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

Donald R. Rowlett

on behalf of

Oklahoma Gas and Electric Company

September 28, 2010

Q. **Please state your name, by whom you are employed, business address and the position you hold.**

A. My name is Donald R. Rowlett. I am Director of Regulatory Policy and Compliance with Oklahoma Gas and Electric Company ("OG&E" or "Company"). My business address is 321 N. Harvey, Oklahoma City, Oklahoma 73102.

Q. **Please state your educational qualifications and employment history with OG&E.**

A. I earned a Bachelor of Science degree in Business with an accounting emphasis (1980) and a Masters in Business Administration (1992), from Oklahoma City University. In 1983, I became a Certified Public Accountant. Prior to joining OG&E, I was employed by Arthur Andersen & Co. as a financial consultant and audit manager. During my employment, I performed audits of financial statements in a variety of industries. Additionally, I participated in the preparation of filings with the Securities and Exchange Commission (SEC) and provided clients with guidance on the financial reporting requirements of the SEC and Generally Accepted Accounting Principles (GAAP).

Q. **What are your responsibilities as Director of Regulatory Policy and Compliance?**

A. I am responsible for the analysis, development and communication of regulatory policy for OG&E. This includes establishing policies to be followed by the Company in the Oklahoma, Arkansas and Federal Energy Regulatory Commission ("FERC") jurisdictions and monitoring compliance with those policies throughout the Company. I have testified on behalf of the Company before the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC" and "Commission") and the Environmental and Public Works Committee in the United States Senate.

Q. **Please state the purpose of your testimony in this proceeding.**

A. The purpose of my testimony in this proceeding is to sponsor several accounting adjustments, a pension and OPEB regulatory asset and tracker, certain tax adjustments, request approval of the SPP Cost Recovery ("SPPCR") rider, transmission related adjustments, changes to the current Energy Cost Recovery Rider (“ECR”), and an alternative ECR tariff to remove non-approved renewable wind energy. The specific areas covered in my testimony are enumerated in Chart 1.

Chart 1

REFERENCE	ACCOUNTING ADJUSTMENTS, REGULATORY ASSETS AND RIDERS
WP C 2-20	Removal of Oklahoma amortization of pension related regulatory asset/liability
WP C 2-20	Recognition of Arkansas amortization for settlement loss authorized in last rate case
WP C 2-33	Gains on SO_2 allowances
Schedule B 4	Overall working capital (Including fuel inventories and M & S)
WP D 1-5	ADIT -- accumulated deferred income tax adjustment for OU Spirit
Schedule C-5	Manufacturer deduction and revenue conversion factor
WP C 2-22	Southwest Power Pool (“SPP”) Expense
Exhibit DRR-1	SPP Cost Recovery Rider
WP C 2-2 & C 2-28	Elimination of Fuel Revenues and Expenses
	Pension & Other Post Employment Benefits (“OPEB”) Regulatory Asset and Tracker
WP C 2-12	Pension, Medical and Other Employee Costs
	TAX ADJUSTMENTS
Schedules C 9 – C 12	Income tax expense
WP C 2-34	Ad Valorem Taxes
Schedule C-11, WP C-10	Medicare Part D amortization
	TRANSMISSION RELATED ADJUSTMENTS
WP C 2-39	Removal of Transmission O&M, depreciation and taxes other than income expense recovered from third party Load Serving Entities (“LSEs”)
WP B 2-6	Removal of Transmission Plant in Service (“PIS”) and Accumulated Depreciation recovered from third party LSE
WP D 1-4	Removal of ADIT Related to Transmission PIS (WP B 2-6)
WP B 4-5	Removal of Materials and Supplies Inventory (LSE Adjustment)
WP C 2-40	SPP revenue and expense elimination
	ENERGY COST RECOVERY RIDER (ECR)
Exhibit DRR-2	ECR Tariff for Time Of Use (TOU) on peak and off peak factors
Exhibit DRR-3	Alternative ECR Tariff for Removal of non-approved renewable wind energy
Exhibit DRR-4	Modify existing ECR for Recovery of the fuel and energy portion of customer accounts charged off as uncollectible and carbon tax assessment fees

I. ACCOUNTING ADJUSTMENTS

Q. Please explain the elimination of the Oklahoma jurisdiction amortization of certain pension regulatory assets/liabilities.

A. The Company identified certain test year pension expenses are currently being recovered from Oklahoma customers and therefore need to be removed. The OCC established a tracker mechanism to recognize the volatility of the year to year pension expense fluctuations. To the extent pension expense varies each year from the level of pension expense authorized in the last rate case, a regulatory asset or liability is recorded. The regulatory asset/liability balance increases or decreases between rate cases. OG&E also has a pension regulatory asset in Oklahoma related to the McClain plant acquisition. In OG&E's most recent Oklahoma rate case the OCC authorized amortization of both of the accumulated balances. A *pro forma* adjustment is proposed to eliminate the amortization of both of the Oklahoma jurisdiction pension regulatory asset/liability balances from the test year expense.

Q. Why is this adjustment necessary?

A. Without this *pro forma* adjustment, the total company test year pension expense would be overstated by $1,827,756. This amount is reflected in Chart 2.

Chart 2

Line No.	Description		Ferc Account		Amount
5	Remove Amortization of OK Reg. Asset - McClain Pension	(a)	926		$ (41,631)
6	Remove Amortization of OK Reg. Asset - Pension	(a)	926		$ (1,749,426)
9	Remove Amortization of OK Reg. Asset - McClain OPEB	(a)	926	(A)	$ (20,672)
10	Remove Amortization of OK Reg. Asset - McClain Medical	(a)	926	(A)	$ (16,027)
	Pro forma adjustment				$ (1,827,756)

Source WP C 2 - 20

Q. What is the Company proposing with respect to recognition of the Arkansas amortization of the settlement loss authorized in Docket No. 08-103-U?

A. The Company is proposing to include a *pro forma* adjustment to reflect the treatment of certain pension settlement charges as a result of APSC Order No. 6 in Docket No. 08-103-U. In the 2009 test year there was $174,316, or seven months of the amortization, included in O&M expense. Therefore, the Company is annualizing this amount to include $298,828 in prospective rates.

Q. Please explain why this adjustment is appropriate.

A. In OG&E's last rate case, the Company proposed that the settlement charge be amortized over 2 years so that it would have been fully amortized by the time of the next rate case. Within the settlement agreement approved by the Commission in that case it was concluded that the pension settlement charge was to be amortized over 10.627 years, as recommended by APSC staff. This was the average remaining years of service of the participants in the pension plan at that time. This *pro forma* adjustment is necessary to continue the recovery of the balance and annualize the amount.

Q. Does OG&E have any other pension related proposals in this Docket?

A. Yes. As discussed above, the OCC has authorized a regulatory asset and tracking mechanism for pension expenses. OG&E is requesting the Commission to authorize a similar tracking mechanism for the Arkansas jurisdiction. In addition to tracking variations in the level of annual pension expense from the amount included in base rates, the Company is proposing that the difference in OPEB costs (actual versus base rates) also be included in the proposed tracking mechanism.

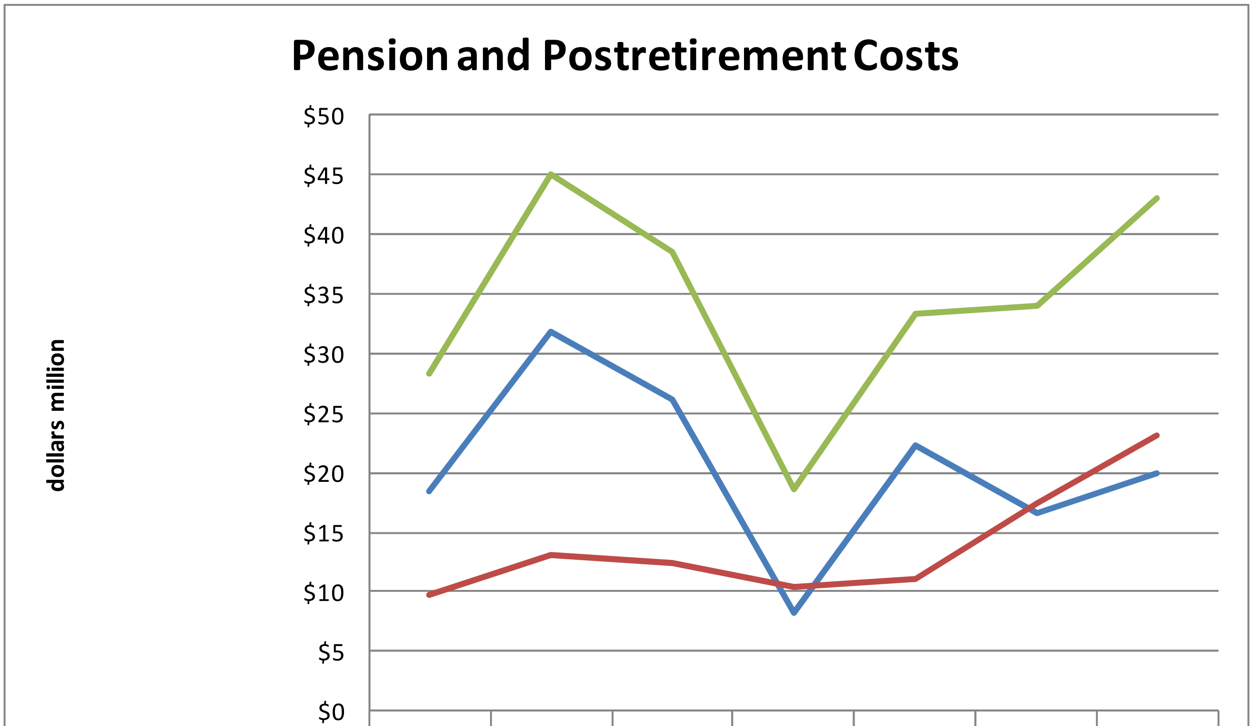
Q. How would the tracking mechanism work?

A. To the extent the annual pension and OPEB incurred by the Company varied from the level authorized in this case a regulatory asset or regulatory liability would be recorded. The net regulatory asset or liability balance would be included in the Company's next general rate case for amortization over future periods.

Q. **Why does the Company believe a tracker is necessary for these costs?**

A. These costs have experienced significant volatility in recent years. Chart 3 shows the range of cost experience between 2004 and 2009.

Chart 3



	2005	2006	2007	2008	2009	2010	2011
Pension	18.5	31.9	26.1	8.2	22.3	16.6	19.9
Postretirement Benefit	9.8	13.1	12.4	10.4	11.1	17.4	23.2
Total	28.3	45.0	38.5	18.6	33.4	34.0	43.1

As shown in Chart 3, these costs have demonstrated significant volatility over recent years. A cost tracker would protect customers from overpaying if rates are set on a high cost level and then the costs decrease. Additionally, the tracker will allow the shareowners to recover their actual costs.

Q. **Please explain the *pro forma* adjustment for gains on SO_2 allowances.**

A. The Company credits gains realized on the sale of SO_2 allowances to Arkansas customers through the ECR rider. This *pro forma* adjustment is necessary to avoid double counting the benefit. The $823,579 total company gain is reflected in the test year results and the Arkansas jurisdiction benefit has already been passed through the ECR to customers.

Q. **Can you please discuss what gives rise to the gains on SO_2 sales?**

A. Yes. OG&E is granted allowances to emit a certain level of SO_2 by the Federal government. Each year the Environmental Protection Agency ("EPA") withholds a portion of OG&E's allowances and sells them at auction. This process was established by the EPA to insure a minimum amount of liquidity in the SO_2 allowance market. The Company receives its annual allotment of allowances, including those withheld by the EPA, at no cost so all sale proceeds, net of sales costs, result in a gain. Additionally, to the extent the Company determines it has accumulated allowances in excess of what is necessary for operational needs, it sells such excess allowances. The gains from these sales are also flowed through the ECR and are included in the $823,579 total company *pro forma* adjustment as well.

Q. **What is the Company proposing with respect to Working Capital Assets?**

A. A component of OG&E's rate base is working capital assets. Generally these assets include: inventories for natural gas, coal and fuel oil; materials and supplies; and short-term assets. In order to arrive at a reasonable level for working capital assets, the Company analyzed each asset account and its related year-end balance. Based on this information, the Company first determined the relevance of the account to providing utility service. This analysis resulted in the exclusion of some account balances. The Company next determined the expected level of investment for the remaining accounts. If the year-end balance was appropriate it was retained. In other instances, some adjustments which are discussed below were made either up or down to reflect balances that are more indicative of expected investment levels. After reflecting these adjustments in Schedule B 4, the Company included $443,618,910 for working capital assets in the calculation of rate base for this proceeding.

Q. **What adjustment is the Company proposing regarding coal?**

A. OG&E is requesting a 60 day inventory (1,980,000 tons) of coal in this proceeding. This inventory level was approved in the Company's last two rate cases. The Company still believes the 60 day level requested is sufficient to meet normal operations and maintain fuel security during periods of uncontrollable events such as rail transportation and supply interruptions. The Company proposes a *pro forma* adjustment to reduce the test year balance for coal inventory to 60 days.

Q. **Please explain the basis of the adjustment for natural gas inventory.**

A. The Company maintains approximately 7 to 8 BCF of natural gas in inventory. The purpose of this inventory is to supplement the daily demands for gas at the power plants and to provide a hedge against the volatility of short-term natural gas prices. As can be seen in WP B 4-1, natural gas inventory consists of both short-term and long-term storage. The long-term inventory represents cushion gas which ensures the optimal operation of the natural gas storage facilities. It consists of 5.3 BCF of natural gas. The amount of cushion gas was primarily established in 1994 and increased slightly in 2000. The average cost of the non-current inventory is $2.59 per MMBTU. The total value of $13,737,806 is included in plant in service.

The current natural gas inventory varied from a low of 1,786,522 MMBTU to a high of 2,523,866 MMBTU during the test year. The 13 month average was 2,017,400 MMBTU. OG&E proposes a *pro forma* adjustment to increase the year-end quantity to the 13 month average. This is an adjustment of 150,310 MMBTU. Using the Company's 2010 forecasted natural gas cost of $3.96 per MMBTU[1], this would result in an increase in the Company's working capital assets of $665,168.

Q. **Please explain the adjustment being proposed for the fuel oil inventory.**

A. OG&E proposes to adjust the fuel oil inventory to the 13 month average. This results in a reduction of the test year-end balance by 130,937 gallons or $268,753. The proposed 13-

[1] The Company develops a short-term forecast of natural gas prices based on the NYMEX forward market prices plus or minus the basis difference for delivery points at which OG&E purchases its natural gas. This forecast is used to establish the annual ECR factor.

month average balance is priced using $2.04 which is the 2009 weighted average cost per gallon.

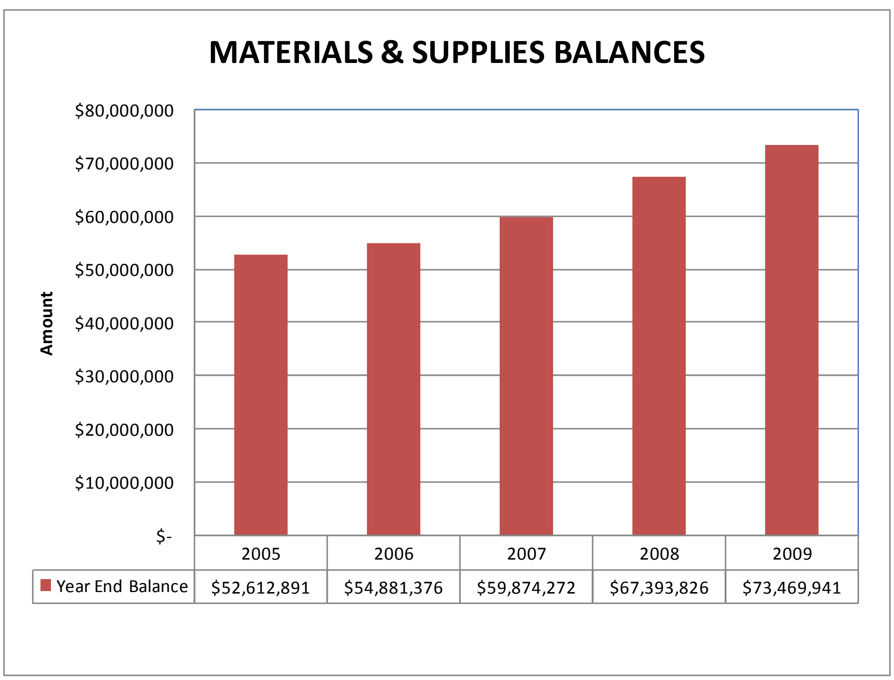
Q. **Why does the Company believe a 13 month average approach is proper for natural gas and fuel oil inventories?**

A. Even though these inventories represent a permanent investment, the dollar amounts vary as items move in and out. As a result, the thirteen month average ensures the normalization of the fluctuations during the test year. Additionally, it allows OG&E to prudently maintain appropriate fuel inventories to assure a safe and dependable supply.

Q. **Please explain the materials and supplies component of the working capital adjustment.**

A. Materials and supplies consist of items that are necessary to sustain ongoing utility construction, operations and maintenance. OG&E's *pro forma* adjustment updates the materials and supplies balance to June 30, 2010. As demonstrated in Chart 4, materials and supplies balances have shown a steady increase over the last five years. The Company expects this trend to continue into the future.

Chart 4



Q. **Why does the Company believe a June 30, 2010 balance is proper for the materials and supplies component of working capital?**

A. Unlike fuel inventories, materials and supplies have demonstrated a steady upward trend from year to year. Utilizing a 13-month average in this instance would not reflect the level of investment necessary to sustain ongoing operations. Therefore, the most recent quarter ending balance is most representative of the Company's ongoing investment. As a result, the June 30, 2010 balance is more appropriate than the 13-month average.

Q. **Please explain the adjustment of Accumulated Deferred Income Taxes ("ADIT") related to the OU Spirit Wind Facility.**

A. The Company proposes a *pro forma* adjustment to reduce the *pro forma* test year Accumulated Deferred Income Tax ("ADIT") balance by $55,292,877 related to the OU Spirit wind facility. The Company has a separate application for recovery of the revenue requirement for OU Spirit, Docket No. 10-073-U, pending before the Commission. As I described in my testimony in that application, income tax benefits related to the OU Spirit wind facility are significantly front loaded because the capital investment is depreciable over five years for income tax purposes. Additionally, as a result of the American Recovery and Reinvestment Act, OU Spirit qualified for bonus depreciation. Under the provisions of bonus depreciation, 50% of the capital investment was depreciated for federal income purposes in 2009. This resulted in approximately $47.5 of ADIT being recorded on the Company's books at the end of the test year. Traditionally, the Arkansas Commission has recognized that, as a component of revenue requirement, deferred income taxes have been funded by customers. Thus, ADIT has been included as part of the Company's permanent capital and assigned zero cost. This has the effect of reducing the overall average rate of return.

In the case of OU Spirit, approximately $47.5 million of ADIT was reflected on the Company's books at the end of the test year and was not funded by Arkansas customers due to regulatory lag.

Q. **Has OG&E proposed similar adjustments for ADIT related to regulatory lag in the past?**

A. No. The Company recognizes that there is a certain amount of regulatory lag inherent in the regulatory process as described in OG&E witness Howard Motley's testimony. However, due to the significant impact of regulatory lag associated with OU Spirit and the fact that it is a discrete asset that can be tracked; the Company believes it is appropriate to make the adjustment to the ADIT balances. The adjustment should not only be accepted in this proceeding but in future OG&E rate cases as well.

Q. **How does the amount of ADIT accrued in the early years of wind plants compare to fossil fuel plants?**

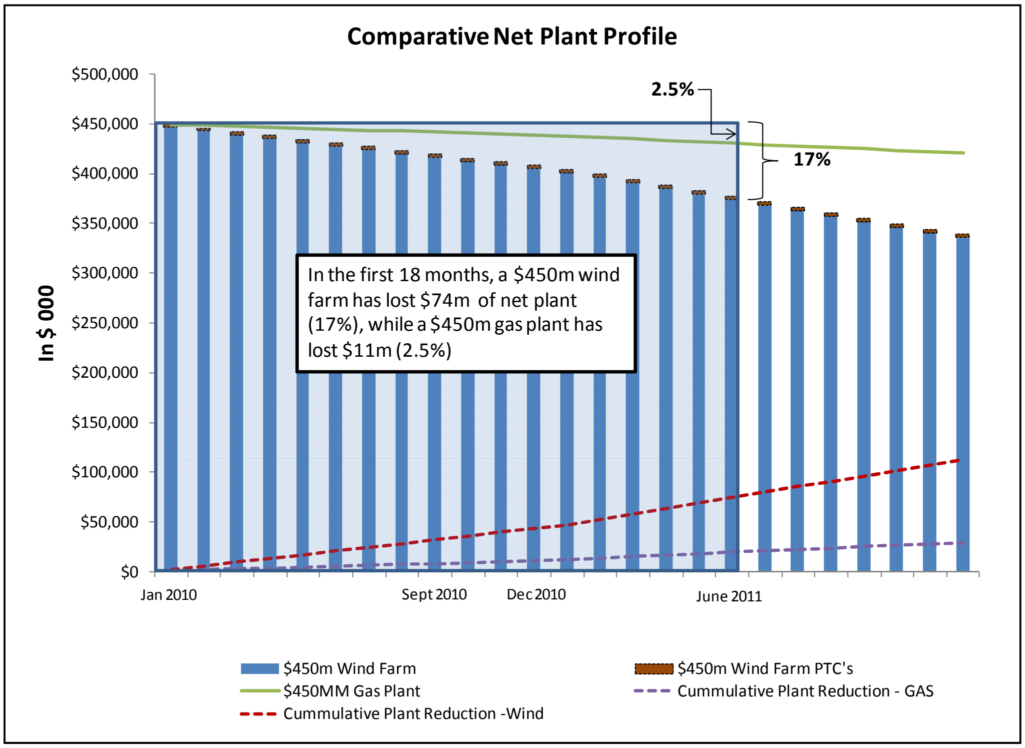
A. Both renewable and fossil fuel generation facilities qualify for several Federal and state tax incentives including MACRS accelerated depreciation, bonus depreciation, and Oklahoma Investment Tax Credits. For income tax purposes wind generation facilities are depreciated on an accelerated basis over five years compared to 20 years for a fossil fuel plant.

The traditional Arkansas regulatory formula assumes that customers have supplied zero cost capital through the deferred income tax component of rates. Because of the front loading of income tax benefits for wind generation facilities, much of the benefit accrues before there is any recognition of the deferred income tax cost in rates.

Assuming an 18 month gap between OU Spirit's in-service date and its inclusion in rate base, Arkansas regulation would deny investors a return on approximately 17% of the plant investment by treating it as having been funded with zero cost capital. This compares with a lost return on only 2.5% of the plant investment in the case of a comparably priced natural gas fired plant over the same 18 month period.

Because of the timing of rate cases, a certain amount of loss of investor return and recovery of investment occurs in traditional cost of service regulation. However, in the case of wind energy projects, investors' lost recovery due to regulatory lag is significantly magnified by the structure of tax depreciation. Chart 5 illustrates this disparity.

Chart 5



Q. **Has the Commission approved anything similar in the past?**

A. Yes. The Commission has historically adjusted upward the Company's accumulated depreciation balance to reflect the regulatory lag created by the delay in authorization of new depreciation rates. The Company tracks the balance of accumulated depreciation that reflects what would have been recorded if the Company had waited to use new rates until they had been approved by the Commission and reflected in customer rates. The Commission's rational for this adjustment is that it is necessary to recognize that Arkansas customers have funded more accumulated depreciation than reflected on the Company's books.

Q. **What is the issue related to the Manufacturer Deduction and revenue conversion factor?**

A. OG&E has not adjusted the effective income tax rate used in its revenue conversion factor for an estimated Manufacturer Deduction. The Company has estimated that even assuming the Commission grants the relief requested in this application it would not recognize any benefit from the Manufacturer Deduction due to the level of generation related income tax incentives being utilized by the Company currently and for the period in which these rates are expected to be in place. As I discuss later, the reason OG&E does not have use of a Manufacturers Deduction for 2009 and does not expect to be able to utilize the deduction in 2010 through 2014 is because no qualifying taxable income is being created by the Company's electric production activities.

Q. **What is the Manufacturer Deduction?**

A. The Domestic Production Activities Deduction was passed into law as part of the American Jobs Creation Act of 2004 ("2004 Act"). Section 102 of the 2004 Act provides the text for Internal Revenue Code ("IRC") Section No. 199. Section No. 199 of the IRC provides guidance in determining the amount of the Manufacturer Deduction that can be used to decrease taxable income. Under the IRC, for tax years 2007, 2008 and 2009 the deduction allowed shall be an amount equal to 6 percent of the lesser of: the qualified production activities income ("QPAI") of the taxpayer for the taxable year; or, taxable income for the taxable year determined without regard to Section No. 199 of the IRC.

Q. **Does OG&E qualify for the Manufacturer Deduction?**

A. Yes. OG&E's electric production activities qualify for the Manufacturer Deduction. However, as a vertically integrated utility, OG&E charges customers a bundled rate for electric service that includes production, transmission and distribution of electricity. As a result of this bundled rate it is not possible to directly compute OG&E's QPAI.

Subsequent to the passage of the 2004 Act, OG&E began discussions with representatives of the Internal Revenue Service ("IRS") to develop a mutually agreeable methodology to compute QPAI since it is not possible to determine the amount directly. In June 2008, OG&E and the IRS signed a Closing Agreement which established how the Manufactures Deduction would be determined.

Q. **Was OG&E able to utilize the Manufacturer Deduction in 2009?**

A. No. Using the IRS agreed-to methodology for determining QPAI, OG&E determined it was not entitled to a deduction in its 2009 income tax return. This deduction was subject to the QPAI income limitation for 2009. OG&E generated no QPAI as a result of bonus depreciation on new generation assets, five year accelerated depreciation on Centennial and OU Spirit wind generation facilities and PTCs associated with those facilities,

Q. **Please explain the *pro forma* fuel adjustment.**

A. OG&E's test year revenues reflect recovery of energy costs recovered through the ECR. All of the Company's recovery of the energy component of costs is through the ECR therefore a *pro forma* adjustment is proposed to eliminate all energy related revenues and a corresponding *pro forma* adjustment is proposed to eliminate all fuel and energy costs from the cost of service.

Q. **Are any other elimination adjustments necessary?**

A. Yes. An adjustment is necessary to eliminate revenue and expense paid to and received by OG&E from the SPP for network transmission service provided to OG&E. The FERC has provided guidance to the industry that while these are intra-company charges and are normally eliminated in accordance with generally accepted accounting principles ("GAAP") they should be reflected gross in the FERC Form 1. The Company's revenues already reflect revenues received from retail and wholesale customers related to network transmission service and the operating expenses necessary to provide this service. This *pro forma* adjustment is necessary to avoid double counting these revenues and expenses.

II. TAX RELATED ADJUSTMENTS

Q. **What are the proposed adjustments related to income tax expense?**

A. Schedules C-11 and C-12 reflect the Company's current and deferred income tax expenses. These schedules capture adjustments necessary to recognize differences in the timing of income and expenses between book accounting and tax accounting. Adjustments necessary to recognize permanent differences between taxable income and book income are also reflected on these schedules. Lastly, these schedules reflect the impact that all other *pro forma* adjustments have on income tax expense. The resulting net change in income tax expense of $19,505,663 and $4,719,618 federal and state income taxes, respectively, is reflected in WP C2 Summary.

Q. Is the OG&E proposing a *pro forma* adjustment for taxes other than income taxes?

A. Yes. OG&E is proposing an adjustment related to ad valorem taxes.

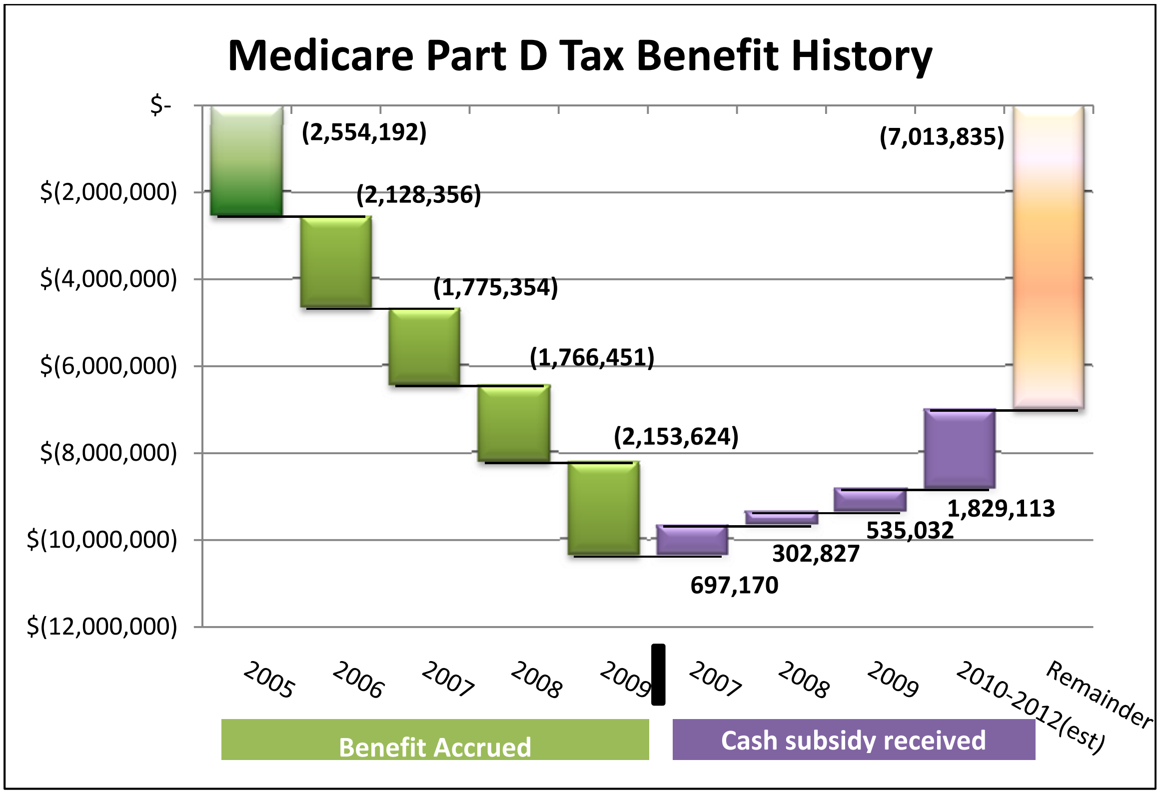
Q. Please explain *Pro Forma* Adjustment C 2-34, Ad Valorem Taxes.

A. This adjustment increases property taxes by $3,921,553. The adjustment recognizes an increase in property taxes based on historic trend in the levels of increases in valuations and the five year historic average increase in millage rates.

Q. Can you please explain the *pro forma* adjustment the Company has proposed regarding the Medicare Part D subsidy?

A. Yes. This *pro forma* adjustment increases the provision for income taxes to recognize the change in the tax treatment required by the recent health care legislation. Chart 6 below shows the income tax benefits that OG&E has accrued related to the Medicare Part D subsidy, the amount of non-taxed subsidy actually and estimated to be received and the accrued benefit reversed as a result in the recent Patient Protection and Affordable Care Act ("PPACA") law change.

Chart 6



The Medicare Prescription Drug Improvement and Modernization Act was signed into law in 2003. This legislation introduced a prescription drug benefit under Medicare Part D. This Act also introduced a federal subsidy available to sponsors of retiree health benefit plans, like OG&E, that provide a benefit that is at least actuarially equivalent to the benefits under Medicare Part D. This additional subsidy is known as the retiree drug subsidy (RDS). OG&E is not currently taxed on the RDS payments it receives. In response to the 2003 legislation, the FASB issued FSP FAS 106-2, Accounting and Disclosure Requirements related to the Medicare Prescription Drug Improvement and Modernization Act of 2003. The FSP addressed the accounting for the change in the benefit obligation due to the expected subsidies to be received, as well as the accounting for the related tax implications. Since the subsidy was not subject to tax the guidance indicates that the subsidy's impact on the benefit obligation should have no bearing on any plan related temporary difference accounted for under ASC 740, income taxes (formally FAS 109, accounting for income taxes). Thus, the measure of any temporary difference related to the benefit obligation is currently determined as if the subsidy did not exist.

Q. **How are the RDS payments treated under the PPACA?**

A. PPACA contains a provision that changes the tax treatment related to the RDS, by requiring the amount of the subsidy received to be offset against the employer's deduction for health care expenses. That is, the change in tax treatment does not affect the taxation of the subsidy itself but would reduce the employer's deduction for the cost of health care for retirees by the amount of the subsidy received.

As a result, under PPACA, the deductible temporary difference and any related deferred tax asset on the employer's balance sheet associated with the benefit plan will be reduced under ASC 740. The impact of the change in tax law should be immediately recognized in continuing operations in the income statement for the period that includes the enactment date which is the date signed into law by the President. That is true regardless of the effective date of the change in tax law (though the effective date would likely impact the amount of the change in the deferred tax asset). This immediate income statement recognition is required for the change in tax law even though some portions of the cumulative actuarial gains or losses related to the subsidy may be recorded in accumulated other comprehensive income in the balance sheet.

Beginning in 2003, OG&E began accruing an income tax benefit each year to reflect the fact that the Medicare Part D subsidy was not taxable while OG&E's cost of health care for retirees continues to be deductible. These accruals reduced the level of income tax expense in OG&E's cost of service. The income tax benefits that have not yet been realized are reflected as a deferred tax asset on the Company's balance sheet. As a result of the change in the deductibility of the Company’s cost of health care for retirees the value of these future benefits has been reduced.

Q. **How has the change in tax treatment of the RDS been reflected in the Company’s accounting records?**

A. In March 2010, the Company recorded a provision for income tax expense of approximately $7 million to reflect the reduction in this value.

OG&E proposes to amortize this adjustment over two years. The income tax benefit related to the Medicare Part D subsidy was reflected in the Company's most recent rate case and Arkansas customers have been enjoying the benefit.

III. TRANSMISSION RELATED ADJUSTMENTS

Q. **Can you briefly summarize the relief being requested regarding transmission revenues and expenses?**

A. Yes. OG&E is requesting the Commission to:

1. Authorize the SPPCR rider to (i) recover payments made to SPP for the revenue requirement related to transmission plant owned and operated by third parties of which OG&E has been regionally allocated a portion of the costs; (ii) recover OG&E’s SPP Administrative Fee; and (iii) credit customers for point to point transmission revenue and revenue credits associated with sponsored transmission upgrades; and
2. Unbundle certain OG&E transmission investment and related expenses that are paid for by other LSE. This adjustment retains the retail jurisdiction authority to

establish rates (including return on equity level) on OG&E's transmission investment assigned to the customers in the respective jurisdiction.

SPPCR Rider

Q. **What is the basis for OG&E's request for a rider?**

A. OG&E is proposing to modify the manner in which it recovers a portion of its transmission costs from Arkansas retail customers. This modification is based on SPP's practice of allocating costs for certain transmission projects across the SPP footprint. [2] SPP developed these cost allocation methodologies with input and guidance from state regulatory commissions through the SPP's Regional State Committee ("RSC"), in order to reduce barriers to regional transmission expansion, reduce transmission congestion, improve reliability of the transmission grid, and facilitate wholesale competition. Furthermore, these cost allocation methodologies were found to be appropriate for transmission upgrades that benefit retail customers within the SPP region including OG&E's Arkansas customers. These cost allocation mechanisms mean that there will be increased regional responsibility for costs associated with certain SPP transmission upgrade/expansion projects. This is important to OG&E and its customers in two distinct ways. First, costs associated with certain transmission projects that SPP directs OG&E to build will be spread around the SPP footprint to other load serving entities. Second, these cost allocation mechanisms mean that OG&E retail customers are responsible for a portion of the costs of certain transmission projects built by other entities across the SPP footprint.

[2] SPP provides services to members in nine states: Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. The SPP RTO/Tariff footprint is comprised of the Balancing Authorities and Transmission Owners that have committed their transmission facilities to the SPP Open Access Transmission Tariff (OATT). American Electric Power West, City Utilities of Springfield (part of the Southwestern Power Administration BA, which is not under the SPP Tariff), Empire District Electric, Grand River Dam Authority, Kansas City Power and Light, Lincoln Electric System, Midwest Energy (distinct Tariff entity which is part of the Westar BA), Nebraska Public Power District, OG&E, Omaha Public Power District, Southwestern Public Service, Sunflower Electric Power, Westar Energy, Western Farmers Electric Cooperative.

Q. **Please describe the SPPCR rider.**

A. The rider would recover the actual amounts paid by OG&E to the SPP for the above described costs. The annual estimate of the SPP transmission costs would be recovered from Arkansas customers on a per kWh basis. The SPPCR rider is reflected in Exhibit DRR-1. OG&E proposes to annually true up the amounts recovered through the SPPCR rider to actual costs. Monthly, one twelfth of the estimated base line expense level will be compared to that month's actual retail Arkansas portion of SPP transmission expenses to be recovered through the rider. The overall difference will be deferred on OG&E financial statements as either a regulatory liability or a regulatory asset to be refunded or recovered through the rider in the subsequent year.

Q. **Will the SPPCR rider be used to pass through point to point revenues and any transmission credits received from the SPP?**

A. Yes. In addition to the cost described above, the SPPCR rider would pass through to customers revenues received by the Company from the SPP for point-to-point transmission service and revenue credits received from SPP associated with sponsored transmission upgrades included in OG&E's Arkansas jurisdictional rate base.

Q. **When will the SPPCR rider become effective?**

A. The SPPCR rider would become effective with the implementation of new rates approved by the Commission.

Q. **What developments have led to the Company's belief that the rider is appropriate?**

A. As a Regional Transmission Organization ("RTO"), SPP is a transmission provider currently administering transmission service over 57,575 miles of transmission lines covering portions of Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. In addition, as an RTO under FERC rules, SPP has responsibility and authority over transmission planning for its member Transmission Owners (including OG&E). To that end, SPP annually develops an SPP Transmission Expansion Plan ("STEP") in accordance with the SPP open access transmission tariff ("OATT"). This plan sets out the projects needed to enhance the reliability of the transmission system and those needed to facilitate the economic transfer of energy. This plan focuses on what is needed from a regional perspective. After SPP determines what projects should be constructed, it directs the appropriate members to construct the projects. In recent years, SPP also has begun to allocate transmission costs across the SPP footprint. Prior to 2005, the costs of new facilities were allocated exclusively to customers in the zone in which a facility was located. This historic approach was rooted in the utility-by-utility planning paradigm that was both normal and common before SPP became an RTO in 2005. Due to SPP's responsibility for independent regional transmission planning and the transition from individual transmission owners planning for their individual zones to coordinated regional planning for the entire SPP Region, SPP began to implement a series of regional cost allocation methodologies to spread costs of certain transmission projects to the load serving entities[3] within the SPP footprint that benefit from such projects.

Q. **Why has the implementation of regional cost allocation led to OG&E's request for a recovery rider?**

A. As stated above, regional cost allocation mechanisms mean that OG&E retail customers will be responsible for a portion of the costs of certain transmission projects built by other entities across the SPP footprint. These projects result from an SPP regional planning process and are built by third party entities across the SPP. OG&E will not construct, operate or own these transmission projects, yet OG&E will be responsible for paying for a portion of the revenue requirement associated with these projects by virtue of paying FERC approved transmission rates for SPP provided transmission service. Therefore, OG&E seeks the Commission approved authority to recover, on a timely basis, through a SPPCR rider, its payments made to SPP related to these costs for transmission projects constructed by third parties and allocated to OG&E. The rider would not be used to recover costs associated with any OG&E owned and operated facilities.

[3] A load-serving entity secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers.

Q. **What is the expected amount of costs that OG&E stands to incur from projects built by other SPP utilities and allocated to OG&E through the above mentioned cost allocation methodologies?**

A. According to a January 21, 2010 report released by the SPP's RSC Cost Allocation Working Group ("CAWG"), OG&E's zone will be allocated an annual transmission revenue requirement for transmission projects that (i) qualify for the various cost allocation methodologies; and (ii) are built by entities other than OG&E. From 2010 through 2015, this CAWG report estimates that OG&E's zone will be charged approximately: $2.4 million in 2010; $3.5 million in 2011; $7.9 million in 2012; $14.0 million in 2013; $34.4 million in 2014; and $36.4 million in 2015. The Arkansas jurisdictional amount and impact on the typical Arkansas residential customer is shown on Chart 7 below.

Chart 7

Arkansas Jurisdiction and Customer Impact						
	2010	2011	2012	2013	2014	2015
Arkansas jurisdiction Cost	$230,383	$335,976	$758,976	$1,343,902	$3,302,159	$3,494,145
Residential 1,100 kWh monthly impact	10¢	15¢	32¢	57¢	$1.38	$1.44

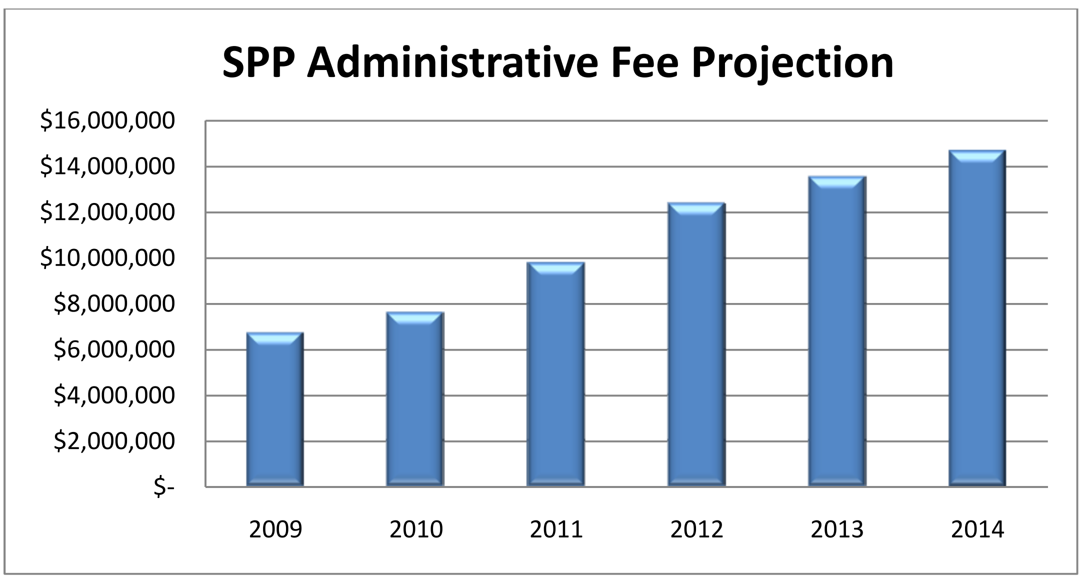
Q. **Why is OG&E seeking to recover these costs through a rider instead of through base rates?**

A. The above costs are not only significant but are also outside OG&E's control. Without a rider, cost increases occurring between rate cases would be lost and not recoverable. In such a circumstance, OG&E is denied the opportunity to earn a fair return on its other investments. To be clear, the Company is not asking for any kind of return for these costs. OG&E will simply pass through these costs without any return component. This methodology allows the Company to collect expenses it is required to pay as a member of the SPP; authorization for which was granted by this Commission.

Q. **Why is OG&E proposing to use the same rider to recover its SPP Administrative Fee?**

A. SPP charges this Administrative Fee through Schedule 1A of the SPP OATT. This fee supports the cost incurred by SPP in administering the tariff and conducting its operations. These costs are related to all SPP activities, including but not limited to employees, maintenance of facilities, information technology and outside consulting. According to projections received from the SPP, this SPP Administrative Fee is likely to increase quite dramatically in the coming years due to the implementation of the Day 2 market. In fact, SPP has indicated that it plans to increase such a fee incrementally over the next several years. Chart 8 below shows how the SPP expects to raise the overall fee between 2010 and 2014. These numbers do not assume any increase in OG&E's average peak load, which is used to calculate the SPP Administrative Fee.

Chart 8



Arkansas Jurisdiction and Customer Impact						
	2010	2011	2012	2013	2014	2015
Arkansas jurisdiction Cost	$643,919	$729,664	$939,209	$1,189,914	$1,302,170	$1,410,684
Residential 1,100 kWh monthly impact	29¢	32¢	40¢	50¢	54¢	58¢

As one can see from the above chart, OG&E expects its SPP Administrative Fee to go from approximately $6.7 million in 2009 to $14.7 million in 2014. While these administrative fees are properly recoverable from retail customers, OG&E believes that, given the projected level of increase and the lack of control the Company has over these fees, these costs should be recovered through the SPPCR rider instead of base rates.

Transmission Unbundling *Pro Forma* Adjustments

Q. **What is OG&E specifically proposing?**

A. OG&E is requesting that the Commission authorize two *pro forma* adjustments to exclude certain transmission costs from Arkansas rate base and operating and maintenance ("O&M") expense. The Company is requesting the exclusion of a portion of its net investment in current transmission plant in service from the total company retail rate base. The Company is also requesting that the operating expenses associated with the excluded transmission plant in service be excluded from its Arkansas jurisdictional cost of service. The transmission plant in service and associated operating expenses to be excluded is that portion constructed as SPP Base Plan upgrades for which OG&E receives revenues from other members of the SPP. These revenues were not included in the Arkansas jurisdictional test year revenues. The cost of service directly assigns transmission revenues received from other SPP members to the FERC Jurisdiction.

Q. **What are the two *pro forma* adjustments the Company is proposing?**

A. The first is a rate base adjustment to remove certain transmission investment that is related to revenues allocated to OG&E through the SPP process from other non-affiliated LSEs. The second is an O&M adjustment related to recovery of this revenue from other LSEs.

Q. **Please indicate which items were adjusted on each *pro forma* adjustment.**

A. For the rate base adjustment reflected on WP B 2-6, the Transmission Investment and Accumulated Depreciation adjustments show a reduction in the cost of service to net plant in the amount of $9,002,371. On WP B 4-5, the M&S adjustment reflects a reduction of $362,707. For the expense adjustment reflected on WP C 2-39, Transmission

O&M, Depreciation and Taxes Other Than Income were adjusted which reduced expenses in the cost of service by $693,432. Finally, for the adjustment reflected on WP D 1-4, the ADIT adjustment reduced the ADIT balance in the capital structure by $1,694,724.

Q. **Please explain the intention of the Company regarding transmission unbundling.**

A. In this proceeding, OG&E has unbundled certain transmission investment and related expenses that are paid for by other LSEs. The Company recognizes that this adjustment does not affect this Commission's jurisdiction or authority to establish rates (including return on equity level) on OG&E's transmission investment assigned to the customers in the Arkansas jurisdiction. Over the next 12 to 24 months, the Company will be developing a comprehensive transmission unbundling plan which includes an unbundled cost of service model. OG&E will then jointly evaluate the cost of service model with the APSC staff. The Company will then make a decision whether to file a transmission unbundling application.

Q. **Please explain why OG&E is proposing adjustments to its transmission plant and related operating expenses.**

A. As explained above, one of the significant ramifications of regional cost allocations is that costs associated with certain transmission projects that SPP directs OG&E to build will be spread around the SPP footprint to other load serving entities. By doing so, SPP recognized that various LSEs within the SPP would benefit from OG&E transmission upgrades and expansion. For example, SPP may require OG&E to build a certain transmission line and, because the entire SPP footprint benefits from this new OG&E line, a portion of the cost responsibility for OG&E's revenue requirement would shift from OG&E's customers to the other benefiting LSEs in the SPP. To recognize that other LSEs are responsible for a portion of this revenue requirement, OG&E is seeking to reduce the cost responsibility of Arkansas customers by removing certain transmission costs from rate base and O&M expense. OG&E has calculated the costs recorded on its books that are assigned to others around the SPP. These costs result from the various SPP cost allocation mechanisms and were removed from total Company costs. These costs and expenses that will be removed from rate base and O&M expense in Arkansas will be recovered by OG&E from the SPP through FERC approved transmission rates.

Q **Which transmission plant is providing benefit to other LSEs?**

A. OG&E's current transmission plant in service that has been determined to be providing benefit to other LSEs is generally that plant that has been described by the SPP as "Base Plan Projects". OG&E's current Base Plan projects are generally transmission projects required to maintain a reliable transmission system needed to provide service from generation resources. The regional cost allocation for OG&E's current Base Plan projects is generally (i) one third on a region-wide basis (*i.e.*, by all ratepayers in the SPP region); and (ii) two thirds by the utilities within the zone(s) that directly benefit from the upgrade using the SPP's MW-mile impact study process.

Q. **How did OG&E determine what regionally allocated costs to remove from rate base and O&M expense in the Arkansas jurisdiction?**

A. OG&E used cost information contained in its FERC approved transmission formula rate. Specifically, the costs to be removed from rate base and O&M expense were based on the data included in the Company's Informational Filing of its Transmission Formula Rate True-Up Adjustment that was filed with the FERC on June 1, 2010. This FERC filing reflects actual 2009 Form 1 amounts to be included in the transmission formula rate. Two calculations were made in order to remove appropriate costs from rate base and O&M expense in Arkansas. First, transmission investment, accumulated depreciation and depreciation expense used in the calculation of the Base Plan project revenue requirement will be adjusted by 48.1531% of these amounts as adjustments to the cost of service. The 48.1531% was derived by dividing the Base Plan project revenue to be collected from others during 2010 by the sum of the net revenue requirements of all Base Plan projects ($1,518,540/$3,153,565). This percentage was applied to the costs as reflected in the transmission formula rate template on Schedule G, which is exclusively for Base Plan project revenue requirement purposes.

A second calculation was necessary to reflect those costs that were included in the net plant carrying charge less depreciation expense (NPCC) that was used in the derivation of the Schedule G revenue requirements on an indirect basis. This NPCC factor was derived from the Annual Transmission Revenue Requirement (ATRR) in the formula rate template for Network Integration Transmission Service (NITS), and was applied to BPU projects on Schedule G in the template. By dividing the revenue from others for base plan projects ($1,518,540) by the total ATRR ($83,525,865), the resulting 1.8180% was applied to each component making up the ATRR to remove that portion of costs from the cost of service that was part of the revenue requirement on Schedule G. These cost components that the 1.8180% was applied to and included in the *pro forma* adjustments were materials and supplies ("M&S"), ADIT, Transmission O&M and Taxes Other Than Income.

Q. **Is the Company proposing any other transmission related adjustments?**

A. Yes, *pro forma* adjustment WP C 2-22 is proposed to update certain SPP transmission costs and transmission oversight assessments. These costs include the SPP Schedule 1-A, SPP Annual Fee, North American Electric Reliability ("NERC") Assessment, SPP Additional Schedule 1, SPP Additional Schedule 9, SPP Base plan Schedule 11 and the SPP Schedule 12 assessment. The test year level of expense was $12,178,194. The 2010 level of expense is $14,360,678. A *pro forma* adjustment to increase these expenses of $2,182,484 is necessary to update these costs.

Q. **Are any of these SPP costs included in the Company's proposed SPPCR rider?**

A. Yes, the proposed SPPCR rider would include the SPP Schedule 1-A and SPP Base Plan Schedule 11 paid to others. If the Commission approves the SPPCR rider, the *pro forma* adjustment of $2,182,484 would be reduced to $408,919. An additional *pro forma* adjustment would then be necessary to remove the test year SPP Schedule 1-A and SPP Base Plan Schedule 11 paid to others of $6,707,982 and 2,007,194, respectively.

ENERGY COST RECOVERY RIDER

Q. **Is OG&E proposing any changes to the current Energy Cost Recovery Rider?**

A. Yes. OG&E is proposing four changes to the ECR. These changes are as follows:

(1) Incorporate time differentiated ECR factors for customers that have elected to be on time of use (“TOU”) rates;

(2) Exclude the energy purchased through purchased power agreements or produced by wind energy facilities owned by the Company and the associated purchased power costs that have not been approved by the Commission from the ECR;

(3) Add the fuel and purchased energy component of Arkansas customer accounts charged off as uncollectible to the costs recoverable through the ECR; and

(4) Add carbon taxes or other costs imposed through legislation or administrative order on the consumption of fossil fuels used in electricity generation as a cost recoverable through the ECR.

Q. **What is the purpose of proposing ECR factors to be used with OG&E’s TOU rates?**

A. As discussed in OG&E witness Howard Motley’s testimony, in 2009 the Company kicked off the Positive Energy TOGETHER® campaign that encourages consumers to use less power but a key goal is to shift energy demand away from the time of day when everyone uses the most electricity. Shaving the peak is crucial to advance the *2020 Goal*. OG&E is proposing for its TOU customers on-peak and off-peak ECR factors to reflect a higher fuel cost for on-peak consumption and a lower fuel cost for off-peak usage. This is intended to improve the price signals customers receive so they can better manage their energy use and take full advantage of smart grid technology when made available to Arkansas customers. The objective of TOU rates is to encourage customers to move energy consumption from on-peak periods to off-peak periods. This is more likely to be accomplished with meaningful differences in the cost per kWh customers experience for the time period of electric usage. OG&E’s current approach of using a single ECR factor for all rates in a service level dampens the price signals currently contained in the customer’s bill.

Q. **Does this proposed change impact non-TOU customers?**

A. No. Customers that have elected not to utilize TOU rates will see no changes. These customers will continue to be responsible for the same amount of fuel cost under the existing ECR methodology.

Q. **Have other state jurisdictions approved fuel cost recovery clauses that reflect time differentiated factors?**

A. Yes. In OG&E's last Oklahoma rate filing, Cause No. PUD 200800398, the Oklahoma Corporation Commission approved OG&E's TOU fuel costs recovery modification. In addition, there are fuel clauses for major utilities in Florida and Georgia that use time differentiated factors. In Florida, this includes Florida Power & Light, Progress Energy, and Gulf Power. In Georgia, it includes Georgia Power Company.

The concepts in both Florida and Georgia are very similar to OG&E's proposal for time differentiating fuel recovery in Arkansas. The utilities in both states have no fuel cost embedded in base rates and each have non-TOU fuel adjustment factors by service level, TOU on-peak fuel adjustment factors by service level, and TOU off-peak fuel adjustment factors by service level. The utilities in both states use a forecasted period combined with annual true-up. They all calculate the on-peak period and off-peak period fuel factors by load weighting their system incremental production cost. Florida required all major utilities to offer TOU rates and TOU fuel cost recovery[4]. Georgia Power has a pilot TOU fuel cost recovery procedure that started April 2010[5].

Q. **Have you prepared an exhibit that shows how to determine the ECR factors for the proposed approach?**

A. Yes. In Exhibit DRR-2, I have calculated the three ECR factors utilizing the annual filing made by OG&E for the 2010/2011 ECR factors.

Q. **Please explain the exclusion from the ECR of wind energy kWhs and the cost of wind energy purchases approved by the Commission.**

[4] Florida PURPA Rate Making Standards hearing, Dockets 780793-EU and 790859-EU.
[5] Georgia Docket 28945

A. This second change is required to adjust the Arkansas jurisdictional fuel expense when a portion of total energy available to the system is provided from company owned wind generation facilities that are not currently in the Arkansas rate base or are from purchased power agreements not yet approved by the Commission.

Q. **Please explain why it is necessary to make adjustments to the current ECR Rider for energy supplied by company owned wind facilities not in the Arkansas rate base.**

A. Among the differences in the economics of fossil fueled and wind generation is the trade-off between capital costs and fuel cost. The Company's current ECR determines the weighted average cost of fuel by dividing total costs by the total amount of energy produced. Introducing zero fuel cost wind energy production into this equation lowers the weighted average cost of fuel. The result is an immediate pass through of the benefits of wind generation without any recognition of the associated cost. Eliminating wind generated energy from the calculation results in the true weighted average cost of fuel. Thus, the weighted average cost of fuel that the customers pay is no difference than it would have been without the wind energy. This matches the benefit of zero fuel cost wind energy with its associated costs. In the period between the time the wind facility become operational and its costs are approved by the Commission, the Company is recovering the weighted average cost of fuel for the energy produced to offset its unrecovered costs and the customers are no worse off that they would have been without the wind energy being available.

Q. **What proposed changes are required to the ECR to adjust energy costs for generating facilities not in the Arkansas rate base and for purchase power costs which have not been approved by the Commission?**

A. The proposed changes are contained in Exhibit DRR-3.

Q. **What is the purpose of including language in the ECR to allow the recovery of fuel and purchased energy portion of customer accounts charged off as uncollectable?**

A. The ECR allows the Company to recover its actual cost of fuel and purchased power. However because a certain portion of customer accounts are ultimately written off as uncollectible, OG&E does not fully recover its actual cost of fuel. Currently, the Company's base rates include a level of recovery for uncollectible accounts however since a significant portion of the customers total bill represent fuel OG&E is proposing that this portion of accounts charged off be collected through the ECR. By moving this recovery out of base rates to the ECR, the amount of recovery would reflect the volatility of fuel costs and assure collection of the actual cost of fuel.

Q. **How would this recovery be accomplished through the ECR?**

A. OG&E produces a monthly charge off report that identifies the fuel component of bad debt bills by service level. The resulting fuel cost portion of the charge-offs for Arkansas customers will be included as uncollectable fuel charges in the monthly ECR true-up calculation.

Q. **How are uncollectible accounts recovered in the Oklahoma jurisdiction?**

A. In the last Oklahoma rate case[6] the Oklahoma Commission directed that "OG&E shall file tariffs allowing the Company to recover the actual amount of the fuel and energy costs in uncollectible customer bills through the FCA as opposed to including an estimated amount in base rates".

Q. **Have you prepared an exhibit that reflects the changes to the ECR to include recovery of the fuel and purchased power components of uncollectible accounts?**

A. The proposed ECR Rider is included as Exhibit DRR-4 or in the section with revised tariffs).

Q. **What is the purpose of including language to allow the recovery of potential carbon tax assessment fees?**

[6] Oklahoma Corporation Commission Order No. 569281, Cause No. PUD 200800398, 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.

A. Policy makers at various levels of government continue to study the need to reduce the level of carbon emitted by fossil fuel electric generation sources. Methods proposed to accomplish this include taxing carbon, establishing markets to trade the rights to emit carbon and establishment of carbon emission limits. The purpose of this change to the ECR is to allow timely recovery of the cost imposed by future government carbon policy on OG&E's generation fleet.

Q. **What are the proposed changes to the ECR for recovery of carbon policy assessments?**

A. The proposed changes are included in Exhibit DRR-4.

Q. **Are there any other changes the Company is proposing to the ECR?**

A. No. However, I wanted to note that for several years the Company has flowed transmission point-to-point revenues it receives through the ECR to Arkansas customers without being direct to do so by the Commission. No change is necessary to the ECR as there was not a specific provision to do so. Upon approval of the SPPCR rider by the Commission, these revenues would then begin being flowed through that rider.

CONCLUSION

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

A. Yes.

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. 76.0

Replacing ________ Sheet No. _____

OKLAHOMA GAS AND ELECTRIC COMPANY
Name of Company

Kind of Service: Electric Class of Service: All

Part I. Schedule No. SPPCR

Title: **SOUTHWEST POWER POOL COST RECOVERY RIDER**

PSC File Mark Only

PURPOSE

The purpose of the Southwest Power Pool ("SPP") Cost Recovery ("SPPCR") rider is to establish the rates by which Oklahoma Gas and Electric Company ("OG&E" or "Company") will return to and recover from its Arkansas retail ratepayer's credits and expenses associated with the transmission of energy. These credits and expenses are not included in the Company's base rates or collected through the Energy Cost Recovery (ECR) Rider. Credits and expenses in this rider may include SPP Point-to-Point Credits; SPP Sponsor Revenue Credits; SPP Administration (Schedule 1-A); SPP Base Plan Fees (Schedule 11); and other credits and expenses (SPP Credits and Expenses).

INITIAL RATES

The initial SPPCR Rates shall be effective on and after the first billing cycle following the APSC order adopting this tariff (prorated for the remaining calendar period).

SPP Cost Recovery formula (SPPCRf)

The SPPCRf calculates charges, on a per kilowatt-hour (kWh) basis, for each of the five (5) service levels at which Arkansas retail ratepayers are served.

$$\mathrm{SPPCRf_{sl}} = \frac{\left[\left(\mathrm{A} * \mathrm{CAP3SY_j}\right) * \mathrm{TA_{sl}}\right] \pm \mathrm{B_{sl}}}{\mathrm{kWh_{sl}}}$$

Where:

sl	=	Service Level
j	=	Jurisdiction
A	=	SPP Credits and Expenses
CAP3SY	=	The most recently approved Arkansas Jurisdictional Transmission Allocator

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. 76.1

Replacing ____________ Sheet No. _____

OKLAHOMA GAS AND ELECTRIC COMPANY
Name of Company

Kind of Service: Electric Class of Service: All

Part I. Schedule No. SPPCR

Title: **SOUTHWEST POWER POOL COST RECOVERY RIDER**

PSC File Mark Only

TA_{sl}	=	Intra-jurisdictional Transmission Allocator for each service level within the Arkansas Retail jurisdiction based on the most recently approved transmission allocator
B_{sl}	=	Over / (under) collection of previous calendar year's actual Arkansas SPP Cost Recovery, (net of carrying costs), for each service level
kWh_{sl}	=	Projected Kilowatt-hour sales for each service level

ANNUAL RE-DETERMINATION

On or before March 1 of each year, beginning in 2012, the Company will submit the re-determined SPPCR rates to the Commission Staff for implementation on the first billing cycle of April of that year. Calculations for the re-determined rates shall be by the application of the SPPCR formula set forth in this tariff. The Company shall submit a set of work papers sufficient to document the calculations of the re-determined SPPCR rates with each such re-determined SPPCR rates.

The re-determined SPPCR rates shall reflect the projected credits and expenses for the 12-month period commencing on January 1 of the current year adjusted for the over-recovery or under-collection, including carrying costs, of the previous calendar year's actual costs. Carrying costs based upon the most recent Rate of Return ("ROR") approved by this Commission.

INTERIM ADJUSTMENT

Should a cumulative over or under recovery balance arise during any SPPCR cycle which exceeds ten percent (10%) of the current SPPCR expected revenues, then either the Commission Staff or the Company may propose an interim revision to the currently effective SPPCR rate.

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. 76.2

Replacing ___________ Sheet No. _____

OKLAHOMA GAS AND ELECTRIC COMPANY
Name of Company

Kind of Service: Electric Class of Service: All

Part I. Schedule No. SPPCR

Title: **SOUTHWEST POWER POOL COST RECOVERY RIDER**

PSC File Mark Only

TERM

The SPPCR will become effective with the first billing cycle of the month following Commission approval of Rider SPPCR and shall remain in effect until closed by commission order.

APPLICABILITY

The SPPCR rider is applicable to all electric service billed under OG&E's Arkansas retail rate schedules and subject to the jurisdiction of the Commission.

EXHIIBIT - Oklahoma Gas & Electric
April 2010 Through March 2011 Annual ECR Current and Proposed Calculations

	Current	Proposed		
	2010/2011 Annual ECR Factors	Annual ECR_S Factors	TOU On-Peak Annual ECR_{ON} Factors	TOU Off-Peak Annual ECR_{OFF} Factors
Service Level 1	0.029293	0.029293	0.072411	0.026727
Service Level 2	0.029887	0.029887	0.073198	0.027481
Service Level 3	0.030613	0.030613	0.074502	0.027689
Service Level 4	0.031482	0.031482	0.076246	0.028485
Service Level 5	0.032350	0.032350	0.077670	0.029281

Ln	Tariff Component	Description	SL1	SL2	SL3	SL4	SL5	Total
			Current Annual ECR Factors					
1	Ecj	Total Company Forecasted Fuel & Purchase Power Expense	$ 868,185,431	$ 868,185,431	$ 868,185,431	$ 868,185,431	$ 868,185,431	$ 868,185,431
2	EAFj	Jurisdictional/Service Level Allocation	0.016604	0.006383	0.021083	-	0.065939	0.110009
3	ECj * EAFj	Allocated Arkansas Fuel by Jurisdiction/Service Level	$ 14,415,454	$ 5,541,427	$ 18,304,155	$ -	$ 57,247,366	$ 95,508,402
4	RRj (Ark Kwhs)	kWh Sales (Non-TOU plus TOU)	419,669,000	159,913,000	519,102,000	-	1,554,395,000	2,653,079,000
5	RRj (Current ECR)	2010/2011 Annual ECR Factors	**0.029293**	**0.029887**	**0.030613**	**0.031482**	**0.032350**	**0.031378**
6	RRj (1)	Projected Fuel Revenues	$ 12,293,363	$ 4,779,320	$ 15,891,271	$ -	$ 50,284,679	$ 83,248,633
7	PTUj	Prior Year Fuel Over-Recovery Credit	(2,121,960)	(762,084)	(2,412,684)	(2,364)	(6,962,268)	(12,261,360)
8	(RRj - PTUj)	Net Recoverable Fuel	$ 14,415,323	$ 5,541,404	$ 18,303,955	$ 2,364	$ 57,246,947	$ 95,509,993
9	TUA (ECj - (RRj - PTUj))	Projected Fuel Over Recovery April 2010 through March 2011	$ 131	$ 23	$ 200	$ (2,364)	$ 419	$ (1,591)
			Proposed TOU Annual ECR Factors					
10		Projected TOU ON-Peak kWh Sales	23,569,477	7,264,980	22,140,970	-	7,987,784	60,963,212
11		Projected TOU Off-Peak kWh Sales	396,099,523	130,763,285	332,380,451	-	117,970,094	977,213,352
12		Total Projected TOU kWh Sales	419,669,000	138,028,265	354,521,421	-	125,957,878	1,038,176,564
13		Total Non-TOU kWh Sales (Ln 4 - Ln 12)	-	21,884,735	164,580,579	-	1,428,437,122	1,614,902,436
14		TOU Projected Fuel Revenues (Ln 12 * Ln 5)	$ 12,293,364	$ 4,125,251	$ 10,852,964	$ -	$ 4,074,737	$ 31,346,316
15		Non-TOU Projected Fuel Revenues (Ln 13 * Ln 5)	$ -	$ 654,069	$ 5,038,305	$ -	$ 46,209,941	$ 51,902,315
16		Total Projected Fuel Revenues	$ 12,293,364	$ 4,779,320	$ 15,891,270	$ -	$ 50,284,678	$ 83,248,632
17		TOU On-Peak ECR_{ON} for 2010/2011 (Ln 27 / Ln 28)	**0.072411**	**0.073198**	**0.074502**	**0.076246**	**0.077670**	**0.073953**
18		TOU On-Peak Projected Fuel Revenue (Ln 17 * Ln 10)	$ 1,706,680	$ 531,782	$ 1,649,545	$ -	$ 620,414	$ 4,508,421
19		TOU Off-Peak ECR_{OFF} for 2010/2011 ((Ln 14 - Ln 18)/Ln 11)	**0.026727**	**0.027481**	**0.027689**	**0.028485**	**0.029281**	**0.027463**
20		TOU Off-Peak Projected Fuel Revenue (Ln 19 * Ln 11)	$ 10,586,552	$ 3,593,506	$ 9,203,282	$ -	$ 3,454,282	$ 26,837,622
21		On-Peak Prior Year Fuel Over-Recovery Credit (Ln 10/Ln 4 * Ln 7)	$ (119,174)	$ (34,622)	$ (102,907)	$ -	$ (35,778)	$ (292,481)
22		Off-Peak Prior Year Fuel Over-Recovery Credit (Ln 11/Ln 4 * Ln 7)	$ (2,002,786)	$ (623,168)	$ (1,544,839)	$ -	$ (528,398)	(4,699,191)
23		Non-TOU Prior Year Fuel Over-Recovery Credit (Ln 13/Ln 4 * Ln 7)	$ -	$ (104,294)	$ (764,938)	$ (2,364)	$ (6,398,092)	(7,269,688)
24		Total Prior Year Fuel Over-Recovery Credit	$ (2,121,960)	$ (762,084)	$ (2,412,684)	$ (2,364)	$ (6,962,268)	$ (12,261,360)
25		**Net Recoverable Fuel (Ln 15 + Ln 18 + Ln 20 - Ln 21 - Ln 22 - Ln 2**	**$ 14,415,192**	**$ 5,541,441**	**$ 18,303,816**	**$ 2,364**	**$ 57,246,905**	**$ 95,509,718**
26		**Projected Fuel Over Recovery Apr 2010 thru Mar 2011 (Ln 3- Ln 2**	**$ 262**	**$ (14)**	**$ 339**	**$ (2,364)**	**$ 461**	**$ (1,316)**
27		**Incremental On-Peak Period Fuel Cost**	0.07068					
28		**Energy Loss Factors**	0.9761	0.9656	0.9487	0.927	0.91	

EXHIBIT DRR-2

Oklahoma Gas And Electric Company
Energy Cost Recovery Rider
EAF Calculation
3/31/2010

	A	B	C	D	E	F	G
Line	**Description**	**Energy Loss Factors**	**As Filed kWh Sales**	**As Filed kWh Sales Adjusted for Losses**	**As Filed Jurisdictional Allocation Factor (EAF)**	**Alternative kWh Sales Adjusted for Losses**	**Alternative Jurisdictional Allocation Factor (EAF)**
	Oklahoma		Oklahoma	With Losses		With Losses	
1	SL 1 (Ln 1 Col C/Ln 1 Col B)	0.9761	50,079,662	51,305,872		51,305,872	
2	SL 2 (Ln 2 Col C/Ln 2 Col B)	0.9656	287,581,775	297,827,025		297,827,025	
3	SL 3 (Ln 3 Col C/Ln 3 Col B)	0.9487	131,113,511	138,203,342		138,203,342	
4	SL 4 (Ln 4 Col C/Ln 4 Col B)	0.9270	51,459,851	55,512,245		55,512,245	
5	SL 5 (Ln 5 Col C/Ln 5 Col B)	0.9100	1,203,432,899	1,322,453,735		1,322,453,735	
6	Oklahoma Free Service (Ln 6 Col C / Ln 6 Col B)	0.9100	5,439,149	5,977,087		5,977,087	
7	**Total**		1,729,106,847	1,871,279,306		1,871,279,306	
	Adjustment for Facilities only paid for by Oklahoma						
8	Less AES Co-generation			124,508,000		124,508,000	
9	Less Smith Co-generation			3,000		3,000	
10	Less Sooner Wind Farm			15,322,000		15,322,000	
	Less OU Spirit Wind Farm			-		**27,978,000**	
11	**Adjusted Oklahoma**			**1,731,446,306**		**1,703,468,306**	
	Arkansas		Arkansas	With Losses		With Losses	
12	SL 1 (Ln 12 Col C/Ln 12 Col B)	0.9761	43,853,264	44,927,020		44,927,020	
13	SL 2 (Ln 13 Col C/Ln 13 Col B)	0.9656	12,440,800	12,884,010		12,884,010	
14	SL 3 (Ln 14 Col C/Ln 14 Col B)	0.9487	40,067,620	42,234,236		42,234,236	
15	SL 4 (Ln 15 Col C/Ln 15 Col B)	0.9270	4,800	5,178		5,178	
16	SL 5 (Ln 16 Col C/Ln 16 Col B)	0.9100	120,390,634	132,297,400		132,297,400	
17	**Total (PES)**		**216,757,118**	**232,347,844**		**232,347,844**	
	FERC		FERC	With Losses		With Losses	
18	SL 1 (Ln 18 Col C/Ln 18 Col B)	0.9761	89,698,500	91,894,785		91,894,785	
19	SL 2 (Ln 19 Col C/Ln 19 Col B)	0.9656	-	-		-	
20	SL 3 (Ln 20 Col C/Ln 20 Col B)	0.9487	7,881,976	8,308,186		8,308,186	
21	SL 4 (Ln 21 Col C/Ln 21 Col B)	0.9270	3,050,482	3,290,703		3,290,703	
22	SL 5 (Ln 22 Col C/Ln 22 Col B)	0.9100	36,300	39,890		39,890	
23	**Total**		**100,667,258**	**103,533,565**		**103,533,565**	
24	**Grand Total (Ln 11 Col D +Ln 17 Col D + Ln23 Col D)**			**2,067,327,715**		**2,039,349,715**	
	Arkansas Jurisdictional Allocation Factors						
25	SL 1 (Ln 12 Col D/Ln 24 Col D)				0.021732		0.022030
26	SL 2 (Ln 13 Col D*Ln 24 Col D)				0.006232		0.006318
27	SL 3 (Ln 14 Col D*Ln 24 Col D)				0.020429		0.020710
28	SL 4 (Ln 15 Col D*Ln 24 Col D)				0.000003		0.000003
29	SL 5 (Ln 16 Col D*Ln 24 Col D)				0.063994		0.064872
30	**Total**				0.112390		0.113933
31	**Arkansas Jurisdictional Loss Factor (L17 Col C / L17 Col**	0.9329					

Oklahoma Gas And Electric Company
Energy Cost Recovery Rider
ECj Calculation Adjustment for OU Spirit
3/31/2010

	A	B	C
Ln	Description	As Filed Dollars	Adjusted Dollars for OU Spirit
1	**Fej***		
2	Gas	$ 27,534,471	$ 27,534,471
3	Coal	$ 26,368,206	$ 26,368,206
4	Oil	$ 10,531	$ 10,531
5	OU Spirit Wind Adjustment (No associated fuel cost)	$ -	$ -
6	SPP Revenue	$ (575,588)	$ (575,588)
7	SO2 Allowances	$ (832,500)	$ (832,500)
8	Gas Storage	$ (406,583)	$ (406,583)
9	Retained Fuel	$ (90,223)	$ (90,223)
10	**Total FEj**	$ 52,008,314	$ 52,008,314
11	**PEj**	$ 12,767,662	$ 12,767,662
12	EIS Sales	$ (1,675,828)	$ (1,675,828)
13	Total Purchased Power	$ 11,091,833	$ 11,091,833
14	Less: Other		
15	Less: AES Co-gen	$ 8,825,288	$ 8,825,288
16	Less: Smith Co-gen	$ 999,701	$ 999,701
17	Less: Wind Power Sooner	$ 378,038	$ 378,038
	Less: OU Spirit Wind (No associated fuel Cost)	$ -	$ -
18	**Total PEj**	$ 888,806	$ 888,806
	OSSRj		
19	Off System Sales - Monthly Transaction Summary	$ -	$ -
20	Reserve Sharing	$ 16,359	$ 16,359
21	FERC Assessment Fees	$ (134,445)	$ (134,445)
22	**Total OSSRj**	$ (118,087)	$ (118,087)
	Ecj		
23	FEj	$ 52,008,314	$ 52,008,314
24	PEj	$ 888,806	$ 888,806
25	OSSRj	$ (118,087)	$ (118,087)
26	**Total Ecj (Ln 23+ Ln 24 - Ln 25)**	$ 53,015,207	$ 53,015,207

Oklahoma Gas And Electric Company
Energy Cost Recovery Rider
Summary of ECj Calculation Adjustment for OU Spirit
3/31/2010

		Summary of all Service Levels		
Ln	**Period j Description**	**AS Filed Mar-10**	**Adjusted for OU Spirit Mar-10**	**Difference Mar-10**
1	Ecj	$ 53,015,207	$ 53,015,207	$ -
2	EAFj	0.11239	0.113933	
3	ECj * EAFj	$ 5,958,379	$ 6,040,182	$ 81,803

Ln		**SL - 1 As Filed Mar-10**	**SL - 1 Adjusted for OU Spirit Mar-10**	**Difference Mar-10**	**SL - 2 As Filed Mar-10**	**SL - 2 Adjusted for OU Spirit Mar-10**	**Difference Mar-10**	**SL - 3 As Filed Mar-10**	**SL - 3 Adjusted for OU Spirit Mar-10**	**Difference Mar-10**	**SL - 4 As Filed Mar-10**	**SL - 4 Adjusted for OU Spirit Mar-10**	**Difference Mar-10**	**SL - 5 As Filed Mar-10**	**SL - 5 Adjusted for OU Spirit Mar-10**	**Difference Mar-10**
4	Ecj	$ 53,015,207	$ 53,015,207	$ -	$ 53,015,207	$ 53,015,207	$ -	$ 53,015,207	$ 53,015,207	$ -	$ 53,015,207	$ 53,015,207	$ -	$ 53,015,207	$53,015,207	$ -
5	EAFj	0.021732	0.02203		0.006232	0.006318		0.020429	0.02071		0.000003	0.000003		0.063994	0.064872	
6	ECj * EAFj	$ 1,152,126	$ 1,167,925	$ 15,799	$ 330,391	$ 334,950	$ 4,559	$ 1,083,048	$ 1,097,945	$ 14,897	$ 159	$ 159	$ -	$ 3,392,655	$ 3,439,203	$ 46,547

		Total Difference
7	SL - 1	$ 15,799
8	SL - 2	$ 4,559
9	SL - 3	$ 14,897
10	SL - 4	$ -
11	SL - 5	$ 46,547
12	Total	$ 81,802

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. 70.0

Replacing ____________ Sheet No. ______

OKLAHOMA GAS AND ELECTRIC COMPANY
Name of Company

Kind of Service: Electric Class of Service: All

Part I. Schedule No. ECR

Title: Energy Cost Recovery Rider (Rider ECR)

PSC File Mark Only

~~1.~~ RECOVERY OF ENERGY COST

Energy Cost Recovery Rider ("Rider ECR") defines the procedure by which the "Energy Cost Rates" of Oklahoma Gas and Electric Company ("OG&E" or "Company") shall be established and periodically redetermined. The Energy Cost Rate shall recover the Company's net fuel and purchased energy cost, as defined in this Rider ECR.

APPLICABILITY

The ECR On-Peak (ECR_{on}) and the ECR Off-Peak (ECR_{off}) are applicable to their appropriate energy component in the R-TOU, CS-TOU, PL-TOU, and VPP tariffs. The ECR Standard (ECR_s) is applicable to the energy of all remaining tariffs.

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~~2.~~ ENERGY COST RATES

The Energy Cost Rates to be effective under this Rider ECR shall be determined in the manner prescribed ~~by the Arkansas Public Service Commission ("APSC" or "Commission")~~ in ~~its final order in~~ Docket No. ~~08~~10-~~103~~067-U and shall become effective upon the date established by the Commission. The Energy Cost Rate shall then be redetermined annually through filings made in accordance with the provisions of ~~Paragraph 3 of this Rider ECR~~the Annual Redetermination. ~~The Energy Cost Rate shall be applied to each customer's monthly billing energy (kWh).~~

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~~3.~~ ANNUAL REDETERMINATION

On or before March 15 of each year ~~beginning in 2008~~, the Company shall file redetermined Energy Cost Rates, Standard and TOU, for each service level with the Commission. The redetermined Energy Cost Rates for each service level shall be determined by application of the Energy Cost Rates Formula set out in attachment A of this Rider ECR. Each such revised service level Energy Cost Rate shall be filed in proper underlying docket and shall be

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ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. 70.1

Replacing ___________ Sheet No. ______

OKLAHOMA GAS AND ELECTRIC COMPANY
Name of Company

Kind of Service: Electric Class of Service: All

Part I. Schedule No. ECR

Title: Energy Cost Recovery Rider (Rider ECR)

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accompanied by a set of work papers sufficient to fully document the calculations of the five service level revised Energy Cost Rates.

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The redetermined Energy Cost Rates shall reflect the projected Energy Cost for the 12-month period commencing on April 1 of each year ("Projected Energy Cost Period") together with each service level true-up adjustment reflecting the over-recovery or under-recovery of the Energy Cost for the 12-month period ended December 31 of the prior calendar year ("Historical Energy Cost Period"). The Energy Cost Rates so determined shall be effective for bills rendered on and after the first billing cycle of April of the filing year and shall remain in effect for twelve (12) months, except as otherwise provided for below. The annual ECR filing shall include a report that identifies the components of the Company's net fuel and purchased energy costs for the Historical Energy Cost period.

~~4.~~ ADJUSTMENTS

If prior to the annual redetermination of the Energy Cost Rates APSC General Staff ("Staff") or the Company becomes aware of an event that is reasonably expected to occur and/or has occurred which will materially impact the Company's Energy Cost, either the Staff or the Company may propose an adjustment to the Energy Cost Rate Formula set out in Attachment A of this Rider ECR. Furthermore, should a cumulative over-recovery or under-recovery balance for all service levels arise during any Rider Cycle which exceeds ten percent (10%) of the Projected Energy Cost Period, then either the Staff or the Company may propose an interim revision to the then currently effective Energy Cost Rates.

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Original Sheet No. 70.2

Replacing ____________ Sheet No. _______

OKLAHOMA GAS AND ELECTRIC COMPANY
Name of Company

Kind of Service: Electric Class of Service: All

Part I. Schedule No. ECR

Title: Energy Cost Recovery Rider (Rider ECR)

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Original Sheet No. 70.3

Replacing ____________ Sheet No. ______

OKLAHOMA GAS AND ELECTRIC COMPANY
Name of Company

Kind of Service: Electric Class of Service: All

Part I. Schedule No. ECR

Title: Energy Cost Recovery Rider (Rider ECR)

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ATTACHMENT A

STANDARD ENERGY COST RATE FORMULA

ECR_S = STANDARD ENERGY COST RATE

$$ECR_S = \frac{TUA + PEC * EAF}{PES}$$

WHERE,

TUA = TRUE-UP ADJUSTMENT FOR THE HISTORICAL ENERGY COST PERIOD INCLUDING CARRYING CHARGES (1)

$$TUA = \sum_{j=1}^{12}((ECj * EAFj) - (RRj - PTUj - UFCj)) + CCj$$

~~WHERE~~

EC_j = ENERGY COST FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD

$EC_j = FE_j + PE_j - OSSR_j$

~~WHERE:~~

FE_j = FUEL EXPENSE CHARGED TO ACCOUNTS 501 AND 547 IN MONTH j OF THE HISTORICAL ENERGY COST PERIOD (5)

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ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. 70.4

Replacing ____________ Sheet No. _______

OKLAHOMA GAS AND ELECTRIC COMPANY
Name of Company

Kind of Service: Electric Class of Service: All

Part I. Schedule No. ECR

Title: Energy Cost Recovery Rider (Rider ECR)

PSC File Mark Only

~~(Continued)~~

PE_j = PURCHASED ENERGY EXPENSE FOR THE HISTORICAL ENERGY COST PERIOD CHARGED TO ACCOUNT~~S~~ 555 AND ASSOCIATED TRANSMISSION SERVICES IN ACCOUNT~~S~~ 565, LESS COGENERATION EXPENSE, ~~LESS~~ EIS SALES, AND NON-APPROVED ARKANSAS JURISDICTIONAL ENERGY PURCHASES

$OSSR_j$ = OFF SYSTEM SALES REVENUE RECORDED IN ACCOUNT 447 IN MONTH j OF THE HISTORICAL ENERGY COST PERIOD

EAF_j = ENERGY COST ALLOCATION FACTOR FOR MONTH j OF THE HISTORICAL COST PERIOD

RR_j = REVENUE UNDER RIDERS ECR, ECR_{vg}, AND ECR_{off}, FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD

PTU_j = PRIOR PERIOD TRUE-UP ADJUSTMENT APPLICABLE FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD

UFC_j = UNCOLLECTIBLE FUEL COST CHARGE OFFS FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD

CC_j = CARRYING CHARGES FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD

$CC_j = (BB_j + EB_j)/2 * CCR * DAYS_j/365$

~~WHERE:~~

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ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. 70.5

Replacing ____________ Sheet No. ______

OKLAHOMA GAS AND ELECTRIC COMPANY
Name of Company

Kind of Service: Electric Class of Service: All

Part I. Schedule No. ECR

Title: Energy Cost Recovery Rider (Rider ECR)

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BB_j = BEGINNING OVER/UNDER-RECOVERY BALANCE EXCLUDING CARRYING CHARGES FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD

EB_j = ENDING OVER/UNDER-RECOVERY BALANCE EXCLUDING CARRYING CHARGES FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD

CCR = CARRYING CHARGE RATE (3)

$DAYS_j$ = NUMBER OF DAYS IN MONTH j OF THE HISTORICAL ENERGY COSTS PERIOD

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ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. 70.6

Replacing ____________ Sheet No. _______

OKLAHOMA GAS AND ELECTRIC COMPANY
Name of Company

Kind of Service: Electric Class of Service: All

Part I. Schedule No. ECR

Title: Energy Cost Recovery Rider (Rider ECR)

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PEC = ESTIMATED ENERGY COST FOR THE PROJECTED ENERGY COST PERIOD (4)

$$PEC = \sum_{p=1}^{12} \cancel{EC}\, ECp$$

ECp = FEp + PEp – OSSRp

FEp = PROJECTED FUEL EXPENSE CHARGED TO ACCOUNT 501 AND 547 IN MONTH p OF THE PROJECTED ENERGY COST PERIOD(5)

PEp = PROJECTED PURCHASED ENERGY EXPENSE CHARGED TO ACCOUNT 555 AND ASSOCIATED TRANSMISSION SERVICES IN ACCOUNT 565, LESS COGENERATION EXPENSE, EIS SALES, AND NON-APPROVED ARKANSAS JURISDICTIONAL ENERGY PURCHASES.

OSSRp = PROJECTED OFF SYSTEM SALES REVENUE RECORDED IN ACCOUNT 447 IN MONTH j OF THE PROJECTED ENERGY COST PERIOD

-EAF = ENERGY COST ALLOCATION FACTOR FOR MONTH p OF THE PROJECTED ENERGY COST PERIOD WITH LOSSES MOST RECENTLY APPROVED BY THE APSC FOR APPLICATION OF THIS RIDER ECR (2)

PES = TOTAL PROJECTED SALES (kWh) SUBJECT TO THE ENERGY COST RECOVER ~~THIS~~ RIDERS ~~ECR~~ FOR THE PROJECTED ENERGY COST PERIOD (5)

$$PES = \sum_{p=1}^{12} ESp$$

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ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. 70.7

Replacing __________ Sheet No. ______

OKLAHOMA GAS AND ELECTRIC COMPANY
Name of Company

Kind of Service: Electric Class of Service: All

Part I. Schedule No. ECR

Title: Energy Cost Recovery Rider (Rider ECR)

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TIME OF USE ENERGY COST RATE FORMULA

ECR_{on} = ON-PEAK ENERGY COST RATE

ECR_{on} = PROJECTED INCREMENTAL ON PEAK PERIOD FUEL COST PER KWH

ECR_{off} = OFF-PEAK ENERGY COST RATE

$$ECR_{off} = \frac{(ECR_s * (PES_{on} + PES_{off}) - (ECR_{on} * PES_{on})}{PES_{off}}$$

PES_{on} = TOTAL PROJECTED SALES FOR THE ON-PEAK PERIOD (kWh)

PES_{off} = TOTAL PROJECTED SALES FOR THE OFF-PEAK PERIOD (kWh)

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ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. 70.8

Replacing ____________ Sheet No. _______

OKLAHOMA GAS AND ELECTRIC COMPANY
Name of Company

Kind of Service: Electric Class of Service: All

Part I. Schedule No. ECR

Title: Energy Cost Recovery Rider (Rider ECR)

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NOTES:

(1) The Historical Energy Cost Period is the calendar year immediately preceding the filing year.

(2) The value of EAF which will be used to calculate the Estimated Energy Costs shall be based on the ratio of: Arkansas projected sales adjusted for losses, to: system projected sales adjusted for losses less energy (kWh) from non-approved Arkansas jurisdictional generation sources. For true-up purposes, the EAF which will be used to calculate the actual energy cost applicable to Arkansas retail customers will be based on the ratio of: Arkansas actual billing determinants, adjusted for losses, to: system actual sales adjusted for losses less energy from non-approved Arkansas jurisdictional generation sources. ~~on projected kWh sales. For true-up purposes, the actual billing determinants adjusted for losses shall be used to calculate the actual energy costs applicable to Arkansas retail customers.~~

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(3) The Carrying Charge Rate shall be the Commission-approved rate of interest on customer deposits.

(4) Should there be unusual circumstances associated with any Projected Energy Cost Period either the Company or the Staff may propose use of a Projected Energy Cost (PEC variable) different from that defined by this formula.

~~(5)~~ The fuel cost associated with the DAP incremental kWh will be deducted from fuel cost and the fuel cost associated with the DAP decremental kWh will be added to fuel cost. ~~In addition T~~The incremental DAP kWh will be removed from PES ~~incremental~~ and the

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. 70.9

Replacing ____________ Sheet No. _______

OKLAHOMA GAS AND ELECTRIC COMPANY
Name of Company

Kind of Service: Electric Class of Service: All

Part I. Schedule No. ECR

Title: Energy Cost Recovery Rider (Rider ECR)

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decremental DAP kWh ~~kWh~~ will be added ~~removed from the~~ to PES. Carbon tax assessment fees will be included in both historical and projected fuel cost.

(5)

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ATTESTATION

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

____

24 September 2010
____
Date