notes that PSO made the same request in Cause PUD 201500208 with the Commission rejecting that requested change. (Exhibit 112, pp. 16-18.)
>
> 142. THE COMMISSION FURTHER FINDS that the data demonstrates and the Commission has determined that PSO is clearly a summer peaking system for retail load. (Exhibit 124, p. 5.) This is the reason that both PSO's production costs and its transmission costs have historically been allocated using a 4CP allocation methodology. (Id. at 6.)
>
> 143. THE COMMISSION FURTHER FINDS that PSO's proposed transmission cost allocation is rejected and, instead, approves PSO's continued use of the 4CP allocation methodology for transmission costs.

Q. HAS THE COMMISSION ALSO CONSISTENTLY UTILIZED THE 4CP ALLOCATION METHODOLOGY FOR OG&E'S TRANSMISSION COST ALLOCATION?

A. Yes. The 4CP allocation has been the longstanding allocation methodology for transmission costs for many years for both PSO and OG&E.

Q: WHAT METHODOLOGY DOES THE TEXAS PUBLIC UTILITY COMMISSION AUTHORIZE FOR ALLOCATION OF TRANSMISSION COSTS?

A: Like Oklahoma, the Texas PUC has a long-standing precedent of using a 4CP allocation for transmission costs.[2] In fact, PSO's sister utility in Texas, SWEPCO, has tried in two rate case filings to change from a 4CP method to a 12CP method, making similar

[2] Texas uses an Average and Excess 4 CP which gives virtually the same results as a straight 4CP.

arguments to those OG&E has made in this case. The Texas PUC rejected SWEPCO's attempt in Docket No. 40443, and again in Docket No. 46449, in which the ALJs stated:

> SWEPCO's arguments on the question of replacing the Commission's historically-approved A&E/4CP methodology with the 12CP methodology it proposed here and in its last rate case, Docket No. 40443, brings to mind the old adage that "you can't hit a home run unless you come to the plate." While SWEPCO may be applauded by some for continuing to advocate a method it believes best fits its system (particularly with reference to the manner in which SPP allocates transmission costs), it is also true that, as TIEC states, "if there is one constant in Commission ratemaking, it is the use of the A&E/4CP methodology for the class allocation of both production and transmission costs." The ALJs concur with TIEC.
>
> SWEPCO has not presented any persuasive evidence in this case that there are dispositive facts, or any real facts, that are different today than they were when the Commission decided Docket No. 40443.[3]

Q: DOES THE SAME PROBLEM EXIST IN TEXAS THAT PSO POINTS TO HERE?

A: Yes. OG&E's purported rationale for the change to a 12CP is based in part on the assertion that OG&E is a member of the SPP and the SPP allocates its costs using a 12CP.4 However, SWEPCO-TX is a member of the SPP and pays its SPP costs on a 12CP basis but it charges its retail customers on a 4CP basis because that is how they use the system, which is what matters in an allocation of *retail* system costs.

---

[3] *See* Texas PUC Docket No. 46449, Proposal for Decision, Sept. 22, 2017, p. 322; *aff'd.* Order, (Jan. 11, 2018), p. 46, ¶¶ 291-293, Order on Rehearing, (Mar. 19, 2018), p. 46 (requiring SWEPCO's continued use of A&E/4CP for allocating transmission costs as it "is standard and the most reasonable methodology.").

[4] Direct Testimony of Lauren E. Maxey at 18, lines 20-24.

Q: IN ADDITION TO ADHERENCE TO SOUND RATEMAKING PRINCIPLES, ARE THERE REASONS FROM A POLICY PERSPECTIVE THAT THE COMMISSION SHOULD CONTINUE TO USE A 4CP TO ALLOCATE TRANSMISSION COSTS?

A: Yes. If the other large electric utilities in Oklahoma and Texas allocate transmission costs using a 4CP allocation, OG&E's manufacturing customers will be put at a competitive disadvantage compared to the manufacturing customers on these other systems if OG&E is allowed to use a 12CP to allocate its transmission costs.

Q: ARE THERE REASONS FROM A LEGAL PERSPECTIVE WHY TRANSMISSION COSTS SHOULD BE ALLOCATED TO THE CUSTOMER CLASSES USING OG&E'S PRODUCTION COST ALLOCATOR?

A: Yes. OG&E is attempting to relitigate an issue that has long since been resolved by this Commission. In prior litigated rate cases, Cause Nos. PUD 2001500208 and PUD 201700151, PSO proposed a departure from the use of the 4CP methodology for transmission cost allocation. The Commission, however, rejected PSO's requests and reaffirmed its use of a 4CP-A&E allocation for transmission assets. This Commission has consistently allocated transmission cost using a 4CP demand allocator for both PSO and OG&E. The Company provides no new arguments or rationale to support its requested change from the Commission's longstanding treatment of this issue, nor does it provide any change in circumstance that would help justify a departure from longstanding precedent. Without these, it would be inappropriate for the Commission to repudiate its position on this issue.

Q: ARE THERE OTHER REASONS WHY THE COMMISSION SHOULD REJECT OG&E'S PROPOSED CHANGE IN TRANSMISSION COST ALLOCATION METHOD?

A: Yes. Customers must be able to rely on the Commission to be consistent on important issues such as this. Stability, consistency, and predictability are fundamental attributes in our system of law. These attributes allow people to conduct their lives more efficiently. Here, these attributes allow customers, especially large industrial customers, to rely on prior precedent and organize their business decisions accordingly.

Industrial customers make facility location decisions, based in large part, on the cost it takes to operate in one location versus another. Since electricity is one of the largest costs of a manufacturing facility, a great deal of focus is placed on the cost of electricity in one jurisdiction versus another. Moreover, most industrial customers are typically sophisticated in their understanding of the regulatory treatment of electric rates in the jurisdictions in which they operate.

Industrial customers are aware when regulatory commissions allow and maintain inter-class subsidies from industrial customers to the other classes and they are aware when commissions work to eliminate such subsidies. They are also very aware when a commission makes decisions that create subsidies to low-load factor customers, such as the subsidies OG&E is trying to create here. Many industrial customers have made the decision to site, maintain, or expand facilities in this state based on the low energy rates the electric utilities of this state have historically provided. It would be patently unfair to those companies for the Commission to change course at this point and take a very large step in the wrong direction, as OG&E recommends.

Q: WHAT IS THE IMPACT OF THE TRANSMISSION COST ALLOCATION CHANGE?

A: The increase this allocation causes in the industrial classes along with the percentage change in base rates is set forth in the table below.

Table 1: Customer Class Impacts from Proposed Transmission Allocation Change			
Customer Class	LPL-SL1	LPL-SL2	LPL-SL3
Amount of Increase[5]	$525,595	$3,632,992	$587,771
Percentage Increase in Rates[6]	3.947%	4.092%	2.419%

III. ALLOCATION OF WIND PRODUCTION COSTS

Q: PLEASE DESCRIBE THE ISSUE REGARDING THE ALLOCATION OF WIND GENERATION COSTS.

A: The Company currently allocates all wind production costs based on its production demand allocator, which is a four coincident peak ("4CP") average and excess ("A&E")

[5] See Direct Testimony of Lauren E. Maxey at 19 (Figure 8).

[6] Percentage increase in rates is calculated from the Company's Cost of Service Study (COSS) by dividing the increase by customer class provided in the testimony of Lauren E. Maxey, Figure 8, into the non-fuel rate revenues of each class in the COSS.

allocator ("4CP A&E").[7] The Company is proposing to change the allocation of wind production costs to a blended allocation of 84% energy and 16% demand, based on a recent partial stipulation filed in PSO Rate Case No. PUD 2022-000093,[8] in which the Commission approved a blended allocation for a new PSO wind facility. The wind allocation provision of the partial stipulation in that case, however, conflicts with long-standing Commission precedent, sound ratemaking principles and good public policy. Moreover, circumstances giving rise to the allocation provision of the PSO partial stipulation in that case are not present in OG&E's application here.

Q: PLEASE DISCUSS PRIOR CASES IN WHICH THE COMMISSION HAS DECIDED THE ALLOCATION OF WIND GENERATION COSTS/

A: In Cause No. PUD 200900031, the Commission determined that wind generation costs should be allocated using PSO's production cost allocator.

> The Commission finds that the wind energy costs should be allocated by the use of PSO's production cost allocator rather than an energy allocator as recommended by the ALJ in Findings paragraph 7. It is the Commission's understanding that PSO's production cost allocator contains components of both demand and energy and is therefore acceptable to allocate the costs of wind power.[9]

Again, in Cause No. PUD 201300188, the Commission found that wind generation costs should be allocated using a production demand allocation.

---

[7] Direct Testimony of Lauren E. Maxey at 14, lines 17-19.

[8] See Stipulation in PSO 2022 Rate Case, Cause No. PUD 2022-000093, accepted by the Commission in Order No. 738571.

[9] See PSO Rate Case, Cause No. PUD 200900031, Order No. 568769 at 2.

> THE COMMISSION FURTHER FINDS that the costs of the Renewable Energy Purchase agreements should be recovered through the Fuel Cost Adjustment Rider using PSO's Production Demand Allocator;
>
> IT IS THEREFORE THE ORDER OF THE COMMISSION that the Renewable Energy Purchase Agreements are hereby approved for cost recovery through Public Service Company of Oklahoma's Fuel Cost Adjustment Rider using PSO's Production Demand Allocator.[10]

Q: PLEASE DESCRIBE THE SPECIFIC CIRCUMSTANCES THAT WERE UNIQUE IN PSO'S LAST RATE CASE.

A: This wind allocation issue was partially litigated in PSO's last rate case, Case No. PUD 2022-000093. In that case, the Commission authorized a different allocation, other than the 4CP, for the Sundance Wind facility. The Commission authorized an 84% energy and 16% demand allocation of the Sundance facility – based on the recommendations of AARP – as a *pilot project* to further evaluate the allocation of wind.[11] Sundance was a new wind project that was coming into rates for the first time in that case. The Commission adopted a new allocation for the Sundance project on a trial basis, but left the allocation of all of the Company's other wind projects as they were being allocated using a 4CP allocation.

Q: IS THERE A NEW WIND PROJECT BEING ADDED TO OG&E'S SYSTEM IN THIS CASE FOR WHICH THE COMMISSION COULD CHANGE THE ALLOCATION ON A TRIAL BASIS?

---

[10] See PSO Rate Case, Cause No. PUD 201300188, Order No. 621229 at 9.

[11] See Final Order in Case No. PUD 2022-000093.

A: No. There is no new wind project coming onto the OG&E system in this case. Here, OG&E is attempting to change the allocation of all of its existing wind facilities.

Q: FROM A RATEMAKING PERSPECTIVE, WHY SHOULD THE COST OF WIND GENERATION BE ALLOCATED TO CUSTOMER CLASSES USING OG&E'S PRODUCTION COST ALLOCATOR?

A: From a ratemaking perspective, it would be inappropriate to carve out one type of generation asset and allocate its costs using a different methodology. For example, all of OG&E's generation plants are allocated using a 4 CP-A&E methodology. Base load plants are not allocated with one methodology to include more energy in the allocation, intermediate plants are not allocated with another method to include a mix of energy and demand and the peaking plants are not allocated with a third approach to include only demand. Instead, all generation plants are allocated with a 4CP average and excess methodology which already includes about 50% energy in the formula. This means base-load generation, intermediate generation, peaking plants and renewable energy plants are all allocated with the same formula, to recognize the fact that one type of generation should not be carved out and treated differently for the sole purpose of deriving a subsidy for the residential class.

Likewise, the allocation of energy costs is not based on the type of generation that produces the costs. For example, this Commission has not allocated the extremely high energy costs of the peaking units to the low-load factor classes that require their use – the residential and commercial classes primarily. Energy costs are averaged and have been allocated to all classes equally.

Consequently, all generation costs should be allocated using the same methodology without treating some generating units differently than others, just like all energy costs are allocated with the same method without making allowances for which classes actually cause their costs to be incurred.

Q: ARE THERE REASONS FROM A LEGAL PERSPECTIVE WHY WIND GENERATION SHOULD BE ALLOCATED TO THE CUSTOMER CLASSES USING OG&E'S PRODUCTION COST ALLOCATOR?

A: Yes. As discussed above, OG&E is attempting to relitigate an issue that has long since been resolved by this Commission. In prior litigated rate cases, Cause Nos. PUD 200900031 and PUD 201300188, PSO proposed a departure from the use of the 4CP methodology for wind cost allocation. The Commission, however, rejected PSO's requests and reaffirmed its use of a 4CP-A&E allocation for all generation assets. This Commission has consistently allocated wind using a 4CP production cost demand allocator for both PSO and OG&E.

OG&E provides no new arguments or rationale to support its requested change from the Commission's longstanding treatment of this issue, nor does it provide any change in circumstance that would help justify a departure from longstanding precedent. Without these, it would be inappropriate for the Commission to repudiate its position on this issue.

Q: SHOULD THERE BE CHANGED CIRCUMSTANCES OR NEW RATIONALE TO JUSTIFY A DEPARTURE FROM THE COMMISSION'S LONGSTANDING TREATMENT?

A: Yes. Customers must be able to rely on the Commission to be consistent on important issues such as this. Stability, consistency, and predictability are fundamental attributes in our system of law. Reliable precedent is important because it allows people, here ratepayers, to plan and conduct their affairs more efficiently. In short, the Commission's consistency in allocation methodology allows residential and commercial customers alike, and especially large industrial customers, to rely on prior precedent and organize their business decisions accordingly. Because OG&E has not demonstrated any new circumstance or raised any new argument, the Commission should be consistent and continue its longstanding allocation methodology.

Q: WHY IS IT PARTICULARLY IMPORTANT TO INDUSTRIAL CUSTOMERS THAT THE COMMISSION FOLLOW PRIOR PRECEDENT?

A: Industrial customers make facility siting decisions based in part on the cost it takes to operate in one location versus another. Moreover, most industrial customers are fairly sophisticated in their understanding of the regulatory treatment of electric rates in the jurisdictions in which they operate. They are aware when regulatory commissions allow and maintain inter-class subsidies from industrial customers to the other classes and they know those commissions that work to eliminate such subsidies. Many industrial customers have made the decision to site and maintain facilities in this state based on the low energy rates the electric utilities this state have historically provided. It would be patently unfair to those companies for the Commission to change course at this point and take a large step in the wrong direction, as OG&E proposes.

Q: FROM A POLICY PERSPECTIVE, WHY SHOULD WIND GENERATION BE ALLOCATED ON A PRODUCTION COST DEMAND BASIS?

A: Industrial customers are high load factor customers that use a great deal of energy. If the wind generation costs are allocated on an energy basis, this will shift significant costs on to the industrial customers, making these renewable resources an uneconomic source of power for them. In essence, the Commission would be promoting one industry in Oklahoma, the wind industry, at the expense of the manufacturing and oil and natural gas industries.

Q: WOULD THE WIND PROJECTS CURRENTLY LOCATED ON OG&E'S SYSTEM HAVE BEEN APPROVED IF THE COSTS WERE ALLOCATED ON AN ENERGY BASIS FROM THE START?

A: Likely, no. An energy allocation makes the wind costs uneconomic for large, high-load factor customers. I know that OIEC specifically supported Commission approval of these projects because the allocation was not punitive to the large customers. It would patently unfair, at this point, to change the terms of the projects that were either approved by the Commissions or agreed to by the parties.

Q: ASIDE FROM THE SUNDANCE WIND PROJECT, ARE PSO'S WIND GENERATION COSTS ALLOCATED USING A 4CP-A&E ALLOCATION?

A: Yes. Like OG&E, this has been the longstanding treatment authorized by the Commission for both PSO's and OG&E"s wind generation costs. It is important that this treatment remain consistent because, if other large electric utilities in Oklahoma allocate wind costs using a 4CP allocation, OG&E's manufacturing customers will be put at a competitive disadvantage compared to the manufacturing customers on these other systems if OG&E is allowed to use an energy-based allocation for its wind costs.

Q: WHAT IS THE IMPACT OF THE WIND ALLOCATION CHANGE?

A: The increase this allocation change causes the industrial classes along with the % change in base rates is set forth below.

Table 2: Customer Class Impacts from Proposed Wind Allocation Change

Customer Class	LPL-SL1	LPL-SL2	LPL-SL3
Increase Amount[12]	$698,370	$5,774,833	$1,014,957
Percentage Increase in Rates[13]	5.245%	6.505%	4.178%

[12] From OG&E's response to OIEC 4-02-Att1.

[13] Percentage increase in rates is calculated based on the Company's Cost of Service Study (COSS).

IV. TREATMENT OF 1 MW CUSTOMER COSTS

Q: PLEASE DESCRIBE THE ISSUE REGARDING THE ALLOCATION OF COSTS FOR CONNECTIONS TO CUSTOMERS LOCATED OUTSIDE THE SERVICE TERRITORY OF OG&E.

A: Under Oklahoma law, regulated utilities such as OG&E can extend service beyond its certified service territory to customers in an unincorporated area if the customer has a load greater than one Mega Watt ("1MW"). OG&E over the past several years has extended service to many such customers outside of its service territory. In its last rate case, pursuant to the Joint Stipulation reached in that case, OG&E agreed to file a cost of service study in this rate case that would treat the 1MW customers as a separate class of customers for cost allocation purposes. OG&E filed the 1MW cost of service study in this case but has declined to use it for ratemaking purposes. In other words, OG&E filed the 1MW cost of service study, but has elected to ignore its results.

Q: WHAT WERE THE RESULTS OF THE 1MW STUDY?

A: The 1MW cost service study showed that significant subsidies were being provided to the 1MW customers. In other words, a significant portion of the costs of the 1MW customers were being paid by other customers. The lion's share of the subsidy to the 1MW class is being paid by other large industrial customers in the Service Level 2 class. In short, the cost of service study showed that the 1MW customers were not paying their way on the system and their costs were being paid by other customers, potentially competitors. This raises significant concerns about the anti-competitive nature of OG&E's approach.

Q: WHAT RATE CLASSES ARE PAYING THE MOST SIGNIFICANT SUBSIDIES?

A: The 1MW cost of service study shows that the vast majority of the subsidy to the 1MW customers is coming directly from the Large Power and Light Service Level 2 ("LPL-SL2") class.

Table 3: OG&E's Proposed Subsidy to the 1MW Customers from LPL-SL2 Class		
	Amount of Subsidy to 1MW Customers	% of Base Rates Subsidizing 1MW
LPL-SL2	$3.5 Million	11.1%

As shown in the table above, 11% of OG&E's existing SL2 customers' base rates are nothing more than a subsidy to new 1MW customers to pay for OG&E's connection of new customers outside the service territory. This also means that the rates that SL2 customers pay are ***not*** just, reasonable and non-discriminatory rates, as required by law, because they are paying the electric costs of other large customers, sometimes their competitors.

Q: WHY IS THIS TYPE OF SUBSIDY OBJECTIONABLE FROM A POLICY PERSPECTIVE?

A: A subsidy such as the one with the 1MW customers is particularly objectionable because it is forcing manufacturing facilities, who already operate in an intensely competitive environment, to pay the electric costs of other large customers. In some cases, they are being forced to pay the electricity costs of their competitors. This flawed and patently unfair approach must be corrected.

Q: ARE THER OTHER REASONS THE SUBSIDY SHOULD BE CORRECTED?

A: Yes. The subsidy to the 1MW class is unlawful. 17 O.S. § 158 (F), which became effective November 1, 2023, requires (1) that 1MW customers be put into their own customer class and (2) that 1MW customers ***not*** be subsidized by other customers. The bill specifically states:

> F. [r]etail electric service providers are required to establish and utilize rate tariffs which are specifically applicable to a rate class of customers composed of electric consuming facilities ***being served*** under the 1,000 kw size exception found in subsection E of this section and located outside the service provider's certified territory.
>
> . . .
>
> For electric service providers that are rate-regulated by the commission, the rates supporting this rate class shall be determined in the rate-regulated service provider's most recent rate proceeding. Rates for this class shall be designed to recover (i) the cost extending service to the to the competitive load . . . and (ii) the allocated share of other costs associated with providing service to the electric consuming facility. Such tariffs shall be cost-of-service based and ***shall not subsidize other rate classes or be subsidized by other rate classes***.[14]

Q: IF THE LAW REQUIRES THAT THE 1MW CUSTOMERS BE PUT INTO THEIR OWN CUSTOMER CLASS, WHY DID OG&E CHOOSE NOT TO UTILIZE THE 1MW COST OF SERVICE STUDY THAT PUTS THESE CUSTOMERS IN A SEPARATE CLASS?

---

[14] See 17 O.S. § 158 (F) (Emphasis added).

A: OG&E apparently interprets the statute to require a separate class for these customers going forward.[15] So, it kept the existing 1MW customers on the system with the other customer classes thereby perpetuating their sizeable subsidies.

Q: IS THIS TREATMENT CONTRARY TO THE STATUTE?

A: Yes. It is. The language in the statute is clear. The statute requires that customers ***"being served"*** under the 1MW exception to be put into their own customer class, without any subsidies.

Q: CAN THE STATUTE BE INTERPRETED TO ONLY APPLY TO CUSTOMERS COMING ONTO THE SYSTEM UNDER THE 1MW EXCEPTION IN THE FUTURE?

A: No. The language is clear. It specifically applies to ***"customers being served"*** under the 1MW exception.

Q: IS IT INAPPROPRIATE TO APPLY THE STATUTE TO EXISTING CUSTOMERS?

A: Absolutely not. By placing these customers into their own separate class these customers

[15] See response to OAEC 01-09:

The Outside Certified Territory (OCT-1) tariff is applicable only to 1MW customers who have signed contracts for service after September 30, 2022. As of the filing of this case, OG&E has not signed a contract for service for a 1MW customer since October 1, 2022. Because there are no 1MW customers on the system subject to this tariff, nor are there any 1MW customers projected to be signed and/or active by the end of the 6 month pro forma period (March 31, 2024), there are no results for this class of customers in Schedules K, L or M.

will, on a going-forward basis, pay their own actual cost of service which is consistent with traditional ratemaking objectives.

Q: WHY IS THERE SUCH A LARGE SUBSIDY TO THESE CUSTOMERS RIGHT NOW?

A: OG&E's response to Data Request OAEC 1-02 shows the transmission and distribution investment cost that was required to extend service to the 1MW customers. It also shows the amount of these investments collected from the 1MW customers as a Contribution in Aid of Construction ("CIAC"). The response shows that OG&E spent $59.127M to extend service to these customers, but it collected only $0.996M in CIAC. This means that these customers paid about 1.64% of their costs to connect service.

Q: IS THIS IMPROPER?

A: Yes. It is highly improper. Typically, large customers, especially those with radial service (service to one customer), as is the case with many of these customers, pay most, if not all, of the costs incurred to extend service to them. Here, OG&E's new 1MW customers have paid virtually none of the costs to extend service.

Q: IS THAT A CONCERN?

A: Yes. My concern is that OG&E waived the CIAC charges for competitive load outside the certified service territory in an attempt to entice these customers onto OG&E's system. This approach is unfair to the electric providers that OG&E was competing with for this load. It is also unfair to the existing customers on the system expected to subsidize this scheme.

Q: WHO IS PAYING THE CIAC CHARGES OG&E FAILED TO COLLECT?

A: Under OG&E's proposed treatment, other customers in the LPL-SL2 class are paying the line extension costs for the new 1MW customers. That is why there is such an enormous subsidy revealed when the 1MW customers are put into their own rate class. Thus, not only did OG&E engage in anti-competitive behavior when it waived its CIAC charges to new 1MW customers to unfairly entice these customers onto the system, but it also further abused its monopoly power when it forced existing customers on the system to pay the line extension costs for these new 1 MW customers.

Q: IS OG&E'S CONDUCT DEFENSIBLE?

A: No. OG&E may assert that adding load to the system spreads system costs over a larger customer base, which reduces costs for all customers over time. However, that rationale is not valid. Here, the costs to other customers – that result from adding the 1MW customers to the system – are significantly higher, not lower. The costs allocated to the LPL-SL2 class alone are $3.47M higher because of the addition of these new customers. On a percentage basis, this means that the LPL-SL2 rates are 3.9% higher than they should be, due to OG&E's erroneous treatment of line extension costs

Q: WHO ARE THE WINNERS AND LOSERS FROM THIS SCHEME?

A: The losers in this flawed scheme are: (1) OG&E's existing customers, mainly SL2 customers, that are being forced to pay the line extension costs that the 1MW customers should be paying, and (2) the CO-OPS who lost the 1MW customers to OG&E, based on rates improperly and involuntarily subsidized by other customers. The winners are: (1) the 1MW customers who are paying rates far below their actual cost of service, and (2) OG&E shareholders who are reaping the profits from the capital investment expended to connect these customers.

Q: HOW MUCH ADDITIONAL PROFIT IS OG&E MAKING AS A RESULT OF ADDING THE 1MW CUSTOMERS?

A: The Company's response to OAEC 01-02-Att1 shows that OG&E spent about $59.127M in capital investment to connect the 1MW customers, and only collected $966,848 in CIAC charges, which is only about 1.64% of the total line extension costs. This means OG&E's capital investment level for the 1MW customers is about $59.161M. OG&E's profit on that amount is $2.967M per year.[16]

Q: IS IT TRUE THAT LPL-SL2 CUSTOMERS ARE OVERPAYING RATES BY $3.48 MILLION PER YEAR SO THAT OG&E CAN MAKE ADDITIONAL PROFITS OF $2.97 MILLION PER YEAR?

A: Yes, in a nutshell, that's it.

---

[16] $58.161M x 9.5% x 53.7% = $2.967M, using an ROE of 9.5% and a capital structure of 53.7%, from OG&E's last rate case, PUD 21-164, Order No. 728277.

Q: WHAT CAN BE DONE AT THIS POINT, NOW THAT THESE CUSTOMERS ARE ON THE SYSTEM?

A: These customers must be put into their own separate 1MW class. Further, that class must pay its full cost of service, so that other customers are not subsidizing them.

Q: SHOULD THE COMPANY'S 1MW COST OF SERVICE STUDY FROM OG&E WITNESS MAXEY'S TESTIMONY BE USED TO ACCOMPLISH THIS?

A: Yes, with some corrections. The 1MW COSS has at least one material error in it that needs to be corrected. Evidently, when OG&E allocated transmission costs to the 1MW class, it used an "average dollars/mile." This approach could significantly understate the transmission costs assigned to the 1MW class. The Company should provide the study with its rebuttal testimony to include the actual cost of the radial lines installed to serve these customers.

Q: WHAT WAS THE IMPACT OF THIS ERROR?

A: Because OG&E did not provide the necessary information requested in OAEC 6-1, I was not able to calculate the impact of this error. I reserve the right to supplement my testimony on this issue when the information becomes available.

Q: WHAT DO YOU RECOMMEND?

A: I make the following recommendations for the 1MW customers.

1. The Commission should order OG&E to correct its 1MW cost of service study to include actual radial-line transmission costs to the 1MW customers.

2. The Commission should order OG&E to put the 1MW customers into their own class for ratemaking purposes with no subsidies to or from the 1MW class.

3. OG&E's under-recovered line extension costs attributable to 1 MW customers should be recovered from the Company's shareholders.

4. The Commission should order OG&E to make a compliance filing using the corrected 1MW cost of service study updated to include all of the revenue requirement adjustments and cost of service allocations ordered by the Commission in this case, along with the resulting rate design and proof of revenues.

V. VEGETATION MANAGEMENT COST TRACKER MECHANISM

Q: WHAT IS OG&E'S PROPOSED VEGETATION MANAGEMENT TRACKER?

A: As discussed in Scott Norwood's direct testimony, OG&E is proposing to increase test year vegetation management expense by $28 million.[17] OG&E is also proposing approval of a Vegetation Management Tracker that would allow the Company to defer vegetation management expenses that are above or below the amount set in base rates.[18] The resulting deferred asset or liability, as the case may be, would then be presented for recovery in the Company's next general rate case.[19]

Q: IS THE PROPOSED TRACKER MECHANISM REASONABLE?

A: No. As discussed in Mr. Norwood's Direct Testimony in the revenue requirements phase of this proceeding, OG&E's request to increase the level of Distribution Vegetation Management O&M expenses by $28.0 million per year is unreasonable and unnecessary

17 See the Direct Testimony of OG&E witness Robert Shaffer, page 3.
18 See the Direct Testimony of OG&E witness Jason Thenmadathil, pages 18-19.
19 Ibid.

due to the fact that vegetation-related outage time on OG&E's system averages about 27 minutes per year, which equates to approximately .005% of total minutes per year, and is a very small impact on OG&E's system reliability.[20] Moreover, the Company does not expect its proposed increase in vegetation management spending to improve vegetation-related outage time in the future.[21]

Q: DO YOU HAVE CONCERNS WITH OG&E'S PROPOSED VEGETATION MANAGEMENT TRACKER?

A: Yes. The proposed Vegetation Management Tracker meets none of the ratemaking criteria for tracker recovery: it is not a cost outside the control of the utility, it is not a volatile cost, it is not a nonrecurring cost and it is not a cost that would cause substantial financial harm to the utility if not tracked. Moreover, the proposed tracker is a classic example of piecemeal ratemaking, because the Company would be allowed to defer and recover increases in a single category of expenses (i.e., vegetation management) without considering other cost increases and decreases in other categories. This type of piecemeal ratemaking is objectionable and should not be approved.

Q: WHAT ARE THE RATEMAKING CRITERIA FOR A TRACKER MECHANISM?

20 See the Direct Testimony of Scott Norwood, page 12.
21 See the Direct Testimony of Scott Norwood, page 13 and Exhibit SN-4.

A: According to the National Regulatory Research Institute's (NRRI) white paper published in 2009,[22] public utility commissions traditionally approve riders only under "extraordinary circumstances." Commissions consider cost trackers / riders an exception to the general rule for cost recovery and place the burden on a utility to demonstrate why certain costs require special treatment. According to the NRRI, the circumstances typically required for approval of riders occur when costs are:

(1) Largely outside the control of the utility;
(2) Unpredictable and volatile;
(3) Substantial and recurring; ***and***
(4) Causing severe financial consequences to the company.

Based on these criteria, fuel costs historically have been viewed as good candidates for rider recovery because fuel prices are largely beyond the utility's control, are volatile, recurring and significant in size. A second example could be storm-related expenses for costs incurred to restore power after a major weather occurrence. Such costs are generally considered to be emergency costs that are largely outside the control of management and are significant in size.

Q: DO YOU AGREE WITH THE NRRI CRITERIA?

A: Yes. I agree that these are the appropriate criteria to apply when evaluating a utility's request for rider treatment.

Q: DO THE VEGETATION MANAGEMENT COSTS MEET THESE CRITERIA?

22 Costello, Ken, NRRI, "How Should Regulators View Cost Trackers?" published in September 2009.

A: No. To qualify for rider treatment, the vegetation management costs would have to meet all of the NRRI requirements. OG&E's vegetation management costs, though, meet none of the requirements. Vegetation management costs are completely within the control of management, in that OG&E is completely in control of deciding both the type and timing of the money it spends on vegetation management. Moreover, vegetation management costs are not unpredictable and volatile. Instead, management knows precisely what the costs will be and when they will occur, making them both predictable and completely stable. And finally, the vegetation management costs are not so significant that they will cause severe financial harm to the Company, mainly because these costs can easily be addressed in periodic rate case proceedings.

Q: WHY IS IT IMPORTANT THAT A UTILITY DEMONSTRATE SEVERE FINANCIAL CONSEQUENCES OR HARDSHIP TO JUSTIFY TRACKER RECOVERY?

A: It is widely recognized that tracker mechanisms tend to reduce a utility's incentive to control costs. For this reason, commissions reserve tracker recovery for *extreme* or *special* circumstances where there is a risk to the financial health of the utility, such as storm cost of fuel cost recovery. In this case, OG&E has made no showing that special circumstances exist or that the OG&E would suffer financial distress without tracker recovery of its vegetation management costs.

Q: WHY IS PIECEMEAL RATEMAKING OBJECTIONABLE?

A: A basic ratemaking principle is that utility rates are set to recover the cost levels of a utility that exist within a given period of time, a test year.[23] The test year provides a "snap-shot" of the utility's, operating revenues and expenses, depreciation and taxes, and average investment level (rate base) in place to produce those revenues. As time passes after the test period, these revenue and cost levels change. Some operating expense levels may increase, but these increases are often offset to some degree by increases in revenue levels from customer growth or from decreases in other expense accounts driven by new efficiency gains or other cost-cutting measures.

Likewise, investment levels may increase with the addition of new plant, but these increases are generally offset to some degree with decreases from lower operating expense levels or higher revenues from customer growth. If, after rates are set, the utility earns more than its authorized return because either revenue increased and/or cost levels declined, the utility is allowed to keep the difference. If conversely, the utility earns less than its authorized return either because revenues declined and/or cost levels increased, the utility suffers the loss. This is the prudent management incentive (regulation substituting for the disciplines of the market), ratemaking paradigm utilized throughout the country. An important part of this paradigm is the risk element, the risk the utility assumes that it may not earn more, and perhaps will earn less, than its authorized return. It is this element of risk embedded in the paradigm that allows the utility's return on equity to be set at levels above that of risk-free capital. If, during the period new rates are in

[23] *See*, *e.g.*, Accounting for Public Utilities, Hahne and Aliff, §7.02.

effect, a utility wants to earn its authorized return, or more than its authorized return, it will have to operate its business in an efficient manner.

Q: ARE THERE OTHER REASONS PIECEMEAL RATEMAKING IS OBJECTIONABLE?

A: Yes. There is also a substantial issue of fairness when a utility seeks to recover an isolated set of cost increases without giving effect to the offsetting cost decreases that have also occurred. Utility rates must be both just and reasonable. Rates set in a piecemeal manner are not generally considered reasonable rates because they do not fairly take into consideration mitigating offsets leaving an imbalanced picture of a utility's overall financial situation. A few examples of commission decision about piecemeal ratemaking are set forth below.

The **Minnesota** commission described piecemeal ratemaking and its objections to piecemeal ratemaking in the following manner:

> There are sound reasons for traditional regulatory practice. Basing revenue requirements on financial data from a test year, a representative slice of the utility's normal operations, is intended to base rates on experience instead of conjecture. It is also intended to replace the fiscal discipline of the marketplace, which is absent for monopolies, with the fiscal discipline of prior determination of reasonable costs. Finally, it is intended to give utilities and ratepayers the assurance that their rates will not be changed retroactively. Only the most exigent circumstances would justify the radical departure from traditional regulatory principles the Transitional Rate Increase represents. The Commission does not believe the Company has established such circumstances here.
>
> The Company's Transitional Rate Increase proposal also runs counter to established regulatory policy against piecemeal ratemaking. Ratemaking involves a host of complex and interrelated issues: necessary operating, maintenance, and capital expenses, reasonable cost of capital, appropriate

> capital structure, reasonable revenue projections, proper attribution of the costs of providing service, fair return on investment. Rates are set in general rate cases because they provide the comprehensive review of a utility's financial situation necessary for understanding these issues and how they affect one another. Examining ratemaking issues in isolation produces a less accurate result than a comprehensive review. . .[24]

The **Missouri** commission described the problems with single-issue, or piecemeal, ratemaking in this manner:

> The law is quite clear that when the Commission determines the appropriateness of a rate or charge that a utility seeks to impose on its customers, it is obligated to review and consider all relevant factors, rather than just a single factor. To consider some costs in isolation might cause the Commission to allow a company to raise rates to cover increased costs in one area without recognizing counterbalancing savings in another area. Such a practice is justly considered single-issue ratemaking.[25]

The **Hawaii** commission described the objectionable aspects of piecemeal ratemaking in this way:

> In order to make this ultimate determination, it is necessary to match ordinary and necessary expenses with income from the same period, and determine whether the net income is sufficient to provide a reasonable return on allowable rate base. Single-issue rate cases do not allow for this determination of overall net income. They focus on the change in a single expense (or revenue) item since the last rate case, ignoring completely what changes may have taken place in the other factors of net income. To consider some costs in isolation may allow a company to essentially 'raise rates to cover increased costs in one area without realizing that there were counterbalancing savings in another area.'[26]

---

[24] *In re Application of Northern States Power Co., for Authority to Increase its Rates for Electric Service in the State of Minnesota*, 1990 Minn. PUC LEXIS 186, *9-12 (Nov. 26, 1990).

[25] *In re Utilicorp United Inc.'s Tariff Filed to Update the Rules and Regulations for Electric and to Increase the Interest Rate Paid on Deposits, the Late Payment Charge, and the Reconnection Fee, and the Charge for Returned Checks*, 2001 Mo. PSC LEXIS 966, *5-6, 10 Mo. P.S.C. 3d 227 (April 3, 2007).

[26] 2005 Haw. PUC LEXIS 584 at *31-32, quoting *State ex rel. Midwest Gas Users' Ass'n v. Public Service Comm'n*, 976 S.W.2d 470, 480 (Mo. Ct. App. 1998).

Q: WHAT IS YOUR RECOMMENDATION REGARDING OG&E'S REQUEST FOR APPROVAL OF A VEGETATION MANAGEMENT COST TRACKER?

A: I recommend that OG&E's requested Vegetation Management Tracker be rejected.

VI. SUMMARY OF RECOMMENDATIONS

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A: In this testimony, I make the following recommendations.

1. The Commission should authorize OG&E's allocation of transmission costs using a 4CP method.

2. The Commission should authorize OG&E's allocation of wind costs using a 4CP average and excess method.

3. The Commission should order OG&E to correct its 1MW cost of service study to include actual radial-line transmission costs to the 1MW customers.

4. The Commission should order OG&E to put the 1MW customers into their own class for ratemaking purposes with no subsidies to or from the 1MW class(es).

5. OG&E's under-recovered line extension costs attributable to 1 MW customers should be recovered from the Company's shareholders.

6. The Commission should order OG&E to make a compliance filing using the corrected 1MW cost of service study updated to include all of the revenue requirement adjustments and cost of service allocations ordered by the Commission in this case, along with the resulting rate design and proof of revenues.

7. The Commission should reject OG&E's proposed Vegetation Management Tracker.

VII. CONCLUSION

Q: DO YOU HAVE ANY FURTHER COMMENTS?

A: Yes. My testimony does not address every potential issue. The fact that I do not express an opinion on a particular issue is not to be interpreted as agreement with the Company's position on that issue.

Q: DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A: Yes, it does.

CERTIFICATE OF MAILING

This is to certify that on this 3rd day of May, 2024, a true and correct copy of the above and foregoing was emailed, addressed to:

Mr. Mark Argenbright
Mr. Geoffrey Rush
Public Utility Division
Oklahoma Corporation Commission
Jim Thorpe Building
2101 North Lincoln Boulevard
Oklahoma City, Oklahoma 73105
Mark.Argenbright@occ.ok.gov
Geoffrey.Rush@occ.ok.gov

Mr. Michael L. Velez
Mr. Michael S. Ryan
Mr. Justin Cullen
Mr. Jonathon Herndon
Ms. Nathasha Scott
Oklahoma Corporation Commission
P.O. Box 52000
Oklahoma City, Oklahoma 73152
michael.velez@occ.ok.gov
michael.ryan@occ.ok.gov
justin.cullen@occ.ok.gov
jonathon.herndon@occ.ok.gov
natasha.scott@occ.ok.gov
pudenergy@occ.ok.gov
Attorneys for the Public Utility Division

Mr. A. Chase Snodgrass
Ms. K. Christine Chevis
Ms. Ashley Youngblood
Utility Regulation Unit
Oklahoma Attorney General
313 NE 21st St.
Oklahoma City, OK 73105
chase.snodgrass@oag.ok.gov
christine.chevis@oag.ok.gov
ashley.youngblood@oag.ok.gov
utilityregulation@oag.ok.gov
Office of The Attorney General of Oklahoma

Mr. William L. Humes
Oklahoma Gas and Electric Company
P.O. Box 321, MC 1208
Oklahoma City, Oklahoma 73101
Humeswl@oge.com
Reginfor@oge.com
Attorney for Oklahoma Gas and Electric Company

Ms. Deborah Thompson
Mr. Kenneth A. Tillotson
Thompson Tillotson PLLC
PO Box 54632
Oklahoma City, Oklahoma 73154
deborah@ttfirm.com
kenneth@ttfirm.com
Attorneys for Oklahoma Gas and Electric Company

Mr. Jack G. Clark, Jr.
Clark, Wood & Patten, P.C.
3545 Northwest 58th Street, Suite 400
Oklahoma City, Oklahoma 73112
cclark@cswp-law.com
Attorney for OG&E Shareholders Association

Mr. Ronald E. Stakem
Cheek & Falcone, PLLC
6301 Waterford Boulevard, Suite 320
Oklahoma City, Oklahoma 73118
rstakem@cheekfalcone.com
jhenry@cheekfalcone.com
Attorney for OG&E Shareholders Association

Mr. J. David Jacobson
Jacobson & Laasch
212 E. 2nd Street
Edmond, OK 73034
Jdj8788@aol.com
Attorney for The Petroleum Alliance of Oklahoma

Mr. Adam Singer
Derryberry & Naifeh, LLP
4800 North Lincoln Boulevard
Oklahoma City, OK 73105
asinger@derryberrylaw.com
Attorney for AARP

Mr. Jeremy E. Melton
Trimble Law Group, PLLC
5510 N. Francis Ave.
Oklahoma City, OK 73118
jmelton@trimblelawgroup.com
Attorney for CMC Steel Oklahoma

Ms. Kayla D. Dupler
Attorney-Advisor
Administrative and Civil Law Division
Office of the Staff Judge Advocate
Bldg. 463 (Rm. 201)
Fort Sill, OK 73503
kayla.d.dupler.civ@army.mil
Attorney for The United States Dept. of Defense and all other Federal Executive Agencies (DOD/FEA)

Mr. Adam J. Singer
Derryberry & Naifeh, LLP
4800 N. Lincoln Blvd.
Oklahoma City, OK 73105
asinger@derryberrylaw.com
hdavis@derryberrylaw.com
Attorney for AARP

Mr. J. Eric Turner
Derryberry & Naifeh, LLP
4800 North Lincoln Boulevard
Oklahoma City, OK 73105
eturner@derryberrylaw.com
Attorneys for OAEC

Mr. Rick D. Chamberlain
P.O. Box 21866
Oklahoma City, OK 73156-1866
rick@chamberlainlawoffices.com
Attorney for Walmart Inc.

Maj. Leslie R. Newton
Ashley N. George
Thomas A. Jernigan
Ebony Payton
Rafael A. Franjul
USAF
139 Barnes Dr., Ste. 1
Tyndall AFB, FL 32403-5317
leslie.newton.1@us.af.mil
ashley.george.4@us.af.mil
thomas.jernigan.3@us.af.mil
ebony.payton.ctr@us.af.mil
rafael.franjul@us.af.mil

Scott A. Hodges, Colonel, USAF
Staff Judge Advocate
AFIMSC/JA
2261 Hughes Ave., Ste. 133
JPSA-Lackland, TX 78236
scott.hodges@us.af.mil
Attorneys for Federal Executive Agencies (FEA)

Thomas P. Schroedter