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	)	PUD 2023-000087
COMMISSION AUTHORIZING APPLICANT	)	
TO MODIFY ITS RATES, CHARGES, AND	)	
TARIFFS FOR RETAIL ELECTRIC SERVICE	)	
IN OKLAHOMA	)	

RESPONSIVE TESTIMONY OF MICHAEL P. GORMAN

ON BEHALF OF

THE FEDERAL EXECUTIVE AGENCIES

Scott A. Hodges attorney for the Federal Executive Agencies ("FEA"), hereby submits the Responsive Testimony of Michael P. Gorman in the proceeding referenced above.

Respectfully submitted,

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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	)	**CASE NO. PUD2023-000087**

Responsive Testimony and Exhibits of

Michael P. Gorman

for Cost of Service and Rate Design Issues

On behalf of

Federal Executive Agencies

May 3, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11603

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Responsive Testimony of Michael P. Gorman

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Responsive Testimony of Michael P. Gorman

I. INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am testifying on behalf of the Federal Executive Agencies ("FEA"), consisting of certain agencies of the United States government which have offices, facilities, and/or installations in the service area of Oklahoma Gas and Electric Company ("OG&E" or "Company"), from whom they purchase electricity and energy services.

Q WHAT IS THE SUBJECT MATTER OF YOUR RESPONSIVE TESTIMONY?

A In this testimony, I will address the following issues:

1. The Company's proposed spread of the revenue deficiencies across its various rate classes in this proceeding. As outlined below, I believe the spread of the increase across rate classes should generally follow the results of the most accurate class cost of service study ("COSS"), but limit changes in rate class increases to guard against excessive increases in any specific class while making a gradual movement toward cost of service.

2. I reject the Company's proposed Filed COSS for three reasons:

    a. It does not accurately allocate customer dedicated radial line distribution connections to 1 Megawatt ("MW") exception customers to the specific customers that benefit from these extraordinary connection costs. Rather, they are allocated to all retail customers.

    b. OG&E's proposal to use separate production demand allocators for Wind resources and Non-Wind resources is imbalanced and does not follow cost causation; it is not consistent with OG&E resource adequacy plans cost incurrence and it is not a cost-based allocation of production capacity cost.

    c. OG&E's proposal to change the transmission demand allocator to 12 coincident peaks ("CP") from 4CP does not accurately allocate transmission delivery capacity cost across OG&E's rate classes consistent with how the transmission capacity is used and needed to provide firm service to OG&E's retail rate classes.

3. I recommend a separate rate class for 1 MW exception customers.

4. I comment on the Company's proposed adjustments to peak and off-peak energy rates to the Power and Light ("PL") time of use ("TOU") rate. I recommend adjustments to component price changes that continue to enhance the price signal to reduce on-peak usage, which is consistent with the intent of a TOU rate structure.

5. My silence with regard to any position taken by OG&E in its application or direct testimony in this proceeding does not indicate my endorsement of that position.

II. SUMMARY

Q PLEASE SUMMARIZE YOUR RECOMMENDED REVENUE SPREAD ACROSS THE RATE CLASSES FOR THE REVENUE DEFICIENCY ULTIMATELY APPROVED BY THE COMMISSION.

A A comparison of the class revenue spread relative to current revenues based on the Company's proposal and my proposal is outlined in Table 1 below.

TABLE 1

OG&E vs. Gorman
Proposed Class Revenue Spread

Line	Rate Class	Base Non-Fuel Revenue at Current Rates	OG&E Proposed[1] Amount	OG&E Proposed[1] Percent	Gorman Proposed[2] Amount	Gorman Proposed[2] Percent
		(1)	(2)	(3)	(4)	(5)
1	RS	$646,246,336	$160,494,538	24.8%	$172,383,319	26.7%
2	GS	140,022,610	43,017,056	30.7%	41,653,867	29.7%
3	OGP	11,657,574	897,761	7.7%	1,475,300	12.7%
4	PS-S	9,849,699	1,530,589	15.5%	3,739,525	38.0%
5	PS-L	10,731,110	2,211,013	20.6%	4,074,161	38.0%
6	PL & PL TOU	294,181,231	67,364,987	22.9%	61,369,532	20.9%
7	LPL TOU	152,037,839	47,500,563	31.2%	31,725,444	20.9%
8	MP	4,276,858	841,119	19.7%	1,082,498	25.3%
9	Lighting	38,064,003	8,679,715	22.8%	12,341,325	32.4%
10	BK & Maintenance	320,316	414,120	129.3%	40,537	12.7%
11	LPL - 1 MW	$8,075,548			$ 3,065,953	38.0%
11	Total Retail	$1,315,463,124	$332,951,461	25.3%	$332,951,461	25.3%

Sources:
[1]Direct Testimony of Bryan Scott, Tables 1 and 2.
[2]Exhibit MPG-2.

As outlined in Table 1, my proposed revenue spread is based on what I believe to be the most accurate class COSS and employs a gradual movement to cost of service. For the reasons stated below, the Company filed two COSS: the Filed COSS and a 1 MW COSS. As a starting basis, I rejected the Company's Filed COSS and accepted the 1 MW COSS because it presents the most accurate cost of service for specific customers that were added to the system after 2014 and reflects extraordinary costs of interconnecting these customers to OG&E's retail system.

Despite the differences in recommended COSS, the Company's and my proposed spreads are comparable for Residential ("RS") and General Service ("GS") rate classes. My recommended spread allocates more cost to the Public Schools ("PS") rate classes and less cost to the Large Power and Light ("LPL") rate class. My recommended spread reflects the most reasonable COSS and should be adopted.

Q ARE YOU RECOMMENDING ANY MODIFICATIONS TO THE COMPANY'S PROPOSED RATE ADJUSTMENTS FOR THE PL AND LPL RATE CLASSES?

A Yes. I make several adjustments to the Company's proposed rate design. First, I recommend a separate rate class for the 1 MW exception customers served in the PL and LPL rate classes. A separate rate class is necessary to design rates for these customers that reflect the cost of interconnection of these customers to OG&E's system without seeking excessive subsidies from other OG&E customers.

I also recommend adjustments in the rate design for PL TOU rates specifically, to have a gradual systematic redesign of all these rates, while still maintaining strong price incentives to reduce consumption during on-peak periods. I am recommending a much larger increase in the on-peak energy rate for the PL TOU Level 2 and 3 customers compared to what the Company has proposed, and a reduction to the increase in demand charges, and off-peak energy charges. This will support a gradual realignment to the rate for PL Service Levels 2 and 3, but do so while still maintaining a strong economic incentive to reduce energy demands during on-peak periods.

III. SPREAD OF REVENUE DEFICIENCIES ACROSS THE RATE CLASSES

Q PLEASE DESCRIBE THE COMPANY'S PROPOSED SPREAD OF THE REVENUE DEFICIENCY ACROSS THE VARIOUS RATE CLASSES.

A The Company's proposed spread of the revenue deficiency across the rate classes is outlined in OG&E witness Bryan J. Scott's Direct Testimony. At pages 5 and 6 of Mr. Scott's testimony, in his Table 1 (Class Cost of Service Study Results) and Table 2 (Proposed Revenue Allocation), Mr. Scott demonstrated the increase in the results across various rate classes needed to move customers' rates to cost of service, and the Company's proposed gradual movement toward that objective. Mr. Scott, in presenting this, however, reviews the percent increase in the various rate classes based on "total" revenue.

I have revised Mr. Scott's allocation of the revenue increase across rate classes and restated it on "non-fuel" revenue rather than "total" revenue. The allocation of the proposed non-fuel revenue increase to each rate class is the same as that proposed by the Company, but the percentage increase to each class is different because it is based on non-fuel current revenue rather than total current revenue. The Company's estimated revenue increase needed to move to cost of service (Columns 2 and 3) and the proposed class revenue increase (Columns 4 and 5) stated as a percentage of increase in non-fuel revenue are shown below in Table 2

TABLE 2

OG&E Cost of Service Comparison
Filed COSS vs. 1 MW COSS

			OG&E Filed COSS[1]		1 MW COSS: Wind Prod and Trans Allocators Changed to 4 CP A&E[2]	
			Increase / (Decrease) to Reach Proposed Revenue		Increase / (Decrease) to Reach Proposed Revenue	
Line	**Rate Class**	**Base Non-Fuel Revenue at Current Rates**	**Amount**	**Percent**	**Amount**	**Percent**
		(1)	**(2)**	**(3)**	**(4)**	**(5)**
1	RS	$647,049,430	$160,494,538	24.8%	$174,527,655	27.0%
2	GS	140,178,520	43,017,056	30.7%	39,698,280	28.3%
3	OGP	12,155,292	897,761	7.4%	158,154	1.3%
4	PS-S	9,866,440	1,530,589	15.5%	7,330,656	74.3%
5	PS-L	10,748,530	2,211,013	20.6%	5,506,824	51.2%
6	PL & PL TOU	297,574,344	67,364,987	22.6%	58,488,324	19.7%
7	LPL TOU	158,074,089	47,500,563	30.0%	30,235,982	19.1%
8	MP	4,282,130	841,119	19.6%	539,254	12.6%
9	Lighting	38,068,923	8,679,715	22.8%	11,761,918	30.9%
10	BK & Maintenance	320,465	414,120	129.2%	(243,409)	-76.0%
11	LPL - 1 MW				$ 4,947,822	
11	Total Retail	$ 1,318,318,163	$332,951,461	25.3%	$332,951,461	25.3%

Sources:
[1]Direct Testimony of Bryan Scott, Tables 1 and 2.
[2]Exhibit MPG-2.

As shown in Table 2, the changes in cost of service for the RS and GS classes are small. Specifically, the increase to cost of service from current rates for the RS and GS classes increases from 24.8% to 27.0% for the RS class and decreases from 30.7% to 28.3% for the GS class. The change in the cost of service for the LPL class is much larger, changing from 30.0% under the Company's recommended COSS, to 19.1% under my recommended COSS.

Q IS OG&E'S PROPOSED REVENUE SPREAD REASONABLE?

A No. The primary issue I take with OG&E's proposed revenue spread is that both its Filed COSS and its 1 MW COSS are flawed. The Filed COSS is flawed in its failure to allocate extraordinary connection cost for 1 MW customers that were connected to its retail system after January 1, 2014. OG&E attempted to correct this deficiency in its 1 MW COSS. However, both the Filed and 1 MW COSS are flawed by an imbalanced allocation of wind production resources, and transmission capacity costs.

For the reasons outlined below, I am recommending the rejection of the Company's Filed COSS, and I propose modifications to the Company's 1 MW COSS to improve the balance in allocating production and transmission capacity costs across rate classes. These adjustments I propose to the Company's 1 MW COSS better align cost allocations with OG&E's system Integrated Resource Plan ("IRP"), cost incurrence, and more reasonably estimate the Company's cost of providing service across its rate classes. Based on this revised class 1 MW COSS, I recommend a moderated movement to cost of service across all rate classes. My proposed revenue spread, in comparison to my adjusted 1 MW COSS, is summarized in Table 3 below.

TABLE 3

1 MW COSS vs. Gorman Proposed Spread

Line	Rate Class	Base Non-Fuel Revenue at Current Rates[1]	1 MW COSS: Wind Prod and Trans Allocators Changed to 4 CP A&E[2]		Gorman Proposed Increase / (Decrease) to Reach Proposed Revenue[3]		
			Amount	Percent	Amount	Percent	Index
		(1)	(3)	(4)	(5)	(6)	(7)
1	RS	$646,246,336	$174,527,655	27.0%	$172,383,319	26.7%	1.05
2	GS	140,022,610	39,698,280	28.4%	41,653,867	29.7%	1.17
3	OGP	11,657,574	158,154	1.4%	1,475,300	12.7%	0.50
4	PS-S	9,849,699	7,330,656	74.4%	3,739,525	38.0%	1.49
5	PS-L	10,731,110	5,506,824	51.3%	4,074,161	38.0%	1.49
6	PL & PL TOU	294,181,231	58,488,324	19.9%	61,369,532	20.9%	0.82
7	LPL TOU	152,037,839	30,235,982	19.9%	31,725,444	20.9%	0.82
8	MP	4,276,858	539,254	12.6%	1,082,498	25.3%	0.99
9	Lighting	38,064,003	11,761,918	30.9%	12,341,325	32.4%	1.27
10	BK & Maintenance	320,316	(243,409)	-76.0%	40,537	12.7%	0.50
11	LPL - 1 MW	8,075,548	$4,947,822		$ 3,065,953	37.97%	1.49
11	Total Retail	$ 1,307,387,576	$332,951,461	25.5%	$332,951,461	25.5%	1.00

Sources:
[1]Direct Testimony of Bryan Scott, Tables 1 and 2.
[2]Oklahoma Gas and Electric filed 1 MW COSS
[3] Exhibit MPG-2.

As shown in Table 3 above, I recommend a gradual movement to cost of service produced by a minimum increase to all rates classes of 50% of the system average increase, and a maximum increase set at 150% of the system average increase.

In the remainder of my testimony, I outline the Company's deficiencies in its Filed COSS and 1 MW COSS, and then explain the reasons why I believe my modified 1 MW COSS reflects the most accurate measurement of class cost of service and should be used as the basis of measuring the spread of the revenue deficiencies across rate classes in this proceeding.

IV. OG&E FILED CLASS COST OF SERVICE STUDY ("FILED COSS")

Q PLEASE DESCRIBE OG&E'S FILED COSS IN THIS PROCEEDING.

A OG&E's presented two COSS that are presented by OG&E witness Lauren E. Maxey. Ms. Maxey outlines the Company's jurisdictional COS and two retail class COSS: (1) Filed COSS; and (2) 1 MW COSS. OG&E proposed the Filed COSS be used in this case. The 1 MW COSS was presented in response to the Commission order in OG&E's last rate case, but OG&E does not use this COSS to support adjustments to customers' rates in this case.

As demonstrated in Figure 6 of Ms. Maxey's testimony, both of the Company's COSS first functionalize costs between Production, Transmission, Distribution, Customer Service, and Administrative & General costs. The Company then classifies costs within each of these functionalized categories into number of customers, energy, and demand. Costs are also directly assigned to classes to the extent the costs reflect costs incurred to serve specific customers or customer classes. The difference between the Filed COSS and the 1 MW COSS concerns the allocation or direct assignment of specific interconnection costs for customers served pursuant to 17 O.S. § 158.25(E), which the Company titles "1 MW Exception" rule, which applies to new load initially served by OG&E after January 1, 2014. In the 1 MW COSS, the Company directly assigned radial line connections incurred to serve these customers served after January 1, 2014 directly to these 1 MW customers. In contrast, the Filed COSS simply includes these with distribution costs serving all customers and applies an allocation of these costs across the various customers.

Q DID MS. MAXEY ASSERT PRINCIPLES FOR JUDGING THE REASONABLENESS OF A COSS?

A Yes. Ms. Maxey states that her recommended criteria to judge the reasonableness of an allocation methodology[1] include:

1. Should reflect planning and operating characteristics of the system.
2. Should recognize individual customer class characteristics.
3. Should produce reliable results that are relatively stable.
4. Customers should benefit from the use of the system and should also bear appropriate cost responsibility for the system.

I agree with these principles in judging the reasonableness of a COSS.

Q DO YOU HAVE ANY CONCERNS WITH OG&E'S FILED COSS?

A Yes, I have two concerns. First, the Company's development of its Filed COSS in this case still does not resolve a dispute from its last rate case concerning the extraordinary costs to connect out of service territory 1 MW exception customers to OG&E's retail system.

In the Company's Filed COSS, it did not directly assign the extraordinary (radial line dedicated distribution) connection costs incurred to connect the 1 MW exception customers to OG&E's retail service area. Rather, in its Filed COSS, OG&E allocated these extraordinary radial line connection costs across all customers, despite the fact that these dedicated radial line connection investments are not used to provide service to non-1 MW exception customers but rather are dedicated extraordinary costs to connect specific 1 MW customers to its retail system. Hence, the Filed COSS is flawed because it harms the non-1 MW customers by allocating portions of extraordinary 1 MW customer connection costs to customers and rate

[1]Maxey Direct at 11.

classes that do not benefit and are not served by the 1 MW customer dedicated connection costs.

Second, the Company Filed COSS proposes two changes to allocators relative to how costs were allocated in COSS offered in prior rate cases. The first change concerns the allocation of production capacity cost allocation for wind resources, and the second change concerns the allocation of transmission capacity costs. The changes to the Production and Transmission demand costs are:

1. The Company is proposing a different production demand allocation factor for wind production resources compared to the production demand allocation for all other (non-wind) production capacity resources. In the last case, production capacity costs were allocated using the same demand allocator for all production resources. All production resources provide both capacity and energy benefits to customers and OG&E plans and operates its production resource portfolio to maximize these production benefits. OG&E's proposal to separate the capacity allocator of wind and non-wind resources does not reasonably nor accurately reflect how OG&E operates its production resources nor does it reflect its resource adequacy planning to provide reliable firm service while minimizing the operating energy costs of the production portfolio.

2. The Company is proposing to change its allocation of transmission capacity costs to a 12CP allocator from the 4CP allocator method that has been used in prior cases. The 4CP allocator reflects the load profile of OG&E's system and describes the amount of transmission capacity needed to provide firm service to its Oklahoma retail customers. The 12CP method is an allocation factor used in the Southwest Power Pool ("SPP") and describes how costs are allocated in the SPP. The SPP use of transmission services is not the same as OG&E's need for reliable transmission capacity. Hence, the proposed change in allocation of transmission capacity cost is not reasonable.

Below I will address each of these flawed aspects of the Filed COSS, and justify why this COSS should be rejected by the Commission for its failure to appropriately allocate the revenue deficiency across rate classes to adjust customer classes' rates to cost of service or provide a gradual movement of rates toward cost of service in this proceeding.

IV.A. 1 MW Customer Connection Costs

Q DID OG&E OFFER AN ALTERNATIVE TO THE COMPANY'S FILED COSS BASED ON DIRECTIONS FROM THE COMMISSION IN ITS LAST RATE CASE, TO ADDRESS THE DEDICATED COST OF SERVING 1 MW CUSTOMERS IN CASE NO. PUD 2021-000164?

A Yes. While the Company offered a 1 MW COSS based on the directions from the Commission in its last rate case, it is not recommending the Commission accept that COSS in this proceeding. Rather, Ms. Maxey states that the Commission should accept the Company's Filed COSS.[2]

Ms. Maxey sponsors the alternative 1 MW COSS, but she states the 1 MW alternative COSS was based on a disagreement by the parties in Case No. PUD 2021-000164. In that proceeding, certain parties took objection to the allocation of the interconnection costs for connecting the 1 MW customers to OG&E's retail system. The radial line investments needed to connect those new 1 MW customers to OG&E's retail system are being allocated over all OG&E's customers, rather than directly assigning these customer-specific connection costs across all rate classes per the Filed COSS. Hence, the Filed COSS does not accurately measure OG&E's cost of providing service to 1 MW customers nor does it accurately measure cost of service for the non-1 MW customers.[3] Therefore, OG&E's Filed COSS is flawed and unreliable.

[2]Maxey Direct at 21.
[3]*Id.* at 20.

Q IS OG&E'S RECOMMENDATION REASONABLE THAT ITS FILED COSS AND NOT ITS 1 MW COSS SHOULD BE ACCEPTED BY THE COMMISSION?

A No.

Q PLEASE DESCRIBE THE CUSTOMERS THAT FALL INTO THE 1 MW EXCEPTION CUSTOMER GROUP.

A The Company's 1 MW COSS provides details on various 1 MW customers.[4] In that COSS, the Company outlines significant radial line investments for 1 MW customers located in both Arkansas and Oklahoma. For Oklahoma, the largest investments for 1 MW customers are the LPL Service Level 2 rate class and the PL Service Level rate class, both taking service on time-of-use rates. In the Company's 1 MW COSS, it estimates the revenue for current 1 MW customers served in OG&E retail operations is approximately $8.1 million per year. However, the radial line costs reflect an average length of around 51 miles at an estimated installation cost of $11.8 million in the manner in which OG&E is estimating. Importantly, OG&E could not identify the actual costs of the radial line interconnect costs so it simply assumed the connection costs could be estimated based on the average installed cost of radial lines per mile for its system.[5]

[4]OG&E Okla PUD 2023000087 1MW.xlsx, 1MW COSS Tab: Radials.
[5]Response OAEC 01-08 and FEA 3-01 f (iv).

Q DID OG&E DEMONSTRATE THAT THE AMOUNT OF CONNECTION COSTS THE COMPANY SEEKS TO RECOVER IN COST OF SERVICE IS CONSISTENT WITH STANDARD SERVICE EXTENSIONS OUTLINED IN ITS TARIFF TERMS AND CONDITIONS OF SERVICE?

A No, it did not. Indeed, I requested that information from OG&E and it did not respond to the data request. Specifically, in response to FEA 03-01(iv.), the Company was asked to provide an analysis that illustrates the line extension costs to connect the 1 MW customers to its system was consistent with the Oklahoma Commission-approved tariff rate terms and conditions. In that response, OG&E stated that it outlined the expenditure calculations in a different data response, but neglected to provide any analysis demonstrating that the amount of line extension costs for 1 MW customers is consistent with the standard service extension rule costs in its tariff terms and conditions.

Q PLEASE DESCRIBE OG&E'S TARIFF RATE TERMS WHICH DESCRIBE STANDARD SERVICE EXTENSIONS.

A OG&E's tariff rate terms and conditions do address standard service extension included in the 6th revised Sheet No 144, paragraph 403 and Allowable Expenditure Formula ("AEF") paragraph 408. That Allowable Expenditure Formula determines an allowable interconnection cost based on a comparison of annual fixed revenue (annual revenue less Variable Operating costs) collection adjusted by a scaling factor. A scaling factor is attempted to determine whether the amount of margin revenue collected from the new customer when discounted back to the point of interconnection justifies the interconnection cost being recovered in cost of service.

OG&E has provided no evidence that the amount of radial line connection costs it seeks for 1 MW customers complies with this AEF tariff rate's terms and conditions.

Q DO OKLAHOMA RULES COMMENT ON COST OF SERVICE AND SEPARATE RATES FOR ADDING CUSTOMERS TO RETAIL SERVICE?

A Yes. Requiring 1 MW customers to pay their interconnection costs is consistent with the Enrolled House Bill No. 2845. In that bill, which describes practices for extending radial connection lines for certain electric suppliers in the state, it states in Section F as follows:

> F. To achieve the purposes of efficient, cost-effective retail electric service without duplication of electric facilities and to avoid unfairly shifting costs to residential consumers, retail electric service providers are required to establish and utilize rate tariffs which are <u>specifically applicable to a rate class of customers composed of electric consuming facilities being served in accord with the 1,000 kw size exception found in subsection E of this section and located outside the retail electric service provider's certified territory</u>. <u>These tariffs may be for a specific electric consuming facility or for a class of electric consuming facilities taking service under this provision.</u> For retail 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 rate class shall be designed to recover (i) the costs of extending service to the competitive load of electric consuming facilities of 1,000 kw or larger located outside the retail electric service provider's certified territory; 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. Unless costs of extending service to such a new load are collected from the customer, those costs shall be included in the cost of service study in the next rate proceeding. If the electric service provider, in whose certified territory the competitive load is seeking electric service, chooses in writing not to compete for said competitive load or does not respond within thirty (30) days of receiving written notice by the customer, the terms of this subsection shall not apply.[6]

[6]Enrolled House Bill No. 2845, Section 158.25 F. Emphasis added

Q IS OG&E'S PROPOSED ALLOCATION OF INTERCONNECTION COSTS FOR 1 MW CUSTOMERS CONSISTENT WITH THE COST-BASED RATES AS OUTLINED IN HOUSE BILL 2845?

A No, OG&E has not provided proof of its compliance with this rule. However, under the 1 MW COSS, the objective of directly assigning the interconnection costs to the 1 MW customers does meet the cost of service based standard addressed in the rule. OG&E should be obligated to estimate its actual costs, rather than simply approximate them based on the length of the line, and the average costs of its installed radial lines. To the extent these customers were installed more recently, and the costs of installed 1 MW customer radial lines exceed the average of historical costs, then OG&E's method of estimating its interconnection costs for 1 MW customers could be significantly understated.

Q HOW CAN OG&E'S FILED COSS BE CORRECTED TO ACCURATELY DIRECTLY ALLOCATE INTERCONNECTION COSTS FOR 1 MW EXCEPTION CUSTOMERS?

A In order to produce an accurate cost of service study, at a minimum, OG&E's Filed COSS should be rejected, and the Commission should use the 1 MW COSS, but with the adjustments to the allocation of production and transmission costs I describe next.

IV.B. Production Capacity Cost Allocation

Q PLEASE DESCRIBE THE CHANGES IN THE PRODUCTION DEMAND ALLOCATION FACTORS AND TRANSMISSION ALLOCATION FACTORS OG&E IS PROPOSING IN THIS CASE.

A Ms. Maxey also outlines specific changes the Company is proposing in this case relative to how it has filed class cost of service studies in prior cases. Those changes include the following:

1. She states that the Company proposes to allocate wind production resources using a blended demand allocator, and continue to allocate non-wind production capacity costs using the 4 coincident peak average and excess ("4CP A&E") allocator that has been used in the past.

2. The proposed blended wind production allocator classifies the production demand cost into energy and demand components. The energy/demand classification is based on the effective load-carrying capability of wind resources which estimates the percentage of nameplate capacity rating of the wind resource that is accredited and used to meet OG&E's resource adequacy obligation to the SPP. OG&E states that wind resource accredited capacity is around 16% of nameplate capacity rating based on the SPP Effective Load Carrying Capability ("ELCC") wind and solar study.

3. Based on this analysis, Ms. Maxey proposes a blended wind resource capacity allocator that is weighted 16% capacity and 84% energy. The capacity portion is allocated based on the 4CP A&E production capacity allocator, and the energy portion is allocated based on class generation level energy.

4. For transmission costs, Ms. Maxey proposes to use a 12CP allocator rather than OG&E's past practice of using a 4CP allocator. Ms. Maxey states the Company is doing this to be consistent with how SPP allocates transmission costs, using a 12CP allocator. She states that a 12CP allocator makes sense when one considers how SPP plans its transmission system. The difference in allocating transmission cost across rate classes by switching to the 12CP rather than the 4CP allocator is outlined in Figure 8 of her testimony at page 19.

Q WHY IS OG&E PROPOSING TO MODIFY ITS COSS AND USE A DIFFERENT PRODUCTION DEMAND ALLOCATOR FOR WIND AND NON-WIND PRODUCTION RESOURCES IN THIS CASE?

A OG&E witness Maxey states that this is reasonable because the Commission made a similar distinction in allocating production costs for wind facilities in a Public Service Oklahoma case in Order 738571, in Case No. PUD 2022-000093. Ms. Maxey goes on to state that the split between the demand and energy components is based on the ELCC methodology to correctly assess the capacity value of renewable resources. She cites the SPP ELCC wind and solar study report based on SPP resource adequacy from November 2022 in footnote 2 on page 15 of her testimony. Based on SPP criteria, she proposed composite allocators of 16% production demand and 84% production energy.[7]

Ms. Maxey goes on to state that a benefit of wind facilities is fuel savings. She maintains that high-volume users gain a larger share of these fuel savings, thus justifying a separate production cost allocator.[8]

Q IS THE COMPANY'S PROPOSAL TO USE DIFFERENT PRODUCTION CAPACITY COST ALLOCATORS FOR WIND AND NON-WIND PRODUCTION RESOURCES REASONABLE?

A No. The Company's proposal fails to meet the standards outlined by Ms. Maxey to ensure a fully allocated COSS is reasonable. Specifically:

1. Having two separate production demand allocations for wind and non-wind production capacity costs does not adhere to OG&E's production resource planning and operating characteristics of its production resources. At page 11 of Ms. Maxey's direct, she asserts that a criterion to judge the reasonableness of a COSS is whether it reflects the planning and

[7] Maxey Direct at 15.
[8] *Id*. at 16.

operating characteristics of the system. Two separate production demand allocators do not comply with this criterion and do not accurately allocate production capacity costs across rate classes in proportion to how costs are incurred and used to provide reliable firm service to customers.

2. In contrast, using a single production cost allocator is consistent with OG&E's resource planning to ensure its production resource portfolio is consistent with SPP's resource adequacy obligations, and the amount of resource capacity is designed based on accredited capacity of the various resources and not nameplate capacity, to ensure that OG&E does have adequate accredited capacity to reliably provide firm service to its customers. Second, OG&E operates its various production resource portfolio in a manner that minimizes energy costs across rate classes, but to have adequate production resource capacity to provide sustainable and reliable service to its customers while minimizing energy costs. From this standpoint, the 4CP A&E methodology more accurately allocates production resource capacity costs for all resource portfolio costs of OG&E that balances the need for capacity to provide sustained energy to the system, and have adequate capacity that is needed to serve demands in excess of average energy load up to peak demands .

3. The proposed composite allocator for wind facilities does not accurately allocate these costs on the energy and capacity classification proposed by Ms. Maxey. Rather, the capacity classified wind costs are themselves allocated on another composite energy/demand allocator, the 4CP A&E allocator. Hence, Ms. Maxey is allocating the wind resources on primarily energy, and the capacity benefit of the wind resources are largely not reflected in the allocation across rate classes.

4. Concerning the fuel savings produced through wind resources, Ms. Maxey is also overlooking the fact that the Company needs to invest in additional capacity to maintain the stability of fuel production in response to the inadvertent operating characteristics of wind and other renewable production resources. Further, because wind facilities' accredited capacity is very low in relationship to its nameplate rating, significant amounts of nameplate wind capacity are needed to meet the accredited capacity requirements of the OG&E system. With wind facilities reducing fuel costs to all customers, OG&E must invest in sufficient amounts of accredited capacity to maintain its ability to balance load, sustain energy delivery during periods where inadvertent resources are unexpectedly not available, and to assure it has adequate capacity that can respond to variations in environmental, market and customer demands and still maintain high quality and reliable service to customers. Stated more succinctly, customers pay very high resource portfolio capacity costs for the economic fuel savings, and to also receive reliable firm service. The resource portfolio costs are coordinated in the total resource portfolio costs. It is not accurate nor reasonable to separate the resource portfolio costs to assume energy benefits to wind resources without regard to the increased capacity cost needed for system balancing and serving peak demand.

Q PLEASE EXPLAIN WHY USING A DIFFERENT PRODUCTION COST ALLOCATOR FOR WIND AND NON-WIND FACILITIES DOES NOT FOLLOW THE COST INCURRENCE AND SYSTEM RESOURCE PLANNING CONDUCTED BY OG&E.

A I state this based on clear statements in OG&E's own IRP filed in 2024. While this is a draft plan, it clearly does not distinguish the need for designated amounts of accredited production capacity regardless of whether the production resource is a wind or non-wind resource. In the draft Executive Summary, OG&E specifically describes its production resource planning in its draft IRP as follows:

> OG&E plans to meet future capacity needs through a balanced portfolio of solar resources, and hydrogen-capable combustion turbines that provide affordable costs for customers while satisfying IRP objectives. OG&E will also seek market opportunities for intermediate capacity needs.[9]

Further, OG&E states that it plans its resource portfolio to balance its resource portfolio's limitations and satisfy its capacity needs:

> The IRP analysis contained in this report evaluates a range of potential generation portfolios to meet the capacity needs and determines a balanced portfolio of solar resources and combustion turbines is the preferred plan to satisfy expected capacity needs. This plan helps maintain system resiliency and reliability, advances fuel and technology diversity of the generation fleet, improves operational flexibility, is scalable, and expands OG&E's renewable generation portfolio. Adding zero-emitting technologies along with high-efficiency combustion turbines that enable and support renewable generation growth are important building blocks to meet expectations for cleaner energy in the future. [10]

Further, in its draft IRP, OG&E goes on to state that over the next five years, load growth, unit retirement and changes in resource adequacy policy will result in the need for additional generating capacity to meet OG&E's planning

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[9]Draft OG&E 2024 IRP, provided in OG&E's response to DR PUD 04-02(b), Executive Summary, at page i.
[10]Draft OG&E 2024 IRP, provided in OG&E's response to DR PUD 04-02(b), Executive Summary, at page i.

reserve margins ("PRM"). To meet its PRM, OG&E measured its peak native load obligation plus a PRM, in comparison to its production resource portfolio accredited capacity using SPP capacity accreditation protocols for <u>all</u> production resources, not just wind resources. OG&E plans its resource portfolio to manage capacity needs to achieve operational flexibility and resiliency benefits:

> V. H. 1. Operational Flexibility and Resiliency Benefits
>
> Wind generation capacity in SPP has grown significantly over the past five years to approximately 33 GW20 as of the end of August 2023 and the growth of wind generation capacity in SPP is expected to continue in the future. SPP also expects growth in solar generation resources and energy storage resources over the next decade. Combustion turbines complement the intermittency of renewable generation to support reliability during renewable output fluctuations and can respond quickly in the SPP Integrated Marketplace.
>
> SPP recognizes the need for and importance of resources with ramping capability to support reliability. Within the past year, SPP has presented options to address ramping flexibility. "…ramp is critical to serving load under fast-changing conditions; more than adequate capacity is needed; the capacity must be rampable when intermittent resources rapidly reduce."[11]

SPP includes a performance-based accreditation ("PBA") methodology for conventional resources, and an ELCC for renewable resources. In determining OG&E's portfolio generating resources capacities' ability to meet peak demand plus a PRM, it employs these methodologies to determine whether its actual capacity resources are sufficient to serve peak demand plus a PRM.

Hence, in allocating production resources based on the accredited capacity versus nameplate capacity rating as outlined by Ms. Maxey, applying this method only to wind resources ignores the fact that SPP requires OG&E to invest in sufficient amounts of accredited capacity to reliably serve load and to plan for a resource portfolio that has the operating flexibility to resiliently respond to

[11]Draft OG&E 2024 IRP, provided in OG&E's response to DR PUD 04-02(b), at page 53 (footnotes omitted).

variability of resources. Hence, production resources are planned on a portfolio basis to achieve the complex goals of serving energy, serving peak demands, and to have operating flexibility to respond to variability in resource outputs.

OG&E does not plan resources' capacity separately for wind and non-wind capacity, but rather plans its resources on a portfolio basis to reliably and economically serve customers' demands.

Q HOW DOES THE NAMEPLATE CAPACITY RATING FOR ALL OF OG&E'S PRODUCTION PORTFOLIO COMPARE TO ITS SPP ACCREDITED CAPACITY RATING BASED ON SPP'S RESOURCE PLANNING PBA MEASUREMENTS?

A A comparison of nameplate capacity to accredited summer and winter capacity based on the SPP PBA ratings for all of OG&E's owned and firm purchased power agreement ("PPA") capacity resources is outlined in my Exhibit MPG-1.

As shown in this exhibit, all of OG&E's production resources included in its production portfolio have a nameplate capacity, and an accredited capacity rating in both summer and winter periods. As noted by OG&E in its filing, the percentage of accredited capacity to nameplate capacity for wind resources is approximately 14%.[12] However, the ratio of accredited capacity to nameplate capacity for non-wind resources is around 87.5%. The entire resource portfolio (wind and non-wind) of OG&E resources is about 81%.

[12]Maxey Direct at 16.

Q CAN YOU DESCRIBE THE SIGNIFICANCE OF THE DIFFERENCE BETWEEN THE ACCREDITED CAPACITY AND THE NAMEPLATE CAPACITY THAT OG&E MUST MANAGE IN MEETING ITS SPP RESOURCE ADEQUACY OBLIGATIONS?

A Yes. As noted above, OG&E must invest in adequate amounts of resource accredited capacity such that its peak demand plus a PRM can be reliably served. Hence, if OG&E invests in wind resources which have accredited capacity versus a nameplate capacity ratio of 14%, and it needs 10 MW of accredited capacity to meet the SPP resource adequacy obligation, then OG&E would need to invest in approximately 70 MW of nameplate wind capacity to have 10 MW of accredited capacity.[13] In contrast, for its non-wind resources with a 87.5% ratio of accredited/nameplate capacity, to increase its accredited capacity by 10 MW, OG&E would have to invest in approximately 12 MW of nameplate capacity.

The point being OG&E must invest in enough accredited capacity to meet its peak demand plus a PRM. It does not matter whether the portfolio is a wind resource or a non-wind resource, or a combination of wind and non-wind resources. OG&E must plan and invest in enough accredited capacity to comply with the SPP resource adequacy requirement. To meet SPP's resource adequacy obligation, OG&E must invest in enough resource nameplate capacity rating to have adequate accredited capacity to meet its targeted peak demand plus the PRM.

Further, adequate accredited capacity for all the resources is also needed to balance the system because renewable resources, both wind and solar, can suddenly stop producing energy if the wind stops blowing or the sun is not shining. Under these conditions, other capacity resources are necessary to quickly make up for the lost energy requirement, to ensure that the Company can balance its energy supply

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[13]Nameplate capacity of 70 MW times an accredited capacity ratio of 14% indicates that this resource provides approximately 10 MW of accredited capacity.

with its energy demands and do so while managing energy costs to customers. To disregard how the resource portfolio operates wind and non-wind production resources in harmony does not reasonably allocate the cost of the portfolio of resources which are able to meet peak demand, manage energy balancing, and manage energy costs, and spread these costs across rate classes in the most reasonable and balanced manner possible.

Q PLEASE EXPLAIN WHY THE 4CP A&E PRODUCTION CAPACITY COST ALLOCATOR REASONABLY ALLOCATES ALL PRODUCTION RESOURCE PORTFOLIO COSTS INCLUDING BOTH WIND AND NON-WIND RESOURCES.

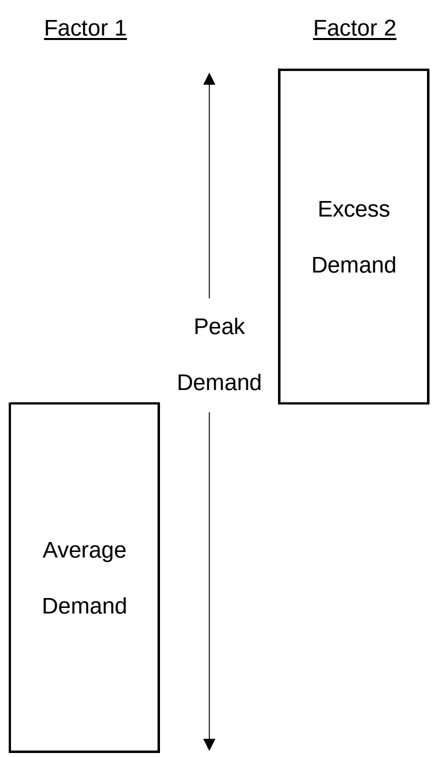
A As outlined in more detail below, the 4CP A&E allocator outlines the Company's total production portfolio resource capacity across rate classes based on separating that capacity into two buckets. The first bucket is the amount of capacity necessary to meet average energy demands of the customer classes. The second bucket is the additional capacity needed to serve demands in excess of the average energy demand, up to the peak period demands on the system. Hence, the 4CP A&E production allocator is itself a hybrid allocator used to allocate costs across rate classes based on capacity needed to serve average energy demands, and additional capacity needed to serve peak demands. The 4CP A&E production allocator by separating capacity costs into the two buckets provides a reasonable assessment of the resource accredited capacity that is needed to manage the Company's ability to serve energy demands, a need for capacity to respond quickly to inadvertent loss of certain production resources, and to have adequate capacity to serve peak demands of the system. A more detailed assessment of the 4CP A&E and how it accomplishes all of these resource portfolio obligations is described below.

Q PLEASE EXPLAIN WHY THE 4CP A&E PRODUCTION DEMAND ALLOCATOR IS ALREADY A COMPOSITE BETWEEN SERVING ENERGY AND DEMAND.

A The A&E production demand allocator allocates total system capacity in two blocks: (1) the first block is the amount of total system accredited capacity that is needed and used to serve average system demands or energy; and 2) the second block is the amount of additional capacity needed to serve demands in excess of the average energy demand up to peak demands. The two blocks used to develop the A&E allocators are shown graphically in Figure 1 below .

Figure 1

Average & Excess Method



Average & Excess =

(LF x Factor 1) + (1 - LF) x Factor 2

Peak Demand = Average Demand + Demand in Excess of Average

Hence, the Average & Excess production allocator is a composite allocator that weights energy demand and the need for capacity in excess of average to serve peak demands. As outlined above, a resource portfolio is designed to serve energy demands from reliable resources, and to have an adequate accredited capacity to also serve peak demands, hence, to analyze the capacity resources needed for both serving energy and serving peak demand. Hence, it most accurately describes the objectives outlined by OG&E in producing its IRP.

Q WOULD IT BE APPROPRIATE AND CONSISTENT WITH OG&E'S RATIONALE FOR WIND RESOURCES TO SIMPLY CONTINUE TO ALLOCATE ALL PRODUCTION RESOURCES USING A 4CP A&E ALLOCATOR?

A Yes. As outlined above, the 4CP A&E allocator is already a composite allocator. A 4CP A&E allocator for OG&E separates total production resource capacity needed to meet SPP resource adequacy obligations into an energy component, and a component that represents additional capacity needed to serve demands above average demand, up to peak demand. The amount of total capacity that is allocated on a pure energy component is set at the Company's load factor, or around 56%. The remaining 44% of the capacity is then allocated based on the additional capacity needed to serve customers' demands in excess of average energy demand, up to peak period demands.

Hence, the 4CP A&E is already a composite allocator and already reasonably reflects the Company's use of its production portfolio to serve both average energy demands and to serve additional demands in excess of average up to peak demand. Using the same production capacity cost allocator for all production resources also aligns with OG&E's system portfolio resource planning, which does not distinguish between production resources, other than to the extent to accurately measure the amount of accredited capacity for each of the production resources, which can vary relative to nameplate capacity for the various resources. But importantly, the amount of capacity OG&E must invest in to meet its SPP resource capacity obligation is tied to the accredited capacity rating of its various resources.

V. PROPOSED COMPOSITE WIND PRODUCTION ALLOCATOR IS FLAWED

Q PLEASE COMMENT ON THE REASONABLENESS OF OG&E'S PROPOSED NEW COMPOSITE PRODUCTION ALLOCATOR FOR WIND RESOURCES.

A OG&E develops a composite allocator based on its classification of wind resource production costs being classified as energy (84%) and capacity (16%). OG&E then develops a composite allocator using an energy weight times generation level energy consumption across rate classes, and a capacity weight using a 4CP A&E production capacity allocator.

The flaw in this methodology is a 4CP A&E production allocator is itself a composite allocator that considers the production capacity needed to serve average energy demands, and additional capacity needed to serve above average demand up to peak demand. Hence, OG&E's proposed "composite" wind resource allocator is flawed because it does not use a pure capacity allocator for accredited capacity classified costs, but rather uses another capacity/energy composite allocator – the 4CP A&E.

Q IS OG&E PROPOSING TO CHANGE THE ALLOCATION OF TRANSMISSION CAPACITY COSTS IN THIS PROCEEDING?

A Yes. OG&E proposes to change from a 4CP A&E allocation of transmission costs that aligns with its production resources to a 12CP allocation of transmission resources. OG&E witness Maxey states that this changed transmission allocator aligns with how SPP allocates transmission costs across its system and aligns with how SPP incurs transmission costs.[14]

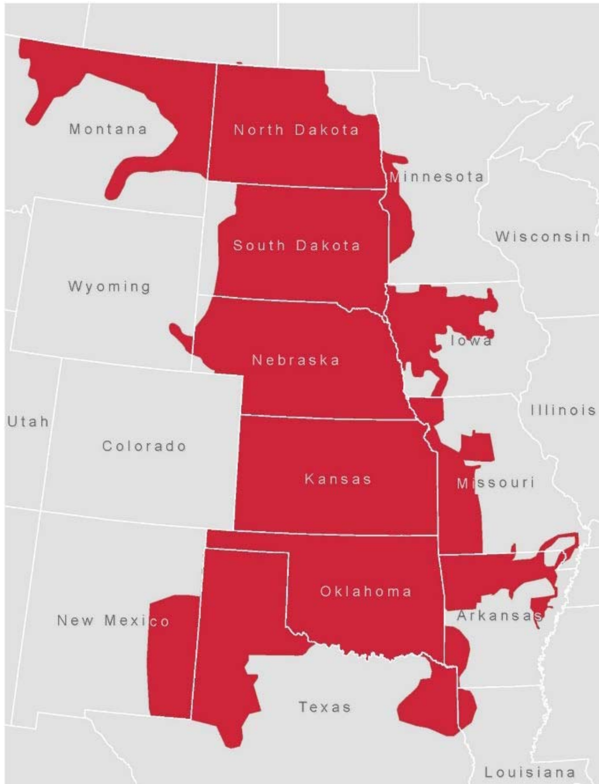
Q IS THE CHANGE IN ALLOCATION OF TRANSMISSION CAPACITY COSTS REASONABLE FOR OG&E?

A No. OG&E and SPP have very different service territories, and the planning and use of transmission capacity are also different. For example, SPP's footprint ranges from the westernmost portion of the Eastern Interconnection with Midcontinent Independent System Operator ("MISO") to the east, to the Electric Reliability Council of Texas to the south, the Western Interconnection to the west, and up to Canada in the north. SPP provides a map of its service territory of its footprint operating in the U.S. as shown in Figure 2 below.

[14]Maxey Direct at 17-18.

Figure 2

SPP Market Footprint and RTO/ISO Operating Regions



[15]

SPP's footprint includes service area loads that have winter peaking demands such as in North and South Dakota, which is very different than service territory such as OG&E that has a very distinct demand during the summer. Further, OG&E is planning transmission resources specifically for its ability to meet its reliable firm service obligations to customers, and to effectively operate its own resource portfolio, and to buy and sell into SPP. In contrast, SPP designs its transmission system to provide reliable service across its entire footprint, to alleviate fuel congestion rates across its region, and to have adequate transmission capacity to move carbon-free renewable resources throughout SPP, and into other market regions. Its design of

[15] "State of the Market 2022," Southwest Power Pool, Inc. Market Monitoring Unit presentation, Figure 2-1, page 25.

transmission capacity and its related costs do not reflect OG&E's load characteristics of customers' demand on the system, and do not simply relate it to the provisions of reliable firm delivery transmission service that allows for meeting reliable peak demands on the system, and effectively relying on the use of OG&E's load specifically.

SPP states it operates an Integrated Marketplace within its footprint. SPP states that it is authorized by the Federal Energy Regulatory Commission ("FERC") to ensure reliable power supplies, adequate transmission infrastructure, and competitive wholesale electricity prices. SPP states that it provides many services to its various members including tariff administration, regional scheduling, reserve sharing, transmission expansion planning, wholesale electric market operations, and training.

Q HOW DOES OG&E DESCRIBE ITS TRANSMISSION PLANNING WITHIN ITS 2024 IRP?

A OG&E does acknowledge that the SPP largely controls its transmission planning, but SPP planning is designed for multiple factors necessary to maintain a viable integrated marketplace. Further, transmission planning and investments occur across the entire region, and can benefit participants in SPP for various factors including reliability, fuel diversity, fuel efficiency, and the benefits of market participation.

OG&E describes this SPP planning process in its draft 2024 IRP as follows:

> VIII. C. Transmission Capability and Needs
>
> OG&E's transmission system is directly interconnected to seven other utilities' transmission systems at over 50 interconnection points. Indirectly, OG&E is connected to the entire Eastern interconnection through the SPP regional transmission organization. The SPP footprint covers 552,000 square miles, serves over 19 million customers, and has members in 14 states across all of Kansas and

> Oklahoma and parts of Arkansas, Colorado, Iowa, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, South Dakota, Texas, and Wyoming. In compliance with FERC Order 890 for transmission planning, SPP performs annual expansion planning for the entire SPP footprint. OG&E provides input to the SPP planning process, and SPP is ultimately responsible for the planning of the OG&E system.[16]

Q DOES CHANGING FROM A 4CP ALLOCATION OF OG&E'S TRANSMISSION CAPACITY TO A 12CP ALIGN WITH OG&E'S NEED TO PROCURE ADEQUATE TRANSMISSION CAPACITY TO SERVE ITS RETAIL CUSTOMERS' DEMAND?

A No. Most generally, OG&E's system demand is different than that of the SPP market region. While the SPP does plan for system reliability, it also plans for maintaining a robust marketplace which includes transmission upgrades to interconnect generating facilities, and to alleviate fuel congestion. While these upgrades may be economic and benefit OG&E through minimizing the operating costs of its production portfolio, the benefits are not specifically described in how OG&E must procure transmission capacity to maintain reliable service to its retail classes.

Q PLEASE EXPLAIN WHY OG&E'S DEMANDS REQUIRE TRANSMISSION CAPACITY THAT MORE REASONABLY REFLECTS THE 4CP A&E CAPACITY ALLOCATOR, RATHER THAN THE 12CP ALLOCATOR.

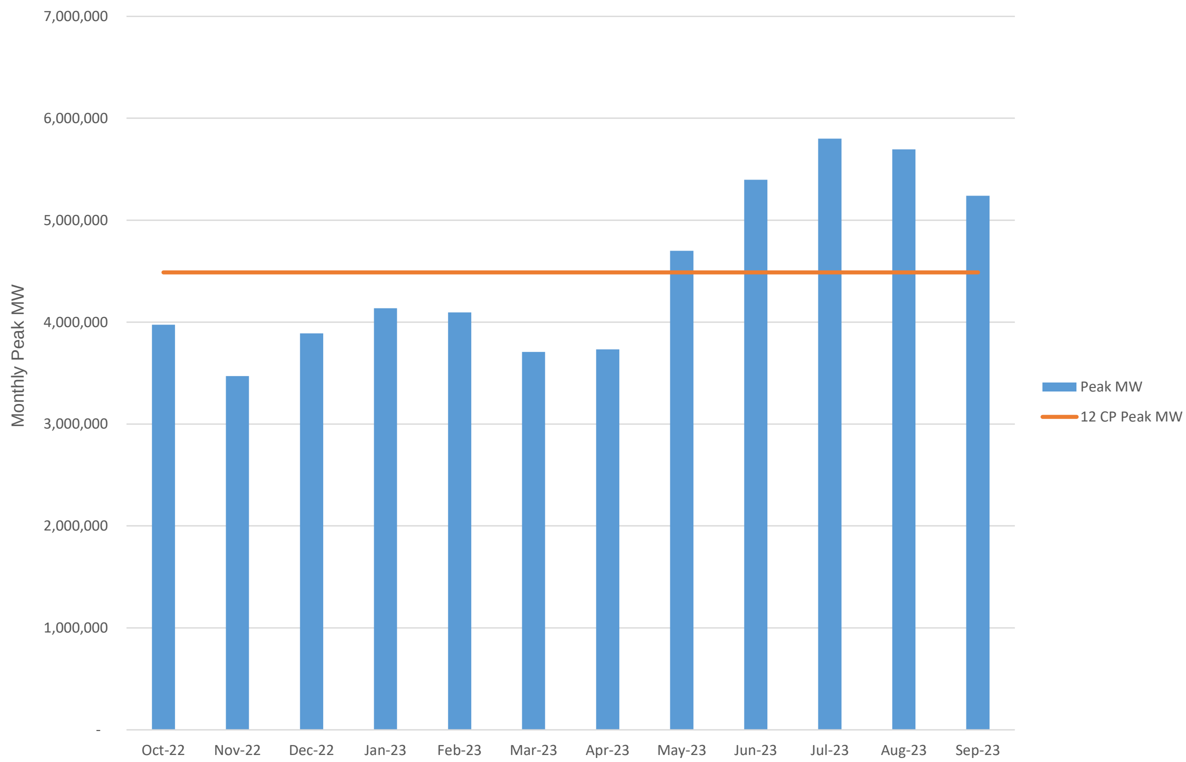
A As outlined in the table below, OG&E's system peaks largely in four months. The amount of transmission capacity it must have on hand has to be adequate to serve demands during those months, but then may be in excess of the demands it needs

[16]Draft OG&E 2024 IRP, provided in OG&E's response to DR PUD 04-02(b), at page 60.

throughout the year. Nevertheless, the cost of the amount of capacity OG&E needs for reliable firm service ties to its 4CP allocation during the summer.

An outline of OG&E's monthly transmission peak demands is shown in the graph below. As shown in this graph, OG&E has a very prolific form of peaking period over the year.

Figure 3
2022-2023 OG&E Monthly Peaks



Source: Oklahoma Gas and Electric Filed Cost of Service Study

As shown in the graph above, a 12CP smooths the allocation of transmission capacity needed to serve customers over the year. A significant amount of transmission capacity is incurred during the peak period, and an average 12CP demand allocator does not properly assign this increased transmission cost to the customer class that requires transmission capacity for firm service during peak periods. Hence, a 12CP allocator does not reasonably allocate these transmission costs across rate classes.

On the other hand, a 4CP A&E capacity allocator does reasonably assign transmission cost across rate classes because it reflects the average demands over the 12-month period, but it also separately allocates additional capacity needed during peak periods to meet demands above average demands up to peak period demands. This is shown below in Table 4, where I outline the Company's 12 monthly coincident peak demands on its system.

TABLE 4

Oklahoma Gas and Electric Company
2022- 2023 Monthly Peaks (MW)

Month	Peak MW
Oct-22	3,975,987
Nov-22	3,472,281
Dec-22	3,890,669
Jan-23	4,136,909
Feb-23	4,095,933
Mar-23	3,709,514
Apr-23	3,733,066
May-23	4,701,155
Jun-23	5,398,757
Jul-23	5,800,458
Aug-23	5,695,078
Sep-23	5,240,155
Total	53,849,962
On-Peak Avg Demand	5,533,612
Off-Peak Avg Demand	3,964,439
Excess Demand	1,569,173
Excess vs Peak	28%

Source: Oklahoma Gas and Electric Filed Cost of Service Study

As shown in the table above, the average demands during the eight-month non-peak period are approximately 3,964,439 MW. During the peak period, the demands in excess of these average non-peak demands are 1,569,173 MW, or about 28% of the average demands. Hence, the weight of average demands to additional capacity needed to serve peak demand is roughly 70% average demands, and 30% excess demands needed to serve peak period demands. This weighting reasonably aligns with the 4CP A&E capacity allocator, which is weighted at 56% average energy demands, and 44% peak demand.

Hence, a 4CP A&E more reasonably aligns with the variability in cost across the year, which is impacted by load characteristics on OG&E's system, which is not dependent on SPP load characteristics and monthly peak demands. For this reason, I recommend transmission costs continue to be allocated using a 4CP A&E allocator.

VI. REVISED 1 MW COSS

Q WHAT COSS DO YOU RECOMMEND THE COMMISSION USE TO APPORTION THE CLAIMED REVENUE DEFICIENCY ACROSS THE VARIOUS RATE CLASSES IN THIS PROCEEDING?

A I recommend the Company start with OG&E's filed 1 MW COSS, but modify it to adjust the allocation of all production resources and transmission plant using the 4CP A&E methodology. I provided this revised COSS on my Exhibit MPG-2. A comparison of class COSS using the Company's Filed COSS compared to my 1 MW COSS adjusted for the use of 4CP A&E methodology is summarized in Table 5 below.

TABLE 5

OG&E Cost of Service Comparison
Filed COSS vs. 1 MW COSS

Line	Rate Class	Base Non-Fuel Revenue at Current Rates	OG&E Filed COSS[1] Increase / (Decrease) to Reach Proposed Revenue		1 MW COSS: Wind Prod and Trans Allocators Changed to 4 CP A&E[2] Increase / (Decrease) to Reach Proposed Revenue	
			Amount	**Percent**	**Amount**	**Percent**
		(1)	**(2)**	**(3)**	**(4)**	**(5)**
1	RS	$647,049,430	$160,494,538	24.8%	$174,527,655	27.0%
2	GS	140,178,520	43,017,056	30.7%	39,698,280	28.3%
3	OGP	12,155,292	897,761	7.4%	158,154	1.3%
4	PS-S	9,866,440	1,530,589	15.5%	7,330,656	74.3%
5	PS-L	10,748,530	2,211,013	20.6%	5,506,824	51.2%
6	PL & PL TOU	297,574,344	67,364,987	22.6%	58,488,324	19.7%
7	LPL TOU	158,074,089	47,500,563	30.0%	30,235,982	19.1%
8	MP	4,282,130	841,119	19.6%	539,254	12.6%
9	Lighting	38,068,923	8,679,715	22.8%	11,761,918	30.9%
10	BK & Maintenance	320,465	414,120	129.2%	(243,409)	-76.0%
11	LPL - 1 MW				$ 4,947,822	
11	Total Retail	$ 1,318,318,163	$332,951,461	25.3%	$332,951,461	25.3%

Sources:
[1]Direct Testimony of Bryan Scott, Tables 1 and 2.
[2]Exhibit MPG-2.

As outlined in the table above, a more accurate allocation of all production resources and transmission plant does not have a significant impact on the class cost of service across the various rate classes. The Residential customer class goes up modestly, as well as Small General. However, a more accurate allocation of production resources needed to provide firm service has a material impact on the Large Power & Light class because this class has a much higher load factor than the remaining system. But the benefit to this class comes at a relatively minor impact on the other rate classes. More importantly, the 1 MW COSS using 4CP A&E is more accurate, and a better estimate of the cost of providing service to the various rate classes. For these reasons, I recommend the Commission reject the Company's Filed COSS and 1 MW COSS, and instead adopt the use of a 1 MW COSS adjusted to allocate all production and transmission capacity resources using a 4CP A&E methodology.

Q CAN YOU EXPLAIN THE ADJUSTMENTS YOU MADE TO THE COMPANY'S 1 MW COSS?

A Yes. Two primary changes were made with respect to which accounts are allocated using the Company's 4CP-A&E allocator. Those changes involve wind farm accounts and accounts allocated on transmission demand.

In the Company's COSS, wind farm accounts are allocated on a 16% demand, 84% energy basis with the portion of the account allocated on demand using the 4CP-A&E allocator and the remainder allocated on an energy basis, a change from the previous case COSS approach. For these accounts, I changed the energy allocator to the Company's 4CP-A&E allocator, resulting in 100% of those accounts being allocated on a demand basis, as they were in the previous case.

The Company is currently using a 12CP allocator for their jurisdictional transmission demand allocator, and their Oklahoma transmission demand allocator. This is a departure from the previous case in which a 12CP allocator was used for the jurisdictional section, but a 4CP allocator was used for the Oklahoma allocation. To more closely reflect this, I changed the Oklahoma transmission demand allocator to the Company's 4CP-A&E allocator, scaling the allocator to match the total portion of transmission which falls under Oklahoma retail, and no changes were made to the wholesale transmission allocation accounts.

VII. RATE DESIGN

Q DO YOU HAVE ANY COMMENTS CONCERNING THE COMPANY'S PROPOSED RATE DESIGN?

A Yes. I make the following recommendations concerning the Company's proposed rate design:

1. I recommend a separate rate class for 1 MW Exception customers served under the LPL and PL rate schedules. Rate schedules for these specific customers should be separated from the other LPL and PL customers and should be adjusted to reflect cost of service to these specific rate classes.

2. I recommend modifications to certain on-peak energy charges relative to those offered by OG&E. In many cases, the Company's proposed increase in time-of-use energy charges for the PL and LPL rate classes are unreasonably low, and the increase in off-peak and demand charges that measure demand over all hours does not produce an effective time-of-use rate structure, and does not reflect adequately OG&E's higher cost during on-peak periods.

Q ARE YOU RECOMMENDING A RATE DESIGN FOR THE 1 MW EXCEPTION CLASS CUSTOMERS IN THIS PROCEEDING?

A No. But I intended to, and sought a proof of revenue from OG&E for the 1 MW customers for that purpose. However, the Company indicated that it had not performed a proof of revenue for the 1 MW COSS class, which includes a separation for 1 MW customers, in response to FEA 3-01(c). Hence, I do not have the billing units needed to design a specific rate for the 1 MW customer class.

Nevertheless, I recommend the Commission direct the Company to do a proof of revenue for these specific customers and adjust revenues to recover the revenue assignment being made for this customer class in this proceeding.

Q DID YOU OUTLINE THE COMPANY'S PROPOSED CHANGE IN RATES FOR LPL AND PL CUSTOMERS ON TOU RATES SERVED AT SERVICE LEVEL 1 THROUGH SERVICE LEVEL 5?

A Yes. This is shown on my Exhibit MPG-3. As shown on that exhibit, I believe the Company's proposed increase for on-peak energy rates is not uniform across its rate classes, and in many cases understates an increase in on-peak energy rates that aligns with its increased cost of service in this proceeding.

Q ARE YOU PROPOSING TO REVISE THE COMPANY'S PROPOSED RATE DESIGN FOR THE LPL TOU, AND PL TOU?

A Yes. The Company's proposed increase in on-peak energy rates for PL TOU rate Service Levels 2 and 3 is too low in comparison to the increased cost for on-peak resources in this proceeding. Specifically, the major drivers of this case are the increased production and transmission costs, which are largely incurred to serve increased demands during peak periods. Further, energy costs during peak periods exceed those for off-peak periods so encouraging customers to shift from the on-peak to the off-peak period will help alleviate demands on energy production resources during peak periods as well.

The Company's proposed increase in the energy rate for PL Service Level 2 and Service Level 3 is 17.07% and 6.67%,[17] respectively. This is relatively low compared to the 58.15% increase in max demand (all hour demand) charge for level 2, 16.7% increase in demand charge for level 3, and approximately 11.1% increase in the off-peak energy rate.

[17] Section M Individual Class Page W/P M-4-1

I recommend far more emphasis be placed on increasing the price signal to encourage customers to reduce demands and energy consumption during an on-peak period. To accomplish this, I am recommending a reduction in the demand charge, a reduction in off-peak energy charge, and a relatively large increase in on-peak energy rates for PL Service Level 2 and 3.

The Company appears to be attempting to align the PL TOU Service Level 2 and 3 energy rates to align with one another. While I do not dispute this objective may be reasonable, I propose to achieve this on more of a gradual level. Diminishing the economic signal to reduce demand during on-peak periods is more important than the time period necessary to phase in an alignment of PL Service Level 2 and Service Level 3 energy rates.

Q PLEASE DESCRIBE YOUR PROPOSED ENERGY RATES FOR PL 2 AND PL 3 RATES.

A For illustrative purposes, based on the Company's proposed revenue assignment for these rate classes, I am showing an increase in on-peak energy rates, and a lower increase in the demand and off-peak energy rates proposed by the Company. Producing the same proposed revenue requirement for PL 2 and PL 3 as proposed by the Company, I recommend an increase in on-peak energy rate to 62.04% for PL 2 and 15.22% for PL 3. A corresponding reduction in demand and off-peak energy rates is shown in my attached Exhibit MPG-4.

Q DOES THIS CONCLUDE YOUR RESPONSIVE TESTIMONY ON COST OF SERVICE AND RATE DESIGN ISSUES?

A Yes, it does.

Qualifications of Michael P. Gorman

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A In 1983 I received a Bachelor of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Master's Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission ("ICC"). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the Staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. ("DBA"). In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating to industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals ("RFPs") for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have participated in rate cases on rate design and class cost of service for electric, natural gas, water and wastewater utilities. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements, and have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the Federal Energy Regulatory Commission and numerous state regulatory commissions including: Alaska, Arkansas, Arizona, California, Colorado, Delaware, the District of Columbia, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta, Nova Scotia, and Quebec, Canada. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the designation of Chartered Financial Analyst ("CFA") from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of the CFA Institute's Financial Analyst Society.

493793

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	**)**	**CASE NO. PUD2023-000087**

STATE OF MISSOURI	**)**	
	)	**SS**
COUNTY OF ST. LOUIS	**)**	

Affidavit of Michael P. Gorman

Michael P. Gorman, being first duly sworn, on his oath states:

1. My name is Michael P. Gorman. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Federal Executive Agencies in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my responsive testimony and exhibits which were prepared in written form for introduction into evidence in the Corporation Commission of the State of Oklahoma Case No. PUD2023-000087.

3. I hereby swear and affirm that the testimony and exhibits are true and correct and that they show the matters and things that they purport to show.

Michael Gorman

Michael P. Gorman

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

SALLY D. WILHELMS
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: Aug. 5, 2024
Commission # 20078050

Sally D Wilhelms

Notary Public

Oklahoma Gas & Electric Company

Production Portfolio Accredited Capacity

	Nameplate Capacity (MW)	Summer Accredited Capacity	Winter Accredited Capacity	Accredited Capacity to Nameplate Percent Summer	Accredited Capacity to Nameplate Percent Winter
Muskogee 4	572	489	489	85.5%	85.5%
Muskogee 5	572	488	488	85.3%	85.3%
Muskogee 6	572	521	521	91.1%	91.1%
Sooner 1	569	516	516	90.7%	90.7%
Sooner 2	569	520	520	91.4%	91.4%
McClain CC[1]	551	484	484	87.8%	87.8%
Redbud 1[2]	358	307	307	85.7%	85.7%
Redbud 2	358	301	301	84.0%	84.0%
Redbud 3	358	301	301	84.0%	84.0%
Redbud 4	358	300	300	83.7%	83.7%
Horseshoe Lake 7	220	211	211	95.9%	95.9%
Horseshoe Lake 8	443	375	375	84.7%	84.7%
Horseshoe Lake 9	60.5	45	45	74.4%	74.4%
Horseshoe Lake 10	60.5	43	43	71.1%	71.1%
Mustang 6	66	57	57	86.4%	86.4%
Mustang 7	66	56	56	84.8%	84.8%
Mustang 8	66	58	58	87.9%	87.9%
Mustang 9	66	57	57	86.4%	86.4%
Mustang 10	66	57	57	86.4%	86.4%
Mustang 11	66	58	58	87.9%	87.9%
Mustang 12	66	57	57	86.4%	86.4%
Mustang 5A (Tinker)	41	33	33	80.5%	80.5%
Mustang 5B (Tinker)	41	31	31	75.6%	75.6%
Seminole 1	567	500	500	88.2%	88.2%
Seminole 2	567	513	513	90.5%	90.5%
Seminole 3	567	509	509	89.8%	89.8%
River Valley 1	175	161	161	92.0%	92.0%
River Valley 2	175	160	160	91.4%	91.4%
Frontier	131	121	121	92.4%	92.4%
Centennial Wind Farm	120	19	8	15.8%	6.7%
OU Spirit Wind Farm	101	9	10	8.9%	9.9%
Crossroads Wind Farm	228	33	26.69	14.5%	11.7%
Taloga Wind Farm (PPA)	130	14	1	10.8%	0.8%
Keenan Wind Farm (PPA)	152	22	19	14.5%	12.5%
Cowboy Wind Farm (PPA)	60	12	14	20.0%	23.3%
Mustang Solar Farm	2.5	2	0	80.0%	0.0%
Covington Solar Farm	9.7	8	0.01	82.5%	0.1%
Choctaw Solar Farm	5	4	0.07	80.0%	1.4%
Chickasaw Solar Farm	5	4	0.07	80.0%	1.4%
Butterfield Solar Farm	5	2	0.1	40.0%	2.0%
Branch Solar Farm	5	3	0.06	60.0%	1.2%
Total Portfolio	9172	7461	7408	81.3%	80.8%
Wind Resources	791	109	79	13.8%	9.9%
Non-Wind Resources	8381	7352	7329	87.7%	87.5%

Source and Notes:
Source: OG&E Response to FEA Data Request 02-11, Attachment 1.
[1]OG&E owns 55% of McClain.
[2]OG&E owns 51% of Redbud.

Oklahoma Gas & Electric Company

1MW COSS Adjusted for 4CP A&E

ACCT(S) / DESCRIPTION	ALLOCATOR	1 TOTAL COMPANY PRO FORMA	2 TOTAL OKLA RETAIL JURISDICTION	3 TOTAL JURISDICTIONS NOT AT ISSUE	1 RESIDENTIAL STANDARD S/L-5	2 RESIDENTIAL TOU S/L-5	3 RESIDENTIAL VPP S/L-5
SUMMARY OF RATE BASE							
GROSS ELECTRIC PLANT IN SERVICE		15,417,660,662	13,925,511,738	1,492,148,924	6,099,751,438	151,878,462	691,473,638
LESS: ACCUM PROV FOR DEPR		5,622,718,605	5,088,353,293	534,365,312	2,255,323,760	55,321,495	251,745,326
CONSTRUCTION WORK IN PROGRESS		0	0	0	0	0	0
PLANT HELD FOR FUTURE USE		2,099,537	2,027,482	72,055	906,013	22,365	108,742
NET ELECTRIC UTILITY PLANT IN SERVICE		9,797,041,593	8,839,185,927	957,855,666	3,845,333,691	96,579,332	439,837,054
ADDITIONS TO RATE BASE:							
CASH WORKING CAPITAL		(60,236,091)	(52,914,819)	(7,321,272)	(24,521,530)	(605,601)	(2,792,396)
PREPAYMENTS		10,400,353	9,514,531	885,822	3,085,329	81,426	374,596
MATERIALS AND SUPPLIES		200,241,292	184,267,563	15,973,729	86,658,084	2,234,898	10,100,196
FUEL INVENTORIES		98,020,977	89,579,214	8,441,763	26,512,714	721,434	3,323,499
GAS IN STORAGE		16,840,880	15,390,510	1,450,370	4,555,121	123,949	571,007
REGULATORY ASSETS		220,796,384	195,571,872	25,224,512	87,232,814	2,156,085	9,874,808
NET PENSION BENEFIT ASSET (OBLIGATION)		(24,364,274)	(21,402,969)	(2,961,306)	(9,918,460)	(244,953)	(1,129,467)
TOTAL ADDITIONS		461,699,521	420,005,902	41,693,619	173,604,071	4,467,239	20,322,242
DEDUCTIONS TO RATE BASE:							
ASSET RETIREMENT OBLIGATION		(81,168,936)	(74,466,168)	(6,702,768)	(30,589,812)	(705,683)	(3,269,241)
CUSTOMER DEPOSITS		(99,885,522)	(89,860,322)	(10,025,200)	(49,850,578)	(1,032,724)	(4,429,904)
ACCUMULATED DEFERRED TAXES		(1,215,890,316)	(1,098,861,037)	(117,029,278)	(480,216,102)	(11,926,215)	(54,328,658)
REGULATORY LIABILITIES		(884,705,536)	(798,979,331)	(85,726,205)	(350,193,608)	(8,725,558)	(39,719,709)
TOTAL DEDUCTIONS		(2,281,650,310)	(2,062,166,858)	(219,483,452)	(910,850,100)	(22,390,180)	(101,747,512)
TOTAL RATE BASE		7,977,090,804	7,197,024,971	780,065,834	3,108,087,662	78,656,391	358,411,785
SUMMARY OF RETURN AT PRESENT RATES							
RATE BASE		7,977,090,804	7,197,024,971	780,065,834	3,108,087,662	78,656,391	358,411,785
RETURN		324,003,159	314,170,966	9,832,193	131,394,925	1,536,174	13,753,953
RATE OF RETURN ON RATE BASE		4.06167%	4.36529%	1.26043%	4.22752%	1.95302%	3.83747%
RELATIVE RATE OF RETURN			1.000000		0.968439	0.447397	0.879088
FUEL		1	1	0	0	0	0
PURCHASED POWER		0	0	0	0	0	0
O&M (LESS FUEL), INCLUDES REGULATORY ASSET AMORTIZATION		470,611,268	413,727,604	56,883,665	186,049,154	4,587,991	21,142,493
INTEREST OF CUSTOMER DEPOSITS		2,718,667	2,606,796	111,871	1,446,140	29,960	128,510
DEPRECIATION EXPENSE		536,719,081	488,096,054	48,623,028	211,496,701	5,258,336	23,933,754
MISCELLANEOUS TAXES		226,320	198,812	27,508	92,133	2,275	10,492
PROPERTY TAXES		87,720,601	79,524,915	8,195,686	34,394,966	845,891	3,860,600
PAYROLL TAXES		14,002,403	12,300,509	1,701,893	5,700,243	140,777	649,117
FEDERAL & STATE INCOME TAX LIABILITY		(2,863,109)	4,837,468	(7,700,577)	714,414	(556,255)	(366,406)
TOTAL OPERATING EXPENSES		1,109,135,231	1,001,292,158	107,843,073	439,893,750	10,308,975	49,358,558
TOTAL OPERATING REVENUES (COST OF SERVICE)		1,433,138,390	1,315,463,124	117,675,266	571,288,676	11,845,149	63,112,511
LESS: OPERATING REVENUE CREDIT		18,954,914	18,051,062	903,852	13,644,262	162,188	944,682
PRESENT SALES REVENUE		1,414,183,476	1,297,412,062	116,771,414	557,644,414	11,682,962	62,167,829
SUMMARY - EQUALIZED REQUESTED RATE OF RETURN							
RATE BASE		7,977,090,804	7,197,024,971	780,065,834	3,108,087,662	78,656,391	358,411,785
RATE OF RETURN ON RATE BASE		7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%
RETURN		628,594,755	567,125,568	61,469,188	244,917,308	6,198,124	28,242,849
O&M (LESS FUEL), INCLUDES REGULATORY ASSET AMORTIZATION		472,497,180	415,457,788	57,039,392	186,759,893	4,604,388	21,218,452
INTEREST ON CUSTOMER DEPOSITS		2,718,667	2,606,796	111,871	1,446,140	29,960	128,510
DEPRECIATION EXPENSE		536,719,081	488,096,054	48,623,028	211,496,701	5,258,336	23,933,754
TAXES OTHER THAN INCOME TAXES		101,949,323	92,024,236	9,925,087	40,187,341	988,943	4,520,208
FED INCOME TAX LIABILITY @ CURRENT ROR		(2,863,109)	4,837,468	(7,700,577)	714,414	(556,255)	(366,406)
ADDITIONAL FED INCOME TAX LIABILITY		97,783,040	81,206,016	16,577,024	36,444,090	1,496,626	4,651,370
TOTAL OPERATING EXPENSES		1,208,804,182	1,084,228,357	124,575,825	477,048,579	11,821,997	54,085,888
RETURN DEFICIENCY BEFORE INCOME TAXES @ REQUESTED ROR		304,591,597	252,954,602	51,636,995	113,522,382	4,661,950	14,488,896
TOTAL PROPOSED OPERATING REVENUE (COST OF SERVICE)		1,837,398,938	1,651,353,925	186,045,013	721,965,887	18,020,121	82,328,736
LESS: OTHER OPERATING REVENUE		18,954,914	18,051,062	903,852	13,644,262	162,188	944,682
PROPOSED SALES REVENUE @ EQUALIZED ROR		1,818,444,023	1,633,302,863	185,141,161	708,321,625	17,857,933	81,384,055
TOTAL PRESENT OPERATING REVENUE		1,433,138,390	1,315,463,124	117,675,266	571,288,676	11,845,149	63,112,511
LESS: OTHER OPERATING REVENUE		18,954,914	18,051,062	903,852	13,644,262	162,188	944,682
PRESENT SALES REVENUE		1,414,183,476	1,297,412,062	116,771,414	557,644,414	11,682,962	62,167,829
REVENUE DEFICIENCY		404,260,547	335,890,801	68,369,747	150,677,211	6,174,972	19,216,225
PCT INCREASE TOTAL SALES REVENUE		28.59%	25.89%	58.55%	27.02%	52.85%	30.91%

Oklahoma Gas & Electric Company

1MW COSS Adjusted for 4CP A&E

ACCT(S) / DESCRIPTION	5 GENERAL SERVICE STANDARD S/L-5	6 GENERAL SERVICE TOU S/L-5	7 GENERAL SERVICE VPP S/L-5	9 OIL & GAS PRODUCTION STANDARD S/L-3	10 OIL & GAS PRODUCTION STANDARD S/L-5	11 OIL & GAS PRODUCTION TOU S/L-5	12 OIL & GAS PRODUCTION VPP S/L-5	13 PUBLIC SCHOOLS-SM STANDARD S/L-5	14 PUBLIC SCHOOLS-SM TOU S/L-5	15 PUBLIC SCHOOLS-SM VPP S/L-5	16 PUBLIC SCHOOLS-LG STANDARD S/L-3
SUMMARY OF RATE BASE											
GROSS ELECTRIC PLANT IN SERVICE	1,320,478,171	121,577,492	84,647,856	34,925,126	55,515,475	5,337,635	2,376,580	19,294,049	49,490,214	76,289,900	671,110
LESS: ACCUM PROV FOR DEPR	469,454,902	43,918,837	31,111,037	13,239,179	20,317,800	2,034,214	879,623	7,090,810	17,936,872	27,362,350	255,963
CONSTRUCTION WORK IN PROGRESS	0	0	0	0	0	0	0	0	0	0	0
PLANT HELD FOR FUTURE USE	170,745	17,664	12,415	7,074	8,066	916	389	3,439	10,042	15,769	153
NET ELECTRIC UTILITY PLANT IN SERVICE	851,194,014	77,676,319	53,549,234	21,693,021	35,205,740	3,304,337	1,497,346	12,206,678	31,563,384	48,943,319	415,300
ADDITIONS TO RATE BASE:											
CASH WORKING CAPITAL	(4,829,567)	(440,578)	(313,694)	(138,030)	(219,801)	(20,928)	(9,375)	(73,650)	(190,057)	(295,667)	(2,776)
PREPAYMENTS	618,810	73,353	43,669	41,854	55,031	6,194	2,622	9,500	25,254	39,571	441
MATERIALS AND SUPPLIES	19,392,556	1,716,963	1,152,512	432,415	767,232	66,134	31,814	258,730	677,627	1,065,998	8,290
FUEL INVENTORIES	5,314,403	677,031	382,674	435,311	563,425	64,106	27,054	81,553	217,999	346,406	4,019
GAS IN STORAGE	913,062	116,320	65,747	74,790	96,801	11,014	4,648	14,012	37,454	59,516	690
REGULATORY ASSETS	18,051,029	1,664,349	1,171,252	501,258	787,536	76,391	33,890	270,410	696,069	1,073,554	9,849
NET PENSION BENEFIT ASSET (OBLIGATION)	(1,953,462)	(178,205)	(126,883)	(55,830)	(88,905)	(8,465)	(3,792)	(29,790)	(76,874)	(119,591)	(1,123)
TOTAL ADDITIONS	37,506,832	3,629,233	2,375,277	1,291,769	1,961,319	194,447	86,860	530,765	1,387,471	2,169,784	19,390
DEDUCTIONS TO RATE BASE:											
ASSET RETIREMENT OBLIGATION	(5,628,092)	(568,994)	(412,906)	(207,224)	(268,182)	(31,818)	(12,906)	(96,753)	(253,409)	(370,374)	(4,221)
CUSTOMER DEPOSITS	(11,908,239)	(613,032)	(394,667)	(265,835)	(496,962)	0	(7,969)	0	0	0	0
ACCUMULATED DEFERRED TAXES	(103,411,142)	(9,549,077)	(6,657,717)	(2,767,197)	(4,364,935)	(422,978)	(187,628)	(1,518,948)	(3,899,092)	(5,999,388)	(53,321)
REGULATORY LIABILITIES	(75,917,468)	(6,984,296)	(4,860,981)	(2,001,627)	(3,188,310)	(305,894)	(136,336)	(1,107,694)	(2,840,725)	(4,381,208)	(38,437)
TOTAL DEDUCTIONS	(196,864,941)	(17,715,399)	(12,326,271)	(5,241,883)	(8,318,390)	(760,691)	(344,838)	(2,723,395)	(6,993,227)	(10,750,969)	(95,979)
TOTAL RATE BASE	691,835,905	63,590,153	43,598,240	17,742,907	28,848,669	2,738,094	1,239,368	10,014,048	25,957,629	40,362,134	338,711
SUMMARY OF RETURN AT PRESENT RATES											
RATE BASE	691,835,905	63,590,153	43,598,240	17,742,907	28,848,669	2,738,094	1,239,368	10,014,048	25,957,629	40,362,134	338,711
RETURN	29,431,609	2,231,280	1,100,183	1,046,365	2,484,564	233,568	108,714	218,103	87,172	124,316	404
RATE OF RETURN ON RATE BASE	4.25413%	3.50884%	2.52346%	5.89737%	8.61241%	8.53031%	8.77174%	2.17797%	0.33582%	0.30800%	0.11929%
RELATIVE RATE OF RETURN	0.974536	0.803806	0.578073	1.350968	1.972929	1.954122	2.009430	0.498929	0.076930	0.070557	0.027328
FUEL	0	0	0	0	0	0	0	0	0	0	0
PURCHASED POWER	0	0	0	0	0	0	0	0	0	0	0
O&M (LESS FUEL), INCLUDES REGULATORY ASSET AMORTIZATION	37,088,868	3,400,880	2,394,532	1,068,678	1,671,788	173,381	74,671	562,145	1,455,266	2,248,855	21,522
INTEREST OF CUSTOMER DEPOSITS	345,447	17,784	11,449	7,711	14,416	0	232	0	0	0	0
DEPRECIATION EXPENSE	47,049,804	4,295,931	3,048,662	1,243,952	2,033,498	191,729	84,843	691,807	1,723,469	2,669,342	22,913
MISCELLANEOUS TAXES	18,146	1,655	1,179	519	826	79	35	277	714	1,111	10
PROPERTY TAXES	7,273,939	679,593	476,104	203,162	311,206	31,081	13,593	108,939	280,400	428,265	3,948
PAYROLL TAXES	1,122,675	102,416	72,921	32,086	51,095	4,865	2,179	17,121	44,180	68,730	645
FEDERAL & STATE INCOME TAX LIABILITY	218,134	(132,096)	(228,485)	99,193	412,728	38,451	18,365	(63,587)	(318,335)	(498,592)	(4,389)
TOTAL OPERATING EXPENSES	93,117,013	8,366,163	5,776,362	2,655,302	4,495,557	439,585	193,919	1,316,702	3,185,694	4,917,712	44,650
TOTAL OPERATING REVENUES (COST OF SERVICE)	122,548,622	10,597,443	6,876,545	3,701,666	6,980,122	673,153	302,633	1,534,805	3,272,866	5,042,028	45,054
LESS: OPERATING REVENUE CREDIT	1,153,427	66,878	47,940	14,139	35,092	1,446	1,593	4,765	14,021	22,210	202
PRESENT SALES REVENUE	121,395,195	10,530,565	6,828,605	3,687,527	6,945,030	671,707	301,040	1,530,040	3,258,845	5,019,819	44,852
SUMMARY - EQUALIZED REQUESTED RATE OF RETURN											
RATE BASE	691,835,905	63,590,153	43,598,240	17,742,907	28,848,669	2,738,094	1,239,368	10,014,048	25,957,629	40,362,134	338,711
RATE OF RETURN ON RATE BASE	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%
RETURN	54,516,669	5,010,904	3,435,541	1,398,141	2,273,275	215,762	97,662	789,107	2,045,461	3,180,536	26,690
O&M (LESS FUEL), INCLUDES REGULATORY ASSET AMORTIZATION	37,219,633	3,414,100	2,404,126	1,073,493	1,678,019	174,120	74,971	564,393	1,461,154	2,257,460	21,620
INTEREST ON CUSTOMER DEPOSITS	345,447	17,784	11,449	7,711	14,416	0	232	0	0	0	0
DEPRECIATION EXPENSE	47,049,804	4,295,931	3,048,662	1,243,952	2,033,498	191,729	84,843	691,807	1,723,469	2,669,342	22,913
TAXES OTHER THAN INCOME TAXES	8,414,760	783,664	550,204	235,767	363,127	36,024	15,808	126,337	325,294	498,107	4,604
FED INCOME TAX LIABILITY @ CURRENT ROR	218,134	(132,096)	(228,485)	99,193	412,728	38,451	18,365	(63,587)	(318,335)	(498,592)	(4,389)
ADDITIONAL FED INCOME TAX LIABILITY	8,053,057	892,343	749,720	112,931	(67,830)	(5,716)	(3,548)	183,309	628,670	981,138	8,439
TOTAL OPERATING EXPENSES	101,300,836	9,271,726	6,535,676	2,773,047	4,433,958	434,608	190,671	1,502,259	3,820,252	5,907,456	53,186
RETURN DEFICIENCY BEFORE INCOME TAXES @ REQUESTED ROR	25,085,060	2,779,624	2,335,358	351,776	(211,289)	(17,806)	(11,052)	571,004	1,958,289	3,056,220	26,286
TOTAL PROPOSED OPERATING REVENUE (COST OF SERVICE)	155,817,505	14,282,630	9,971,217	4,171,188	6,707,233	650,370	288,333	2,291,366	5,865,713	9,087,992	79,877
LESS: OTHER OPERATING REVENUE	1,153,427	66,878	47,940	14,139	35,092	1,446	1,593	4,765	14,021	22,210	202
PROPOSED SALES REVENUE @ EQUALIZED ROR	154,664,078	14,215,752	9,923,277	4,157,049	6,672,142	648,924	286,740	2,286,602	5,851,692	9,065,782	79,675
TOTAL PRESENT OPERATING REVENUE	122,548,622	10,597,443	6,876,545	3,701,666	6,980,122	673,153	302,633	1,534,805	3,272,866	5,042,028	45,054
LESS: OTHER OPERATING REVENUE	1,153,427	66,878	47,940	14,139	35,092	1,446	1,593	4,765	14,021	22,210	202
PRESENT SALES REVENUE	121,395,195	10,530,565	6,828,605	3,687,527	6,945,030	671,707	301,040	1,530,040	3,258,845	5,019,819	44,852
REVENUE DEFICIENCY	33,268,883	3,685,187	3,094,672	469,522	(272,888)	(22,783)	(14,300)	756,562	2,592,847	4,045,964	34,823
PCT INCREASE TOTAL SALES REVENUE	27.41%	35.00%	45.32%	12.73%	-3.93%	-3.39%	-4.75%	49.45%	79.56%	80.60%	77.64%

Oklahoma Gas & Electric Company

1MW COSS Adjusted for 4CP A&E

ACCT(S) / DESCRIPTION	17 PUBLIC SCHOOLS-LG STANDARD S/L-4	18 PUBLIC SCHOOLS-LG STANDARD S/L-5	19 PUBLIC SCHOOLS-LG TOU S/L-3	20 PUBLIC SCHOOLS-LG TOU S/L-4	21 PUBLIC SCHOOLS-LG TOU S/L-5	22 PWR & LGHT STANDARD S/L-1	23 PWR & LGHT STANDARD S/L-2	24 PWR & LGHT STANDARD S/L-3	25 PWR & LGHT STANDARD S/L-4	26 PWR & LGHT STANDARD S/L-5	27 PWR & LGHT TOU S/L-1	28 PWR & LGHT TOU S/L-2	29 PWR & LGHT TOU S/L-3
SUMMARY OF RATE BASE													
GROSS ELECTRIC PLANT IN SERVICE	1,002,666	22,526,139	4,830,363	6,301,948	103,536,288	527,132	29,351,636	87,955,334	36,363,694	1,551,323,768	8,340,475	45,509,306	152,152,383
LESS: ACCUM PROV FOR DEPR	357,557	8,051,763	1,855,909	2,355,154	37,260,066	201,252	9,548,522	34,394,643	13,931,981	564,678,911	3,612,132	15,528,480	59,176,859
CONSTRUCTION WORK IN PROGRESS	0	0	0	0	0	0	0	0	0	0	0	0	0
PLANT HELD FOR FUTURE USE	264	4,072	1,076	1,431	19,211	13	1,326	18,073	7,654	245,372	787	2,186	31,998
NET ELECTRIC UTILITY PLANT IN SERVICE	645,373	14,478,447	2,975,530	3,948,225	66,295,433	325,893	19,804,440	53,578,763	22,439,367	986,890,229	4,729,130	29,983,012	93,007,522
ADDITIONS TO RATE BASE:													
CASH WORKING CAPITAL	(4,291)	(80,443)	(19,821)	(25,712)	(374,587)	(468)	(173,451)	(350,352)	(145,212)	(5,348,574)	(26,304)	(233,268)	(611,178)
PREPAYMENTS	590	13,329	3,159	4,516	64,049	231	21,759	114,459	41,764	1,087,976	14,402	41,357	189,543
MATERIALS AND SUPPLIES	13,848	317,331	58,161	79,646	1,439,886	1,022	417,899	1,011,679	435,066	21,182,068	61,867	567,190	1,768,704
FUEL INVENTORIES	5,293	120,468	28,524	42,247	583,323	2,451	213,882	1,191,151	426,881	10,257,307	153,697	423,549	1,958,753
GAS IN STORAGE	909	20,697	4,901	7,258	100,220	421	36,747	204,650	73,342	1,762,297	26,406	72,769	336,531
REGULATORY ASSETS	14,759	308,323	70,881	91,806	1,427,584	4,981	494,029	1,279,922	528,779	21,036,547	114,122	717,684	2,221,927
NET PENSION BENEFIT ASSET (OBLIGATION)	(1,736)	(32,537)	(8,017)	(10,400)	(151,513)	(189)	(70,158)	(141,710)	(58,735)	(2,163,389)	(10,639)	(94,352)	(247,209)
TOTAL ADDITIONS	29,373	667,169	137,788	189,362	3,088,962	8,448	940,707	3,309,799	1,301,886	47,814,231	333,551	1,494,929	5,617,071
DEDUCTIONS TO RATE BASE:													
ASSET RETIREMENT OBLIGATION	(5,357)	(115,585)	(31,981)	(38,799)	(553,816)	(1,218)	(123,377)	(607,549)	(245,617)	(8,411,780)	(73,214)	(203,328)	(1,054,871)
CUSTOMER DEPOSITS	0	0	0	0	0	0	(80,290)	(919,091)	(32,271)	(10,235,552)	(214,307)	(223,292)	(547,088)
ACCUMULATED DEFERRED TAXES	(79,121)	(1,774,848)	(384,520)	(500,088)	(8,170,120)	(40,698)	(2,297,688)	(7,015,977)	(2,897,558)	(122,478,661)	(673,863)	(3,569,109)	(12,138,937)
REGULATORY LIABILITIES	(57,529)	(1,292,968)	(276,479)	(361,025)	(5,940,400)	(30,417)	(1,687,682)	(5,031,641)	(2,080,851)	(88,995,007)	(475,447)	(2,615,429)	(8,703,729)
TOTAL DEDUCTIONS	(142,007)	(3,183,401)	(692,980)	(899,912)	(14,664,336)	(72,333)	(4,189,037)	(13,574,259)	(5,256,297)	(230,121,000)	(1,436,832)	(6,611,158)	(22,444,625)
TOTAL RATE BASE	532,738	11,962,215	2,420,338	3,237,675	54,720,059	262,009	16,556,109	43,314,303	18,484,957	804,583,460	3,625,849	24,866,784	76,179,967
SUMMARY OF RETURN AT PRESENT RATES													
RATE BASE	532,738	11,962,215	2,420,338	3,237,675	54,720,059	262,009	16,556,109	43,314,303	18,484,957	804,583,460	3,625,849	24,866,784	76,179,967
RETURN	5,806	483,223	15,697	36,328	1,035,430	(6,994)	(33,211)	3,612,907	1,138,069	41,562,972	2,576,596	418,830	5,546,826
RATE OF RETURN ON RATE BASE	1.08978%	4.03958%	0.64855%	1.12203%	1.89223%	-2.66923%	-0.20060%	8.34114%	6.15673%	5.16578%	71.06187%	1.68430%	7.28121%
RELATIVE RATE OF RETURN	0.249646	0.925386	0.148569	0.257033	0.433472	-0.611466	-0.045953	1.910788	1.410383	1.183375	16.278846	0.385839	1.667980
FUEL	0	0	0	0	0	0	0	0	0	0	0	0	0
PURCHASED POWER	0	0	0	0	0	0	0	0	0	0	0	0	0
O&M (LESS FUEL), INCLUDES REGULATORY ASSET AMORTIZATION	32,553	622,384	154,725	199,139	2,907,382	3,921	1,261,805	2,837,625	1,140,875	42,221,191	224,214	1,719,650	5,679,099
INTEREST OF CUSTOMER DEPOSITS	0	0	0	0	0	0	2,328	26,662	936	296,927	6,217	6,478	15,870
DEPRECIATION EXPENSE	34,455	780,635	164,226	217,400	3,552,353	15,084	985,847	2,990,754	1,246,934	54,406,494	283,775	1,500,605	5,167,781
MISCELLANEOUS TAXES	16	302	74	97	1,407	2	652	1,316	546	20,096	99	876	2,296
PROPERTY TAXES	5,707	127,903	28,701	36,897	592,014	2,759	158,839	527,924	217,178	8,902,214	53,307	249,930	913,792
PAYROLL TAXES	998	18,700	4,608	5,977	87,076	109	40,320	81,442	33,756	1,243,322	6,115	54,225	142,074
FEDERAL & STATE INCOME TAX LIABILITY	(5,244)	(4,468)	(27,252)	(31,534)	(397,657)	(5,741)	(231,549)	581,964	118,733	2,608,418	778,790	(197,309)	764,325
TOTAL OPERATING EXPENSES	68,485	1,545,456	325,081	427,975	6,742,575	16,134	2,218,242	7,047,687	2,758,957	109,698,663	1,352,516	3,334,456	12,685,237
TOTAL OPERATING REVENUES (COST OF SERVICE)	74,291	2,028,679	340,778	464,303	7,778,005	9,140	2,185,031	10,660,595	3,897,026	151,261,635	3,929,113	3,753,287	18,232,063
LESS: OPERATING REVENUE CREDIT	372	5,582	1,323	1,929	25,430	12	3,616	50,232	13,587	854,368	7,612	(5,853)	90,797
PRESENT SALES REVENUE	73,919	2,023,097	339,455	462,374	7,752,575	9,128	2,181,415	10,610,363	3,883,439	150,407,267	3,921,501	3,759,140	18,141,266
SUMMARY - EQUALIZED REQUESTED RATE OF RETURN													
RATE BASE	532,738	11,962,215	2,420,338	3,237,675	54,720,059	262,009	16,556,109	43,314,303	18,484,957	804,583,460	3,625,849	24,866,784	76,179,967
RATE OF RETURN ON RATE BASE	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%
RETURN	41,980	942,623	190,723	255,129	4,311,941	20,646	1,304,621	3,413,167	1,456,615	63,401,177	285,717	1,959,503	6,002,981
O&M (LESS FUEL), INCLUDES REGULATORY ASSET AMORTIZATION	32,677	625,070	155,468	200,041	2,920,249	3,949	1,264,672	2,851,741	1,146,582	42,416,634	225,915	1,724,375	5,703,609
INTEREST ON CUSTOMER DEPOSITS	0	0	0	0	0	0	2,328	26,662	936	296,927	6,217	6,478	15,870
DEPRECIATION EXPENSE	34,455	780,635	164,226	217,400	3,552,353	15,084	985,847	2,990,754	1,246,934	54,406,494	283,775	1,500,605	5,167,781
TAXES OTHER THAN INCOME TAXES	6,721	146,905	33,383	42,970	680,498	2,869	199,811	610,683	251,479	10,165,633	59,520	305,032	1,058,162
FED INCOME TAX LIABILITY @ CURRENT ROR	(5,244)	(4,468)	(27,252)	(31,534)	(397,657)	(5,741)	(231,549)	581,964	118,733	2,608,418	778,790	(197,309)	764,325
ADDITIONAL FED INCOME TAX LIABILITY	11,613	147,481	56,188	70,242	1,051,858	8,873	429,484	(64,123)	102,263	7,010,719	(735,441)	494,602	146,440
TOTAL OPERATING EXPENSES	80,222	1,695,623	382,013	499,119	7,807,301	25,035	2,650,593	6,997,681	2,866,927	116,904,825	618,776	3,833,782	12,856,186
RETURN DEFICIENCY BEFORE INCOME TAXES @ REQUESTED ROR	36,174	459,400	175,026	218,801	3,276,510	27,640	1,337,833	(199,740)	318,546	21,838,204	(2,290,879)	1,540,672	456,155
TOTAL PROPOSED OPERATING REVENUE (COST OF SERVICE)	122,202	2,638,246	572,735	754,247	12,119,241	45,682	3,955,215	10,410,848	4,323,541	180,306,002	904,493	5,793,285	18,859,168
LESS: OTHER OPERATING REVENUE	372	5,582	1,323	1,929	25,430	12	3,616	50,232	13,587	854,368	7,612	(5,853)	90,797
PROPOSED SALES REVENUE @ EQUALIZED ROR	121,830	2,632,663	571,412	752,318	12,093,811	45,669	3,951,599	10,360,616	4,309,955	179,451,633	896,881	5,799,138	18,768,371
TOTAL PRESENT OPERATING REVENUE	74,291	2,028,679	340,778	464,303	7,778,005	9,140	2,185,031	10,660,595	3,897,026	151,261,635	3,929,113	3,753,287	18,232,063
LESS: OTHER OPERATING REVENUE	372	5,582	1,323	1,929	25,430	12	3,616	50,232	13,587	854,368	7,612	(5,853)	90,797
PRESENT SALES REVENUE	73,919	2,023,097	339,455	462,374	7,752,575	9,128	2,181,415	10,610,363	3,883,439	150,407,267	3,921,501	3,759,140	18,141,266
REVENUE DEFICIENCY	47,912	609,566	231,957	289,945	4,341,236	36,541	1,770,184	(249,747)	426,516	29,044,366	(3,024,619)	2,039,998	627,104
PCT INCREASE TOTAL SALES REVENUE	64.82%	30.13%	68.33%	62.71%	56.00%	400.33%	81.15%	-2.35%	10.98%	19.31%	-77.13%	54.27%	3.46%

Oklahoma Gas & Electric Company

1MW COSS Adjusted for 4CP A&E

ACCT(S) / DESCRIPTION	30 PWR & LGHT TOU S/L-4	31 PWR & LGHT TOU S/L-5	32 LARGE PWR & LGHT STANDARD S/L-2	33 LARGE PWR & LGHT TOU S/L-1	34 LARGE PWR & LGHT TOU S/L-2	35 LARGE PWR & LGHT TOU S/L-3	36 LARGE PWR & LGHT TOU S/L-4	37 LARGE PWR & LGHT TOU S/L-5	38 MUNICIPAL PUMPING STANDARD S/L-5	39 MUNICIPAL PUMPING TOU S/L-5	40 MUNICIPAL LIGHTING S/L-5	41 SECURITY LIGHTING S/L-5
SUMMARY OF RATE BASE												
GROSS ELECTRIC PLANT IN SERVICE	53,628,357	1,045,519,007	126,377,818	136,726,207	926,444,921	240,546,194	32,796,265	98,836,659	39,779,825	419,585	35,919,103	48,621,339
LESS: ACCUM PROV FOR DEPR	20,823,406	387,552,871	53,799,199	59,672,663	381,701,320	93,219,995	12,529,925	37,206,167	14,814,208	161,175	(5,849,157)	(5,109,340)
CONSTRUCTION WORK IN PROGRESS	0	0	0	0	0	0	0	0	0	0	0	0
PLANT HELD FOR FUTURE USE	10,760	184,319	12,462	14,202	84,525	51,950	7,026	18,626	7,221	74	1,769	3,540
NET ELECTRIC UTILITY PLANT IN SERVICE	32,815,711	658,150,455	72,591,081	77,067,745	544,828,125	147,378,150	20,273,366	61,649,118	24,972,837	258,484	41,770,029	53,734,218
ADDITIONS TO RATE BASE:												
CASH WORKING CAPITAL	(211,183)	(3,776,365)	(462,497)	(462,617)	(3,676,179)	(976,778)	(131,550)	(368,138)	(156,820)	(1,616)	(33,349)	(63,084)
PREPAYMENTS	56,502	884,336	219,141	227,960	1,416,790	304,244	41,221	104,393	42,896	536	7,627	15,270
MATERIALS AND SUPPLIES	622,044	13,691,927	1,115,345	1,115,413	8,862,642	2,810,086	394,086	1,253,777	518,897	5,076	92,342	184,631
FUEL INVENTORIES	567,149	8,626,532	2,321,627	2,395,535	14,859,294	3,147,552	426,881	1,056,176	440,212	5,587	78,711	157,618
GAS IN STORAGE	97,441	1,482,115	398,876	411,574	2,552,960	540,777	73,342	181,460	75,632	960	13,523	27,080
REGULATORY ASSETS	778,271	14,507,759	1,827,244	1,934,412	13,695,697	3,529,933	477,828	1,393,561	568,485	5,993	334,526	481,955
NET PENSION BENEFIT ASSET (OBLIGATION)	(85,419)	(1,527,463)	(187,071)	(187,119)	(1,486,940)	(395,087)	(53,209)	(148,904)	(63,430)	(654)	(13,489)	(25,516)
TOTAL ADDITIONS	1,824,805	33,888,842	5,232,665	5,435,158	36,224,263	8,960,727	1,228,599	3,472,325	1,425,873	15,882	479,891	777,953
DEDUCTIONS TO RATE BASE:												
ASSET RETIREMENT OBLIGATION	(378,572)	(6,221,924)	(1,159,255)	(1,321,106)	(7,862,835)	(1,682,307)	(222,159)	(628,166)	(224,189)	(2,679)	(37,500)	(75,000)
CUSTOMER DEPOSITS	(180,085)	(3,846,982)	0	0	(3,614,569)	(484,086)	0	(55,846)	(350)	0	(385)	(89,370)
ACCUMULATED DEFERRED TAXES	(4,282,273)	(82,848,679)	(10,238,206)	(11,113,314)	(74,704,376)	(19,199,153)	(2,613,645)	(7,853,979)	(3,145,346)	(33,350)	(2,749,436)	(3,735,016)
REGULATORY LIABILITIES	(3,067,027)	(59,918,748)	(7,198,755)	(7,780,995)	(52,840,918)	(13,758,634)	(1,876,642)	(5,660,017)	(2,281,138)	(24,027)	(2,077,557)	(2,809,635)
TOTAL DEDUCTIONS	(7,907,957)	(152,836,333)	(18,596,216)	(20,215,415)	(139,022,698)	(35,124,181)	(4,712,446)	(14,198,008)	(5,651,023)	(60,055)	(4,864,878)	(6,709,021)
TOTAL RATE BASE	26,732,559	539,202,964	59,227,530	62,287,488	442,029,691	121,214,697	16,789,519	50,923,435	20,747,688	214,311	37,385,042	47,803,150
SUMMARY OF RETURN AT PRESENT RATES												
RATE BASE	26,732,559	539,202,964	59,227,530	62,287,488	442,029,691	121,214,697	16,789,519	50,923,435	20,747,688	214,311	37,385,042	47,803,150
RETURN	1,432,061	21,831,089	2,071,530	3,463,812	20,292,038	6,456,616	887,753	3,259,288	1,230,995	12,990	2,890,761	4,462,231
RATE OF RETURN ON RATE BASE	5.35699%	4.04877%	3.49758%	5.56101%	4.59065%	5.32660%	5.28754%	6.40037%	5.93317%	6.06111%	7.73240%	9.33460%
RELATIVE RATE OF RETURN	1.227179	0.927492	0.801225	1.273915	1.051626	1.220216	1.211270	1.466196	1.359169	1.388479	1.771338	2.138368
FUEL	0	0	0	0	0	0	0	0	0	0	0	0
PURCHASED POWER	0	0	0	0	0	0	0	0	0	0	0	0
O&M (LESS FUEL), INCLUDES REGULATORY ASSET AMORTIZATION	1,672,377	30,166,087	4,255,449	3,965,792	29,919,381	7,691,394	1,033,382	2,905,254	1,206,913	12,665	598,827	895,568
INTEREST OF CUSTOMER DEPOSITS	5,224	111,600	0	0	104,856	14,043	0	1,619	10	0	10	2,594
DEPRECIATION EXPENSE	1,834,852	35,918,115	4,279,539	4,628,355	31,339,015	8,145,240	1,119,995	3,333,031	1,409,821	14,721	761,126	1,100,268
MISCELLANEOUS TAXES	793	14,189	1,738	1,738	13,812	3,670	494	1,383	589	6	125	237
PROPERTY TAXES	323,536	6,098,874	814,867	895,827	5,841,129	1,447,057	195,972	583,777	229,154	2,479	179,474	246,889
PAYROLL TAXES	49,091	877,849	107,511	107,539	854,560	227,060	30,580	85,577	36,454	376	7,752	14,665
FEDERAL & STATE INCOME TAX LIABILITY	103,076	(185,471)	(125,175)	280,964	616,908	455,553	60,994	366,922	118,376	1,311	429,240	794,733
TOTAL OPERATING EXPENSES	3,988,949	73,001,242	9,333,930	9,880,215	68,689,661	17,984,017	2,441,417	7,277,563	3,001,317	31,557	1,976,554	3,054,953
TOTAL OPERATING REVENUES (COST OF SERVICE)	5,421,010	94,832,331	11,405,460	13,344,027	88,981,699	24,440,633	3,329,170	10,536,851	4,232,312	44,547	4,867,315	7,517,184
LESS: OPERATING REVENUE CREDIT	28,060	476,902	12,493	13,645	103,083	126,527	10,253	35,089	10,973	109	3,350	26,998
PRESENT SALES REVENUE	5,392,950	94,355,429	11,392,966	13,330,382	88,878,616	24,314,107	3,318,916	10,501,762	4,221,339	44,438	4,863,965	7,490,186
SUMMARY - EQUALIZED REQUESTED RATE OF RETURN												
RATE BASE	26,732,559	539,202,964	59,227,530	62,287,488	442,029,691	121,214,697	16,789,519	50,923,435	20,747,688	214,311	37,385,042	47,803,150
RATE OF RETURN ON RATE BASE	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%
RETURN	2,106,526	42,489,194	4,667,129	4,908,254	34,831,940	9,551,718	1,323,014	4,012,767	1,634,918	16,888	2,945,941	3,766,888
O&M (LESS FUEL), INCLUDES REGULATORY ASSET AMORTIZATION	1,681,172	30,310,650	4,282,384	3,996,487	30,102,070	7,730,482	1,038,543	2,919,850	1,212,121	12,727	599,698	897,310
INTEREST ON CUSTOMER DEPOSITS	5,224	111,600	0	0	104,856	14,043	0	1,619	10	0	10	2,594
DEPRECIATION EXPENSE	1,834,852	35,918,115	4,279,539	4,628,355	31,339,015	8,145,240	1,119,995	3,333,031	1,409,821	14,721	761,126	1,100,268
TAXES OTHER THAN INCOME TAXES	373,421	6,990,911	924,116	1,005,104	6,709,501	1,677,788	227,046	670,737	266,198	2,861	187,351	261,791
FED INCOME TAX LIABILITY @ CURRENT ROR	103,076	(185,471)	(125,175)	280,964	616,908	455,553	60,994	366,922	118,376	1,311	429,240	794,733
ADDITIONAL FED INCOME TAX LIABILITY	216,524	6,631,871	833,265	463,709	4,667,745	993,621	139,732	241,889	129,671	1,251	17,714	(223,226)
TOTAL OPERATING EXPENSES	4,214,268	79,777,676	10,194,130	10,374,620	73,540,094	19,016,725	2,586,310	7,534,048	3,136,197	32,871	1,995,140	2,833,470
RETURN DEFICIENCY BEFORE INCOME TAXES @ REQUESTED ROR	674,465	20,658,104	2,595,599	1,444,442	14,539,902	3,095,102	435,261	753,479	403,923	3,898	55,180	(695,342)
TOTAL PROPOSED OPERATING REVENUE (COST OF SERVICE)	6,320,794	122,266,870	14,861,259	15,282,874	108,372,034	28,568,443	3,909,324	11,546,814	4,771,115	49,758	4,941,081	6,600,358
LESS: OTHER OPERATING REVENUE	28,060	476,902	12,493	13,645	103,083	126,527	10,253	35,089	10,973	109	3,350	26,998
PROPOSED SALES REVENUE @ EQUALIZED ROR	6,292,735	121,789,967	14,848,766	15,269,229	108,268,951	28,441,917	3,899,071	11,511,725	4,760,142	49,650	4,937,731	6,573,361
TOTAL PRESENT OPERATING REVENUE	5,421,010	94,832,331	11,405,460	13,344,027	88,981,699	24,440,633	3,329,170	10,536,851	4,232,312	44,547	4,867,315	7,517,184
LESS: OTHER OPERATING REVENUE	28,060	476,902	12,493	13,645	103,083	126,527	10,253	35,089	10,973	109	3,350	26,998
PRESENT SALES REVENUE	5,392,950	94,355,429	11,392,966	13,330,382	88,878,616	24,314,107	3,318,916	10,501,762	4,221,339	44,438	4,863,965	7,490,186
REVENUE DEFICIENCY	899,784	27,434,539	3,455,799	1,938,847	19,390,335	4,127,810	580,155	1,009,963	538,803	5,212	73,766	(916,826)
PCT INCREASE TOTAL SALES REVENUE	16.68%	29.08%	30.33%	14.54%	21.82%	16.98%	17.48%	9.62%	12.76%	11.73%	1.52%	-12.24%

Oklahoma Gas & Electric Company

1MW COSS Adjusted for 4CP A&E

ACCT(S) / DESCRIPTION	42 LED LIGHTING S/L-5	43 BACK UP & MAINTENANCE S/L-1	65 1 MW OUTSIDE S/L-1	66 1 MW OUTSIDE S/L-2	67 1 MW OUTSIDE S/L-3	68 1 MW OUTSIDE S/L-4	69 1 MW OUTSIDE S/L-5	1 OKLA RETAIL JURISDICTION	2 ISSUE ARK RETAIL	3 ISSUE WHOLESALE
SUMMARY OF RATE BASE										
GROSS ELECTRIC PLANT IN SERVICE	271,617,277	664,969	1,390,047	89,450,670	9,035,775	878,965	3,430,477	13,925,511,738	1,247,911,090	244,237,834
LESS: ACCUM PROV FOR DEPR	52,158,954	291,041	607,688	32,706,447	3,458,435	358,072	1,304,822	5,088,353,293	453,779,907	80,585,405
CONSTRUCTION WORK IN PROGRESS	0	0	0	0	0	0	0	0	0	0
PLANT HELD FOR FUTURE USE	4,682	69	145	5,976	2,047	140	693	2,027,482	72,055	0
NET ELECTRIC UTILITY PLANT IN SERVICE	219,463,005	373,997	782,504	56,750,199	5,579,387	521,033	2,126,348	8,839,185,927	794,203,238	163,652,429
ADDITIONS TO RATE BASE:										
CASH WORKING CAPITAL	(237,172)	(2,264)	(4,733)	(449,217)	(37,266)	(3,264)	(13,416)	(52,914,819)	(7,010,973)	(310,298)
PREPAYMENTS	20,975	1,259	2,654	97,023	11,105	1,390	4,423	9,514,531	884,196	1,626
MATERIALS AND SUPPLIES	431,261	5,413	11,379	1,075,329	108,997	9,070	42,034	184,267,563	15,581,483	392,247
FUEL INVENTORIES	208,491	13,429	28,328	991,286	114,783	14,703	46,168	89,579,214	8,441,763	0
GAS IN STORAGE	35,821	2,307	4,867	170,312	19,721	2,526	7,932	15,390,510	1,450,370	0
REGULATORY ASSETS	2,479,012	9,424	19,716	1,422,573	132,946	12,605	49,294	195,571,872	23,313,162	1,911,350
NET PENSION BENEFIT ASSET (OBLIGATION)	(95,931)	(916)	(1,914)	(181,699)	(15,073)	(1,320)	(5,427)	(21,402,969)	(2,835,796)	(125,509)
TOTAL ADDITIONS	2,842,457	28,652	60,296	3,125,606	335,212	35,710	131,007	420,005,902	39,824,204	1,869,415
DEDUCTIONS TO RATE BASE:										
ASSET RETIREMENT OBLIGATION	(99,270)	(6,412)	(13,474)	(555,926)	(60,309)	(6,981)	(21,997)	(74,466,168)	(6,702,768)	0
CUSTOMER DEPOSITS	0	0	0	(71,615)	(253,919)	0	(11,315)	(89,860,322)	(10,025,200)	0
ACCUMULATED DEFERRED TAXES	(20,689,544)	(54,037)	(113,012)	(7,101,167)	(719,609)	(70,626)	(272,686)	(1,098,861,037)	(98,505,717)	(18,523,561)
REGULATORY LIABILITIES	(15,730,212)	(37,844)	(79,102)	(5,123,874)	(517,135)	(50,185)	(196,430)	(798,979,331)	(71,595,928)	(14,130,277)
TOTAL DEDUCTIONS	(36,519,025)	(98,294)	(205,588)	(12,852,582)	(1,550,971)	(127,791)	(502,428)	(2,062,166,858)	(186,829,613)	(32,653,839)
TOTAL RATE BASE	185,786,437	304,355	637,212	47,023,223	4,363,628	428,953	1,754,928	7,197,024,971	647,197,829	132,868,005
SUMMARY OF RETURN AT PRESENT RATES										
RATE BASE	185,786,437	304,355	637,212	47,023,223	4,363,628	428,953	1,754,928	7,197,024,971	647,197,829	132,868,005
RETURN	5,021,334	209,980	58,611	(191,556)	252,867	240,027	144,730	314,170,966	5,899,221	3,932,972
RATE OF RETURN ON RATE BASE	2.70275%	68.99165%	9.19797%	-0.40736%	5.79488%	55.95650%	8.24704%	4.36529%	0.91150%	2.96006%
RELATIVE RATE OF RETURN	0.619145	15.804600	2.107069	-0.093319	1.327491	12.818510	1.889231	1.000000	0.208807	0.678090
FUEL	0	0	0	0	0	0	0	1	0	0
PURCHASED POWER	0	0	0	0	0	0	0	0	0	0
O&M (LESS FUEL), INCLUDES REGULATORY ASSET AMORTIZATION	4,566,385	19,370	40,547	3,410,852	291,050	26,546	104,980	413,727,604	53,605,507	3,278,157
INTEREST OF CUSTOMER DEPOSITS	0	0	0	2,078	7,367	0	328	2,606,796	111,871	0
DEPRECIATION EXPENSE	15,579,933	22,729	47,260	3,015,188	306,171	30,233	119,377	488,096,054	42,632,529	5,990,498
MISCELLANEOUS TAXES	891	9	18	1,688	140	12	50	198,812	26,342	1,166
PROPERTY TAXES	1,322,543	4,353	9,115	521,501	53,784	5,461	20,270	79,524,915	7,029,034	1,166,652
PAYROLL TAXES	55,133	526	1,100	104,424	8,663	759	3,119	12,300,509	1,629,762	72,132
FEDERAL & STATE INCOME TAX LIABILITY	(866,716)	63,349	10,314	(688,867)	22,960	71,333	23,049	4,837,468	(7,113,914)	(586,663)
TOTAL OPERATING EXPENSES	20,658,169	110,336	108,354	6,366,864	690,134	134,344	271,173	1,001,292,158	97,921,131	9,921,942
TOTAL OPERATING REVENUES (COST OF SERVICE)	25,679,503	320,316	166,965	6,175,308	943,001	374,371	415,903	1,315,463,124	103,820,352	13,854,913
LESS: OPERATING REVENUE CREDIT	12,732	176	206	21,528	4,430	188	2,472	18,051,062	903,852	0
PRESENT SALES REVENUE	25,666,771	320,140	166,759	6,153,781	938,571	374,184	413,431	1,297,412,062	102,916,500	13,854,913
SUMMARY - EQUALIZED REQUESTED RATE OF RETURN										
RATE BASE	185,786,437	304,355	637,212	47,023,223	4,363,628	428,953	1,754,928	7,197,024,971	647,197,829	132,868,005
RATE OF RETURN ON RATE BASE	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%	7.88000%
RETURN	14,639,971	23,983	50,212	3,705,430	343,854	33,801	138,288	567,125,568	50,999,189	10,469,999
O&M (LESS FUEL), INCLUDES REGULATORY ASSET AMORTIZATION	4,568,692	19,519	40,860	3,423,769	292,451	26,708	105,491	415,457,788	53,761,235	3,278,157
INTEREST ON CUSTOMER DEPOSITS	0	0	0	2,078	7,367	0	328	2,606,796	111,871	0
DEPRECIATION EXPENSE	15,579,933	22,729	47,260	3,015,188	306,171	30,233	119,377	488,096,054	42,632,529	5,990,498
TAXES OTHER THAN INCOME TAXES	1,378,567	4,887	10,233	627,613	62,587	6,232	23,440	92,024,236	8,685,138	1,239,949
FED INCOME TAX LIABILITY @ CURRENT ROR	(866,716)	63,349	10,314	(688,867)	22,960	71,333	23,049	4,837,468	(7,113,914)	(586,663)
ADDITIONAL FED INCOME TAX LIABILITY	3,087,871	(59,710)	(2,696)	1,251,049	29,209	(66,205)	(2,068)	81,206,016	14,478,443	2,098,582
TOTAL OPERATING EXPENSES	23,748,346	50,774	105,971	7,630,830	720,745	68,302	269,616	1,084,228,357	112,555,301	12,020,524
RETURN DEFICIENCY BEFORE INCOME TAXES @ REQUESTED ROR	9,618,637	(185,997)	(8,398)	3,896,986	90,987	(206,225)	(6,441)	252,954,602	45,099,968	6,537,027
TOTAL PROPOSED OPERATING REVENUE (COST OF SERVICE)	38,388,318	74,757	156,184	11,336,260	1,064,599	102,103	407,905	1,651,353,925	163,554,490	22,490,522
LESS: OTHER OPERATING REVENUE	12,732	176	206	21,528	4,430	188	2,472	18,051,062	903,852	0
PROPOSED SALES REVENUE @ EQUALIZED ROR	38,375,586	74,582	155,978	11,314,732	1,060,169	101,916	405,433	1,633,302,863	162,650,638	22,490,522
TOTAL PRESENT OPERATING REVENUE	25,679,503	320,316	166,965	6,175,308	943,001	374,371	415,903	1,315,463,124	103,820,352	13,854,913
LESS: OTHER OPERATING REVENUE	12,732	176	206	21,528	4,430	188	2,472	18,051,062	903,852	0
PRESENT SALES REVENUE	25,666,771	320,140	166,759	6,153,781	938,571	374,184	413,431	1,297,412,062	102,916,500	13,854,913
REVENUE DEFICIENCY	12,708,814	(245,558)	(10,781)	5,160,951	121,598	(272,268)	(7,998)	335,890,801	59,734,138	8,635,609
PCT INCREASE TOTAL SALES REVENUE	49.51%	-76.70%	-6.47%	83.87%	12.96%	-72.76%	-1.93%	25.89%	58.04%	62.33%

Oklahoma Gas and Electric Company

Present vs. Proposed Rate Increase

Power and Light Time-of-Use Service Level 1

Line	Description	Tariff Rates Present	Tariff Rates Proposed	Proposed Change Amount	Proposed Change Percentage
1	**Customer Charge**	$234.00	$234.00	-	0.00%
2	**Demand Charge**			-	
3	WINTER MAX KW	$3.600	$3.600	-	0.00%
4	SUMMER MAX KW	$3.600	$3.600	-	0.00%
5	ON-PEAK KW	-	-	-	
6	**Energy Charge**			-	
7	Winter			-	
8	First Block kWh	$0.0050	$0.0050	-	0.00%
9	Second Block kWh	$0.000	$0.000	-	
10	Summer			-	
11	First Block kWh	$0.000	$0.000	-	
12	Second Block kWh	$0.000	$0.000	-	
13	On-peak hours	$0.060	$0.060	-	0.00%
14	Off-peak hours	$0.005	$0.005	-	0.00%
15	Shoulder			-	
16	Super Off-Peak kWh	$0.000	$0.000	-	

Power and Light Time-of-Use Service Level 2

Line	Description	Tariff Rates Present	Tariff Rates Proposed	Proposed Change Amount	Proposed Change Percentage
17	**Customer Charge**	$234.00	$150.00	($84.000)	(35.90%)
18	**Demand Charge**				
19	WINTER MAX KW	$4.110	$6.500	$2.390	58.15%
20	SUMMER MAX KW	$4.110	$6.500	$2.390	58.15%
21	ON-PEAK KW				
22	**Energy Charge**				
23	Winter				
24	First Block kWh	$0.009	$0.010	$0.001	11.11%
25	Second Block kWh	$0.000	$0.000		
26	Summer				
27	First Block kWh	$0.000	$0.000		
28	Second Block kWh	$0.000	$0.000		
29	On-peak hours	$0.082	$0.096	$0.014	17.07%
30	Off-peak hours	$0.009	$0.010	$0.001	11.11%
31	Shoulder				
32	Super Off-Peak kWh	$0.000	$0.000	-	

Source: Oklahoma Gas and Electric Proof of Revenue Schedule M-4.

Oklahoma Gas and Electric Company

Present vs. Proposed Rate Increase

Power and Light Time-of-Use Service Level 3

	Description	Tariff Rates		Proposed Change	
		Present	Proposed	Amount	Percentage
33	**Customer Charge**	$121.00	$125.00	$4.000	3.31%
34	**Demand Charge**				
35	WINTER MAX KW	$5.570	$6.500	$0.930	16.70%
36	SUMMER MAX KW	$5.570	$6.500	$0.930	16.70%
37	ON-PEAK KW				
38	**Energy Charge**				
39	Winter				
40	First Block kWh	$0.010	$0.010	$0.000	0.00%
41	Second Block kWh	$0.000	$0.000	$0.000	
42	Summer				
43	First Block kWh	$0.000	$0.000	$0.000	
44	Second Block kWh	$0.000	$0.000	$0.000	
45	On-peak hours	$0.090	$0.096	$0.006	6.67%
46	Off-peak hours	$0.010	$0.010	$0.000	0.00%
47	Shoulder				
48	Super Off-Peak kWh	$0.000	$0.000	-	

Power and Light Time-of-Use Service Level 4

	Description	Tariff Rates		Proposed Change	
		Present	Proposed	Amount	Percentage
49	**Customer Charge**	$91.00	$120.00	$29.000	31.87%
50	**Demand Charge**				
51	WINTER MAX KW	$6.130	$7.750	$1.620	26.43%
52	SUMMER MAX KW	$6.130	$7.750	$1.620	26.43%
53	ON-PEAK KW		$0.000		
54	**Energy Charge**				
55	Winter				
56	First Block kWh	$0.011	$0.012	$0.001	9.09%
57	Second Block kWh	$0.000	$0.000	$0.000	
58	Summer				
59	First Block kWh	$0.000	$0.000	$0.000	
60	Second Block kWh	$0.000	$0.000	$0.000	
61	On-peak hours	$0.090	$0.105	$0.015	16.67%
62	Off-peak hours	$0.011	$0.012	$0.001	9.09%
63	Shoulder				
64	Super Off-Peak kWh	$0.000	$0.000	-	

Source: Oklahoma Gas and Electric Proof of Revenue Schedule M-4.

Oklahoma Gas and Electric Company

Present vs. Proposed Rate Increase

Power and Light Time-of-Use Service Level 5

	Description	Tariff Rates		Proposed Change	
		Present	Proposed	Amount	Percentage
65	**Customer Charge**	$79.00	$119.00	$40.000	50.63%
66	**Demand Charge**				
67	WINTER MAX KW	$7.134	$9.300	$2.166	30.36%
68	SUMMER MAX KW	$7.134	$9.300	$2.166	30.36%
69	ON-PEAK KW	$0.000	$0.000	$0.000	0.00%
70	**Energy Charge**				
71	Winter				
72	First Block kWh	$0.013	$0.017	$0.004	30.53%
73	Second Block kWh	$0.000	$0.000	$0.000	
74	Summer				
75	First Block kWh	$0.000	$0.000	$0.000	0.00%
76	Second Block kWh	$0.000	$0.000	$0.000	0.00%
77	On-peak hours	$0.101	$0.140	$0.039	38.07%
78	Off-peak hours	$0.013	$0.017	$0.004	30.53%
79	Shoulder				
80	Super Off-Peak kWh	$0.000	$0.000	-	0.00%

Large Power and Light Time-of-Use Service Level 1

	Description	Tariff Rates		Proposed Change	
		Present	Proposed	Amount	Percentage
81	**Customer Charge**	$300.00	$400.00	$100.000	33.33%
82	**Demand Charge**				
83	WINTER MAX KW	$6.940	$8.400	$1.460	21.04%
84	SUMMER MAX KW	$6.940	$8.400	$1.460	21.04%
85	ON-PEAK KW				
86	**Energy Charge**				
87	Winter				
88	First Block kWh	$0.003	$0.004	$0.000	12.90%
89	Second Block kWh	$0.003	$0.004	$0.000	12.90%
90	Summer				
91	First Block kWh	$0.000	$0.000	$0.000	0.00%
92	Second Block kWh	$0.000	$0.000	$0.000	0.00%
93	On-peak hours	$0.044	$0.064	$0.020	44.47%
94	Off-peak hours	$0.003	$0.004	$0.000	12.90%
95	Shoulder				
96	Super Off-Peak kWh	$0.000	$0.000	-	0.00%

Source: Oklahoma Gas and Electric Proof of Revenue Schedule M-4.

Oklahoma Gas and Electric Company

Present vs. Proposed Rate Increase

Large Power and Light Time-of-Use Service Level 2

	Description	Tariff Rates		Proposed Change	
		Present	Proposed	Amount	Percentage
97	**Customer Charge**	$350.00	$400.00	$50.000	14.29%
98	**Demand Charge**				
99	WINTER MAX KW	$7.631	$9.830	$2.199	28.82%
100	SUMMER MAX KW	$7.631	$9.830	$2.199	28.82%
101	ON-PEAK KW				
102	**Energy Charge**				
103	Winter				
104	First Block kWh	$0.003	$0.005	$0.001	45.16%
105	Second Block kWh	$0.003	$0.005	$0.001	45.16%
106	Summer				
107	First Block kWh	$0.000	$0.000	$0.000	0.00%
108	Second Block kWh	$0.000	$0.000	$0.000	0.00%
109	On-peak hours	$0.044	$0.065	$0.021	0.00%
110	Off-peak hours	$0.003	$0.005	$0.001	0.00%
111	Shoulder				
112	Super Off-Peak kWh	$0.000	$0.000	-	0.00%

Large Power and Light Time-of-Use Service Level 3

	Description	Tariff Rates		Proposed Change	
		Present	Proposed	Amount	Percentage
113	**Customer Charge**	$135.00	$160.00	$25.000	18.52%
114	**Demand Charge**				
115	WINTER MAX KW	$8.660	$10.600	$1.940	22.40%
116	SUMMER MAX KW	$8.660	$10.600	$1.940	22.40%
117	ON-PEAK KW				
118	**Energy Charge**				
119	Winter				
120	First Block kWh	$0.004	$0.005	$0.001	28.21%
121	Second Block kWh	$0.000	$0.000	$0.000	0.00%
122	Summer				
123	First Block kWh	$0.000	$0.000	$0.000	0.00%
124	Second Block kWh	$0.000	$0.000	$0.000	0.00%
125	On-peak hours	$0.076	$0.092	$0.016	21.37%
126	Off-peak hours	$0.004	$0.005	$0.001	28.21%
127	Shoulder				
128	Super Off-Peak kWh	$0.000	$0.000	$0.000	0.00%

Source: Oklahoma Gas and Electric Proof of Revenue Schedule M-4.

Oklahoma Gas and Electric Company

Present vs. Proposed Rate Increase

Large Power and Light Time-of-Use Service Level 4

	Description	Tariff Rates		Proposed Change	
		Present	Proposed	Amount	Percentage
129	**Customer Charge**	$135.00	$150.00	$15.000	11.11%
130	**Demand Charge**				
131	WINTER MAX KW	$9.360	$11.750	$2.390	25.53%
132	SUMMER MAX KW	$9.360	$11.750	$2.390	25.53%
133	ON-PEAK KW				
134	**Energy Charge**				
135	Winter				
136	First Block kWh	$0.004	$0.005	$0.001	28.21%
137	Second Block kWh	$0.000	$0.000	$0.000	0.00%
138	Summer				
139	First Block kWh				
140	Second Block kWh				
141	On-peak hours	$0.076	$0.094	$0.018	24.01%
142	Off-peak hours	$0.004	$0.005	$0.001	28.21%
143	Shoulder				
144	Super Off-Peak kWh	$0.000	$0.000	$0.000	0.00%

Large Power and Light Time-of-Use Service Level 5

	Description	Tariff Rates		Proposed Change	
		Present	Proposed	Amount	Percentage
145	**Customer Charge**	$77.00	$120.00	$43.000	55.84%
146	**Demand Charge**				
147	WINTER MAX KW	$11.800	$13.950	$2.150	18.22%
148	SUMMER MAX KW	$11.800	$13.950	$2.150	18.22%
149	ON-PEAK KW				
150	**Energy Charge**				
151	Winter				
152	First Block kWh	$0.007	$0.008	$0.001	9.59%
153	Second Block kWh	$0.000	$0.000	$0.000	0.00%
154	Summer				
155	First Block kWh				
156	Second Block kWh				
157	On-peak hours	$0.084	$0.096	$0.012	13.74%
158	Off-peak hours	$0.007	$0.008	$0.001	9.59%
159	Shoulder				
160	Super Off-Peak kWh	$0.000	$0.000	$0.000	0.00%

Source: Oklahoma Gas and Electric Proof of Revenue Schedule M-4.

Oklahoma Gas & Electric Company

Rate Design Demand and Energy Charge Adjustments

Power and Light Time of Use Service Level 2

	Description		Tariff Rates		No. of Customers or Consumption		Revenues		Proposed Change	
			Present	Proposed	Present	Proposed	Present	Proposed	Amount	Percentage
1	**Customer Charge**		$234.00	$150.00	276	276	$ 64,573	$ 41,393	(23,180)	(35.90%)
2	**LIAP**				-	-	-	$ -	-	
3	**Senior Citizen discount**				-	-	-	$ -	-	
4	**Demand Charge**									
5		WINTER MAX KW	4.1100	6.1650	298,693	298,693	1,227,630	1,841,444	613,815	50.00%
6		SUMMER MAX KW	4.1100	6.1650	223,721	223,721	919,494	1,379,242	459,747	50.00%
7		ON-PEAK KW		-	-	-	-	-	-	
8	Total Demand				522,415	522,415	2,147,124	3,220,686		0.00%
9	**Energy Charge**									
10	Winter									
11		First Block kWh	$0.0090	$0.0099	69,433,323	69,433,323	624,900	687,390	62,490	10.00%
12		Second Block kWh	$0.000	$0.0000	-	-	-	-	-	
13		Totals (Winter)			69,433,323	69,433,323	624,900	687,390		
14	Summer									
15		First Block kWh	$0.000	$0.0000	-	-	-	-	-	
16		Second Block kWh	$0.000	$0.0000	-	-	-	-	-	
17		On-peak hours	$0.082	$0.1329	5,768,984	5,768,984	473,057	766,529	293,472	62.04%
18		Off-peak hours	$0.009	$0.0095	55,916,541	55,916,541	503,249	528,411	25,162	5.00%
19		On-peak hours 1			-	-	-	-	-	
20		On-peak hours 2			-	-	-	-	-	
21		On-peak hours 3			-	-	-	-	-	
22		On-peak hours 4			-	-	-	-	-	
23		CRITICAL PEAK			-	-	-	-	-	
24		Totals (Summer)			61,685,525	61,685,525	976,306	1,294,940		
25	Shoulder									
26		Super Off-Peak kWh	$0.000	$0.000	-	-	-	-	-	
27										
28	Total Energy				131,118,848	131,118,848	1,601,205	1,982,330		
29										
30	**Total Revenue, without riders**						$3,812,903	$5,244,409	1,431,506	37.54%

Oklahoma Gas & Electric Company

Rate Design Demand and Energy Charge Adjustments

Power and Light Time of Use Service Level 3

	Description	Tariff Rates		No. of Customers or Consumption		Revenues		Proposed Change	
		Present	Proposed	Present	Proposed	Present	Proposed	Amount	Percentage
1	**Customer Charge**	$121.00	$125.00	2,098	2,098	$ 253,858	$ 262,250	8,392	3.31%
2	**LIAP**			-	-	-	$ -	-	
3	**Senior Citizen discount**			-	-	-	$ -	-	
4	**Demand Charge**								
5	WINTER MAX KW	5.5700	6.3220	926,681	926,681	5,161,611	5,858,429	696,818	13.50%
6	SUMMER MAX KW	5.5700	6.3220	669,174	669,174	3,727,301	4,230,487	503,186	13.50%
7	ON-PEAK KW		-	-	-	-	-	-	
8	Total Demand			1,595,855	1,595,855	8,888,912	10,088,915		0.00%
9	**Energy Charge**								
10	Winter								
11	First Block kWh	$0.0100	$0.0100	347,132,647	347,132,647	3,471,326	3,471,326	-	0.00%
12	Second Block kWh	$0.000	$0.0000	-	-	-	-	-	
13	Totals (Winter)			347,132,647	347,132,647	3,471,326	3,471,326		
14	Summer								
15	First Block kWh	$0.000	$0.0000	-	-	-	-	-	
16	Second Block kWh	$0.000	$0.0000	-	-	-	-	-	
17	On-peak hours	$0.090	$0.1037	36,918,273	36,918,273	3,322,645	3,828,296	505,652	15.22%
18	Off-peak hours	$0.010	$0.0100	226,108,050	226,108,050	2,261,080	2,261,080	-	0.00%
19	On-peak hours 1			-	-	-	-	-	
20	On-peak hours 2			-	-	-	-	-	
21	On-peak hours 3			-	-	-	-	-	
22	On-peak hours 4			-	-	-	-	-	
23	CRITICAL PEAK			-	-	-	-	-	
24	Totals (Summer)			263,026,322	263,026,322	5,583,725	6,089,377		
25	Shoulder								
26	Super Off-Peak kWh	$0.000	$0.000	-	-	-	-	-	
27									
28	Total Energy			610,158,969	610,158,969	9,055,051	9,560,703		
29									
30	**Total Revenue, without riders**					$18,197,822	$19,911,869	1,714,047	9.42%

CERTIFICATE OF SERVICE

On this 3rd day of May 2024, a true and correct copy of the *Responsive Testimony of Michael P. Gorman on Behalf of the Federal Executive Agencies* was sent via electronic mail to the following interested parties:

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