BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR APPROVAL OF A GENERAL CHANGE IN	)	DOCKET NO. 10-067-U
RATES AND TARIFFS	)	

Direct Testimony

of

Greg Veitch

on behalf of

Oklahoma Gas and Electric Company

September 28, 2010

Greg Veitch
Direct Testimony

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

A. My name is Greg Veitch. My business address is 321 N. Harvey, P. O. Box 321, Oklahoma City, Oklahoma 73101.

Q. **By whom are you employed and in what capacity?**

A. I am employed by the Oklahoma Gas and Electric Company ("OG&E" or "Company") as Manager Cost of Service.

Q. **What is your educational background and experience with OG&E?**

A. I earned a Bachelor of Science degree in Accounting from Central State University in 1988. In 1991, I became a Certified Public Accountant, licensed to practice in Oklahoma, and a member of the Oklahoma Society of Certified Public Accountants. I have been employed by OG&E for thirty-seven years. My experience in Regulatory (2005 to present) has been primarily in cost of service studies, revenue requirement calculations for special projects and rate case support. I have attended various courses and seminars on cost of service, rate design and utility industry related issues.

Q. **What is the purpose of your testimony?**

A. I am sponsoring the schedules in the Cost of Service Analyses section of the Company's filing. The schedules G-1 through G-4 summarize the calculated output of the Company's cost of service study ("COSS") and allocation factors used in its development. I also sponsor schedules G-1-1A through G-3-1A, which reflect the cost of service shown on both a functional and classification basis.

Q. **Have you previously filed testimony before the Arkansas Public Service Commission ("APSC") regarding Cost of Service issues?**

A. Yes. I filed cost of service testimony in Docket No. 08-103-U on August 29, 2008, OG&E's most recent base rate filing before the APSC.

Q. **How is your testimony organized?**

A. My testimony is organized into the following sections:

Section I: Development of Cost of Service Study

Section II: Allocations and Direct Assignments

Section III: Results of Cost of Service Study

Q. **Does OG&E's COSS in this filing incorporate recommendations made by staff in Docket No. 08-103-U?**

A. Yes. The COSS contained in this base rate proceeding reflects two allocation changes recommended by Staff Witness Sandra B. Green in her Surrebuttal Testimony in that previous case. Those two recommended allocation changes were: 1) 95% of the cost for major account representatives be direct assigned to the Power and Light (PL) and Power and Light Time of Use (PLTOU) classes and the remaining 5% to the General Service (GS) class; and 2) economic development costs be allocated on base revenues. These changes helped ensure that these costs get allocated to those classes that received the most benefit from these services provided.

I. DEVELOPMENT OF COST OF SERVICE STUDY

Q. **What is the purpose or nature of a COSS?**

A. The COSS is used to determine a utility's total revenue requirement and to allocate the cost-of-service components to determine the revenue requirements for the Arkansas customer classes. The COSS is also used as a tool to determine rates of return for each customer class. In a COSS, particular costs are either allocated or directly assigned to customer classes to determine the cost of service for each class. Because costs are generally determined from historical accounting records, this type of analysis is referred to as an "accounting" or "embedded" COSS. Costs are allocated to customer classes on a cost causation basis; referred to as a "fully distributed" or "fully allocated" COSS. When the COSS is prepared and all costs are allocated to the various jurisdictions, the result is a fully allocated embedded COSS that establishes cost responsibility and makes it possible to determine the cost of providing service to each customer class.

Q. **What are the "cost" components of the COSS you are sponsoring?**

A. The cost components of OG&E's embedded COSS are: (i) Operation and Maintenance Expenses, (ii) Depreciation Expenses, (iii) Federal and State Income Taxes, (iv) Taxes Other Than Income Taxes, and (v) Costs of Capital (Return).

Q. **What are the major steps required in the development of a fully allocated COSS?**

A. The development of a fully allocated COSS consists of three major steps: (i) functionalization, (ii) classification, and (iii) allocation or assignment. First, functionalization is the process of categorizing embedded costs by the operating function with which the costs are primarily associated. The functional categories used in ratemaking are:

- Production
- Transmission
- Distribution
- Customer Service
- Administrative and General (A&G).

The Production function captures the costs associated with facilities used for generating electricity. The Transmission function captures the costs associated with high voltage power lines and stations that deliver power to the distribution system or certain end users. The Distribution function includes costs associated with facilities not classified as "transmission," including distribution stations, primary and secondary power lines, transformers, service drops and meters that connect customers to the utility system. The Customer Service function deals with services and costs associated with providing meter reading, billing, bill collection, customer information and other services. The A&G function captures the costs associated with management of the business and general services of the utility such as staffing, accounting, legal, regulatory, communications, general purpose buildings/facilities, maintenance of such buildings/facilities, and other costs that may not be assignable to other functions.

Q. Please describe the classification process.

A. The second step is to classify the functionalized costs in order to reflect the manner in which the costs were incurred. Classification further defines functional costs into demand-related (*i.e.*, costs associated with being able to serve customers at maximum demand), energy-related (*i.e.*, costs that vary with the amount of energy used by customers), and customer-related (*i.e.*, costs that are directly related to the number of customers served).

The typical cost classifications associated with each functional category are summarized below in Chart 1:

Chart 1

Cost Function	Cost Classification
Production	Demand-Related Energy-Related
Transmission	Demand-Related
Distribution	Demand-Related Customer-Related
Customer Service	Customer-Related

Demand-related costs are fixed in nature, and tend not to vary with the use of electric plant facilities. Thus, demand-related costs are allocated to customer classes based on their respective megawatt (MW) load or demand characteristics.

Energy-related costs vary with use of electric plant facilities. Fuel and variable operation and maintenance expenses are primarily energy-related costs. These costs are allocated to customer classes based on an analysis of class energy consumption, including losses in delivery.

Customer-related costs are those expenses that are a function of the number and size of customers. Customer-related plant investment includes facilities needed to give customers access to OG&E's system. Other customer-related costs include expense items such as customer accounts, customer service and information, meter operation and plant-associated O&M expenses.

Q. **What does the third step – allocation or assignment – involve?**

A. The third step in the process is allocation, which involves dividing functionalized and classified costs to jurisdictions and customer classes of service. Most costs are attributable to more than one jurisdiction or customer class and must be allocated based on each jurisdiction's or customer class' contribution to the costs. At the same time, some costs can be directly assigned to a certain jurisdiction, a single customer class or a certain customer when those costs can be identified as being wholly attributable to such a jurisdiction, customer class, or customer. Investment in a substation used solely by a particular customer is one example of a cost that should be directly assigned to a specific class. After all costs have been allocated or assigned, a cost to serve is calculated for each jurisdiction and customer class.

Q. **What criteria did OG&E use in the development of appropriate allocation factors?**

A. The following criteria, although not an exhaustive list, provides an objective basis upon which to judge the appropriateness of an allocation methodology:

1. The method should reflect the operating and planning characteristics of the utility system;
2. The method should recognize the various customer class characteristics such as peak demand, energy usage, load factor, diversity characteristics, number and size of customers, points of delivery, etc.;
3. The method should produce stable results from year-to-year; and
4. Customers who benefit from the use of plant and equipment should bear the costs in a proportional manner.

II. ALLOCATIONS AND DIRECT ASSIGNMENTS

Q. **Please describe the development of the demand allocation factors used in the COSS you are sponsoring.**

A. I will begin with a description of the production demand allocation factor. Next, I will describe the transmission demand allocation factor. Finally, I will describe the distribution demand-related allocation factor. It should be noted that demand load data used in the development of these allocators in this case were "weather normalized."

Q. **Why is it appropriate to use different demand allocation factors for production, transmission and distribution?**

A. The purpose of the allocation process is to assign costs to the cost causer in the most accurate way possible. Cost causation is an attempt to determine what, or who, is causing costs to be incurred by the utility.[1] As explained below, each of the production, transmission, and distribution categories have different cost drivers that require different allocation methods to most accurately match costs to cost causers.

Q. **Please describe the method of cost allocation used to determine the jurisdictional and customer class production capacity responsibilities.**

A. The 1 Coincident Peak and Average demand method ("1CP & Average") has been used to allocate production related demand costs to the Arkansas jurisdiction and classes. The 1CP & Average demand method incorporates two measurements in the allocation of demand-related costs. The first measurement, the coincident peak demand ("1CP"), is the load of all customer classes at the time of the Company's highest measured one-hour demand for the system in the test year. The second measurement, energy, is the total mega-watt hours used during the test year to determine the average demand ("Average"). The 1CP & Average demand method recognizes not only the class loads at the time of the system maximum peak, but also the amount of energy usage that all classes utilize during all hours of the test year.

Q. **Why was the 1CP and Average demand method used in the allocation of production plant?**

A. The coincident peak and energy usage determinants reflect the cause and effect relationship of production costs incurred to serve each class not only at the system peak, but also during all hours of the year. Secondly, the APSC has approved and the

[1] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, 1992, p 13, 38-39.

APSC staff has supported this method in previous dockets. Finally, in the current COSS, OG&E weather normalized the 1CP component (demand) of the 1CP and Average method. Historically, the Average component (energy) has been weather normalized.

Q. **What adjustment did OG&E make to its production allocator CAP1SY calculation that is different than its last rate case?**

A. The production allocator CAP1SY methodology is the same in this proceeding. However, the Company modified the demand component of the allocator by crediting the Oklahoma jurisdiction for the direct assignment of 440 MW related to cogeneration contracts. Additionally, the demand and energy components of the allocator were adjusted to recognize the megawatts and kilowatt hours associated with the economic recovery pro forma adjustment described in OG&E witnesses Bryan Scott and Adam Bigknife's direct testimonies. The economic recovery energy pro forma kilowatt hours were also utilized in developing the energy allocator ENR1SY, which is discussed later in my testimony.

Q. **Why did OG&E make these modifications to the CAP1SY?**

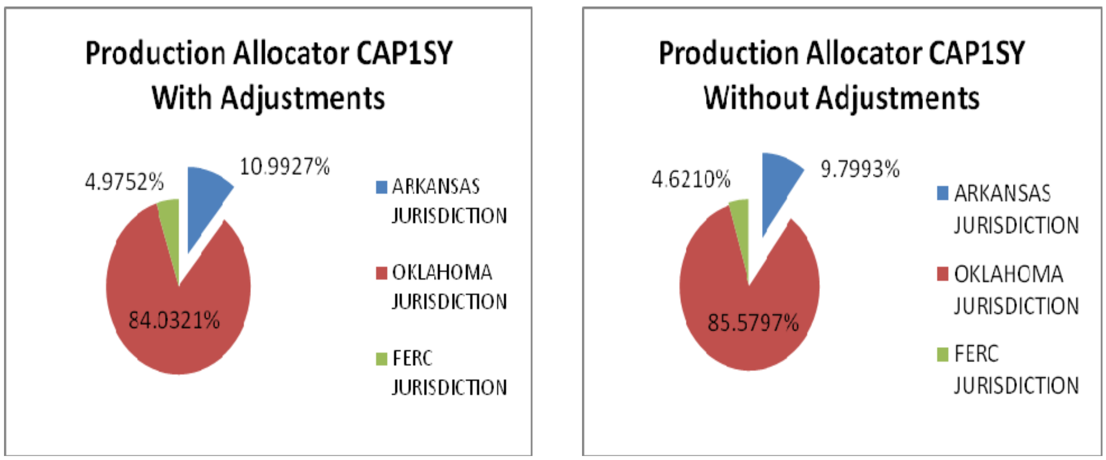
A. Costs not directly assigned in a COSS are considered "joint" costs such as generation resources. Appropriate allocators must be developed to assign these joint costs. Historically, the costs of OG&E's cogeneration contracts have never been charged to Arkansas customers. The cogeneration contracts provide a 440 MW contribution to the Company's overall generation resources and should be considered in developing the allocation for OG&E's generation fleet which is also a component of the overall generation resources. In past cases, notwithstanding the fact that Oklahoma customers paid 100% of the cogeneration contracts, the Oklahoma jurisdiction did not receive credit for the 440 MW in the development of the CAP1SY. The end result was that the Oklahoma jurisdiction was assigned an excessive portion of OG&E's generation fleet investment and related expenses.

Q. **What was the change in the CAP1SY by crediting the Oklahoma jurisdiction for the 440 MW cogeneration contracts and adjusting the test year Arkansas jurisdiction demand and energy for the economic recovery pro forma adjustment?**

A. The CAP1SY allocator increased from 9.7993% to 10.9927% for the Arkansas jurisdiction. This allocation methodology is supported by the cost causation principle discussed previously in my testimony and normalization regulatory practice. Chart 2 illustrates the change in allocation.

Chart 2

Production Allocator CAP1SY Comparison



Q. **What adjustment did OG&E make to its energy allocator ENR1SY calculation that is different than its last rate case?**

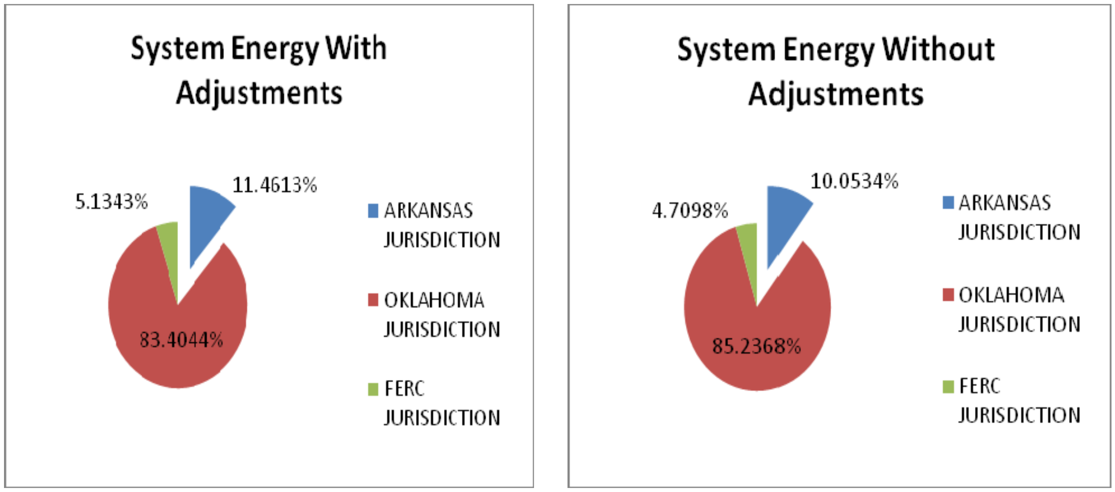
A. The energy allocator ENR1SY methodology is the same in this proceeding. However, the Company modified the energy allocator to reflect the removal of the kilowatt hours associated with both cogeneration contracts and the Sooner wind farm. Additionally, the energy was adjusted to recognize the kilowatt hours associated with the economic recovery pro forma adjustment described in OG&E witnesses Bryan Scott and Adam Bigknife's direct testimonies. These two adjustments also follow the cost causation and normalization regulatory practices.

Q. What was the change in the ENR1SY due to the two adjustments?

A. The ENR1SY increased from 10.0534% to 11.4613% for the Arkansas jurisdiction. Chart 3 illustrates the change.

Chart 3

Energy Allocator ENR1SY Comparison



Q. How has wind generation been allocated in the last two OG&E rate cases?

A. Originally, in Docket No. 06-070-U, the Commission approved an 11.2815% allocator for the Centennial wind farm. This allocator was based on the 2005 energy consumption or billed kWh sales and was 100% allocated to Arkansas and Oklahoma retail customers. The same 11.2815% wind generation allocation for the Arkansas jurisdiction was also approved in Docket No. 08-103-U.

Q. How is OG&E's wind generation facilities investment and associated expenses allocated differently in this case?

A. In this proceeding, the Company is proposing to allocate wind generation <u>between all three jurisdictions</u> using the energy allocator ENR1SY. Additionally, in the development of the energy allocator the actual kilowatt hours in the test year for Arkansas were adjusted for the economic recovery pro forma adjustment and the kilowatt hours in the Oklahoma jurisdiction were reduced by the kilowatt hour contribution for the cogeneration contracts and Sooner wind farm. This adjustment is supported by the principle that customers who pay for the cost of generation capacity have first call on the energy produced by that capacity as explained in previous staff testimony.[2]

Q. **Has OG&E allocated the transmission costs for Centennial and OU Spirit wind farms differently than other transmission facilities in this case?**

A. No. OG&E is allocating all transmission facilities utilizing the CAP3SY allocator that is derived from the average of twelve monthly coincident peak demands (12CP). The Arkansas jurisdiction receives a 9.5993% allocation in this case. This is a departure from OG&E's last Arkansas rate case where transmission costs for Centennial were allocated at 11.2815% which was the same allocation for the Centennial generation facility. Finally, it should be noted that the Windspeed transmission line that opened the corridor to the Oklahoma panhandle for wind is also allocated on the CAP3SY.

Q. **How did you develop the transmission allocation factor?**

A. Investment and expenses functionalized to transmission are classified as primarily demand-related consistent with standard utility cost allocation practices. The Company has used an average of twelve monthly coincident peak demands (12CP) allocation method for allocating these costs. Under this method, transmission demand costs are allocated in proportion to the average of the coincident monthly peak demands of the customer classes (adjusted for losses) at the time of the monthly net system peak demands. These demands were also weather normalized in this case.

Q. **What allocation methodology did you use for demand-related distribution costs?**

A. Demand-related distribution costs were allocated based on class maximum non-coincident peak demands (NCPs), as opposed to coincident peak demands (CPs). The reason for using NCPs is that local distribution demand costs are incurred to serve area load, rather than a system load. Using NCPs instead of CPs in this methodology also recognizes that little or no diversity exists at this level except within each class.

[2] Docket No. 06-101-U, February 5, 2007, Direct Testimony of Alice D. Wright (APSC staff), page 9, lines 17 and 18 through page 10, line1.

Q. **How did OG&E direct assign vegetation management and storm costs to Arkansas customers?**

A. The Arkansas jurisdictional costs for both these items were 100% direct assigned to Arkansas customers. Additionally, so that Arkansas customers did not receive any allocations from Oklahoma related costs, all vegetation management and storm costs related to the Oklahoma jurisdiction were also direct assigned in the COSS in this filing. Please see the Direct Testimony of Sheri Richard for discussion of how the direct assignment costs were derived.

III. RESULTS OF COST OF SERVICE STUDY

Q. **Please discuss the results of the Cost of Service Study.**

A. The results of the Company's COSS by class, as shown on Schedule G-1 of the Company's application, are also summarized in Chart 4 below. Please see attached Exhibit_GV-1 for the various cost components that comprise OG&E's requested revenue requirement in this proceeding.

Chart 4
Summary of OG&E COSS by Class

	1	2	3	4	5
Customer Class	**Non-Fuel Rate Schedule Revenues (Current)**	**Rate Schedule Total Revenue Requirement (Proposed)**	**Revenue Deficiency (Excess) (Col 2 - Col 1)**	**Other Revenues**	**Total Revenue Requirement (Col 2 + Col 4)**
Residential R-1	$ 29,496,237	$ 35,231,218	$ 5,734,981	$467,364	$ 35,698,582
General Service	$ 8,772,460	$ 10,433,710	$ 1,661,250	$ 76,304	$ 10,510,014
Power & Light - Non TOU	$ 20,104,331	$ 25,077,308	$ 4,972,977	$ 24,627	$ 25,101,935
Power & Light - TOU	$ 20,558,002	$ 26,035,808	$ 5,477,806	$ 19,851	$ 26,055,659
Municipal Pumping	$ 61,381	$ 77,527	$ 16,146	$ 424	$ 77,951
Non-AFL Lighting	$ 3,023,370	$ 2,867,324	$ (156,046)	$ 2,857	$ 2,870,181
Athletic Field Lighting	$ 50,059	$ 66,202	$ 16,143	$ 62	$ 66,264
Total Arkansas Retail	$ 82,065,840	$ 99,789,097	$ 17,723,257	$591,489	$ 100,380,586

Column three in Chart 4 quantifies the proposed rate increase for each customer class based on an equalized rate of return of 6.61%.

Q. **Does this conclude your testimony?**

A. Yes.

LINE NO.	DESCRIPTION	TOTAL ARKANSAS JURISDICTION	RESIDENTIAL R-1	TOTAL GENERAL SERVICE	TOTAL PWR & LGHT NON TOU	TOTAL PWR & LGHT TOU	TOTAL MUNICIPAL PUMPING	TOTAL NON-AFL LIGHTING	ATHLETIC FIELD
	RATE BASE (a)								
1	GROSS PLANT IN SERVICE	$678,131,245	$233,317,756	$71,296,008	$171,969,478	$179,613,834	$519,721	$20,972,730	$441,717
2	ACCUMULATED DEPRECIATION	$292,506,677	$99,552,367	$30,046,395	$73,319,353	$80,860,628	$194,866	$8,383,984	$149,083
3	TOTAL NET PLANT (L1-L2)	$385,624,568	$133,765,389	$41,249,613	$98,650,125	$98,753,206	$324,855	$12,588,746	$292,634
4	WORKING CAPITAL ASSETS	$42,042,014	$14,155,246	$4,213,451	$10,572,242	$11,882,220	$29,613	$1,166,014	$23,228
5	OTHER RATE BASE ITEMS	$16,208,693	$5,166,253	$1,524,699	$4,185,383	$5,224,866	$7,169	$96,545	$3,777
6	TOTAL RATE BASE (L3+L4+L5) (A)	$443,875,276	$153,086,888	$46,987,762	$113,407,751	$115,860,292	$361,637	$13,851,305	$319,639
	NON-FUEL OPERATING REVENUES (1)								
7	PRESENT RATE SCHEDULE/CLASS REVENUES (b)	$82,065,840	$29,496,237	$8,772,460	$20,104,331	$20,558,002	$61,381	$3,023,370	$50,059
8	OTHER OPERATING REVENUES	$591,489	$467,364	$76,304	$24,627	$19,851	$424	$2,857	$62
9	TOTAL REVENUES (L7+L8) (A)	$82,657,329	$29,963,601	$8,848,764	$20,128,958	$20,577,853	$61,805	$3,026,227	$50,121
	OPERATING EXPENSES (c)								
10	OPERATION AND MAINTENANCE EXPENSE								
11	PRODUCTION (1)	$15,935,946	$4,783,901	$1,403,317	$4,137,862	$5,481,432	$7,612	$117,687	$4,134
12	TRANSMISSION & REGIONAL MARKET	$2,649,270	$856,577	$252,361	$686,321	$839,962	$1,518	$12,061	$469
13	DISTRIBUTION	$6,397,577	$2,373,894	$796,461	$1,735,183	$995,497	$8,390	$477,689	$10,463
14	CUSTOMER ACCOUNTS	$2,094,610	$1,733,919	$273,015	$64,367	$19,711	$2,220	$532	$846
15	CUSTOMER SERVICES AND INFORMATIONAL	$538,259	$451,632	$77,196	$7,660	$690	$607	$216	$258
16	SALES	$423,217	$187,714	$43,037	$162,041	$27,816	$268	$2,211	$131
17	ADMINISTRATIVE AND GENERAL	$8,932,317	$3,281,564	$921,538	$2,178,814	$2,317,659	$6,742	$220,544	$5,456
18	TOTAL OPERATION AND MAINTENANCE EXPENSE (Sum L11 thru L17)	$36,971,196	$13,669,201	$3,766,924	$8,972,249	$9,682,768	$27,358	$830,940	$21,757
19	DEPRECIATION	$19,714,512	$6,672,423	$2,028,501	$5,030,953	$5,358,909	$14,601	$596,667	$12,459
20	TAXES OTHER THAN INCOME	$7,002,904	$2,404,398	$720,901	$1,768,682	$1,901,951	$5,272	$197,322	$4,378
21	FEDERAL & STATE INCOME TAXES	$363,326	$572,145	$232,747	($127,105)	($706,299)	$450	$391,212	$177
22	TOTAL EXPENSES (Sum L18 thru L21) (A)	$64,051,938	$23,318,167	$6,749,073	$15,644,778	$16,237,329	$47,680	$2,016,141	$38,770
23	OPERATING INCOME (L9-L22)	$18,605,392	$6,645,434	$2,099,692	$4,484,180	$4,340,524	$14,125	$1,010,086	$11,351
24	EARNED RETURN ON RATE BASE (L23 / L6)	4.1916%	4.3410%	4.4686%	3.9540%	3.7463%	3.9058%	7.2924%	3.5510%
	COST OF SERVICE REVENUE REQUIREMENT								
25	REQUIRED RETURN ON RATE BASE GIVEN EQUAL RATES OF RETURN	6.610%	6.610%	6.610%	6.610%	6.610%	6.610%	6.610%	6.610%
26	REQUIRED OPERATING INCOME (L6*L25)	$29,340,156	$10,119,043	$3,105,891	$7,496,252	$7,658,365	$23,904	$915,571	$21,128
27	INCOME DEFICIENCY / (SURPLUS) (L26-L23)	$10,734,764	$3,473,609	$1,006,199	$3,012,072	$3,317,841	$9,779	($94,515)	$9,778
28	REVENUE CONVERSION FACTOR	1.651015	1.651015	1.651015	1.651015	1.651015	1.651015	1.651015	1.651015
29	REVENUE DEFICIENCY / (SURPLUS) (L27*L28)	$17,723,257	$5,734,981	$1,661,250	$4,972,977	$5,477,806	$16,146	($156,046)	$16,143
30	RATE SCHEDULE REVENUE REQUIREMENT (L7+L29)	$99,789,097	$35,231,218	$10,433,710	$25,077,308	$26,035,808	$77,527	$2,867,324	$66,202
31	FUEL REVENUES (b)	$87,031,072	$23,669,917	$6,915,975	$23,035,407	$32,410,129	$51,009	$916,149	$32,486
32	OTHER RIDERS	$0	$0	$0	$0	$0	$0	$0	$0
33	PERCENT INCREASE ON BASE REVENUE (L29 / L7)	21.60%	19.44%	18.94%	24.74%	26.65%	26.30%	-5.16%	32.25%
34	PERCENT INCREASE ON BASE REVENUE + FUEL REVENUES (L29 / (L7+L31))	10.48%	10.79%	10.59%	11.53%	10.34%	14.37%	-3.96%	19.56%
35	PERCENT INCREASE ON BASE REVENUE + FUEL REVENUES + OTHER RIDERS (L29 / (L7+L31+L32))	10.48%	10.79%	10.59%	11.53%	10.34%	14.37%	-3.96%	19.56%
	PROPOSED REVENUE REQUIREMENT								
36	PROPOSED RETURN ON RATE BASE	6.610%	6.610%	6.610%	6.610%	6.610%	6.610%	6.610%	6.610%
37	REQUIRED OPERATING INCOME (L6*L36)	$29,340,156	$10,119,043	$3,105,891	$7,496,252	$7,658,365	$23,904	$915,571	$21,128
38	INCOME DEFICIENCY / (SURPLUS) (L37-L23)	$10,734,764	$3,473,609	$1,006,199	$3,012,072	$3,317,841	$9,779	($94,515)	$9,778
39	REVENUE CONVERSION FACTOR	1.651015	1.651015	1.651015	1.651015	1.651015	1.651015	1.651015	1.651015
40	REVENUE DEFICIENCY / (SURPLUS) (L38*L39)	$17,723,257	$5,734,981	$1,661,250	$4,972,977	$5,477,806	$16,146	($156,046)	$16,143
41	RATE SCHEDULE REVENUE REQUIREMENT (L7+L40)	$99,789,097	$35,231,218	$10,433,710	$25,077,308	$26,035,808	$77,527	$2,867,324	$66,202
42	FUEL REVENUES (b)	$87,031,072	$23,669,917	$6,915,975	$23,035,407	$32,410,129	$51,009	$916,149	$32,486
43	OTHER RIDERS	$0	$0	$0	$0	$0	$0	$0	$0
44	PERCENT INCREASE ON BASE REVENUE (L40 / L7)	21.60%	19.44%	18.94%	24.74%	26.65%	26.30%	-5.16%	32.25%
45	PERCENT INCREASE ON BASE REVENUE + FUEL REVENUES (L40 / (L7+L42))	10.48%	10.79%	10.59%	11.53%	10.34%	14.37%	-3.96%	19.56%
46	PERCENT INCREASE ON BASE REVENUE + FUEL REVENUES + OTHER RIDERS (L40 / (L7+L42+L43))	10.48%	10.79%	10.59%	11.53%	10.34%	14.37%	-3.96%	19.56%
47	TOTAL REVENUE REQUIREMENT (b) (L8+L41+L42+L43)	$187,411,658	$59,368,499	$17,425,990	$48,137,342	$58,465,788	$128,960	$3,786,330	$98,750

NOTE (1): Total Company and Jurisdictions Not At Issue has Fuel Revenues and Fuel Expense included.

Exhibit GV-1

ATTESTATION

I do hereby swear and affirm that the foregoing is my direct testimony in APSC Docket No. 10-067-U.

Greg Vetter

9/25/10

Date