Exhibit No:	
Issue:	Reasons for Rate Increase Review of ANG History Test Year Section A of Filed Schedules Plant Acquisition Adjustment SFAS 106 OPEB Costs Depreciation Rates Rate Design
Witness:	Ricky A. Gunter
Type of Exhibit:	Direct
Sponsoring Party:	Associated Natural Gas
Case No:	GR-97-272

ASSOCIATED NATURAL GAS
DIVISION OF ARKANSAS WESTERN GAS COMPANY

CASE NO. GR-97-272

DIRECT TESTIMONY

OF

RICKY A. GUNTER

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Q. Will you please state your name and business address?

A. My name is Ricky A. Gunter and my business address is 1083 Sain Street, Fayetteville, Arkansas 72703.

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

A. I am employed by Arkansas Western Gas Company (Company) as Director of Rates and Regulation. As Director for the Company, I am responsible for the rates for both the Arkansas Western Gas Company Division (AWG) and the Associated Natural Gas Company Division (ANG).

Q. Please describe your education and utility experience.

A. I graduated from Arkansas State University in 1971, receiving a Bachelor of Science degree with a major in Accounting. In 1971, I was employed by Associated Natural Gas Company and its parent company, Arkansas-Missouri Power Company. I held the position of Internal Auditor and General Accountant before being assigned to the Rate Department in 1975. In 1978, I became Manager of Rates and Statistics, a position held until January, 1981, after which I was employed by Mississippi Power and Light Company of Jackson, Mississippi, as Senior Accountant assigned to the Rate

Department. In August of 1982, I returned to Associated Natural Gas Company as a Senior Accountant, and in April, 1983, I was elected Assistant Treasurer. Upon the acquisition of Associated Natural Gas Company by Arkansas Western Gas Company, I was transferred in August, 1988, to the headquarters of Arkansas Western Gas Company in Fayetteville, Arkansas. Shortly thereafter, I was named Director of Rates and Regulation for both the Arkansas Western Gas Division and the Associated Natural Gas Company Division, the position I presently hold.

Q. What is the purpose your testimony in this proceeding?

A. I will address the reasons for the need to increase rates. I will provide a brief description of the history and operations of ANG. I will describe the test year used by ANG for its filing, I am sponsoring the schedules in Section A of the Accounting Schedules filed in support of the requested rate increase. I will discuss the request to include in the cost of service a portion of the plant acquisition adjustment related to the purchase of ANG and the inclusion of the postretirement benefits other than pensions (OPEB) at the level of expense required by the Statement of Financial Accounting Standards No. 106. In addition I will discuss the Company's request to establish new depreciation rates for ANG and address the need to adjust ANG cost of service between the firm and interruptible rate classes.

Reasons for Rate Increase

Q. Please describe the reasons for seeking a rate increase for ANG.

A. ANG'S last application for a general change in rates was filed January 22, 1990 and the rates approved therein became effective November 15, 1990. The approved increase for ANG was $876,236 which included $624,291 for the allocation of gathering and transmission facilities of the AWG. These facilities are used by ANG to transport gas purchased from the Arkoma Basin in western Arkansas to its system. This case was the first rate application subsequent to the acquisition of ANG by the Arkansas Western Gas Company and presented the first opportunity for ANG to include in its cost of service the equitable allocation of these facilities. Since the cost related to these facilities represents the major portion of the approved increase and was the only increase applicable to ANG's largest district (SEMO District), ANG has been effectively operating on rates that were based on a cost of service relating to ANG's 1986 rate application. ANG has experienced increased operating costs that have not been offset by customer growth and has made new investments in rate base with the result that ANG is now earning substantially below a reasonable rate of return on rate base. Therefore, it is necessary for ANG's rates to be increased in order to maintain just and reasonable rates that will enable it to continue to provide reliable natural gas service to its customers in Missouri.

History and Operations of ANG

Q. Would you provide a brief history of ANG?

A. In the early 1950's a group of investors formed ANG and began natural gas service to communities in southeast Missouri. In 1952, Arkansas Missouri Power Company (Ark-Mo), an electric company headquartered in Blytheville, Arkansas, entered the natural gas distribution business by providing natural gas service to communities in northeast Arkansas and southeast Missouri. Also, in 1952 Ark-Mo purchased all of the common stock of ANG and operated ANG as a wholly owned subsidiary of Ark-Mo. Over the years ANG and Ark-Mo continued to add communities in their respective service territories. In 1961 ANG expanded its operations into the area of Missouri referred to today as the Kirksville District and in 1963 purchased from Missouri Western Gas Company the properties known today as the Butler District. In 1978 Ark-Mo transferred all of its gas properties to ANG thereby putting all of the gas properties under one corporate structure. ANG continued to operate as a wholly owned subsidiary of Ark-Mo until January, 1981 at which time Arkansas Power and Light (AP&L, now Entergy Arkansas) purchased the outstanding stock of Ark-Mo. Ark-Mo was dissolved and ANG became a wholly owned subsidiary of AP&L. In June, 1988 Arkansas Western Gas Company acquired ANG from AP&L and ANG, as a separate corporate entity, ceased to exist becoming an operating division of

Arkansas Western Gas Company. This is the corporate structure existing today. Although ANG is an operating division of Arkansas Western Gas Company, separate accounting records and rates are maintained for ANG.

Q. Would you now describe the operations of ANG?

A. ANG provides natural gas service to approximately 20,000 customers in northeast Arkansas and 47,000 customers in three (3) separate operating districts in Missouri. The Missouri jurisdictional operations serve approximately 37,000 customers in southeast Missouri, referred to as the SEMO District, 5,900 customers in north central Missouri, referred to as the Kirksville District, and 3,900 customers in northwest Missouri, referred to as the Butler District. ANG purchases its gas supply requirements directly from producers or marketers and has transportation and/or storage agreements with one intrastate pipeline and seven interstate pipelines. ANG also owns a liquified natural gas plant (LNG Plant) located approximately three miles north of Blytheville, Arkansas which helps meet the winter peaking requirements of the operations in Arkansas and a portion of the SEMO District.

Q. Are there any special characteristics regarding ANG's operations that must be taken into account when establishing rates for its Missouri districts?

A. Yes. Because ANG has facilities and operating expenses that are devoted to providing service across its entire service territory, jurisdictional allocations are required to establish the cost of service between its Arkansas and Missouri operations and between operating districts within Missouri. Another unique characteristic of ANG is that a portion of the SEMO district and the Arkansas District is served through an interconnected transmission system which is operated as an integrated system. This requires allocations of gas supply, transmission plant and expenses, and LNG storage plant and expenses between the Arkansas and the SEMO districts. In addition to the jurisdictional allocations required for ANG's direct plant and expenses, there are facilities and operating expenses of AWG that also support the ANG operations. This requires allocations of facilities and expenses between AWG and ANG. Some of these allocations are made on a routine monthly basis through the Company's administrative and general expense allocation procedures; however, these procedures do not contemplate all allocations of costs that should be made for ratemaking.

Q. Please provide some examples of the costs that are not routinely allocated between AWG and ANG that require allocations for ratemaking.

A. The general office building in Fayetteville houses the Company's executive management which has responsibilities in both divisions. The plant, depreciation, operating and maintenance expense, and property taxes related to this facility should be allocated between the divisions and between operating districts within ANG. In 1993, the separate meter shop functions of the two divisions were consolidated by closing ANG's old outdated meter shop. The meter shop located in Fayetteville, which is newer and more efficient, now provides the meter shop functions for both divisions. The costs related to the meter shop building must be allocated between divisions and operating districts. And finally, the gathering and a portion of the transmission facilities of AWG are used by ANG to deliver gas purchased behind the AWG system for delivery into the NOARK Pipeline System for redelivery to ANG. The costs related to these facilities, including the operating and maintenance expenses, must be allocated between the divisions; however, these costs are only allocable between ANG's Arkansas and SEMO districts. These are examples of the AWG costs that must be allocated between the divisions. The testimony and exhibits of Ms. Donna Campbell will demonstrate in detail the AWG allocations, other than the routine general and administrative allocations, necessary to establish proper costs for ratemaking purposes between the divisions. There are also costs of Southwestern Energy Company that must also be allocated for rate making purposes that are not included in the routine monthly general and administrative allocations. These costs are included in the proforma adjustments described in the testimony of Mr. Mark Kidd.

Test Year

Q. What test year did ANG use to establish rates in this proceeding?

A. ANG used the actual data from its books and records for the twelve months ended July 31, 1996. This data was adjusted for normal weather and proforma adjustments made for customer growth and known and measurable changes for the twelve month period ending July 31, 1997. For this proceeding the term "test year" refers to the twelve month period of actual data as of July 31, 1996. The term "adjusted test year" refers to the twelve month period for which proforma adjustments were made (the twelve months ending July 31, 1997).

Q. Is this the test period ANG recommends for Staff to audit and make its recommendation regarding ANG's revenue deficiency?

A. The test year selected by ANG as adjusted for known and measurable changes through July 31, 1997 would be an appropriate period for setting rates in this case. However, the books and records for the calendar year 1996 are now available. ANG would have no objection if Staff selected the twelve months ending December 31, 1996 for the test year as long as known and measurable changes through a period closer to the effective date of the tariffs were taken into consideration. For example, ANG's union contract covering all employees except the clerical/secretarial and exempt salaried employees expires as of June 1, 1997. Contract negotiations will commence within the next few months. Assuming that the contact is ratified and signed within a reasonable time prior to the hearing, ANG would consider this a known and measurable change to be included in this proceeding.

Section A Schedules of Accounting Schedules

Q. Would you now describe the schedules contained in Section A of the Accounting Schedules filed in support of ANG's application?

A. Yes. Schedule A-1 is the calculation of the requested increase in the revenue requirement for ANG's Missouri jurisdictional operations. As shown on this schedule the total requested increase in annual revenue is $3,759,002. The increase in annual revenue by operating district is shown on Schedule G-1 and will be addressed in the direct testimony of Ms. Donna Campbell.

Plant Acquisition Adjustment

Q. You previously stated that you would address the requests to include the plant acquisition adjustment and the SFAS 106 postretirement benefit costs in the cost of service. Would you now address the plant acquisition adjustment?

A. ANG is requesting that it be allowed to include in its rates the amortization and return on the unamortized balance of the plant acquisition adjustment related to the acquisition of ANG. The acquisition adjustment represents the purchase price and the costs to acquire ANG which were in excess of the book value of ANG at the time of the acquisition. The amount was $5,716,000 and was recorded in FERC Account No. 114, Acquisition Adjustment. This adjustment is being amortized over a 20.5 year period which represents the average remaining life of ANG's properties at the time of the acquisition. The acquisition was effective June 1, 1988 and the amortization began immediately thereafter. The total annual amortization is $279,000 annually. Since rates including the acquisition adjustment have not yet been approved, the amortization is being recorded in FERC Account 425.

Q. Why does the Company believe that it is appropriate to include the acquisition adjustment in its cost of service?

A. The Company believes that recovery of this cost through rates is appropriate because its ratepayers have realized cost savings in excess of the acquisition adjustment amortization and the return on the unamortized balance. These savings have occurred through increased efficiencies which have resulted directly from the merger and would not have been available without the expenditures made by the Company and included in the acquisition adjustment. The ratepayers of both AWG and ANG have received the benefit of these savings. Because ratepayers of both divisions have received a benefit from the merger, ANG is proposing to allocate the acquisition adjustment between AWG and ANG based upon the net savings (achieved savings in excess of the acquisition adjustment costs) accruing to each division.

Q. You have stated that the acquisition adjustment should be allocated between the Company's divisions based upon net savings in costs accruing to each division. How were the net savings determined?

A. The Company, in connection with its 1990 Arkansas rate application (Docket No. 90-004-U) and its Missouri rate application (Case No. GR-90-152), had Arthur Andersen & Co. identify and document the savings resulting from the merger. Arthur Andersen & Co. quantified these savings by reviewing and comparing the operating costs of both ANG and AWG prior to and after the acquisition of ANG. In addition, for AWG's 1996 Arkansas rate case (Docket No. 96-030-U), Mr. Greg Kerley, Vice President - Treasurer and Secretary, supervised Company personnel in preparing an update of the work performed by Arthur Andersen & Co. The results of this updated analysis were used to allocate the acquisition adjustment between divisions in this proceeding as well as in Docket No. 96-030-U.

Q. Was the acquisition adjustment allowed to be included for recovery in rates in Case No. GR-90-152?

A. Since the acquisition, the Commission has never been required to render a decision regarding the appropriate ratemaking treatment of the acquisition adjustment. Case No. GR-90-152 was concluded by stipulation with no specific ratemaking treatment established for the acquisition adjustment. However, it has been the position of the Staff that recovery of the acquisition adjustment costs should not be allowed in rates. To date, the only position expressed by the Commission was made in the order approving the merger. In that order, the Commission stated "That nothing in this order shall be considered as a finding by the Commission of the reasonableness of any expenditures involved herein nor of the value for ratemaking purposes of any properties involved herein nor as an acquiescence in the value placed upon said properties by the Joint Applicants. Furthermore, the Commission reserves the right to consider the ratemaking treatment to be afforded these transactions in any later proceeding." Because all rate applications have been settled by stipulation with no specific ratemaking treatment identified, the issue of the appropriate rate making treatment of the acquisition adjustment has never been before the Commission.

Q. How does the Company propose to allocate the acquisition adjustment between AWG and ANG in this proceeding?

A. The Company proposes to allocate the acquisition adjustment based upon the results of the updated analysis conducted by Company personnel and used in Docket No. 96-030-U. Attached is Schedule No. RG-1, which is a copy of Exhibit No. GDK-1R included in Mr. Kerley's rebuttal testimony in Docket No. 96-030-U, which shows the net savings between divisions resulting from the Company's updated savings analysis. As shown on this schedule, 89.75% of the savings can be attributed to AWG and 10.25% of the savings can be attributed to ANG. These percentages were provided to Ms. Donna Campbell for use in the allocations in the cost of service.

Q. Schedule No. RG-1 also shows ANG's savings between Arkansas and Missouri resulting from the acquisition. How were the net savings allocated between the Arkansas and Missouri jurisdictions?

A. The net savings for Arkansas and Missouri as shown on Schedule RG-1 that were not directly attributable to a state were allocated between the states based upon the number of customers in each jurisdiction as of August 31, 1995. For this proceeding, the total acquisition adjustment applicable to ANG was allocated between the Arkansas and Missouri jurisdictions based on the number of proforma customers in each jurisdiction.

Q. How much of the plant acquisition adjustment costs have been included in ANG's Missouri jurisdictional revenue requirement?

A. The total, including the return on the unamortized balance and the amortization of the adjustment, is $39,982.

Postretirement Benefits Other Than Pensions (SFAS 106)

Q. Could you now address the Company's request to include in the cost of service the costs of postretirement benefits other than pensions (OPEB) determined in accordance with the Statement of Financial Accounting Standards No. 106 (SFAS 106)?

A. The Financial Accounting Standards Board issued SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," in December of 1990. The adoption of SFAS 106 for publicly held companies was mandatory for fiscal years beginning after December 15, 1992. The Company's parent, Southwestern Energy Company, is publicly held and, accordingly, effective January 1, 1993 the Company adopted SFAS 106. SFAS 106 requires employers to recognize OPEB costs on an accrual basis rather than on a pay-as-you-go or cash basis. Also, companies must recognize the transition benefit obligation (TBO) which is the accumulated benefits earned by employees prior to the adoption of SFAS 106. SFAS 106 provides the TBO may be recognized immediately in the year of adoption as a one-time charge to the income statement; or alternatively, over a period equal to the average remaining years of service of plan participants. If the remaining service period is less than twenty years, companies may use an optional twenty-year period.

Q. What is the amount of the OPEB costs the Company is including in its Missouri jurisdictional cost of service?

A. The OPEB deferral recorded as a regulatory asset and included in rate base (on which a return will be earned) totals $238,453 and is shown by district on Schedule G-2-1 of the filed accounting schedules. The amount included as an operating expense for the amortization of the regulatory asset is $162,675 and is included in the jurisdictional allocation of Account 926 - Pensions and Benefits. The testimony of Mr. Mark Kidd will address the SFAS 106 regulatory asset and expense for the total ANG division.

Q. How does the Company plan to fund its OPEB costs?

A. In AWG's recent rate case (Docket No. 96-030-U) the Company filed to include SFAS 106 determined OPEB costs in its cost of service. All parties to the case signed a stipulation and agreement which among other provisions provided for SFAS 106 costs to be included in rates and the Company agreed to establish an external funding plan. Currently, the Company is funding AWG's OPEB costs by setting aside cash funds in a restricted bank account. The Company prefers to establish one external funding plan to cover all OPEB costs for both ANG and AWG. However, the Company is not aware of what funding requirements, if any, may result from this proceeding. Once all the funding requirements are known, a permanent external funding plan can be implemented.

Depreciation Rates

Q. Would you now turn your attention to the Company's request to establish new depreciation rates for ANG?

A. Yes. 4 CSR 240-40.040 requires gas utilities to file depreciation studies every five (5) years or when tariffs are filed with the Commission proposing a general rate increase. However, if the utility has submitted to the Commission's Staff a depreciation study during the three (3) years prior to the general rate filing, the utility need not submit a depreciation study with the rate filing. ANG submitted its initial depreciation study as required by this rule on July 1, 1994. Since ANG's initial study was submitted to the Commission's Staff within the three (3) year period prior to its filing, a new depreciation study was not included as part of the filing.

The Company engaged Arthur Andersen & Co. to conduct its initial depreciation study for ANG's Arkansas and Missouri districts. The study was conducted using the remaining life method and estimated the remaining lives using both the statistical method and forecast method in conjunction with discussions with management and operating personnel knowledgeable as to the planned use of the facilities as well as their physical condition at the time of the study. The estimated net salvage values were determined using actual experience, engineering estimates and comparable industry experience. In reviewing the study in conjunction with this proceeding, ANG noted two errors which require correction. The first correction restates the reserve due to an error in the original study which allocated the reserve related to the Arkansas "Towns West" properties between Arkansas and Missouri. The second correction reduced the accumulated reserve to adjust the reserve per the original study to agree with the reserve per the continuing property records at the time of the study. These adjustments were relatively minor but did cause a change in many of the recommended depreciation rates per the original study. These corrections were made and revised Exhibits I, IIA, IIB and IIC corresponding to the exhibits in the original study have been attached to Schedule F-8 of the filed accounting schedules in this proceeding. These revised exhibits show the new depreciation rates used by ANG to calculate the proforma depreciation expense and are the rates ANG requests to be approved in this proceeding.

Rate Design

Q. You mentioned earlier that you would address a rate design issue. Would you now address that issue?

A. In this proceeding ANG is proposing to design rates in accordance with its cost of service study. To accomplish this will require a shift in the non-gas cost revenue requirement between the firm and interruptible customer classes. In general, this shift reduces rates to the interruptible class while increasing rates to the firm class. The cost of service study and rate design will be discussed in detail in the direct testimony of Ms. Donna Campbell.

ANG's current rate design places much more of the non-gas cost revenue requirement on the interruptible class and much less on the firm class than is supported by its cost of service study. To understand this disproportionate allocation, a look into the history of ANG's rate design would be helpful. Rate design is not an exact science. Sometimes political and social issues play a role in developing rates. ANG's rates in effect in 1983 reflected the era of the "national natural gas shortage". The difference between the rates for firm service and interruptible service was narrowed. For ANG this difference was set at $0.15 per thousand cubic feet (Mcf). The reasoning for narrowing the difference was the idea that if large commercial and industrial interruptible customers continued to use natural gas, a scarce natural resource in an era of shortage, they should pay a rate close to the rate paid by firm customers. Also, the thought was that larger customers could institute conservation measures or switch to an alternate fuel easier than the smaller firm customers; thereby, saving gas supply for the firm customer classes.

The rates in effect in 1986 began the era of "interstate pipeline open access transportation" and local gas distribution companies began to design rates based upon the cost of service. Up until 1986, ANG's purchased gas adjustment clause provided that firm and interruptible customers paid the same per unit gas cost. However, with the 1986 rate case this changed. The parties to the rate case agreed to establish a firm and interruptible class for recovery of gas costs and that all pipeline demand costs based on a maximum daily contract demand should be assigned to the firm rate class. Due to the impact this shift would have made to the firm class, a portion of the non-gas cost revenue requirement was reassigned to the interruptible class. This reassignment caused the non-gas cost rate for the interruptible class to be higher than the non-gas cost rate for the firm customer class in the SEMO and Kirksville districts. This was not the case for the Butler district because at that time there was no pipeline demand costs based upon a daily contract demand. As a result, there was no shifting of gas cost between the firm and interruptible customers in the Butler district.

In ANG's 1990 rate case, a step towards setting rates based upon the cost of service was taken and it helped eliminate part of the rate design problem created in 1986. However, there is still a disproportionate amount of the non-gas revenue requirement assigned to the interruptible class. ANG proposes to correct for this in the current proceeding.

Q. Can you provide an example to clarify the rate design problem described above?

A. Yes. Attached to my testimony is Schedule RG-2. This schedule shows the non-gas cost rate (margin rate) by rate schedule, by district for the 1983, 1986, and 1990 (the current rate in effect) rate cases and the proposed rate in this proceeding. This schedule visually demonstrates the history leading to the current rate design problem. What follows is the history of the non-gas cost rate per Mcf for the industrial interruptible small rate class compared to the residential firm class for the SEMO district:

Year	Residential	Industrial Interrupt. Small
1983	$1.00040	$0.85040
1986	$0.80370	$1.32040
1990 (Current)	$0.93480	$1.04600
Proposed	$2.08340	$0.20130

As the table above demonstrates, ANG's rate design has for many years been at odds with the cost of service. Many larger interruptible customers receive transportation service only. Industrial interruptible small transport customers in the SEMO district are currently paying a rate of $1.0460 per Mcf which is more than the rate ANG charges to its firm customers who receive a higher level of service. This situation should be corrected.

Q. Does this conclude your direct testimony at this time?

A. Yes.

Exhibit GDK-1R

Arkansas Western Gas Company

Annual Cost Savings Resulting from Merger with Associated Natural Gas Company ($ In Thousands)

Line No.	Description (1)	Total Savings (2)	Total Savings Applicable to: AWG Division (3)	ANG Division Ark. (4)	ANG Division Mo. (5)
1	Elimination of ANG executives and support staff	$ 899	$	$ 279	$ 620
2	Elimination of ANG accounting and information services functions	696	(166)	267	595
3	Elimination of operating personnel	1,068	(67)	352	783
4	Combination of the meter shop function	412	73	105	234
5	Plant allocations	0	257	(80)	(177)
6	Change in intercompany allocations	(343)	2,355	(836)	(1,862)
7	Total	$ 2,732	$ 2,452	$ 87	$ 193
8	Percent of Total	100.00%	89.75%	3.18%	7.07%

Note: The savings not directly attributable to a state were allocated between states based on the number of customers as of August 31, 1995.

ASSOCIATED NATURAL GAS COMPANY
a Division of Arkansas Western Gas Compnay
Comparison of Margin Difference for Rates
Prior to and After Demand Costs being Allocated to Firm
and Proposed Rates

	Prior to Demand Cost Allocated to Firm Only				Demand Cost Allocated to Firm Only				Current Rates		Proposed Rates	
	Date Effective	Tariff Rate	Base Cost of Gas	Margin per Mcf	Date Effective	Tariff Rate	Base Cost of Gas	Margin per Mcf	Date Effective	Margin per Mcf	Date Effective	Margin per Mcf
Southeast Missouri												
Residential	17-Sep-84	3.9802	2.9798	1.0004	01-Sep-86	4.3908	3.5871	0.8037	15-Nov-90	0.9348	13-Dec-97	2.0834
Commercial Firm	11-Nov-83	3.9802	2.9798	1.0004	01-Sep-86	4.6174	3.5871	1.0303	15-Nov-90	0.9669	13-Dec-97	1.2245
Commercial Interruptible	11-Nov-83	3.8302	2.9798	0.8504	01-Sep-86	3.7880	2.5672	1.2208	15-Nov-90	1.0460	13-Dec-97	0.3566
Industrial Firm	11-Nov-83	3.9802	2.9798	1.0004	01-Sep-86	4.6174	3.5871	1.0303	15-Nov-90	0.9669	13-Dec-97	0.5513
Industrial Interruptible Small	11-Nov-83	3.8302	2.9798	0.8504	01-Sep-86	3.8876	2.5672	1.3204	15-Nov-90	1.0460	13-Dec-97	0.2013
Industrial Interruptible Large	13-Jan-83	3.8302	2.9798	0.8504	01-Sep-86	3.1970	2.5672	0.6298	15-Nov-90	0.3375	13-Dec-97	0.152
Kirksville												
Residential	17-Sep-84	4.8026	4.0844	0.7182	01-Sep-86	4.9375	4.5178	0.4197	15-Nov-90	0.4760	13-Dec-97	1.5495
Commercial Firm	11-Nov-83	4.8026	4.0844	0.7182	01-Sep-86	5.0025	4.5178	0.4847	15-Nov-90	0.4760	13-Dec-97	0.8019
Commercial Interruptible	11-Nov-83	4.6526	4.0844	0.5682	01-Sep-86	4.3211	3.1126	1.2085	15-Nov-90	1.0180	13-Dec-97	0.1104
Industrial Firm	11-Nov-83	4.8026	4.0844	0.7182	01-Sep-86	5.0025	4.5178	0.4847	15-Nov-90	0.4760	13-Dec-97	0.6768
Industrial Interruptible Small	11-Nov-83	4.6526	4.0844	0.5682	01-Sep-86	4.4202	3.1126	1.3076	15-Nov-90	1.0180	13-Dec-97	0.2901
Butler												
Residential	17-Sep-84	4.1243	2.9333	1.191	01-Sep-86	5.3500	4.0262	1.3238	15-Nov-90	1.6805	13-Dec-97	2.4882
Commercial Firm	11-Nov-83	4.1243	2.9333	1.191	01-Sep-86	5.3963	4.0262	1.3701	15-Nov-90	1.6805	13-Dec-97	1.5958
Commercial Interruptible	11-Nov-83	3.9743	2.9333	1.041	01-Sep-86	4.9927	4.0262	0.9665	15-Nov-90	1.0760	13-Dec-97	0.4277
Industrial Firm	11-Nov-83	4.1243	2.9333	1.191	01-Sep-86	5.3963	4.0262	1.3701	15-Nov-90	1.6805	13-Dec-97	1.5958
Industrial Interruptible Small	11-Nov-83	3.9743	2.9333	1.041	01-Sep-86	5.3049	4.0262	1.2787	15-Nov-90	1.2760	13-Dec-97	0.2728

Schedule RG-2