CASE NUMBER:

99-070

KY. PUBLIC SERVICE COMMISSION

Index for Case: 1999-00070 AS OF : 03/06/07

Atmos Energy Corporation

General Rates

FULLY-FORECASTED TEST PERIOD

IN THE MATTER OF RATE APPLICATION OF WESTERN KENTUCKY GAS COMPANY

SEQ NBR		Date	Remarks
1		03/01/99	Notice of Intent.
2	(M)	04/14/99	COPY OF DRAFT NOTICE (JACK HUGHES WESTERN KY GAS)
3	(M)	04/28/99	SUPPLMENTAL NOTICE OF INTENT TO FILE RATE APPLICATION (MARK HUTCHINSON WESTERN KY GAS CO.)
4		05/05/99	Order denying motion to use an abbreviated form of notice
5	(M)	05/12/99	MOTION FOR RECONSIDERATION (WESTERN KY GAS CO. JOHN HUGHES)
6		05/28/99	Application.
7		05/28/99	Acknowledgement letter.
8		05/28/99	Order approving use of amended proposed abbreviated notice form submitted 5/12.
9	(M)	06/04/99	MOTION TO INTERVENE (DAVID SPENARD AG)
10	(M)	06/04/99	LETTER OF CONCERN TO RATE INCREASE (EDWARD THOMASON CITIZEN)
11	(M)	06/08/99	CORRECTIONS TO APPLICATION FILED ON MAY 28,99 (JOHN HUGHES WESTERN KY GAS CO)
12		06/10/99	Order granting motion to intervene filed by Attorney General.
13		06/16/99	Order rejecting application; statutory time period to commence with req.info.
14	(M)	06/16/99	MISSING APPLICATION PAGES, REPLACEMENT COPIES. (JOHN N. HUGHES/ATTORNEY)
15	(M)	06/23/99	MOTION FOR RECONSIDERATION (JACK HUGHES WESTERN KY GAS)
16		07/02/99	Order suspending rates to Jan. 23, 2000; sets procedural schedule; info due 7/12
17	(M)	07/08/99	RESPONSE TO ORDER OF JULY 2,99 COPIES OF PUBLICATION (JOHN HUGHES WESTERN KY GAS)
18	(M)	07/12/99	OBJECTION TO RATE INCREASE (JOHN BAIRD/ATTORNEY AT LAW)
19		07/15/99	Letter to Jack Hughes regarding electronic filings
20		07/16/99	Data Request Order; response due 7/30
21		07/22/99	Response sent to John Baird letter of concern to rate increase.
22		07/29/99	Order scheduling 12/14 hearing; supplemental procedural schedule set forth
23	(M)	07/30/99	RESPONSE TO FIRST REQ FOR INFO & PETITION FOR CONFIDENTIALITY (JOHN HUGHES WESTERN KY GAS)
24	(M)	08/13/99	SUPPLEMENTAL RESPONSE TO ITEMS 47F & 60 C-E (JOHN HUGHES WESTERN KY GAS)
25		08/16/99	Letter granting petition for conf. filed 7/30/99 by Western Kentucky Gas.
26	(M)	08/17/99	MOTION FOR FULL INTERVENTION (MEL CAMENISCH WBI SOUTHERN INC)
27	(M)	08/18/99	RESPONSE TO ITEMS 6,10,12,19,23,24D,25,42C,& 71 (JOHN HUGHES WESTERN KY GAS)
28		08/19/99	Data Request Order; response due 9/3
29	(M)	08/19/99	INITIAL REQUEST FOR INFORMATION BY THE AG (AG DAVID SPENARD)
30		09/01/99	Order granting WBI Southern, Inc. intervention
31		09/03/99	Memorandum regarding application for adjustment of rates
32	(M)	09/03/99	RESPONSES TO PSC SECOND REQUEST FOR INFO TO AG FIRST REQ FOR INFO (JOHN HUGHES WESTERN KY GAS)
33		09/15/99	Letter granting petition for conf. filed 9/3/99 on behalf of Western Ky. Gas.
34	(M)	09/15/99	MOTION TO FILE DATA REQ UPON WESTERN KY GAS (MEL CAMENISCH WBI SOUTHERN INC)
35	(M)	09/15/99	DATA REQ TO WESTERN KY GAS BY WBI SOUTHERN INC (WBI SOUTHERN INC MEL CAMENISCH)
36		09/20/99	Order issuing data request; response due 10/4
37	(M)	09/20/99	SUPPLEMENTAL REQUEST FOR INFORMATION (DAVID SPENARD AG)
38	(M)	09/22/99	RESPOSNE TO AG INITIAL DATA REQ NO 181 & 182 (MARK HUTCHINSON WESTERN KY GAS)
39		10/01/99	Data Request Order; response due 10/8
40	(M)	10/01/99	SUPP REQ FOR INFO BY THE AG FOR THE APPLICANT SUPP RESPONSE (AG DAVID SPENARD)

41	(M)	10/04/99	RESPOSNES TO PSC THIRD REQ FOR INFO,AG SUPP REQ,WBI SUPP REQ,& PETITI (JOHN HUGHES WESTERN KY GAS)
42		10/07/99	Letters granting petitions for conf. filed 10/4/99 by Western Kentucky Gas.
43	(M)	10/07/99	UPDATED RESPONSE TO PSC INITIAL DATA REQ ITEM 39C (JOHN HUGHES WESTERN KY GAS)
44	(M)	10/07/99	REVISED RESPONSES TO DATA REQ ITEMS 49 & 153 OF AG INITIAL DATA REQ (MARK HUTHINSON WESTERN KY GAS)
45	(M)	10/07/99	REVISED SCHEDULES & DATA REQ RESPONSES TO FILING OF SPECIAL CONTRACTS (JOHN HUGHES WESTERN KY GAS)
46	(M)	10/08/99	RESPONSE TO ORDER OF OCT 1,99 TO MODIFY ITEMS 6 & 57 & 58 (JOHN HUGHES WESTERN KY GAS)
47	(M)	10/11/99	RESPONSE TO PSC ORDER OF OCT 1,99 ITEMS 57 & 58 (JOHN HUGHES WESTERN KY GAS)
48	(M)	10/14/99	RESPONSE TO AG VERBAL REQ FOR ADDITIONAL INFO TO SUPPORT ITEM 14 (JOHN HUGHES WESTERN KY GAS)
49	(M)	10/18/99	VERIFIED TESTIMONY OF KEITH TIGGELAAR (MEL CAMENISCH WBI SOUTHERN INC)
50	(M)	10/18/99	NOTICE OF FILING & CERTIFICATE OF SERVICE (DAVID SPENARD AG)
51		10/21/99	Order revising procedural schedule
52		10/29/99	Letter granting WKGS's petition for confidentiality filed 10/7/99.
53	(M)	11/03/99	UPDATED RESPONSE TO INITIAL DATA REQ ITEM 39C (MARK HUTCHINSON WESTERN KY GAS)
54		11/04/99	Order entered; info due 12/6
55		11/05/99	Data Request Order; response due 11/22
56	(M)	11/08/99	WESTERNS DATA REQUEST TO THE AG (WESTERN KY GAS JOHN HUGHES)
57	(M)	11/15/99	UPDATED EXHIBITS TO COMMISSION DATA REQ (JOHN HUGHES WESTERN KY GAS)
58	(M)	11/15/99	UPDATED SCHEDULES FOR FORCASTED MONTHS (JOHN HUGHES WESTERN KY GAS)
59	(M)	11/22/99	RESPONSE TO DATA REQ OF THE PSC (AD DAVID SPENARD)
60	(M)	11/22/99	RESPONSE TO WESTERNS DATA REQ TO THE AG (AG DAVID SPENARD)
61		12/03/99	Letter granting petition for conf. filed 11/15/99 on behalf of Western Ky. Gas.
62	(M)	12/03/99	JOINT STIPULATION & SETTLEMENT (JOHN HUGHES WESTERN KY GAS)
63		12/06/99	Order requesting direct testimony due 12/9/99.
64	(M)	12/06/99	REBUTTAL TESTIMONY (WESTERN KY GAS)
65	(M)	12/09/99	RESPONSE TO DEC 6,99 ORDER (AG DAVID SPENARD)
66	(M)	12/09/99	AFFIDAVITS VERIFYING REBUTTAL TESTIMONY OF WESTERNS WITNESSES (JOHN HUGHES WESTEN KY GAS)
67	(M)	12/09/99	RESPONSE TO DEC 6,99 ORDER (JOHN HUGHES WESTERN KY GAS)
68	(M)	12/09/99	SETTLEMENT TESTIMONY OF DALE LAWRENCE (ROBERT WATT WBI SANITATION)
69		12/10/99	Order cancelling 12/14 hearing; case is submitted to Commission for a decision.
70	(M)	12/10/99	AFFIDAVIT OF DALE R LAWRENCE (ROBERT WATT WBI SOUTHERN)
71	(M)	12/13/99	LETTER OF CONCERN TO RATE INCREASE (WALLY BRYAN CITIZEN)
72		12/21/99	Acknowledgment to William Wallace Bryan, Jr. former mayor re: rate increase.
73		12/21/99	FINAL ORDER; APPROVES TERMS AND CONDITIONS OF SETTLEMENT
74	(M)	01/07/00	COMPLIANCE TARIFF FILING PER ORDER OF DEC 21,99 (WESTERN KY GAS WILLIAM SENTER)
75	(M)	03/06/00	RESPONSE TO ORDER FIST COMPANY COMMUNICATION ON NEW LATE PAYMENT (WESTERN KY GAS WILLIAM SENTER)
76	(M)	04/03/00	RESPONSE TO PSC ORDER CUSTOMER EDUCATION ON LATE PAYMENT CHARGE (WILLIAM SENTER WESTERN KY GAS)
77	(M)	05/12/00	COPY OF THE NEW LATE PAYMENT CHARGE (WILLIAM SENTER/WKG)
78	(M)	07/24/00	RESPONSE TO ORDER CONCERNING SEMI ANNUAL REPORTS ON DISCOUNT TARIFF (WESTERN KY GAS WILLIAM SENTER)
79	(M)	08/03/00	CUSTOMER EDUCATION MATERIALS (WILIAM SENTER/WKG)
80	(M)	01/18/01	SEMI-ANNUALLY REPORT ON ANY DISCOUNT NON GIVEN (WILLIAM SENTER WESTERN KY GAS)
81	(M)	06/29/01	WNA ANNUAL REPORT (WILLIAM SENTER/WKG)
82	(M)	07/26/01	William J Senter - Atmos Energy Corporation - SEMI-ANNUAL REPORT
83	(M)	08/02/01	Mark R Hutchinson - Wilson, Hutchinson & Poteat - LETTER GIVING NOTICE OF CHANGE OF ADDRESS FOR MARK HUTCHINSON
84	(M)	01/17/02	William J Senter - Atmos Energy Corporation - Response to Order Semi-Annual report
85	(M)	05/10/02	William J Senter - Atmos Energy Corporation - Annual report on the Gas Technology Institute Research & Development program
86	(M)	07/03/02	William J Senter - Atmos Energy Corporation - Western Kentucky Gas response to Order regarding discounts under Margin Loss Recovery Tariff- none were given
87	(M)	01/06/03	William J Senter - Atmos Energy Corporation - Response to Order concerning semi-annually report on any discount provided under its Margin Loss Recovery tariff during the prior six months
88	(M)	06/30/03	Gary L Smith - Atmos Energy Corporation - WNA Annual Report for Atmos Energy for winter of 2002-2003
89	(M)	08/01/03	Gary L Smith - Atmos Energy Corporation - Semi Annual report of Atmos Energy
90	(M)	06/25/04	Gary L Smith - Atmos Energy Corporation - Annual Report Weather Normalization Adjustment for 2003-2004

?RD 160
Rev. 9/85

RECORD REQUEST

Public Records Division — Kentucky Department for Libraries and Archives

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Request For: ☐ Original ☐ Photocopy

Location in Center	Accession Number	Unit Number	Record Series Title	Identification Number (Voucher, Case, Etc.)	To Be Returned?	Date Record Out	Date Record In
VII-I-255		Box # 37	Case # 99-267				
VI-D-71		21	99-149				
VI-C-58		7	99-070				

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Western Kentucky Gas Company
Case No. 99-070
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Volume 2

RECEIVED
MAY 28 1999
PUBLIC SERVICE COMMISSION

Western Kentucky Gas Company
Case No. 99-070
Forecasted Test Period Filing Requirements
FR10(9)(a)

Description of Filing Requirement:

The prepared testimony of each witness the utility proposes to use to support its application which shall include testimony from the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program;

Response:

See the prepared direct testimony of Mr. Conrad E. Gruber, President – Western Kentucky Gas Company.

1

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	)	
RATE APPLICATION BY	)	**Case No. 99-070**
WESTERN KENTUCKY GAS COMPANY	)	

TESTIMONY OF CONRAD E. GRUBER

Q. Please state your name, position and business address.

A. My name is Conrad E. Gruber. I am President of Western Kentucky Gas Company ("Western" or "Company"). My business address is 2401 New Hartford Road, Owensboro, Kentucky, 42303.

Q. Please briefly describe your current responsibilities, and professional and educational background.

A. I was named President of Western Kentucky Gas Company in January 1999. I began my career with Atmos Energy Corporation in Dallas, Texas in February 1991 as Engineering and Measurement Coordinator. Prior to being named President of Western Kentucky Gas, I served as Vice President, Technical Services of Greeley Gas Company in Denver, Colorado since 1994. Before joining Atmos I was employed for seven years at Entex Corporation. I began my career with Entex as an engineer in 1983, and subsequently held various positions of increasing responsibility in engineering, marketing and operations. I hold a Bachelor of Science degree in Mechanical Engineering from the University of Texas at Austin.

As President, I have primary responsibility for all operational decisions and financial performance of Western Kentucky Gas Company. I am also a member of the Atmos Shared Services Board, which researches industry 'best practices and designs the contracts for services provided by the shared services staff. The Shared Services Board exists to continuously study the shared services functions and ensure that shared services costs are appropriate and in line with the best providers of such services in industry. Ultimately, it is my responsibility to sign off on all shared services billings to Western.

Q. Have your ever submitted testimony before the Kentucky Public Service Commission?

A. No.

Q. Have you ever testified before any other regulatory body?

A. Yes. I have testified before the Colorado Public Service Commission.

Q. Are you sponsoring any of the filing requirements and, if so, which?

A. I am sponsoring the following:

FR 10(1)(b)	Application Supported by a Fully Forecasted Test Period
FR 10(1)(b)1	Statement of Reasons
FR 10(1)(b)3	Certified Copy of Articles of Incorporation
FR 10(1)(b)5	Certificate of Good Standing
FR 10(1)(b)6	Certificate of Assumed Name
FR 10(1)(b)9	Statement on Customer Notice
FR 10(2)	Notice of Intent
FR 10(3)(a-i)	Form of Notice to Customers
FR 10(4)(c)	Manner of Notification
FR 10(4)(c)3	Notice of Publication in Newspapers of General Circulation
FR 10(4)(d)	Publisher Affidavits
FR 10(4)(f)	Notice to Customers Posted in Utility Places of Business
FR 10(5)	Notice of Hearing
FR 10(9)(a)	Statement of Officer in Charge of Kentucky Operations
FR 10(9)(e)1-3	Statement of Attestation
FR 10(11)(a-c)	Request for Waiver of Certain Filing Requirements

Q. Do you adopt these Filing Requirements and make them part of your testimony?

A. Yes.

Q. Please provide an overview of the prepared direct testimony in this proceeding.

A. My testimony will sponsor the application and reasons that Western is filing for rate relief, as well as address the operational plans underlying our forward-looking cost projections. My testimony will also (1) touch on the need for the new rate structures proposed in this case; (2) give a brief description of the history of the Company, including our present operations and service areas; and (3) I will also discuss the Company's Vision and Strategy, which is the basis for our forecasted test period budget.

Mr. R. Earl Fischer, President, Energas Company and former President of Western Kentucky Gas Company, will testify to the origins of this rate request, and on the concept of Shared Services.

Ms. Rebecca M. Buchanan, Senior Analyst – Rates (Shared Services), will sponsor the determination of the revenue deficiency indicated in Western's projected cost of service.

Ms. Betty L. Adams, Vice President and Controller (Western), will sponsor the projected test period cost of service including the Shared Services contract costs, and the assumptions on which the projections are based.

Mr. David H. Doggette, Vice President – Technical Services (Western), will sponsor the projected capital expenditures including the Shared Services contract costs for capital expenditures, and the assumptions on which the projections are based. He will also sponsor the study supporting the proposed special service charges and the study supporting our Electronic Flow Measurement (EFM) charges.

Mr. Donald P. Burman, Assistant Controller (Shared Services), will sponsor the Company's "per books" accounting practices, pension accounting, taxes, and depreciation study.

Mr. J. Patrick Reddy, Treasurer (Shared Services), will sponsor our capital structure and requested return on equity.

Dr. Donald A. Murry, of C. H. Guernsey & Company, will testify to the appropriate rate of return on equity.

Mr. John W. Hack, Director – Gas Supply Operations (Shared Services), will describe Western's gas supply function and procurement of gas and capacity.

Mr. Thomas H. Petersen, Director – Rates (Shared Services), will sponsor the class cost of service study.

Mr. Gary L. Smith, Vice President – Marketing (Western), will support the forecast of growth, volumes and revenues as used in the Company's projections and various cost studies. He will also address the problems with Western's current rate structures and present our proposal for competitive industrial rates, compensatory residential rates, higher base charges, new service charges, a DSM Surcharge, the proposed Premises Charge, other rate mechanisms, and the key changes requested in our tariffs. Mr. Smith will also address Western's proposal for a Weather Normalization Adjustment (WNA) in its rates.

Mr. Michael Marks, of Applied Energy Consulting, will describe our Demand Side Management (WKG CARES) program and support our proposed DSM Surcharge.

Mr. Daniel M. Ives, of Lukens Consulting, will discuss costs associated with new residential growth and present an incremental cost study in support of Western's proposed Premises Charge.

Each witness in turn will describe those filing requirements most applicable to their respective areas of expertise. The Company's testimony and its Filing Requirements submittal combine to illustrate the need for the proposed rates and Western believes that they are just and reasonable.

Q. What is the purpose of Western Kentucky Gas Company's Application in this proceeding?

A. Western Kentucky Gas is seeking approval of an increase in revenues of $14,127,666. This is an 11.7% increase in total revenues based on a forecasted test period twelve months ending December 31, 2000. Just as important, however, we are seeking significant improvements in our rate structures to reflect the structure and costs of our operations in the future.

Although we operate very efficiently, we are not achieving a fair return on our investment with the rates currently in effect. In fact, we are projecting a negative return on common equity over calendar year 2000. The proposed increase will allow the Company a reasonable opportunity to earn a fair return on its investments. Through management efficiencies, knowledge, and the financial strength derived from this increase, Western will be able to continue providing safe, dependable service to our customers. The proposed rates will also help offset the impact of continued plant investment in our system and increased operating expenses.

Q. Mr. Gruber, when was Western last granted a request for rate relief?

A. The last rate increase was granted by the Commission in Case No. 95-010 in its Order dated October 20, 1995 with rates effective in two phases: $2,300,000 on November 1, 1995 and an additional $1,000,000 effective March 1, 1996.

Q. What rate relief are you requesting in this Application?

A. We are asking the Commission to approve new rate schedules which would increase our revenues to provide a projected rate of return of 9.97 % on a projected net rate base of $130,484,159.

Q. What is the rate of return on common equity requested in this Application?

A. We have requested a rate of return on projected common equity of 12.25 %.

Q. Why does Western need this rate relief?

A. The reasons are specifically enumerated in Filing Requirement FR 10(1)(b)1. Since the 1994 test period used in Western's last rate case, Western has increased its net plant investment by over $56 million. Western's rate base has increased about $44.8 million. As a result of the higher level of investment projected in this case, of the $14.1 million revenue increase requested, approximately $10.2 million, or approximately 72%, is attributable to a projected increase in return on investment, income taxes and depreciation expense.

Operating and maintenance expenses as adjusted have also increased since Western's last rate filing. The total change in operating and maintenance expense as adjusted is approximately $800,000. This represents a change of about 3% over the six-year period, which is about ½ of 1 percent per year.

Prompt and adequate rate relief is essential if we are to continue to provide high quality service to our current customers from existing facilities while we continue the construction of needed facilities to serve new customers. Our present rates fall substantially short of providing sufficient revenues for such purposes. If the Company is to continue to grow, and if it is to maintain and promote safe and reliable service, the Company must have rates and rate structures which provide a reasonable rate of return and cash flow to finance additions, improvements, and replacements to its systems.

Q. Is this application different from past rate applications made by Western?

A. Yes. Our proposal involves more than just including in our rates the investment and cost increases we have incurred since our last case in order to sustain us for a while. Our goal is to avoid filing rate cases in the future. To achieve this we have looked forward to develop innovative rate proposals. In doing so, we think there are benefits to our customers and the Commonwealth of Kentucky, as well as to Western.

Q. Is this why you have filed rates based on projected rather than historical costs?

A. Yes. The gas market is evolving, and so is the way we must conduct our business. I will describe many of the business process changes we are undergoing. If we are to be successful in the future we must align our prices to projected costs which reflect the way we will do business in the future.

Q. Is Western's need for rate relief limited to increased rates only?

A. No, although we do have the lowest rates of Kentucky's LDCs. Our need is associated with the structure of our current rates as well as their level. Simply stated, our current rate structures have produced an environment of high risk and low reward. This situation cannot be sustained.

For example, industrial margins subsidize residential rates in our current rate structure; yet, industrial margins for specially situated large volume customers are continually being negotiated downward as a result of threatened bypass. To ensure these customers remain on our system, we have no alternative but to yield to the pressure to lower these rates. Mr. Smith will discuss how bypass threats since our last rate case currently reduce our industrial margins by $800,000 annually. We have no means to recover this lost revenue outside a rate case.

Western's residential rates in the current rate structure simply do not recover the costs of providing residential service, even though most of our costs are attributable to serving our residential customers. Virtually all of these costs are fixed and our current rate design places too much of the responsibility for recovering fixed costs from commodity rates. The warm weather and energy efficiency steps by customers since our last case have caused Western to fail to recover all of its costs. Mr. Smith will discuss how energy conservation in our core markets has adversely affected our earnings since then, $1,600,000 on a weather-normalized annual basis. We also have a problem in that our incremental facility costs exceed the historical costs embedded in our rates. As a consequence, every new residential premises addition further dilutes our earnings.

We have addressed each of these issues through an innovative set of rate design proposals.

Q. How have Western's revenues trended since the implementation of rates from its 1995 case?

A. We have had successively declining revenues since our last rate case in 1995. The combination of exceptional industrial competition and operating costs among the lowest in our industry makes it extremely difficult for Western to offset declining margins in the midst of sustained periods of warm weather and continuing energy efficiency improvements.

Q. What rate structures are you proposing in this case?

A. We propose the following rate structures:

1. To realign residential, commercial and industrial margins and service charges to reflect their embedded class service costs and eliminate cross-class subsidies.

2. To rebalance the fixed and variable elements in our rates to more accurately reflect the underlying fixed and variable cost characteristics of our service and recapture a depletion in revenue caused by changing customer usage patterns.

3. To properly segregate our gas costs from our distribution costs in our commodity rates.

4. A phased-in restructuring of the collection of Gas Research Institute (GRI) Research & Development costs.

5. To establish a margin loss recovery mechanism to capture industrial margins lost as a result of contracts negotiated to avoid bypass.

6. An alternative receipt point service providing more delivery flexibility for transportation customers.

7. To establish a weather normalization adjustment (WNA) of rates.

8. To establish a surcharge to pay the costs of our Demand Side Management program, WKG CARES.

9. We propose a new forward-looking rate element which will prevent the continuous dilution of earnings as we add new residential customers.

Q. Briefly describe Western Kentucky Gas Company.

A. Western Kentucky Gas Company is a high quality, low cost, customer-focused natural gas distribution company that has grown with the communities it serves. We serve approximately 175,000 residential, commercial and industrial customers in 168 communities in 38 counties in Kentucky. The largest cities served by Western are Owensboro, Bowling Green, Paducah, Hopkinsville, Madisonville, Danville, Mayfield, Glasgow, Campbellsville, Franklin, Russellville, Princeton, Harrodsburg, Lebanon, Shelbyville and Central City.

Western was organized and incorporated in 1934 from four separate gas companies serving about 2500 customers. That same year, Western began to acquire various gas distribution properties, including the Indiana-Kentucky Natural Gas Corporation and six systems from the Kentucky Public Service Company. In 1945 systems serving Owensboro, Bowling Green, Russellville and Hopkinsville were added to Western's service area through acquisition of the Owensboro Gas Company. In 1948 Western purchased the distribution system serving Danville from the Kentucky Utilities Company and at the same time acquired various franchises and rights held by the Natural Gas Distributing Company and commenced construction of distribution systems in Central Kentucky.

The gas distribution systems serving Campbellsville and Greensburg were acquired from the Taylor-Green Gas Company and, in 1951, Western acquired from the Kentucky Utilities Company the transmission line and distribution system serving Paducah. Western purchased Marion and Fredonia in 1970, Woodburn in 1974 and the last acquisition, Stanley, in 1980.

On December 1, 1980, Western merged with Texas American Energy Corporation of Midland, Texas, a diversified energy organization. In December of 1987, Energas Company, later known as Atmos Energy Corporation, acquired Western from Texas American Energy.

Q. What is Western's relationship to Atmos Energy Corporation today?

A. Western is an operating division and business unit of Atmos Energy Corporation, d/b/a/ Western Kentucky Gas Company in the Commonwealth of Kentucky.

Q. Please describe Atmos Energy Corporation.

A. Atmos Energy Corporation is one of just a few American corporations whose business activities and expertise are heavily concentrated in local distribution companies that sell, transport, and store natural gas. Although incorporated only 16 years ago, Atmos is primarily comprised of gas utility operations that date back near the beginning of this century. Through periodic acquisitions of similarly profiled companies, Atmos' combined gas utility operations now provide natural gas service to over one million customers in twelve states. Atmos specializes in serving small to medium-sized cities and rural communities, like the markets we serve in Kentucky. Atmos continually strives to enhance the efficiency of its operating divisions while preserving traditional high standards of service quality to the customers residing in the communities we serve.

Q. How is Western operated as one of the five primary business units of Atmos?

A. Western is locally managed by a team of professionals held accountable for its operational decisions and financial performance. Western does join together with the other business units to share knowledge, expertise and common services to achieve economies of scale appropriate in today's increasingly competitive energy marketplace. As a result, Western's O&M costs are lower than its industry peers. The table below, based on A. G. Edwards' most recent study (1997) of the gas industry, compares statistics for the gas industry as a whole to Western's base period in this case.

A. G. Edwards Study of Large LDCs	Operations & Maintenance Costs Per Meter	Gas Utility Employees Per 1000 Customers
Gas Industry Average	$189	2.59
Gas Industry Median	$183	2.65
Western Kentucky Gas	**$115**	**1.94**

Q. How is Western structured to meet the needs of communities in Western Kentucky?

A. Western is organized to lend a preponderance of its resources to customer focused activities. We have regional offices in Bowling Green and Madisonville, each headed by a vice president of operations who is accountable for the safety, quality and efficiency of service provided in the communities which comprise that region. Their operations are supported from Owensboro by a small, but strong staff of engineering, financial, human resource, regulatory and marketing personnel. The success of our operations depends on having a motivated team of employees dedicated to their choice of careers and community and striving to meet the expectations of their customers. We believe the good relationship we have with our customers is evidence to the quality of the team that we have in place.

Q. How does Western intend to maintain this good relationship with its customers as it grows?

A. Western is committed to a shared vision of our business approach, a sound governance philosophy, and allegiance to basic beliefs and behaviors which embrace high quality, low cost service as the cornerstone of our future success. By setting our course, communicating our strategy, understanding our management practices, and embracing a core set of values - visions become plans, plans become expectations, and expectations become reality.

At Western, corporate visions and values are not just words. On-site management and employees are empowered to initiate positive change and be more responsive to customer needs than ever before. Additionally, our process of contracting for shared services is designed to achieve "best practices." In concert with the other Atmos business units, Western determines how its services will be provided, in what form, and at what acceptable level of costs. Our compensation structure provides incentives and tangible feedback on the quality of our contracting for these services. The result is an expectation of the highest quality of services provided at the lowest possible cost.

Q. Have you attached an exhibit to your testimony which states Atmos' Vision, Strategy, Governance Philosophy, Beliefs and Behaviors?

A. Yes. They are described in my Exhibit CEG-1 (Atmos Vision Pamphlet).

Q. Pursuant to KAR 5:001 Chapter 278, Section 10 (9)(a), please describe and explain the purpose of the existing programs Western has in-place to achieve improvements in its efficiency and productivity.

A. I am pleased to say that Western has a number of initiatives in-place designed to improve its efficiency and productivity. Technology improvements throughout the economy are increasing the expectations of customers, suppliers and employees. We are making these changes to meet these expectations.

Q. Please describe these initiatives.

A. There are four primary initiatives:

1. Customer Information System (CIS), whose primary purpose is to support the customer service and accounting functions through streamlined transactions for

billing inquiries and service orders, and to support a centralized customer support center.

2. Centralized Customer Support Center, whose primary purpose is to centralize customer service contacts for all of the states served by Atmos, including Kentucky. Centralized customer service and support allows us to more efficiently and effectively serve our customers.

3. Information Technology (IT) Infrastructure, whose purpose is to update Atmos' IT strategy to accommodate the new CIS and Customer Support Center and provide the flexibility to manage technical assets in a changing environment.

4. Business Process Changes made to accommodate the changes to Western's operations as a result of the new CIS, Customer Support Center and updated IT Infrastructure. The purpose of these changes is to enable Western to provide more efficient and higher quality customer service.

Each of these initiatives will provide benefits to customers that did not previously exist.

Q. Please describe the benefits from each initiative.

A. **Customer Information System (CIS).** The CIS will allow Western to provide more efficient service to its customers through a single unified system (customer accounts receivable and billing, remittance processing, customer inquiry and support) than is currently available through three separate systems. It accommodates an expanded billing format, providing a means for better communication with our customers. It will support the Customer Support Center with Client Server Technology; allow Western to keep a record of customer events and actions; and provide for summary billing of customers with multiple accounts. The timing of this new CIS implementation also addresses the Year 2000 problems with our incumbent CIS that is 25 years old.

Customer Support Center. The Customer Support Center allows Western to provide more efficient and higher quality customer service by centralizing and standardizing customer service and support from a single point of contact. Telephone support is available to customers 24 hours a day, 7 days a week from customer service representatives formally trained by Atmos. Although this centralized service operation is located in Amarillo, Texas, calls from Kentucky to the Customer Support Center are answered "Western Kentucky Gas Company." The Customer Support Center also provides for a system that better measures the quantity and content of customer calls, as well as the quality of service provided when a customer calls.

IT Infrastructure. The IT (Information Technology) Infrastructure will provide for an update to a more current technology of Local Area Networks (LAN's) linked to form a Wide Area Network (WAN) of communication. This will allow Western to support the internet, intranet and extranet services and the Client Server based systems now prevalent with new software installations. The new technology enables a Client Server CIS system; a new Customer Support Center architecture; and Computer Telephony Integration (CTI). It is an infrastructure investment that will enable us to employ software in other areas of the Company that are ready for Year 2000 (Y2K). The overall efficient operation of the Company will improve as a result of this investment and allow us to maintain a relatively flat level of operations and maintenance expense for the foreseeable future.

Business Process Changes. With the addition of non-company-owned payment centers, we are expanding the number of hours and the number of days that payment locations are accessible by our customers. We currently have 54 locations open to take customer payments in 33 towns, compared to the 17 business offices we previously had. The purchase and installation of automated dispatching software allows flexible scheduling of service to better meet the needs of our customers. The introduction of mobile data terminals (MDTs - computers located in service trucks linked to the automated dispatching software and centralized customer support center) provides the most current data available to service representatives, flexible scheduling, paperless processing, and overall efficiencies to the entire process. The automation of meter reading through hand-held devices (ITRONs) allows for more accurate meter reads and automatic upload and download of data once the meter is read and verified. At the Utility Conference in October 1998, the Commission invited Western to demonstrate the performance of its MDTs and ITRONs as examples of the new technologies that are changing the industry.

Q. How much has been invested in each of these initiatives?

A. The investment Western has made in these initiatives, including the costs associated with start-up, is as follows:

Investment in Service Improvement Initiatives	**($MM)**
Customer Information System (CIS) / Banner	13.0
Customer Support Center (CSC)	4.2
Information Technology (IT) Infrastructure	1.7
Business Process Changes / Field Hardware	3.0
Total	**$21.9**

These costs are separate from those we are incurring with our IT costs associated with our conversion to the Oracle/Orbit systems, which I will discuss below.

Q. How do these new systems improve customer service?

A. While all new systems certainly must perform some of the same functions already in place, these changes will allow us to provide <u>better</u> service to our customers and up to our customers' expectations, through economies of scale, improved communication, better response time, and longer customer service hours. We are striving to provide the services requested and required by our customers as efficiently and cost effectively as possible. Our efforts have resulted in a substantial reduction in workforce across all Atmos operations, including a 22 percent reduction for Western since early 1996, primarily in the area of clerical, administrative and supervisory positions.

Through these separate initiatives, we are positioning ourselves with enough flexibility to meet our customers' needs and expectations in this changing business environment. Customers that place orders today with companies such as L.L. Bean or Lands' End and have a positive experience now expect their local utilities to have information systems that enable these utilities to be just as responsive and efficient. We have made this investment for the future of our customers, particularly our residential customers which comprise the vast majority of our customer base. Gains derived from these initiatives are already reflected in our projected cost of service.

Q. You mentioned Information Technology (IT) associated with the conversion to the Oracle systems. Please discuss Western's IT strategy?

A. The Information Technology strategy includes a series of IT projects building a technological infrastructure that will support the Company in running its operations exceptionally well in addition to positioning the Company to be Y2K ready. These projects are scheduled for implementation over five years (through FY2003) except for those projects that are essential for Y2K readiness, which are scheduled for completion prior to the end of 1999. The Oracle projects are the most significant projects currently in process under this initiative.

Q. Please describe the Oracle software projects which highlight the IT strategy.

A. The Oracle implementation project includes redesigning processes and implementing software applications in the following functional areas:

- General Ledger
- Accounts Payable
- Purchasing
- Inventory
- Project Accounting (Work in Progress)
- Fixed Assets
- Payroll
- Budgeting
- Employee Compensation
- Employee Benefit Plan Administration

The initial Oracle installation project began in August 1998. Completion is expected by July 1999.

Q. How will the Oracle system impact the functional areas listed above?

A. In general, the Oracle system will provide the following:

- Transactions will be available for analysis and reporting as soon as they are entered, allowing for faster monthly closing of the books and more effective decision-making by employees at all levels. One example will be faster financial statement reporting due to elimination of transaction posting delays. Another example will be faster availability of information for cost center managers to monitor and control their budgets, providing opportunities for more rapid resolution of problems.

- Transaction data entry will be more efficient. Oracle system shares transaction information across modules in reduced and/or eliminated data entry steps. An example would be establishing reorder points for stock items in inventory. Once inventory is reduced to a certain level, the Inventory Module would automatically create a Purchase Requisition based on an approved vendor and a predetermined order quantity. Once this Purchase Requisition is reviewed and approved, the Purchase Order is then automatically faxed to the vendor. No data entry is required.

Q. How much is being invested to complete the Oracle project?

A. Atmos will spend approximately $18.5 million on the Oracle project. This cost includes computer hardware, application software, internal labor, consulting, training, facilities and miscellaneous costs. Obviously, Western receives all of the benefits of the Oracle project but incurs only a portion of the investment.

Q. Please describe the expected benefits resulting from the Oracle project.

A. The types of efficiencies we will experience upon implementation of this software application fall into three areas:

- Cost Avoidance / Reduction – These are the savings that normally result from more efficient use of labor and materials. As an example, we will be able to reimburse employees for their expense reports as an after-tax item added on to their payroll check. This eliminates the costs of materials and labor needed to separately process expense checks.

- Capital Management – These are elements of value that result in better management of the Company's working capital. Better management of inventory that results in lower overall inventory levels is a good example.

- Qualitative Efficiencies – These are elements of value that result in qualitative benefits. As the system handles more transactions in an automated fashion, there are fewer opportunities for human error. The resulting higher degree of accuracy supports better decision-making by managers and all employees.

Western will share in the increased efficiencies resulting from all of these benefits, which will enhance our expectation of being the lowest cost provider with high customer satisfaction in a bundled or unbundled environment.

Q. What other improvement programs are built into Western's current business plans?

A. There are two other improvement programs I would like to discuss. The first is the integration of resources gained from the merger of Atmos with United Cities Gas Company. The second is our Gas Meter Performance Control Program, which is ongoing.

Q. Please describe the integration of resources gained from the merger with United Cities Gas.

A. The United Cities Gas merger was completed in FY 1997. As a result of the merger a number of positions were re-assigned or eliminated throughout Atmos and particularly at United Cities to eliminate duplication and take advantage of the economies of scale offered by the merger. A number of "general office" functions within Atmos, its existing business units and United Cities Gas were consolidated. Those shared services functions now perform work on behalf of Western and the other business units. These functions include some activities that were partially staffed in Kentucky, such as gas control and certain accounting functions. Western experienced a net reduction of 21 positions as a result of the merger and integration of United Cities Gas with Atmos. The integrated benefits of Western's reductions via a change in shared services staffing are fully reflected in our projected cost of service.

Q. Please describe Western's Gas Meter Performance Control Program.

A. Our proposal to implement a Gas Meter Performance Control Program is another improvement program. This was filed with the Commission in February 1999 and is pending approval. It is a sample meter test plan as provided for under 807 KAR 5:022, Section 8 (5)(c). The primary goal of Western's Gas Meter Performance Control Program is the detection and early removal of any group of meters that does not meet prescribed performance standards. Western's program will employ modern sampling techniques in the evaluation of gas meter performance and is specifically designed to provide a high level of accuracy in the measurement of gas to Western's customers while controlling metering costs.

Q. What are the benefits of the Gas Meter Performance Control Program?

A. The primary benefits of the program are long-term metering accuracy and operational cost control. The gains from the program we have proposed are reflected in our projected cost of service.

Q. What is the cumulative impact of these programs on Western's projected costs?

A. Our test period budget shows that we intend to keep our costs relatively flat over the planning horizon. These programs are an integral part of our strategy to live out our vision of providing high quality, low cost service to our customers.

Q. Are there variables which impact earnings which Western cannot control through programs such as these?

A. Yes. While we make every opportunity to manage those factors within our control, there are critical variables that have impeded our earnings in recent years over which we have no control. When it is evident that such factors continue to limit our ability to earn an adequate return, it is incumbent upon the Company to propose innovations to help mitigate the impact of those factors upon our earnings and customer service. We have done that in our proposal.

Q. Please give an example.

A. We have no control over weather; yet, even though our costs are largely fixed in nature, our current rate structure is highly sensitive to volumes driven by weather. For the past several years, warm weather has cut heavily into our recovery of fixed costs and expected return. This has occurred, despite temporary measures we have employed to try to better manage our way through such periods. Our response to this problem is to propose a Weather Normalization Adjustment (WNA) in this case to mitigate the impact of weather on our earnings. A WNA can also help stabilize customer bills.

Q. Can you give another example?

A. Yes. The Commission has rules providing up to 100 feet of main, a service line and a meter for new customers. Compliance with these rules exacerbates a chronic earnings problem. Making new investments to accommodate system growth causes a deterioration of earnings which requires the filing of more rate cases. Consequently, we are proposing a new rate element that will help ensure that adding new customers to our system is a viable investment that does not erode away our earnings each year. Our proposal is also more equitable to current customers. It would not burden existing customers with the increasing cost of growth, whether on-main in areas of greater service density, or in more rural areas where growth is sparse.

Q. Why are these proposals important?

A. I believe that when the Commission approves rates for the Company, based upon an authorized rate of return, the Commission expects the Company to earn that authorized rate of return each year. I can tell you that we certainly expect to earn at that level because that is the rate of return which reflects the minimum cost of capital required for us to run the business. However, when current rates, in conjunction with the

Company's best efforts to achieve greater efficiencies in its operations, fail to accomplish that return, we have no alternative but to seek new rates. We have projected our cost of service into the future. Our proposed rates are consistent with that level of costs, and our proposed rate structures have been designed to help eliminate the need to request additional rates every three or four years.

Q. How will your proposals impact retail gas choice?

A. Our aim is to operate within our authorized cost structure and set rates in place such that if customer choice becomes the preferred public policy in the Commonwealth of Kentucky, we would only have to restructure our current rates. There may be transition costs as a result of unbundling, or stranded costs, which we would expect to recover through rates or other charges to customers. We would certainly expect to establish appropriate rate mechanisms for any new services offered as well.

Q. Do you anticipate any stranded costs under retail gas choice?

A. I cannot fully answer that question without knowing how retail choice will be made available to customers in Kentucky. It is certainly conceivable that some costs or assets retained to meet the demands of firm core customers could become stranded. We would hope to mitigate any potential stranded costs, but our ability to do this depends upon the timing and rules of open access and transportation set by the Commonwealth. The more advance notice we have of such rules, the more likely we can plan accordingly and mitigate any stranded costs.

Q. Are you proposing to unbundle your rates in this case?

A. No. We need to focus on more fundamental rate design and earnings issues at this time. Further, we do not believe that residential customer demand for choice in our area has developed to the point where the cost to do that is justified. While we are not prepared to implement and administer choice today, we are laying the foundation for that outcome if that is what the market wants.

Q. What effects will the Commission's decision in this case have on energy competition in western Kentucky?

A. Quite frankly, neither the Commission nor the Company is in a position to stop the trend toward increasing competition; nor should we try. Competition is generally good for customers. However, current rate structures aggravate the highly competitive industrial market that we face today. We also face significant competition from electric utilities in residential and commercial markets. Our proposals are designed to make Western a more viable competitor in these markets and a viable service choice for customers. The Commission's approval of our proposals in this case will ensure that Western is a financially healthy and competitive gas company which stands as a viable alternative to electric service providers, and help keep all energy prices lower than they otherwise would be.

Q. What would be the effect of Western receiving an inadequate return from this application?

A. As I stated earlier in my testimony, today Western's rates produce an environment of high risk and low reward. This condition cannot be sustained. Without an award granting us the rates, rate structures and return we have requested, we will fall permanently behind other companies in today's highly competitive capital markets, as well as our sister companies within Atmos with whom we compete for capital. It is unrealistic to expect investors with a variety of options and opportunities to continue to make investments at inadequate return levels when more lucrative investments are readily available.

I would also add that providing safe, reliable gas service to residential customers in western Kentucky is an important societal responsibility. Meeting critical human needs during the heating season is and must be our primary focus. It is our "raison d'être." We ask that the Commission remain focused on the fact that the financial integrity of Western Kentucky Gas Company is synonymous with our ability to provide the delivery of safe and reliable gas supplies to our customers.

Q. Do you have any further comments regarding your request for an increase in rates?

A. Yes. We have set a course to run our gas utility operations exceptionally well. Our request is certainly reasonable in light of that objective, but we need the Commission's help to achieve our goals.

Q. Does this conclude your testimony?

A. Yes.

Our Strategy

Our management team is fortunate that Atmos has a strong history upon which to build. Atmos' successes of the past deserve an ambitious Vision and Strategy for the future. We believe that our Strategy is ambitious and achievable.

Our Strategy is to:

- Communicate the Vision and Strategy.
- Build the Atmos team.
- Run the utility operations exceptionally well.
- Increase the size and market share of the non-utility–propane and gas marketing–operations.
- Engage a partner with whom to pursue "behind the meter" retail services.
- Grow through acquisitions.

Our Vision

Within the next five years, our vision is for Atmos to be the largest provider of gas distribution services east of the Rocky Mountains with superior customer satisfaction ratings and the lowest O&M costs per customer of any peer group competitor.

We will pursue our vision aggressively while conducting our affairs in a safe and reliable manner:

- With fairness, honesty, integrity and trust;
- With respect for the environment;
- With respect for the communities and the customers we serve;
- With respect for individuals and diversity in the workplace;
- With focus on delivering total returns to our shareholders in the top quartile of our peer group; and
- With a rewarding and challenging work environment for our employees.

Our Governance Philosophy

- To govern according to our beliefs and behaviors.
- To encourage ownership of value creation throughout the organization.
- To assign responsibility and expect accountability.
- To give and receive constructive feedback.
- To establish a performance measurement process that is understood and used throughout the organization.
- To align individual compensation with achievement of corporate, team and individual goals and objectives.

Our Beliefs and Behaviors

- We will encourage leadership and accountability without micro-management.
- We will provide diversity in the workplace and respect individuality.
- We will promote diversity in thinking and opinions.
- We will expect open and direct communications and feedback.
- We will set stretch goals and targets for individuals as well as the enterprise; stretch goals will be the norm.
- We will comply with all laws and regulations.
- We will reward according to achievement.
- We will support and encourage teamwork.
- We will support and encourage enterprise thinking.
- We will create an environment that will help individuals achieve their maximum potential.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF RATE APPLICATION OF WESTERN KENTUCKY GAS COMPANY	)))	Case No. 99-070

CERTIFICATE

I, Conrad E. Gruber, have answered the foregoing questions propounded to me in the above enumerated Docket. These answers and exhibits constitute and I hereby adopt, under oath, these answers as my prepared direct testimony in said case, which is true and correct to the best of my information and belief.

Conrad E. Gruber
President
Western Kentucky Gas Company

COMMONWEALTH OF KENTUCKY)
) S.S.
COUNTY OF DAVIESS)

SUBSCRIBED AND SWORN TO before me by Conrad E. Gruber, on this 11th day of May, 1999.

Pearl Ann Simon

Pearl Ann Simon
Notary Public
State of Kentucky At Large.

My Commission expires: September 26, 2001.

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BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	)	
RATE APPLICATION BY	)	**Case No. 99-070**
WESTERN KENTUCKY GAS COMPANY	)	

TESTIMONY OF R. EARL FISCHER

Q. Please state your name, position and business address.

A. My name is R. Earl Fischer. I am President of Energas Company. My business address is 5110 80th Street, Lubbock, Texas, 79408.

Q. Please describe Energas Company and your tenure there.

A. Energas is a Texas-based company serving approximately 315,000 natural gas customers in West Texas and the Panhandle. Energas is the largest of the five local distribution companies which make up Atmos Energy Corporation. I became President of Energas Company in January 1999. Prior to that I was President of Western Kentucky Gas Company ("Company" or "Western").

Q. Please briefly describe your career at Western Kentucky Gas Company.

A. I began my career with Western Kentucky Gas Company in 1962 in the Accounting Department. I held a variety of management positions of increasing responsibility in accounting, operations, and public affairs prior to being named President of Western in 1989.

Q. What is your educational background and civic experience in Kentucky?

A. I hold a degree in Business Administration from Brescia College in Owensboro, Kentucky. I have always been very involved in Kentucky educational activities. I am currently on the Board of Regents of Western Kentucky University, and formerly served as the Chairman of that Board. I am also on the Board of Trustees of Brescia College and have chaired the Governor's Task Force of Business and Industry on Post Secondary Education. I have also been very active in Kentucky's economic development, having served in a number of leadership roles including Chairman of the Kentucky Chamber of Commerce and the Kentucky Economic Development Steering Committee. In 1997, I was honored to be recognized by Governor Patton as Economic Development Volunteer of the Year in Kentucky.

Q. Have you previously testified before the Kentucky Public Service Commission?

A. Yes.

Q. Are you sponsoring any of the filing requirements?

A. No.

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

A. My purpose is to describe the economic plight we identified during Western's five-year business planning process last year and the subsequent efforts we initiated which led to the filing of this rate case. As Chairman of Atmos' Shared Services Board I will also describe the Shared Services concept and how Shared Services are managed and billed under contract to Western and the other Atmos Business Units.

Q. What led Western to realize that rate relief would be necessary?

A. During the preparation of our five year business plan last year, it became evident that despite the number of changes and cost reductions Western had undergone in the previous two years, we could not continue to fund our operations and invest in new plant and equipment without some changes in the near future.

Q. Did you begin to plan a rate case at this time?

A. No. My initial reaction was not to seek new rates but rather to manage our way through. I wanted to revisit our operational decisions to see if we could make further improvements. I also wanted to determine if there were actions we could take to better manage our revenue streams and reduce our budgeted costs to make up for the projected deterioration in earnings. I asked the Western staff to look carefully at everything we were planning as part of several on-going service improvement initiatives and our IT (Information Technology) strategy to see where we could make further operational improvements. We also took another look at and/or initiated programs related to meter replacements, employee staffing, contractor use, vehicle purchases, main installation practices, and other capital projects. While we continued to refine our business plans and felt very positive about the long-term benefits of our service improvement initiatives and IT programs, it became apparent that we would still need significant rate relief in 1999 to affect our earnings during FY2000.

Q. Specifically, what issues were identified as the causes of Western's economic plight?

A. Our projections indicated a significant shortfall of revenues to costs, and costs were remaining relatively flat over the five-year planning horizon. Although we had invested heavily in the operation since our 1995 rate case, this was still a revelation because we were still growing and cutting our costs, gaining in our efficiencies. We had undertaken measures over the previous two years to reduce our number of employees from over 400 to less than 300. Additionally, we were beginning to benefit from the United Cities' merger integration savings and the various service and cost improvement initiatives underway. Clearly while the new plant and equipment added since fiscal year 1994 was the primary driver of this shortfall, but it was also evident that we needed to look deeper into customer usage, growth and revenue streams to determine how best to address the problem.

Q. What issues did you identify related to Western's customer usage, growth and revenue streams?

A. The first thing we began to come to terms with was the degree of weather sensitivity built into our current rate structure, in which residential load is so important. While you hope the effects of weather on earnings evens itself out over a number of years, a series of warm winters drew our attention to how weather sensitive our operations really were.

We wondered if our expectation of normal usage was accurate. We began to consider a number of rate design elements that would mitigate these risks.

The second problem was that residential customers, beyond the weather effect, were simply not using the volume of gas necessary to allow us to earn an appropriate rate of return under a rate design dependent upon commodity usage. We began to question whether there was a decline in customer usage that could be undermining our expected revenue streams.

Thirdly, the industrial sector, given its intensely competitive nature and the continuous threat of bypass, could not continue subsidizing the costs of residential services. Some type of long-term solution would have to be developed to mitigate the problem of the continued erosion of industrial margins.

Fourth, we began to focus on the problem of new investment. As long as rates are based on historical costs, Western would be constrained from earning its authorized return because these rates would not reflect forward-looking increases in costs. With each new increment of investment, Western's opportunity to earn its required rate of return diminishes. Our assumption has always been that growth produces value to the Company and other ratepayers by allowing us to spread our fixed costs over more units of service. We began to question whether the rates we were charging supported this assumption because of the required main extension practices. We also knew that Western could not effectively compete for capital if our returns on new investment did not compare favorably with those of Atmos' other business units.

Q. What actions did you take toward filing a rate case?

A. I asked our Western staff to begin to develop a rate strategy that would support the business plans we had built into our five-year budget. The timing of this formulation of rate strategy was appropriate from the perspective of what Atmos' Shared Services Board had decided to do with the rates and regulatory affairs functions at Atmos. The Atmos' Shared Services Board, of which I am the Chairman, is partly comprised of the presidents of the five LDC business units. The Board had recently determined that since regulatory matters are handled on a state-specific basis, it would be a better fit within the business units, similar to the way we had already reorganized our marketing and technical services functions into Western. While we had already identified aspects of our long-term earnings problem at Western, it was evident that successfully integrating the rate function into Western would be helpful in moving us forward with an in-depth development of Western's rate strategy.

Q. Is this when you decided that a forward-looking test period was appropriate?

A. Yes, although I always knew we had that option. As we discussed our long-term business plans it became evident to all of us that if we were going to continue to meet our service obligations and keep the Commonwealth of Kentucky growing we had to ensure those plans were reflected in our rates. It also became evident that using a forward-looking test period was only a part of this solution. Our business is changing and will continue to change beyond the forecasted test period. We were identifying trends and risks in our operations that required non-traditional solutions that we had not considered before. I asked the Western staff to really think outside the box and determine what rate strategies could be employed that would address the underlying problems we had identified. I believed that with the appropriately designed, forward-looking rate strategy, Western could consistently achieve its authorized return and generate the cash flow necessary to continue investments in western Kentucky while allowing us to remain competitive in the market. I am pleased to say that the Western staff has met this challenge and constructed an excellent long-term rate strategy which is fiscally responsible and beneficial to our customers.

Q. Does this strategy include an unbundling of Western's rates to allow retail gas choice?

A. No. It was my belief that our problems were fundamental in nature and that regardless of the prospects of choice, we had to restructure our rates in such a fashion that the underlying cost characteristics of our services would be more closely reflected in our future rates and send the right economic signals to the market. With this change in place first, I was confident that we would be well positioned to accommodate retail gas choice if and when it became the preferred public policy in Kentucky.

Q. Please describe Shared Services.

A. Shared services are the technical and expert consulting services provided by Atmos' centralized departments and functions to Atmos' business units. Such services include Accounting Services, Legal, Human Resources, Purchasing, Information Technology, Gas Supply and the Customer Support Center. The shared services concept gives Atmos a competitive advantage by providing services from a centralized staff rather than replicating them in every business unit. The provision of shared services is formalized by signed contracts for services between the providers and the business units. The concept makes all providers more accountable to the business units. These providers are required to deliver their products and services in a timely, cost efficient manner and maintain excellent customer service with the business units. The shared services concept follows the beliefs, behaviors and vision established by Atmos, which includes each business unit being fully accountable for their company and performance. It is common practice in industry to measure the performance of external vendors to evaluate the quality and efficiency of services being provided. In this spirit, the shared services contracts establish standards of efficiency and service performance for the services Western is obtaining from Dallas.

Q. Please describe Atmos' Shared Services Board and how it functions.

A. The Shared Service Board illustrates how much the Company has changed since our last rate case. The Shared Services Board is made up of each business unit president and a rotating team of officers from the shared services organization. The Board governs the process by which shared services are contracted. The Board defines and implements the vision and strategy for the shared services organization. Facts regarding service performance, quality and cost form the basis for all discussions. The Board meets quarterly. At these meetings, we meet with providers, review management issues associated with shared services, check contracts, and review their performance.

The shared services departments are required to submit a list of the services they provide to the business units to the Board and support the value of those services. The Board then works with the providers to consolidate these services into a manageable number suitable for contracting. Ultimately, the providers must define their products, quality of service, identify performance metrics and service pricing like any entrepreneurial service or consulting practice. Where feasible, the cost of services may be compared with those of other corporations and external providers. The shared services concept encourages providers to be more aware of external providers' services and more responsive to the business units. Benchmarking processes, which we refer to as a "Best Practices" review, will be implemented as necessary to track performance.

Q. Has the shared service concept been implemented?

A. Yes, however, the design of the concept must be phased in to be workable. This is a new way of doing business for us, so there is a learning curve. The first two years of the process, which began in 1997, have emphasized the development of shared services budgets, usage and metrics to ensure all relevant attributes of the products being provided are identified, including the need and value to customers of the shared services being provided. Over the next two to three years, an increased emphasis is being placed on productivity and using external benchmarking to improve product quality and price.

Q. Please describe the "Best Practices" review process.

A. Shared services providers develop a workplan for conducting a "Best Practices" review. The review begins with the providers developing their own portfolio of products specifying the value as well as the nature of these services to the business units. Where feasible, providers conduct a series of interviews with similar providers of services in industry. The interviews are summarized into in a standard format for comparison purposes. After a period of internal review, providers will identify potential changes to be achieved from outsourcing, process redesign or product elimination or modification. The Board then reviews the proposals and makes recommendations back to the providers. This becomes a somewhat iterative process until the Board is satisfied with the services and prices being proposed. The "Best Practices" process is a dynamic one.

Q. Please describe how Western and the other business units manage the share services contracts.

A. The business units are responsible for articulating their needs as customers, negotiating service agreements and assisting in the collection of data required by the shared service providers. The business units will compare the price of the service being offered with that of outside services identified during the "Best Practices" review. Arbitration may occur to improve the quality and/or price of the service. The business units must be satisfied that the providers have demonstrated that they will produce a high quality service at a competitive price.

The contracts are fairly simple agreements containing (1) the product that is needed, (2) what the business unit is willing to pay for it, and (3) various measures of quality. Once the contract cost has been identified, that is worked into the contract. The contract helps the business unit determine if they want to continue using that product. The contract becomes the report card showing what the shared service providers products are, how much it is going to cost and how their performance will be measured.

Q. What is the goal of the shared services concept and what benefits does this concept provide to Western's customers?

A. The shared services concept is one of continuous review within Atmos. Ultimately, it means that the services obtained by Western and the other Atmos business units reflect the highest quality of service at the lowest possible price.

Q. Do you have any other comments regarding this rate filing?

A. Yes. I am confident that the revenue increases and rate structures proposed in this case are appropriate and necessary to ensure the long term operational and financial integrity of Western Kentucky Gas required to continue providing the citizens of western Kentucky high quality and fairly priced natural gas service.

Q. Does this conclude your testimony in this case?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF RATE APPLICATION OF WESTERN KENTUCKY GAS COMPANY	)))	Case No. 99-070

CERTIFICATE

I, R. Earl Fischer, have answered the foregoing questions propounded to me in the above enumerated Docket. These answers and exhibits constitute and I hereby adopt, under oath, these answers as my prepared direct testimony in said case, which is true and correct to the best of my information and belief.

R. Earl Fischer

R. Earl Fischer
President
Energas Company

STATE OF TEXAS	)
	) S.S.
COUNTY OF LUBBOCK	)

SUBSCRIBED AND SWORN TO before me by R. Earl. Fischer, on this 13th day of May, 1999.

BARBARA CODY
Notary Public
State of Texas
Commission Expires 3-10-00

Barbara Cody

Barbara Cody
Notary Public
State of Texas

My Commission expires: March 10, 2000

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BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	)	
RATE APPLICATION BY	)	**Case No. 99-070**
WESTERN KENTUCKY GAS COMPANY	)	

<u>TESTIMONY OF REBECCA M. BUCHANAN</u>

Q. Please state your name and business address.

A. Rebecca M. Buchanan, 381 Riverside Drive, Suite 440, Franklin, TN 37064.

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

A. I am employed by Atmos Energy Corporation ("Atmos") as a Senior Analyst in the Rates Department.

Q. What is your educational and professional background?

A. I graduated with honors from the University of Oklahoma in 1984 with a Bachelor of Business Administration Degree, majoring in Accounting. I am a Certified Public Accountant in the state of Oklahoma and a member of the Tennessee Society of Certified Public Accountants. In accordance with the Oklahoma Accountancy Board's rules for Certified Public Accountants, each year I complete forty (40) credit hours of accounting related Continuing Professional Education.

I have participated in several Southern Gas Association (SGA) Rate Round Table Conferences. I have completed the following gas industry course studies: The University of Wisconsin/American Gas Association (AGA) – Gas Rate Fundamentals Course, the SGA Intermediate Rate Course, and the University of Maryland/AGA Advanced Regulatory Seminar.

My professional experience includes six years of corporate accounting outside the gas industry (1984 – 1990), in which I held the positions of Staff Accountant, Senior Accountant, Payroll Manager and Regional Accounting Manager. In 1991, I accepted the position of Analyst/Regulatory Affairs at United Cities Gas Company, an operating division of Atmos. In 1995, I was promoted to Senior Analyst. With the 1997 merger of United Cities Gas and Atmos Energy Corporation, I transferred to the Atmos Rates Department.

Q. What are your responsibilities as a Senior Analyst?

A. I prepare general rate filings, specifically the accounting and revenue deficiency exhibits, and I coordinate responses to data requests. I prepare financial data for both internal and external reporting. I have filed regulatory reports with the state Commissions of Virginia, Missouri, South Carolina, Illinois, Georgia, Tennessee, Kansas and Iowa.

Q. Before which Commissions have you previously testified?

A. I have filed testimony before the Kansas Corporation Commission, the Tennessee Public Service Commission, and the Commonwealth of Virginia State Corporation Commission.

Q. What is the scope of your testimony in the Western Kentucky Gas (Western) proceeding?

A. I am responsible for the determination of the revenue deficiency and in that regard I am sponsoring the following Filing Requirements (FR):

FR 10 (8)(f)	Reconciliation of the rate base and capital.
FR 10 (10)(a)	Derivation of the requested revenue increase (Schedule A).
FR 10 (10)(b)	Rate base summary for the base and test period (Sched. B).

FR 10 (10)(c)	Operating income summary for the base and test period (Sched. C).
FR 10 (10)(e)	Income tax summary for the base and test period (Sched. E).
FR 10 (10)(h)	Gross revenue conversion factor for the test period (Sched. H).
FR 10 (10)(k)	Comparative financial data and earnings measures for the ten (10) most recent calendar years, the base and test period (Sched. K).

Q. Do you adopt these Filing Requirements, and their associated schedules, and make them part of your testimony?

A. Yes.

Q. What is the source of the data used to complete the Filing Requirements?

A. The source of the data I utilized is the accounting books and records of Western Kentucky Gas Company along with information provided to me by the following witnesses to this proceeding: Mr. David H. Doggette (capital budget additions); Ms. Betty L. Adams (operating expense forecast and historic financial data); Mr. Gary L. Smith (revenue and margin forecast; sales statistics); Mr. John W. Hack (gas cost forecast); Mr. Donald P. Burman (historic financial data; rates from the most recent depreciation study); and Mr. John P. Reddy (capital structure and rate of return requirements).

Revenue Deficiency

Q. What is the amount of Western's revenue deficiency?

A. The amount of **revenue deficiency** Western seeks to recover in its proposed rates is **$14,127,666**, shown on line 8 of Schedule A. This deficiency is based on the forecasted test period twelve months ended December 31, 2000, an average **rate base** of **$130,484,159**, and a required rate of **return on rate base** of **9.97%.** The required return and projected capital structure are discussed in the testimony of Mr. John P. Reddy.

Q. How did you determine the level of rate base for the test period?

A. The test period rate base of $130,484,159 is summarized in Schedule B-1, and detailed in Schedules B-2 through B-6. Each component of the test period rate base is a thirteen month average forecasted amount, unless noted otherwise. The components of rate base are: net plant in service, plus cash working capital (1/8 method), plus an allowance for other working capital items (materials and supplies, gas stored underground, and prepayments), less customer advances for construction and deferred income taxes.

Q. Please explain how you determined the forecasted test period adjusted operating income of $4,630,553, shown on Schedule A, line 2.

A. I started with Western's test year forecasted operating income, and adjusted this for ratemaking purposes. The summary and detailed operating income is shown in Schedule C.

Q. What are the ratemaking adjustments to forecasted operating income?

A. For ratemaking purposes, Western's forecasted test year operating and maintenance expense (O&M) has been adjusted to remove the following: country club expenses $3,680, promotional advertising and sales expenses $58,305, employee party and gift expenses $81,008, and pension expense $(853,000). Please refer to the testimony of Mr. Donald P. Burman for a discussion of the pension expense adjustment.

Q. Besides these O&M expenses, have you calculated any other expenses differently for ratemaking purposes?

A. Yes. For ratemaking, depreciation expense is calculated by taking the thirteen month average balance of direct Plant in Service for Western Kentucky Gas Company, multiplying this by the depreciation rates from the latest depreciation study, and applying a capitalization factor to arrive at the appropriate level of depreciation expense. In order to achieve interest synchronization, interest expense is calculated by applying the test period projected cost of debt to the test period rate base amount. And finally, income taxes are calculated by multiplying the composite state and federal income tax rate by the test period taxable income (after ratemaking adjustments). This calculation is shown in Schedule E.

Q. Ms. Buchanan, does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 99-070
WESTERN KENTUCKY GAS COMPANY	)	

CERTIFICATE

I, Rebecca M. Buchanan, have answered the foregoing questions propounded to me in the above enumerated Docket. These answers and exhibits constitute and I hereby adopt, under oath, these answers as my prepared direct testimony in said case, which is true and correct to the best of my information and belief.

Rebecca M Buchanan

Rebecca M. Buchanan
Senior Analyst - Rates
Atmos Energy Corporation

COMMONWEALTH OF KENTUCKY	)	
	)	S.S.
COUNTY OF DAVIESS	)	

SUBSCRIBED AND SWORN TO before me by Rebecca M. Buchanan, on this 11th day of May, 1999.

Pearl Ann Simon

Pearl Ann Simon
Notary Public
State of Kentucky At Large.

My Commission expires: September 26, 2001.

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BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF)

RATE APPLICATION BY) Case No. 99-070

WESTERN KENTUCKY GAS COMPANY)

TESTIMONY OF BETTY L. ADAMS

Q. Please state your name, position and business address.

A. My name is Betty L. Adams. My business address is Western Kentucky Gas Company ("Western"), 2401 New Hartford Road, Owensboro, Kentucky 42303. I am employed by Western as Vice President and Controller.

Q. Please state your education and professional background.

A. I have attended Brescia University and Kentucky Wesleyan College. I have taken 30 hours of accounting courses including a number of upper level accounting courses. I have also taken a number of business and management related courses. I did not complete my degree.

I have worked for Western for over 28 years. I have held various positions of responsibility during this time with all of my assignments in the accounting department. I was promoted to my current position in 1991. I have held this position for 8 years.

Q. What are your responsibilities at Western?

A. I am responsible for all financial functions at Western. Many accounting, billing, and similar financial functions are performed by Shared Services. However, there remain some essential financial functions at Western, including the preparation and monitoring of Western's Operations and Maintenance (O&M) budget. I am the officer responsible for monitoring Western's financial results. I am also responsible for the monitoring of Shared Services billings and other expenses to ensure that they are consistent with our contract guidelines and are reasonable. I also serve as a sponsor of the Oracle financial system and am a member of various project teams related to new and/or improved methods of a financial nature. Most of these are Atmos corporate initiatives. I also ensure that all Western employees are properly trained on policies and procedures related to the use of Atmos' accounting and financial systems.

Q. Have you testified before this or any other regulatory commission?

A. No.

Q. Are you sponsoring any of the filing requirements?

A. Yes. I am sponsoring the following filing requirements:

FR 10(8)(a)	Forecasted financial data presented as pro forma adjustments to the base period
FR 10(8)(b)	Forecasted adjustments limited to twelve (12) months immediately following the suspension period
FR 10(9)(c)	Description of all factors used in preparation of the forecast test period – income statement, balance sheet, cash flow, operation and maintenance expenses, employee and labor expenses
FR 10(9)(d)	Annual and monthly budget for the 12 month period preceding filing date, the base period and the forecast period.
FR 10(9)(h)1	Operating income statement
FR 10(9)(h)2	Balance sheet
FR 10(9)(h)3	Statement of cash flows
FR 10(9)(h)4	Revenue requirements necessary to support forecasted rate of return
FR 10(9)(h)9	Employee Level
FR 10(9)(h)10	Labor cost changes
FR 10(9)(h)12	Rate base

FR 10(9)(o)	Complete monthly budget variance reports, with narrative explanations, for the twelve (12) months immediately prior to the base period, each month of the base period, and any subsequent months, as they become available.
FR 10(9)(u)	Shared Services charges during base period or previous three (3) years
FR 10(10)(d)	Summary of jurisdictional adjustments to operating income
FR 10(10)(f)	Summary schedules for the base and forecast periods of various expenses
FR 10(10)(g)	Analysis of payroll costs
FR 10(10)(i)	Comparative income statements, revenue and sales statistics most recent five years, base period, forecast period and two (2) years beyond

Q. Do you adopt these Filing Requirements and make them a part of your testimony?

A. Yes.

Q. What is the purpose of your testimony?

A. My testimony will describe the O&M budgeting process used by Western; describe the process of control and monitoring of O&M variances; and present the forecasted test year O&M budget. I will also present the budgeted Shared Services O&M costs as they pertain to Western Kentucky Gas Company.

OPERATING & MAINTENANCE BUDGETING PROCESS

Q. Please describe the goals of the O&M budgeting process at Western?

A. The goals of the O&M budgeting process are to: (1) formalize the process of identifying the anticipated costs of operating and maintaining Western's system each year; (2) ensure that all policies and procedures associated with the annual budgeting process are consistently adhered to by the functional managers and officers; (3) assess the appropriateness of routine maintenance requirements and non-capital expenditures proposed by the functional managers and officers to ensure that the amounts do not exceed a level necessary to operate safely and efficiently; and (4) ensure that Western's O&M budget properly reflects our strategic operational and financial plans.

Q. Describe your role and required approvals in Western's O&M budgeting process?

A. We budget our O&M costs on a fiscal year basis. Our fiscal year begins on October 1 consistent with the seasonal operations of our business and runs through the following September 30. The O&M budgeting process at Western begins in April of each year with a letter from me to the managers and officers (cost center owners) stating the timelines and guidelines under which their functional budgets should be prepared. These guidelines include proposed wage increases and benefits percentages as well as transportation budget information. I review the submissions of the managers' and officers' individual budgets to ensure that all changes from the prior year are documented and reasonable. This is an iterative process under which I may request additional information from the field and officers. Ultimately, we jointly make appropriate adjustments prior to submitting Western's overall expense budget to the Company's President for review and approval. These adjustments are usually necessary to stay within an overall range of spending in alignment with Western's financial goals. This annual budgeting process is largely completed in June following negotiations between Western and Atmos' senior management, which includes a review of Western's specific operational needs and objectives, culminating in an approval of the final budget by the Atmos Management Committee. Ultimately, Western's O&M budget must be approved by the Atmos Board of Directors at their September Board meeting.

Q. Describe how the O&M budget is prepared.

A. Western's O&M budget is a zero-based budget which is annually prepared from the bottom up. Our budget is prepared by type of cost element, such as labor, benefits, transportation, rents, office expense, and any known factors of increased or decreased cost. The year to date actual cost plus the remaining months' proposed budget is used as a guideline for budgeting by functional managers and officers. The budgets are prepared via Excel spreadsheets. When approved, the functional expense budgets are entered into a mainframe system for monitoring purposes.

Q. Are these budgets prepared by NARUC account?

A. No. NARUC accounts would not allow us a sufficient level of detail to understand the costs within each account. For budgeting purposes, we need individualized expense types that relate to the operation of each cost center. NARUC accounts do not provide that level of detail. However, when we spend, we do identify our expenditures by NARUC account as well as expense type. This provides a timely analysis of the type of charges being expensed by NARUC account.

Q. How did Western convert its O&M budget by cost element into NARUC accounts?

A. We developed a Microsoft Access database to convert the Fiscal Year 1999 (FY1999) budget into NARUC accounts. FY1998 actual expenditures were downloaded from the general ledger by NARUC account and cost element. A calculation was made to determine within each cost element type what percent of spending was attributable to each NARUC account. Each percentage factor was then applied to the FY1999 budget by cost type to develop a NARUC budget. Once this apportionment was accomplished a review was undertaken to determine if these costs reflected Western's current way of operating because changes from FY1998 to FY1999 had the potential to alter a given level of cost element spending within a NARUC account. After this review, adjustments were made as necessary to ensure the most accurate representation of costs within each NARUC account.

<u>Control & Monitoring</u>

Q. Describe how the goals of Western's O&M budgeting process are supported by Western's control and monitoring of variances.

A. Western's variance monitoring ensures financial quality control of O&M expenses by formalizing the analysis of variances by cost center by reviewing spending variance reports on a monthly basis. On a quarterly basis, we present Western's actual to budget variance with explanation to the Atmos Management Committee and Shared Services department heads. The goal is to keep all levels of management informed of Western's O&M spending in comparison to budgeted amounts, in order to allow management to react to undesirable or unanticipated events on a timely basis.

Q. Describe how you evaluate O&M variances on a monthly basis?

A. First, in reviewing the monthly variance reports I look to see which cost centers exceed the monthly budget by five percent (5%) or more. Secondly, I recalculate the expenditures excluding exceptional items such as reimbursements, write-offs for uncollectibles, and benefits since these items are largely uncontrollable. This may bring some cost centers to within acceptable variance levels. Thirdly, I research to determine the reason for a variance and document the reason. Fourth, I attempt to verify the accuracy of charges to a cost center and any errors discovered are corrected. Fifth, I document for future budgeting purposes, known changes in current operational spending from budget. Sixth, I review the results of my variance analysis with the functional officers and discuss ways to correct the observed variances.

Q. Please discuss the variance analysis associated with Western's most recent fiscal year O&M budgets.

A. As of March, FY1999 actual spending to date, without benefits, is on budget. The table below demonstrates that over the past five years, with the explanation for FY1996 noted, Western's actual O&M expenditures have tracked closely to overall budgeted amounts, with or without benefits.

Fiscal Year	Actual $	Budget $	Over/Under $	Variance %	Variance % w/o Benefits
1998	15,360,602	16,106,348	-745,746	-4.6 %	-1.3 %
1997	16,727,588	16,285,048	442,540	2.7 %	1.4 %
1996	14,724,547	16,022,223	-1,277,676	-8.1 %	-1.8 %
1995	14,793,241	15,511,250	-718,009	-4.6 %	-2.4 %
1994	15,742,808	15,827,473	-84,665	-0.5 %	-1.4 %

FY1996 was 8.1 percent under budget, however approximately one-half of this variance, $625,000, was attributable to a change in WKG's overhead allocation methods after our budget was finalized. The effect of this change was to reduce Western's O&M expenses for FY1996. Additionally, actual benefits for the year ran $870,940 under budget.

As you can see, benefit costs represent the most difficult item to budget due to the difficulty of estimating the cost of medical claims. Overall, I believe that these results indicate that we have been successful in our annual budgets in projecting and managing our direct costs of operations and maintenance.

Forecasted Test Year Direct O&M Budget

Q. What is the forecasted test period used in this rate application?

A. The forecasted test period is January 1, 2000 through December 31, 2000. Since our fiscal year begins in October, this time period represents the last 9 months of FY2000 and the first three months of FY2001.

Q. How was the forecasted test period budget developed?

A. The forecasted test period budget largely reflects our FY2000 budget. Consistent with our normal annual budgeting timelines, this budget was prepared just prior to the filing of this case. This budget was prepared in the bottom up, zero-based manner I described earlier. The three months of FY2001 included in the forecast test period were prepared using the last month included in the FY2000 budget, that is September 2000, as a surrogate for each of the first three months of the subsequent fiscal year. The FY2000 O&M budget was converted into NARUC account detail using the same method described above.

Q. What are the primary components of Western's forecasted test period O&M budget?

A. The forecasted test period O&M budget attributable to Western reflects two components. The first component is Western's direct O&M budget. The second component is Western's portion of the Shared Services O&M budget. Mr. Fischer described the contracting for Shared Services in his testimony.

Q. What was Western's direct O&M budget for FY1999?

A. $ 14,870,000.

Q. What is Western's direct O&M budget for the forecasted test period?

A. $ 15,820,000.

Q. Please discuss the differences between the FY1999 and forecasted test period budgets.

A. The total difference is $950,000 and reflects the following:

1. A $400,000 reduction from the FY1999 budget was made for the Demand Side Management (DSM) pilot program, WKG CARES. As Mr. Smith will testify, we are proposing a separate DSM Surcharge to recover the costs of continuing the WKG CARES' programs during the forecasted test year and for two additional years. Our rate proposal is also to amortize the costs of the pilot program over the three-year period and recover those costs via the surcharge. While we did not include an estimated $200,000 annual cost for WKG CARES in our forecasted test period budget, we do intend to incur this cost if the Commission approves our DSM proposal.

2. $690,000 increase above the base period is reflected in the forecasted test period budget. Of this total, $400,000 is attributable to the planned filling of a number of vacant employee positions and $290,000 is attributable to a four percent wage increase over FY1999. We were not at full employee complement at the time that the FY1999 budget was prepared as a result of employee attrition in the field and the fact that we were utilizing contractors to fill this void. For the most part, these contractors were performing construction activities. We did not budget to reflect a full complement of employees for FY1999 because we were substituting contract labor for Western's own employees. In February of this year, after seeing our lower than expected first quarter financial results due to the warm weather, it was determined that we would continue to

hold the line on all vacancies to reduce labor costs. Where possible, we eliminated contractors, which were also performing some O&M duties. This was and remains only a short-term measure made in response to the current earnings situation. We will eventually need to increase the number of employees to the full complement level so as to not undermine our ability to perform all of the necessary O&M functions in the field as well as construction activities over the near term. For this reason, we have adjusted our forecasted test period budget to reflect the full authorized complement of employees.

3. Communications expense in the forecasted test period budget was increased by $300,000 due to an under-budgeted amount in FY1999 and increased expenses associated with technology used in connection with the new mobile data terminals (MDTs) mounted in our service trucks. In large part, this increase reflects higher usage and costs of cellular services associated with the MDTs in the field and the full utilization of the MDTs in conjunction with the new billing system and customer support center. In his testimony, Mr. Gruber discusses the increasing importance of MDTs and other technologies in our operations.

4. We also increased the forecasted test period budget $250,000 to account for an under-budgeted FY1999 amount for write-offs due to uncollectibles. This was substantially under-budgeted in FY1999 based on current FY1999 actuals and in comparison with FY1998.

5. Lastly, we added an additional $110,000 for the amortization of expenses relating to this rate application.

Q. What assumptions regarding labor or changes in operations were provided to the cost center owners for the preparation of their FY2000 bottom up budgets?

A. The assumptions used in the preparation of the forecasted test period budget were the same assumptions used in the preparation of our FY1999 budget.

The primary assumption in the preparation of any O&M budget is related to labor costs. Employees who meet merit performance criteria are eligible for wage increases. The expected effect of such increases is an overall wage increase of 4% in FY1999. Benefits expense of 23% of total wages was also budgeted in FY1999.

From an operational perspective, FY1999 was the first full year to reflect changes driven by the various service improvement initiatives discussed by Mr. Gruber in his testimony. Western's FY1999 budget decreased from the prior fiscal year in overall labor and benefit costs due to the transfer of workload and personnel from Western's field operations to the Customer Support Center in Amarillo, Texas. An increase in Shared Services expense was incurred as a result of this transfer. Western also began to experience the increasing effects of various improvements in technology and (ITRON electronic meter reading technology, mobile data terminals (MDTs) in service trucks, etc.) and business process changes such as the network of third party bill payment centers.

The merger and integration of United Cities Gas into Atmos, as well as the centralization of Western's gas control/dispatching function and certain accounting functions into Shared Services in FY1998, reduced Western's FY1999 O&M budget. This resulted in a corresponding increase in Shared Services expense.

Non-labor savings were budgeted in FY1999 associated with Western's proposed Gas Meter Performance Control Program. Although budgeted, this program has not yet been implemented pending approval by the Commission.

Lastly, a partial year increase to Western's O&M costs was budgeted in FY1999 to account for the transfer of the rates and regulatory vice president position to the business unit from the Shared Services staff.

Q. Are any affiliated or non-regulated operations included in Western's O&M budget?
A. No.

Q. What is the base period level of cost filed in this rate application?

A. The base period level of cost reflects the six months of actual results up through March 1999 and six months forecasted based upon Western's FY1999 budget.

Q. How does the base period level of cost compare to the forecasted test period?

A. The forecasted test period is $1,813,000 higher than the base period.

Q. Please explain the difference.

A. This difference is presented in Filing Requirement FR 10(9)(d). The difference between the base and forecasted test periods is explained earlier in my testimony where I describe the difference between the FY1999 O&M budget and the forecasted test period budget. The amount of this difference was $950,000. In addition, for the first six months of FY1999, our actual benefits, due to FAS 87, have decreased by $886,000. Mr. Burman will explain the FAS 87 changes that brought about this decreased benefits cost in FY1999. The remaining differences can largely be explained by the transfer of labor charges from Western's capital spending in FY1999 to O&M. This change reflects a substantial reduction in capital spending in FY1999 from FY1998. $303,000 is attributable to this transfer of actual labor cost. A $280,000 decrease in actual non-labor related costs reflects temporary measures of cost reduction instituted by Western to offset the effects of warm weather and poor FY1999 earnings.

<u>Shared Services O&M Budget</u>

Q. Mr. Fischer discussed the Shared Services concept. Please discuss the Shared Services costs incurred on behalf of Western.

A. Shared Services contract costs reflect two components. One component is the amount directly billed to Western. These costs are directly incurred on Western's behalf. The directly billed costs include items such as legal services, vendor operated payment centers, outsourced remittance processing, or any supplies or services, such as bill printing. The second component reflects the contracted services rendered on behalf of

Western and the other business units. These are common costs not uniquely attributable to any one business unit. They include the amount for contracted services rendered on behalf of all business units such as executive services, accounting services, information technology services, gas supply/dispatching, and the costs of the Customer Support Center. The contracts are prepared for each business unit based on measurable units of service provided to each business unit.

Q. How do you monitor Shared Services billings to Western?

A. As Mr. Fischer testified, the Shared Services concept is a dynamic process of continuous review. I would characterize FY1999 Shared Services budgeting and billing as a transitional step toward the use of external benchmarking of contract costs.

Currently, we receive a monthly report indicating the amount directly billed and contracted. For FY1999, the Shared Services contracts were prepared on an annual basis. Western's contracts were approved by Western's president. For variance analysis purposes we simply divided the annual cost by 12 to produce a monthly FY1999 Shared Services budget attributable to Western. I am monitoring the actual Shared Services contract cost versus the evenly distributed monthly amount to identify any variances. It is my responsibility to inquire with the Shared Services providers and obtain an explanation for any significant variances. For FY2000, our contracts will be broken out on a monthly basis, again with the contract rates approved by Western's president. The monthly contract amounts will enable us to monitor more closely actual Shared Services billings per unit of service in FY2000 and beyond. Starting with FY2000, the monthly Shared Services billings will include explanatory information wherever variances from the contract amount occur. Any charges above the contracted amount will require our president's approval.

Q. How was the forecasted test period Shared Services O&M budget attributable to Western developed?

A. Shared Services O&M budgets are prepared in detail for the upcoming fiscal year only. Consequently, the detailed Shared Services FY1999 O&M budget was used to develop the forecasted test year O&M budget for Shared Services for the nine months of FY2000 and three months of FY2001.

Q. What was the FY1999 Shared Services O&M budget?

A. $8,255,000.

Q. What is the forecasted test period Shared Services O&M budget?

A. Filing Requirement FR 10(9)(u) shows the Shared Services O&M budget of $8,427,000.

Q. Please discuss the differences between Shared Services FY1999 budget and forecasted test period budgets?

A. The total difference is $172,000. This difference reflects an adjustment of $172,000 from the FY1999 budget to the forecasted test period budget made to reflect an increase in Shared Services expense from FY1999 to FY2000. This increase in FY2000 Shared Services O&M budgeted expense is offset by a corresponding decrease in the labor portion of Atmos' administrative and general overheads, which is a capital expense, for the same period. Consequently, we have reflected this Shared Services O&M increase in the forecasted test period budget. As did Western in its preparation of its direct O&M budget for the forecast test period, the forecasted test period Shared Services O&M budget used September 2000 as a surrogate for each of first three months of FY2001.

Q. How does the Shared Services O&M base period level of cost attributable to Western (six months actual and six months budgeted) compare to the Shared Services O&M forecasted test period level of costs attributable to Western?

A. The forecasted test period is $295,000 higher than the base period.

Q. Please explain the difference.

A. $172,000 of the difference, as discussed above, reflects the transfer of O&M funds to capital in the form of administrative and general overheads. The remainder largely reflects month to month timing differences in the way we budget versus how actual expenditures were made.

Conclusion

Q. Will the forecasted test period budget presented in this rate application be the same budget used by Western to operate the Company for the respective forecast period?

A. Yes. The forecasted test period in this case determines the forecast of costs, or budget, which we were required to file in this case. This budget is shown as Filing Requirement FR 10(9)(d).

Q. Mr. Gruber identified a number of different initiatives to improve service and to affect cost reductions. Are these initiatives reflected in the forecasted test period budget?

A. Yes. The productivity improvements described by Mr. Gruber have been fully incorporated into the forecasted test period budget.

Q. Do you believe that the forecasted test period O&M budget you have presented is the most reasonable estimate of costs for the test period used in this proceeding?

A. Yes. It is the best estimate we have of Western's future operating and maintenance expenses.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF)
RATE APPLICATION OF)
WESTERN KENTUCKY GAS COMPANY)

Case No. 99-070

CERTIFICATE

I, Betty L. Adams, have answered the foregoing questions propounded to me in the above enumerated Docket. These answers and exhibits constitute and I hereby adopt, under oath, these answers as my prepared direct testimony in said case, which is true and correct to the best of my information and belief.

Betty L. Adams

Betty L. Adams
Vice President & Controller
Western Kentucky Gas Company

COMMONWEALTH OF KENTUCKY)
) S.S.
COUNTY OF DAVIESS)

SUBSCRIBED AND SWORN TO before me by Betty L. Adams, on this 11th day of May, 1999.

Pearl Ann Simon

Pearl Ann Simon
Notary Public
State of Kentucky At Large.

My Commission expires: September 26, 2001.

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BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	)	
RATE APPLICATION BY	)	**Case No. 99-070**
WESTERN KENTUCKY GAS COMPANY	)	

TESTIMONY OF DAVID H. DOGGETTE

Q. Please state your name, position and business address.

A. My name is David H. Doggette. I am Vice President of Western Kentucky Gas Company ("Western" or "Company"). My business address is 2401 New Hartford Road, Owensboro, Kentucky, 42303.

Q. Please describe your professional and educational background.

A. I received a Bachelor of Science degree in Mechanical Engineering from the University of Southwestern Louisiana in 1978 with emphasis in mathematics and computer science. I am a Registered Professional Engineer in the area of Mechanical Engineering in the state of Louisiana.

I have been employed in the utility industry for 20 years, predominantly in the natural gas distribution field. I have been employed by Atmos Energy Corporation or its predecessors for that entire period.

I worked in project engineering and as a Large Volume Sales Engineer in Louisiana from 1979 until 1986. I then worked in the measurement and pressure regulation of natural gas, Supervisory Control and Data Acquisition (SCADA) operations of pipeline supply systems, and as an assistant Division Engineer in west Texas until 1988. In 1988 and 1989 I worked in Dallas on the Atmos staff as the Measurement and Regulation Coordinator , providing guidance and technical direction on the use and application of meters, pressure regulators and overpressure safety devices for the Louisiana, Texas and Kentucky operations.

In 1990 I was promoted to the position of Vice President of Engineering and Measurement for Western Kentucky Gas. In 1998, I assumed additional responsibilities for computer and communication functions in Western Kentucky Gas. Accordingly, my title was changed to Vice President of Technical Services.

I have been involved with the Kentucky Gas Association, the Kentucky Oil & Gas Association, the Southern Gas Association, and am a member of the American Gas Association's Underground Storage Committee.

Q. What are your responsibilities as the Vice President of Technical Services?

A. I have overall responsibility for decision-making related to Western's technical operations. This includes engineering, measurement, communications, technological infrastructure, and storage operations. I also oversee Western's pipeline safety compliance and am a member of the Atmos' Utility Operations Council which sets the standard practices and procedures for construction, maintenance and service. I am also responsible for developing Western's annual capital budget and monitoring capital budgetary compliance. In this regard, it is my role to ensure that Western's investment in new plant and equipment is targeted towards meeting the important goals of public safety, system reliability and efficiency.

Q. Have your ever submitted testimony before the Kentucky Public Service Commission?

A. No.

Q. Are you sponsoring any of the filing requirements and, if so, which?

A. I am sponsoring the following:

FR 10(9)(b) Western's most recent capital construction budget containing four fiscal years of construction expenditures.

FR 10(9)(c) A complete description of all factors used in preparing Western's capital construction budget.

FR 10(9)(f) Detailed information for each major construction project constituting more than five percent (5%) of the annual construction budget within the three (3) year forecast.

FR 10(9)(g) Detailed information for the aggregate of construction projects constituting less than five percent (5%) of the annual construction budget within the three (3) year forecast.

Q. Do you adopt these Filing Requirements and make them part of your testimony?

A. Yes.

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

A. The purpose of my testimony is to describe the capital budgeting process used by Western, describe the control and monitoring of capital expenditure variances, and describe the capital budget by major plant category, including the Shared Services capital expenditures. I will also sponsor the service charge studies supporting the proposed service charges and the study supporting our proposed Electronic Flow Measurement (EFM) charges.

<u>Capital Budgeting Process</u>

Q. What are the goals of Western's capital budgeting process?

A. The goals of Western's capital budgeting process are to:

(1) formalize the process of identifying construction needs and prioritizing capital expenditures;
(2) assess the economic feasibility of individual construction projects;
(3) determine overall capital requirements for the planning periods;
(4) reassess long term system maintenance requirements annually; and
(5) review past construction projects and work practices, and apply procedural improvements as appropriate.

Q. How does Western plan its capital construction program?

A. Western plans its capital expenditures over five fiscal years, with a focused emphasis on the first year of that five year period. We normally begin this process during our second fiscal quarter (February-March) some 7-8 months prior to the beginning of the next fiscal year. The process is initiated with a request from my office for a "bottom-up" submission of projects from our town supervisors and operations managers. All proposed projects must be identified at a high level by need and cost. My staff reviews the proposed projects, and advises the town supervisors and managers which projects are most eligible for funding and request more detailed documentation on those particular projects. Once properly documented, these projects are elevated through Western's regional vice presidents of operations to my office for collaborative agreements between the regional vice presidents and me on a one year/five year capital construction program. The process is relatively complete by early June when projects are entered into the Atmos Capital Budget Gathering System (ACBG), although finalization of capital expenditures is not completed until late July. During this time the agreed-to projects have been further substantiated to ensure they meet the appropriate financial criteria. The final proposed budget must be reviewed by Western's president, the Executive Vice President – Operations at Atmos, and the Atmos Management Committee which is chaired by Atmos' president and CEO. The budget is not officially approved until it is presented to Atmos' Board of Directors in September. Upon this approval, all approved projects are transferred into the Atmos Capital Appropriation Gathering System (ACAG) and are ready for appropriation.

Q. How does Western prioritize its capital expenditures?

A. Our priorities for capital expenditure, listed in order of importance, are:

1. Public Safety
2. System Capacity and Reliability
3. Facilities Maintenance
4. Customer Growth
5. Public Works, and
6. Support of Long Term Technological and Service Improvement Programs.

Typically, the funds for growth constitute about 50% of our annual capital expenditures. The other components comprising our non-growth capital expenditures, including our technology investments, make up the balance of our spending.

Q. What financial criteria are the most significant in approving a project during the capital budgeting process?

A. We begin work with an overall capital spending goal which we try to work within, although variations are permitted if justified. We also use key investment criteria to evaluate projects. Any expenditure above targeted levels must be justified. Individual projects, and our construction program as a whole, are assessed on the basis of their return on investment, return on equity, cost of capital, cash flow, new business forecasts, and various capital overheads such as labor, benefits, and inflation.

Q. Must all projects meet the same financial criteria?

A. No. We separate projects into growth and non-growth capital expenditures. Growth projects are revenue-producing investments for which we can identify a stream of revenues, cash flow, return, payback and other standard investment criteria. Non-growth capital expenditures are system maintenance and reliability projects which are evaluated on a cost/benefit basis. We endeavor to keep our annual non-growth capital expenditures below the level depreciation. Since these expenditures do not have an associated stream of revenues, our goal is to fund these expenditures through internal financial cash flow. Obviously, there are certain non-growth expenditures which do not impact public safety which can be scheduled into our five year investment program to ensure that we properly maintain our system while still operating within overall cash flow constraints. Expenditures which impact public safety have always had and will continue to have the highest priority. We take our obligation to build and operate a safe and reliable gas system very seriously. There are also a number of projects we must fund over which we have little control as to timing such as public works projects and highway relocations.

Q. How can Western justify additional expenditures beyond its regular capital budget projections?

A. Western can secure additional funds through Atmos if we can demonstrate that we have potential investments which compare more favorably to competing expenditures in other Atmos business units and are, therefore, more worthy of immediate funding from a purely financial standpoint.

<u>Control & Monitoring of Capital Expenditures</u>

Q. What are the goals of Western's process of controlling and monitoring capital expenditure variances?

A. Variances from budgeted amounts are inherent in making capital expenditures. Our variance monitoring process exists to institute financial quality control by formalizing the analysis of variances by responsibility center in a process that identifies year-to-date spending variances by project. These reports are received and reviewed every month at the business unit level and on a quarterly basis at the corporate level. The goal is to keep all levels of management informed of spending by category or project relative to budgeted levels and to ensure that corrective action is initiated on a timely basis. This supports decision-making related to the cost and appropriate management of current and future capital projects.

Q. Please describe Western's process for controlling and monitoring capital expenditure variances.

A. Western's capital budgeting system maintains projects in two broad categories – Blanket Functionals and Specific Projects. The Blanket Functionals include total capital authorizations of a similar type such as new services, leak repair, main replacements, small maintenance projects, etc. Specific Projects are uniquely identified such as a specific highway relocation project, replacement of work equipment, or some larger significant maintenance project.

Once a project has been entered in the capital budget system an appropriation may be submitted for Authorization for Expenditure (AFE). Projects are then monitored to ensure they stay within budgeted levels. If during the course of a project, field management identifies that the costs of the project will exceed approved amounts, a request for supplemental funding may be submitted. If upon completion of a project, the approved amount was exceeded by 10% or $1000, a variance request must be submitted for approval. All expenditures above authorized appropriation must be approved. The level of authorization for spending per project is $125,000 by Western's president, $300,000 by Atmos' executive vice president of utility operations, and spending at higher levels must be approved by the president and CEO of Atmos. For unbudgeted projects or for variances on budgeted and approved projects the approval levels are $30,000 by Western's president, $50,000 by Atmos' executive vice president of utility operations and spending at higher levels require approval by the president and CEO of Atmos.

Each month, various project variance reports are published. Theses reports track each project against its appropriation and are reviewed by me. Each budget center manager is responsible and held accountable for managing to their overall approved capital budget.

Q. Discuss the variances incurred during the most recent fiscal years' capital budgeting program.

A. Year to date through March of Fiscal Year 1999, Western's actual direct capital expenditures are $3,383,000 or 40.24% of the $8,408,000 we have budgeted. We were 50% the way through the fiscal year at that time. Our expenditures normally are less in the first half of the year than in the second half of the year due to winter and spring weather inhibiting construction. Also, during 1999 Western received reimbursements totaling approximately $193,000 from prior year highway relocation projects which were credited to the capital budget. Additionally, the sale of excess land resulted in a credit to the FY1999 capital budget of $65,000. As we progress into summer, the pace of our construction and the corresponding capital expenditures normally increase. I expect that we will complete the current fiscal year with capital expenditures at, or near, the budgeted amount.

Table 1 shows Western's historical capital expenditures compared to budget.

Fiscal Year	Actual Dollars	Budgeted Dollars	Over/(Under) Budget, $'s	Variance (%)
1998	7,598,321	7,296,716	301,605	4.1
1997	15,085,222	16,595,351	(1,510,129)	(9.1)
1996	14,253,519	17,770,374	(3,516,855)	(19.8)
1995	15,458,055	16,592,170	(1,134,115)	(6.8)
1994	10,872,491	11,453,427	(580,936)	(5.1)

Table 1 - Comparison of Western's Direct Capital Budget to Capital Spending

As this table indicates, variances in capital budgeting do occur. For example, in 1996 and 1997, we budgeted about $1.25 million in each year for the replacement of a high pressure gas line that was in the way of a coal strip mine operation. However, we were able to develop an alternate gas supply solution before the line had to be replaced. This saved us from making this investment. Similarly, during the three year period from 1995 to 1997, a highway relocation project in Hopkinsville was budgeted which was delayed due to difficulties by the State in acquiring rights of way. In this instance the expenditure was not avoided but was deferred for several years, although we budgeted for the project in each year. Such carryover from year to year is not an uncommon occurrence and makes capital budgeting a dynamic process requiring close monitoring and control on an ongoing basis.

Test Period Capital Budget

Q. What is the forecasted test period used in this rate application?

The forecasted test period is January 1, 2000 through December 31, 2000. This represents 9 months of Western's fiscal year 2000 (FY2000) and 3 months of Western's fiscal year 2001 (FY2001).

Q. What is Western's forecasted test period capital budget?

A. Western's capital budget is developed in two components. Western's direct forecasted test period capital budget is about $9.7 million. Western's forecasted investment in the Information Technology (IT) strategy and other shared services projects during the test year will be about $1.8 million.

Q. How was Western's direct capital budget for the forecast period developed?

A. Because of the implementation of the Oracle accounting system this year, we elected to delay a bottom up development of the FY2000 capital budget until June. This delay allows us to prevent having to enter the new budget data into both the old and new systems. Consequently, we relied upon the FY1999 capital budget as a baseline for projecting detailed FY2000 through FY2001 capital expenditures for purposes of the test period in this rate application. I also prepared fiscal year capital budget estimates for FY2002 and FY2003 in the same manner.

Q. What was Western's FY1999 direct capital budget?

A. The approved FY1999 direct capital budget was $8.4 million.

Q. What was Western's FY2000 direct capital budget as estimated in the five year planning process?

A. Western's FY2000 direct capital budget was estimated at $9.0 million when prepared in 1998.

Q. How did you adjust Western's FY1999 direct capital budget in order to prepare the forecasted test period capital budget?

A. The actual estimated cost of budgeted projects planned for FY1999, before the application of overheads, was used as a baseline. That amount was approximately $5.5 million. Three factors were evaluated and used to adjust the baseline. These adjustments were necessary in order to reflect the most current information available which would impact our future level of capital spending and thus ensure that the direct capital budget is accurate. These three factors are:

1. Changing requirements in system maintenance and system improvement projects,
2. Cost increases in materials and labor tied to inflation, and
3. An application of overheads attributable to capital projects.

Q. Please discuss each of these.

A. The change in system maintenance and improvements reflects an anticipated increase in capital spending above FY1999 levels for leak repairs, cathodic protection, and system improvements for increased system capacity and reliability. This increased work on Western's system is anticipated to cost approximately $705,000 in FY2000. We expect to sustain this level of work in FY2001 with an anticipated increase in cost of material and labor resulting in a forecasted cost of $726,000. The resultant cost attributed to the test year capital budget is approximately $721,000.

The increase in material and labor costs due to inflation reflects an anticipated 3% increase for the forecasted test period (Jan 2000 – Dec 2000) not included in the original FY1999 capital budget. This amounts to an increase of $186,000 included in the test year capital budget.

The remainder of the difference between FY1999 and the forecast test period reflects minor decreases related to overhead rates. However, no major changes in overhead rates are anticipated.

Q. How was the shared services test period capital budget developed?

A. Western's shared services test period capital budget was developed as part of an overall process to align our information technology strategy (IT strategy) with our customer services goals and future business needs. A goal of the IT strategy is to share among the business units the investment required to allow us to achieve our shared vision of superior customer service and low cost. This budget was developed with the input and participation of Western in various corporate initiatives and governance councils. Ultimately, this budget was endorsed by Western's and the other business unit presidents, the Shared Services Board and Atmos Management Committee. Finally, the strategy and budget was approved by the Atmos Board of Directors. In his testimony, Mr. Gruber discusses our IT strategy in greater detail.

Q. What was the shared services FY1999 capital budget attributable to Western?

A. The approved FY1999 shared services capital budget was $3.44 million.

Q. What is Western's shared services FY2000 capital budget?

A. Western's shared services FY2000 capital budget is estimated at $1.95 million.

Q. What is Western's shared services FY2001 capital budget?

A. $1.48 million, approximately.

Q. What is Western's shared services FY2002 capital budget?

A. $1.8 million, approximately.

Q. What is Western's shared services FY2002 capital budget?

A. $420,000, approximately.

Q. Please discuss Western's overall forecasted construction program.

A. Western's capital budget was developed by the following major categories:

1. Vehicles
2. Management Information Systems/Information Technology (MIS/IT)
3. System Improvements
4. System Maintenance
5. Growth
6. Equipment

Exhibit DHD-1, which is Filing Requirement FR 10(9)(b), includes subtotals for each of these six categories for each of the forecasted years and for the forecast test period.

Q. What key needs are met through this particular budget?

A. System improvement and system maintenance investments focus on customer safety and system reliability, our two highest priorities for capital budgeting. Also within this category are state and local public works projects such as highway moves. The next priority is customer growth. This category represents the largest component of our annual spending. Next, a modern fleet of vehicles and equipment (backhoes, ditchers, air compressors, welding machines, etc.) allows us to maintain our system and continue to provide a reliable level of service to our customers. To enhance the level of customer service provided in the field, we are also making investments in new technology. Technology is a strategic investment that will enable us to continue improving our business processes, hold down operating costs, and meet the changing expectations of our customers in the next century. The efficiencies of sharing the costs of these new technologies is the focus of the capital investments Western shares with Atmos' other business units. Mr. Gruber discusses a number of technology-based service improvement initiatives, such as our new CIS/Banner billing system, Customer Support Center, IT Infrastructure and field-oriented business process changes. Additionally, an important ancillary benefit of our MIS/IT investments is addressing Y2K readiness by putting into place up-to-date hardware and software by January 2000. Some examples of the MIS/IT types of investments are additional modules of the Oracle accounting system as discussed by Mr. Gruber. Compared to past capital spending, we expect the cost of technology to comprise a larger portion of future budgets to update our system hardware and software.

<u>Service Charge Studies</u>

Q. Have you or persons under your supervision conducted service charge studies related to Western's service charges?

A. Yes. Those studies are attached to my testimony as Exhibit DHD-2.

Q. What is the purpose of these studies?

A. The purpose is to determine the underlying costs associated with performing the non-recurring or special services offered to our customers. This was done to support, through analysis, rates consistent with the cost of these special services by comparing Western's current rates with the actual cost to perform these services.

Q. Which of Western's service charges are the focus of the analysis?

A. The cost analysis focuses on the charges for meter set, turn-on, read, reconnect delinquent service and seasonal turn-on.

Q. What cost studies were performed?

A. We performed a payroll loading analysis, we analyzed mileage between service orders, we reviewed a customer handling time analysis, and we conducted an analysis of annual service order activity. Each of these cost analyses were required to develop a per service cost assignment. We also conducted a survey of banks to determine an appropriate charge for returned checks.

Q. Briefly describe each cost analysis that was performed.

1. Payroll Loading Analysis. We began by developing a salary cost per minute of the service technician, office support, and supervision for the time to perform each order. This analysis included identification of after hours (overtime) costs to perform these services.
2. Trip Mileage Analysis. We determined the average travel time and distance between orders, and by applying the payroll loadings assigned to the service technician; we arrived at a travel cost per order.
3. Customer Handling Time Analysis. We reviewed an independent customer call analysis for assigning cost per call for the services mentioned above.
4. Service Order Activity Analysis. We compiled and reviewed annual service order activity and completion times required to initiate and process all orders. By determining the time to complete each order we were able to calculate the cost to perform each order by Western service order number designation.

Q. Please describe the results of the cost analyses.

A. The results of the Special Service Charge Analysis are displayed in Exhibit DHD-2. The analysis shows that Western is currently recovering its costs to set a meter. The analysis, however, shows that Western is not recovering the full costs to perform the turn-on, read, and seasonal turn-on. The analysis also shows that Western is not recovering any of the costs to disconnect and then reconnect delinquent service. Lastly, the study indicates that performing service order activity using overtime labor causes Western to incur a higher cost for that activity.

Q. What was the result of the survey of banks relative to returned checks?

A. We surveyed eight (8) local banks and identified the average returned check charge being applied. The premise of this survey is that we incur a similar administrative cost when handling checks returned for non-sufficient funds. Our current charge is well below that average.

Q. Based on your analysis, what conclusions have you reached regarding the relative costs of these services?

A. This study indicates that some services have similar cost components but may differ by factors such as the time to perform the services or the number of times a premises must be visited. For example, the cost to initiate service (turn-on) for a new customer that has a meter is similar to the cost for re-establishing service for non-pay except that an additional premises visit is required for reconnecting delinquent service. This study makes it clear that some restructuring of special service charges is necessary if Western is to fully recover its special services costs directly from those customers that cause or benefit from the costs being incurred. Mr. Smith will address the proposed charges in his testimony.

Electronic Flow Measurement Cost Study

Q. Have you or someone under your supervision conducted a cost study pertaining to Western's EFM charges?

A. Yes. That study is attached to my testimony as Exhibit DHD-2.

Q. Why was this EFM cost study performed?

A. In the Commission's order in our last rate case, the Commission directed Western to prepare an EFM cost study to ensure the Company's charges for EFM, which were established in our last rate case, were appropriately set.

Q. What were the results of the EFM study?

A. The study shows that the current monthly fee appropriately recovers the costs of installation and purchase, including a 12% return, of Class 1 EFM equipment, in a five year period. The study also shows that the Class 2 EFM equipment monthly charge is not recovering its installation and purchase costs, including return in a five year period. The cost of ongoing maintenance of this equipment was not included in the study.

Q. As a result of this study, what changes, if any, in Western's EFM charges are you recommending?

A. My recommendation is to maintain the Class 1 EFM equipment monthly charge given its sufficient cost recovery, plus return, over a five year period. My recommendation for the Class 2 EFM equipment charge is to increase the monthly fee to recover its costs and return over five years. I am also recommending to maintain the one-time payment option for both classes of equipment with the stipulation that Western will service the equipment for a five year period. Subsequent equipment needs will require full reimbursement by the customer. Mr. Smith will address the proposed charges for EFM in his testimony.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF)
RATE APPLICATION OF)
WESTERN KENTUCKY GAS COMPANY)

Case No. 99-070

CERTIFICATE

I, David H. Doggette, have answered the foregoing questions propounded to me in the above enumerated Docket. These answers and exhibits constitute and I hereby adopt, under oath, these answers as my prepared direct testimony in said case, which is true and correct to the best of my information and belief.

David H. Doggette

David H. Doggette
Vice President of Technical Services
Western Kentucky Gas Company

COMMONWEALTH OF KENTUCKY)
) S.S.
COUNTY OF DAVIESS)

SUBSCRIBED AND SWORN TO before me by David H. Doggette, on this 11th day of May, 1999.

Pearl Ann Simon

Pearl Ann Simon
Notary Public
State of Kentucky At Large.

My Commission expires: September 26, 2001.

WESTERN KENTUCKY GAS

Capital Budget Forecast and Test Year Calculation

Projected Overheads	50.425%
Projected Increase In Maintenance & Improvements	0.000%
Projected Price Increases	0.000%

Line #	Budg Stat #	Acct #	Budget Category	Fiscal Year 1999: 1999 w/o O/H	Projects	Inflation	Direct Costs	O/H	1999
1			**Vehicles**						
2	39200	392.00	Transportation	-	-	-	-	-	-
3			**Vehicles**	-	-	-	-	-	-
4									
5			**MIS**						
6	3990x	399.00	Office Equipment	-	-	-	-	-	-
7	39906	399.86	PC Hardware	35,980	-	-	35,980	18,143	54,123
8	39907	399.87	PC Software	10,000	-	-	10,000	5,043	15,043
9	39908	399.88	Application Software	-	-	-	-	-	-
10			**MIS**	45,980	-	-	45,980	23,185	69,165
11									
12			**Equipment**						
13	37000	n/a	Communication Equipment - Transmission	-	-	-	-	-	-
14	37100	n/a	Other Equipment - Storage	-	-	-	-	-	-
15	38700	384.00	Other Equipment	2,250	-	-	2,250	1,135	3,385
16	39000	390.00	Structures and Improvements	-	-	-	-	-	-
17	39003	390.03	Improvements	-	-	-	-	-	-
18	39004	390.04	Air Conditioning	-	-	-	-	-	-
19	39009	390.09	Improvements-Leased Premises	10,000	-	-	10,000	5,043	15,043
20	39100	391.83	Office Furniture	-	-	-	-	-	-
21	39103	391.00	Office Machines	1,500	-	-	1,500	756	2,256
22	39300	n/a	Stores Equipment	-	-	-	-	-	-
23	39400	394.77	Tools, Shop & Equipment	4,000	-	-	4,000	2,017	6,017
24	39600	n/a	Power Operated Equipment	-	-	-	-	-	-
25	39603	396.93	Ditchers	-	-	-	-	-	-
26	39604	396.94	Backhoes	-	-	-	-	-	-
27	39605	396.95	Welders	-	-	-	-	-	-
28	39700	397.00	Communications - Telephones	40,000	-	-	40,000	20,170	60,170
29	39701	397.20	Communications - Mobile Radios	6,000	-	-	6,000	3,026	9,026
30	39702	397.20	Communications - Fixed Radios	-	-	-	-	-	-
31	39705	397.22	Communications - Telemetering	-	-	-	-	-	-
32	39800	398.00	Miscellaneous	-	-	-	-	-	-
33			**Equipment**	63,750	-	-	63,750	32,146	95,896
34									
35			**System Maintenance**						
36	36701-30	367.00	Transmission - Leakage	29,750	-	-	29,750	15,001	44,751
37	37601-30	376.00	Steel Mains - Leakage	294,780	-	-	294,780	148,643	443,423
38	37602-30	376.00	Plastic Mains - Leakage	154,308	-	-	154,308	77,810	232,118
39	38000-30	380.00	Services - Leakage	330,770	-	-	330,770	166,791	497,561
40	38200-30	382.00	Meter Loops - Leakage	5,000	-	-	5,000	2,521	7,521
41	3xxxx-98	Various	Retirements	319,480	-	-	319,480	161,098	480,578
42			**System Maintenance**	1,134,088	-	-	1,134,088	571,864	1,705,952
43									
44			**System Improvements**						
45	33400-20	334.00	Field Measurement & Regulation	-	-	-	-	-	-
46	35100-20	351.20	Storage Structures and Improvements	-	-	-	-	-	-
47	35200-20	352.01	Wells	-	-	-	-	-	-
48	35200-40	352.02	Wells	-	-	-	-	-	-
49	35300-10	353.10	Field Lines	25,512	-	-	25,512	12,864	38,376
50	35300-20	353.20	Gathering Lines	5,962	-	-	5,962	3,006	8,968
51	35400-20	354.00	Compressor Station Equipment	-	-	-	-	-	-
52	35500-20	355.00	Measuring and Regulating	-	-	-	-	-	-
53	35600-20	356.00	Purification Equipment	-	-	-	-	-	-
54	36510-20	365.10	Land and Land Rights	-	-	-	-	-	-
55	36600-20	366.20	Structures and Improvements	-	-	-	-	-	-
56	36700-40	367.00	Transmission Mains - Cathodic Protection	3,037	-	-	3,037	1,531	4,568
57	36701-20	367.00	Transmission Mains - System Improvements	9,476	-	-	9,476	4,778	14,254
58	36900-20	369.10	Measurement & Regulation Stations	5,959	-	-	5,959	3,005	8,964
59	37500-20	375.10	Structures - Public Improvements	-	-	-	-	-	-
60	37600-40	376.00	Mains - Cathodic Protection	71,500	-	-	71,500	36,054	107,554
61	37600-69	376.00	Mapping Conversion	100,000	-	-	100,000	50,425	150,425
62	37600-82	376.00	Aid-In-Construction	-	-	-	-	-	-
63	37601-20	376.00	Steel System Improvements	361,230	-	-	361,230	182,150	543,380
64	37602-20	376.00	Plastic System Improvements	34,275	-	-	34,275	17,283	51,558
65	37800-20	378.00	Measurement & Regulation - System Improvements	136,000	-	-	136,000	68,578	204,578
66	37900-20	379.00	Measurement & Regulation - Equipment	23,500	-	-	23,500	11,850	35,350
67	38000-20	380.00	Services - System Improvements	-	-	-	-	-	-
68	38100-20	381.00	Meters - System Improvements	-	-	-	-	-	-
69	38200-20	382.00	Meter Loops - System Improvements	127,463	-	-	127,463	64,273	191,736
70	38300-20	383.00	House Regulators - System Improvements	-	-	-	-	-	-
71	38500-20	385.00	Industrial Measurement & Regulation - System Impr.	98,000	-	-	98,000	49,417	147,417
72	3xxxx-98	Various	Public Works Reimbursements	(190,579)	-	-	(190,579)	(96,099)	(286,678)
73			**System Improvements**	811,335	-	-	811,335	409,116	1,220,451
74									
75			**Growth**						
76									
77	36701-10	367.00	Steel Transmission Mains	-	-	-	-	-	-
78	36900-10	369.00	Measurement & Regulation Stations	-	-	-	-	-	-
79	37600-81	376.00	Forfeitures	(381,919)	-	-	(381,919)	-	(381,919)
80	37601-10	376.00	Steel Revenue Mains	83,705	-	-	83,705	42,208	125,913
81	37602-10	376.00	Plastic Revenue Mains	1,353,647	-	-	1,353,647	682,576	2,036,223
82	37800-10	378.00	Measurement & Regulation - Revenue	11,290	-	-	11,290	5,693	16,983
83	37900-10	379.00	Measurement & Regulation - City Gate	66,000	-	-	66,000	33,281	99,281
84	38000-10	380.00	Services - Revenue	1,386,012	-	-	1,386,012	698,897	2,084,909
85	38100-10	381.00	Meters - Revenue	480,431	-	-	480,431	242,257	722,688
86	38200-10	382.00	Meter Loops - Revenue	300,949	-	-	300,949	151,754	452,703
87	38300-10	383.00	House Regulators - Revenue	106,534	-	-	106,534	53,720	160,254
88	38500-10	385.00	Industrial Measurement & Regulation - Revenue	-	-	-	-	-	-
89			**Growth**	3,406,649	-	-	3,406,649	1,910,385	5,317,034
90									
91			**Total WKG**	$ 5,461,802			$ 5,461,802	$ 2,946,696	$ 8,408,498

WESTERN KENTUCKY GAS

Capital Budget Forecast and Test Year Calculation

Projected Overheads	50.000%
Projected Increase In Maintenance & Imporvements	36.250%
Projected Price Increases	3.000%

Line #	Budg Stat #	Acct #	Budget Category	Fiscal Year 2000: 2000 w/o O/H	Projects	Inflation	Direct Costs	O/H	2000
1			**Vehicles**						
2	39200	392.00	Transportation	-		-	-	-	-
3			**Vehicles**	-	-	-	-	-	-
4									
5			**MIS**						
6	3990x	399.00	Office Equipment	-		-	-	-	-
7	39906	399.86	PC Hardware	35,980		1,079	37,059	18,530	55,589
8	39907	399.87	PC Software	10,000		300	10,300	5,150	15,450
9	39908	399.88	Application Software	-		-	-	-	-
10			**MIS**	45,980	-	1,379	47,359	23,680	71,039
11									
12			**Equipment**						
13	37000	n/a	Communication Equipment - Transmission	-		-	-	-	-
14	37100	n/a	Other Equipment - Storage	-		-	-	-	-
15	38700	384.00	Other Equipment	2,250		68	2,318	1,159	3,476
16	39000	390.00	Structures and Improvements	-		-	-	-	-
17	39003	390.03	Improvements	-		-	-	-	-
18	39004	390.04	Air Conditioning	-		-	-	-	-
19	39009	390.09	Improvements-Leased Premises	10,000		300	10,300	5,150	15,450
20	39100	391.83	Office Furniture	-		-	-	-	-
21	39103	391.00	Office Machines	1,500		45	1,545	773	2,318
22	39300	n/a	Stores Equipment	-		-	-	-	-
23	39400	394.77	Tools, Shop & Equipment	4,000		120	4,120	2,060	6,180
24	39600	n/a	Power Operated Equipment	-		-	-	-	-
25	39603	396.93	Ditchers	-		-	-	-	-
26	39604	396.94	Backhoes	-		-	-	-	-
27	39605	396.95	Welders	-		-	-	-	-
28	39700	397.00	Communications - Telephones	40,000		1,200	41,200	20,600	61,800
29	39701	397.20	Communications - Mobile Radios	6,000		180	6,180	3,090	9,270
30	39702	397.20	Communications - Fixed Radios	-		-	-	-	-
31	39705	397.22	Communications - Telemetering	-		-	-	-	-
32	39800	398.00	Miscellaneous	-		-	-	-	-
33			**Equipment**	63,750	-	1,913	65,663	32,831	98,494
34									
35			**System Maintenance**						
36	36701-30	367.00	Transmission - Leakage	29,750	10,784	893	41,427	20,713	62,140
37	37601-30	376.00	Steel Mains - Leakage	294,780	106,858	8,843	410,481	205,241	615,722
38	37602-30	376.00	Plastic Mains - Leakage	154,308	55,937	4,629	214,874	107,437	322,311
39	38000-30	380.00	Services - Leakage	330,770	119,904	9,923	460,597	230,299	690,896
40	38200-30	382.00	Meter Loops - Leakage	5,000	1,813	150	6,963	3,481	10,444
41	3xxxx-98	Various	Retirements	319,480	115,812	9,584	444,876	222,438	667,314
42			**System Maintenance**	1,134,088	411,107	34,023	1,579,218	789,609	2,368,826
43									
44			**System Improvements**						
45	33400-20	334.00	Field Measurement & Regulation	-	-	-	-	-	-
46	35100-20	351.20	Storage Structures and Improvements	-	-	-	-	-	-
47	35200-20	352.01	Wells	-	-	-	-	-	-
48	35200-40	352.02	Wells	-	-	-	-	-	-
49	35300-10	353.10	Field Lines	25,512	9,248	765	35,525	17,763	53,288
50	35300-20	353.20	Gathering Lines	5,962	2,161	179	8,302	4,151	12,453
51	35400-20	354.00	Compressor Station Equipment	-	-	-	-	-	-
52	35500-20	355.00	Measuring and Regulating	-	-	-	-	-	-
53	35600-20	356.00	Purification Equipment	-	-	-	-	-	-
54	36510-20	365.10	Land and Land Rights	-	-	-	-	-	-
55	36600-20	366.20	Structures and Improvements	-	-	-	-	-	-
56	36700-40	367.00	Transmission Mains - Cathodic Protection	3,037	1,101	91	4,229	2,115	6,344
57	36701-20	367.00	Transmission Mains - System Improvements	9,476	3,435	284	13,195	6,598	19,793
58	36900-20	369.10	Measurement & Regulation Stations	5,959	2,160	179	8,298	4,149	12,447
59	37500-20	375.10	Structures - Public Improvements	-	-	-	-	-	-
60	37600-40	376.00	Mains - Cathodic Protection	71,500	25,919	2,145	99,564	49,782	149,346
61	37600-69	376.00	Mapping Conversion	100,000	36,250	3,000	139,250	69,625	208,875
62	37600-82	376.00	Aid-In-Construction	-	-	-	-	-	-
63	37601-20	376.00	Steel System Improvements	361,230	130,946	10,837	503,013	251,506	754,519
64	37602-20	376.00	Plastic System Improvements	34,275	12,425	1,028	47,728	23,864	71,592
65	37800-20	378.00	Measurement & Regulation - System Improvements	136,000	49,300	4,080	189,380	94,690	284,070
66	37900-20	379.00	Measurement & Regulation - Equipment	23,500	8,519	705	32,724	16,362	49,086
67	38000-20	380.00	Services - System Improvements	-	-	-	-	-	-
68	38100-20	381.00	Meters - System Improvements	-	-	-	-	-	-
69	38200-20	382.00	Meter Loops - System Improvements	127,463	46,205	3,824	177,492	88,746	266,238
70	38300-20	383.00	House Regulators - System Improvements	-	-	-	-	-	-
71	38500-20	385.00	Industrial Measurement & Regulation - System Impr.	98,000	35,525	2,940	136,465	68,233	204,698
72	3xxxx-98	Various	Public Works Reimbursements	(190,579)	(69,085)	(5,717)	(265,381)	(132,691)	(398,072)
73			**System Improvements**	611,335	294,109	24,340	1,129,784	564,892	1,694,676
74									
75			**Growth**						
76									
77	36701-10	367.00	Steel Transmission Mains	-		-	-	-	-
78	36900-10	369.00	Measurement & Regulation Stations	-		-	-	-	-
79	37600-81	376.00	Forfeitures	(390,000)		-	(390,000)	-	(390,000)
80	37601-10	376.00	Steel Revenue Mains	83,705		2,511	86,216	43,108	129,324
81	37602-10	376.00	Plastic Revenue Mains	1,353,647		40,609	1,394,256	697,128	2,091,385
82	37800-10	378.00	Measurement & Regulation - Revenue	11,290		339	11,629	5,814	17,443
83	37900-10	379.00	Measurement & Regulation - City Gate	66,000		1,980	67,980	33,990	101,970
84	38000-10	380.00	Services - Revenue	1,386,012		41,580	1,427,592	713,796	2,141,389
85	38100-10	381.00	Meters - Revenue	480,431		14,413	494,844	247,422	742,266
86	38200-10	382.00	Meter Loops - Revenue	300,949		9,028	309,977	154,989	464,966
87	38300-10	383.00	House Regulators - Revenue	106,534		3,196	109,730	54,865	164,595
88	38500-10	385.00	Industrial Measurement & Regulation - Revenue	-		-	-	-	-
89			**Growth**	3,398,568	-	113,657	3,512,225	1,951,113	5,463,338
90									
91			**Total WKG**	$ 5,453,721	$ 705,216	$ 175,312	$ 6,334,248	$ 3,362,124	$ 9,696,373

WESTERN KENTUCKY GAS

Capital Budget Forecast and Test Year Calculation

			Projected Overheads			
			Projected Increase In Maintenance & Imporvements			
			Projected Price Increases			
				Test Year January, 2000 Through December, 2000		
Line #	Budg Stat #	Acct #	Budget Category	FY2000 Part	FY2001 Part	Test Year
1			Vehicles			
2	39200	392.00	Transportation		-	-
3			Vehicles	-	-	-
4						
5			MIS			
6	3990x	399.00	Office Equipment	-	-	-
7	39906	399.86	PC Hardware	41,692	14,314	56,006
8	39907	399.87	PC Software	11,588	3,978	15,566
9	39908	399.88	Application Software	-	-	-
10			MIS	53,280	18,292	71,572
11						
12			Equipment			
13	37000	n/a	Communication Equipment - Transmission	-	-	-
14	37100	n/a	Other Equipment - Storage	-	-	-
15	38700	384.00	Other Equipment	2,607	895	3,502
16	39000	390.00	Structures and Improvements	-	-	-
17	39003	390.03	Improvements	-	-	-
18	39004	390.04	Air Conditioning	-	-	-
19	39009	390.09	Improvements-Leased Premises	11,588	3,978	15,566
20	39100	391.83	Office Furniture	-	-	-
21	39103	391.00	Office Machines	1,738	597	2,335
22	39300	n/a	Stores Equipment	-	-	-
23	39400	394.77	Tools, Shop & Equipment	4,635	1,591	6,226
24	39600	n/a	Power Operated Equipment	-	-	-
25	39603	396.93	Ditchers	-	-	-
26	39604	396.94	Backhoes	-	-	-
27	39605	396.95	Welders	-	-	-
28	39700	397.00	Communications - Telephones	46,350	15,914	62,264
29	39701	397.20	Communications - Mobile Radios	6,953	2,387	9,340
30	39702	397.20	Communications - Fixed Radios	-	-	-
31	39705	397.22	Communications - Telemetering	-	-	-
32	39800	398.00	Miscellaneous	-	-	-
33			Equipment	73,871	25,362	99,233
34						
35			System Maintenance			
36	36701-30	367.00	Transmission - Leakage	46,605	16,001	62,606
37	37601-30	376.00	Steel Mains - Leakage	461,791	158,548	620,339
38	37602-30	376.00	Plastic Mains - Leakage	241,733	82,995	324,728
39	38000-30	380.00	Services - Leakage	518,172	177,906	696,078
40	38200-30	382.00	Meter Loops - Leakage	7,833	2,689	10,522
41	3xxxx-98	Various	Retirements	500,485	171,833	672,318
42			System Maintenance	1,776,619	609,972	2,386,591
43						
44			System Improvements			
45	33400-20	334.00	Field Measurement & Regulation	-	-	-
46	35100-20	351.20	Storage Structures and Improvements	-	-	-
47	35200-20	352.01	Wells	-	-	-
48	35200-40	352.02	Wells	-	-	-
49	35300-10	353.10	Field Lines	39,966	13,722	53,688
50	35300-20	353.20	Gathering Lines	9,340	3,207	12,547
51	35400-20	354.00	Compressor Station Equipment	-	-	-
52	35500-20	355.00	Measuring and Regulating	-	-	-
53	35600-20	356.00	Purification Equipment	-	-	-
54	36510-20	365.10	Land and Land Rights	-	-	-
55	36600-20	366.20	Structures and Improvements	-	-	-
56	36700-40	367.00	Transmission Mains - Cathodic Protection	4,758	1,633	6,391
57	36701-20	367.00	Transmission Mains - System Improvements	14,845	5,097	19,942
58	36900-20	369.10	Measurement & Regulation Stations	9,335	3,205	12,540
59	37500-20	375.10	Structures - Public Improvements	-	-	-
60	37600-40	376.00	Mains - Cathodic Protection	112,009	38,456	150,465
61	37600-69	376.00	Mapping Conversion	156,656	53,785	210,441
62	37600-82	376.00	Aid-In-Construction	-	-	-
63	37601-20	376.00	Steel System Improvements	565,889	194,289	760,178
64	37602-20	376.00	Plastic System Improvements	53,694	18,435	72,129
65	37800-20	378.00	Measurement & Regulation - System Improvements	213,053	73,148	286,201
66	37900-20	379.00	Measurement & Regulation - Equipment	36,814	12,640	49,454
67	38000-20	380.00	Services - System Improvements	-	-	-
68	38100-20	381.00	Meters - System Improvements	-	-	-
69	38200-20	382.00	Meter Loops - System Improvements	199,679	68,556	268,235
70	38300-20	383.00	House Regulators - System Improvements	-	-	-
71	38500-20	385.00	Industrial Measurement & Regulation - System Impr.	153,523	52,710	206,233
72	3xxxx-98	Various	Public Works Reimbursements	(298,554)	(102,504)	(401,058)
73			System Improvements	1,271,007	436,379	1,707,386
74						
75			Growth			
76						
77	36701-10	367.00	Steel Transmission Mains	-	-	-
78	36900-10	369.00	Measurement & Regulation Stations	-	-	-
79	37600-81	376.00	Forfeitures	(292,500)	(150,638)	(443,138)
80	37601-10	376.00	Steel Revenue Mains	96,993	33,301	130,294
81	37602-10	376.00	Plastic Revenue Mains	1,568,538	538,532	2,107,070
82	37800-10	378.00	Measurement & Regulation - Revenue	13,082	4,492	17,574
83	37900-10	379.00	Measurement & Regulation - City Gate	76,478	26,257	102,735
84	38000-10	380.00	Services - Revenue	1,606,041	551,408	2,157,449
85	38100-10	381.00	Meters - Revenue	556,699	191,133	747,832
86	38200-10	382.00	Meter Loops - Revenue	348,725	119,729	468,454
87	38300-10	383.00	*House Regulators - Revenue*	123,446	42,383	165,829
88	38500-10	385.00	Industrial Measurement & Regulation - Revenue	-	-	-
89			Growth	4,097,502	1,356,597	5,454,099
90						
91			Total WKG	$ 7,272,279	$ 2,446,602	$ 9,718,881

WESTERN KENTUCKY GAS

Capital Budget Forecast and Test Year Calculation

Projected Overheads	50.000%
Projected Increase In Maintenance & Imporvements	0.000%
Projected Price Increases	3.000%

Line #	Budg Stat #	Acct #	Budget Category	Fiscal Year 2001					
				2001 w/o O/H	Projects	Inflation	Direct Costs	O/H	2001
1			Vehicles						
2	39200	392.00	Transportation	-	-	-	-	-	-
3			Vehicles	-	-	-	-	-	-
4									
5			MIS						
6	3990x	399.00	Office Equipment	-	-	-	-	-	-
7	39906	399.86	PC Hardware	37,059	-	1,112	38,171	19,086	57,257
8	39907	399.87	PC Software	10,300	-	309	10,609	5,305	15,914
9	39908	399.88	Application Software	-	-	-	-	-	-
10			MIS	47,359	-	1,421	48,780	24,390	73,170
11									
12			Equipment						
13	37000	n/a	Communication Equipment - Transmission	-	-	-	-	-	-
14	37100	n/a	Other Equipment - Storage	-	-	-	-	-	-
15	38700	384.00	Other Equipment	2,318	-	70	2,387	1,194	3,581
16	39000	390.00	Structures and Improvements	-	-	-	-	-	-
17	39003	390.03	Improvements	-	-	-	-	-	-
18	39004	390.04	Air Conditioning	-	-	-	-	-	-
19	39009	390.09	Improvements-Leased Premises	10,300	-	309	10,609	5,305	15,914
20	39100	391.83	Office Furniture	-	-	-	-	-	-
21	39103	391.00	Office Machines	1,545	-	46	1,591	796	2,387
22	39300	n/a	Stores Equipment	-	-	-	-	-	-
23	39400	394.77	Tools, Shop & Equipment	4,120	-	124	4,244	2,122	6,365
24	39600	n/a	Power Operated Equipment	-	-	-	-	-	-
25	39603	396.93	Ditchers	-	-	-	-	-	-
26	39604	396.94	Backhoes	-	-	-	-	-	-
27	39605	396.95	Welders	-	-	-	-	-	-
28	39700	397.00	Communications - Telephones	41,200	-	1,236	42,436	21,218	63,654
29	39701	397.20	Communications - Mobile Radios	6,180	-	185	6,365	3,183	9,548
30	39702	397.20	Communications - Fixed Radios	-	-	-	-	-	-
31	39705	397.22	Communications - Telemetering	-	-	-	-	-	-
32	39800	398.00	Miscellaneous	-	-	-	-	-	-
33			Equipment	65,663	-	1,970	67,632	33,816	101,449
34									
35			System Maintenance						
36	36701-30	367.00	Transmission - Leakage	41,427	-	1,243	42,670	21,335	64,005
37	37601-30	376.00	Steel Mains - Leakage	410,481	-	12,314	422,796	211,398	634,193
38	37602-30	376.00	Plastic Mains - Leakage	214,874	-	6,446	221,320	110,660	331,980
39	38000-30	380.00	Services - Leakage	460,597	-	13,818	474,415	237,208	711,623
40	38200-30	382.00	Meter Loops - Leakage	6,963	-	209	7,171	3,586	10,757
41	3xxxx-98	Various	Retirements	444,876	-	13,346	458,222	229,111	687,333
42			System Maintenance	1,579,218	-	47,377	1,626,594	813,297	2,439,891
43									
44			System Improvements						
45	33400-20	334.00	Field Measurement & Regulation	-	-	-	-	-	-
46	35100-20	351.20	Storage Structures and Improvements	-	-	-	-	-	-
47	35200-20	352.01	Wells	-	-	-	-	-	-
48	35200-40	352.02	Wells	-	-	-	-	-	-
49	35300-10	353.10	Field Lines	35,525	-	1,066	36,591	18,296	54,887
50	35300-20	353.20	Gathering Lines	8,302	-	249	8,551	4,276	12,827
51	35400-20	354.00	Compressor Station Equipment	-	-	-	-	-	-
52	35500-20	355.00	Measuring and Regulating	-	-	-	-	-	-
53	35600-20	356.00	*Purification Equipment*	-	-	-	-	-	-
54	36510-20	365.10	Land and Land Rights	-	-	-	-	-	-
55	36600-20	366.20	Structures and Improvements	-	-	-	-	-	-
56	36700-40	367.00	Transmission Mains - Cathodic Protection	4,229	-	127	4,356	2,178	6,534
57	36701-20	367.00	Transmission Mains - System Improvements	13,195	-	396	13,591	6,796	20,387
58	36900-20	369.10	Measurement & Regulation Stations	8,298	-	249	8,547	4,273	12,820
59	37500-20	375.10	Structures - Public Improvements	-	-	-	-	-	-
60	37600-40	376.00	Mains - Cathodic Protection	99,564	-	2,987	102,551	51,275	153,826
61	37600-69	376.00	Mapping Conversion	139,250	-	4,178	143,428	71,714	215,141
62	37600-62	376.00	Aid-In-Construction	-	-	-	-	-	-
63	37601-20	376.00	Steel System Improvements	503,013	-	15,090	518,103	259,052	777,155
64	37602-20	376.00	Plastic System Improvements	47,728	-	1,432	49,160	24,580	73,740
65	37800-20	378.00	Measurement & Regulation - System Improvements	189,380	-	5,681	195,061	97,531	292,592
66	37900-20	379.00	Measurement & Regulation - Equipment	32,724	-	982	33,705	16,853	50,558
67	38000-20	380.00	Services - System Improvements	-	-	-	-	-	-
68	38100-20	381.00	Meters - System Improvements	-	-	-	-	-	-
69	38200-20	382.00	Meter Loops - System Improvements	177,492	-	5,325	182,817	91,408	274,225
70	38300-20	383.00	House Regulators - System Improvements	-	-	-	-	-	-
71	38500-20	385.00	Industrial Measurement & Regulation - System Impr.	136,465	-	4,094	140,559	70,279	210,838
72	3xxxx-98	Various	Public Works Reimbursements	(265,381)	-	(7,961)	(273,343)	(136,671)	(410,014)
73			System Improvements	1,129,784	-	33,894	1,163,678	581,839	1,745,516
74									
75			Growth						
76									
77	36701-10	367.00	Steel Transmission Mains	-	-	-	-	-	-
78	36900-10	369.00	Measurement & Regulation Stations	-	-	-	-	-	-
79	37600-81	376.00	Forfeitures	(390,000)	-	(11,700)	(401,700)	(200,850)	(602,550)
80	37601-10	376.00	Steel Revenue Mains	86,216	-	2,586	88,803	44,401	133,204
81	37602-10	376.00	Plastic Revenue Mains	1,394,256	-	41,828	1,436,084	718,042	2,154,126
82	37800-10	378.00	Measurement & Regulation - Revenue	11,629	-	349	11,978	5,989	17,966
83	37900-10	379.00	Measurement & Regulation - City Gate	67,980	-	2,039	70,019	35,010	105,029
84	38000-10	380.00	Services - Revenue	1,427,592	-	42,828	1,470,420	735,210	2,205,630
85	38100-10	381.00	Meters - Revenue	494,844	-	14,845	509,689	254,845	764,534
86	38200-10	382.00	Meter Loops - Revenue	309,977	-	9,299	319,277	159,638	478,915
87	38300-10	383.00	House Regulators - Revenue	109,730	-	3,292	113,022	56,511	169,533
88	38500-10	385.00	Industrial Measurement & Regulation - Revenue	-	-	-	-	-	-
89			Growth	3,512,225	-	105,367	3,617,592	1,808,796	5,426,388
90									
91			Total WKG	$ 6,334,248	$ -	$ 190,027	$ 6,524,276	$ 3,262,138	$ 9,786,414

WESTERN KENTUCKY GAS
Capital Budget Forecast and Test Year Calculation

			Projected Overheads						50.000%
			Projected Increase in Maintenance & Improvements						0.000%
			Projected Price Increases						3.000%
				Fiscal Year 2002					
Line #	Budg Stat #	Acct #	Budget Category	2002 w/o O/H	Projects	Inflation	Direct Costs	O/H	2002
1			**Vehicles**						
2	39200	392.00	Transportation	-	-	-	-	-	-
3			**Vehicles**	-	-	-	-	-	-
4									
5			**MIS**						
6	3990x	399.00	Office Equipment	-	-	-	-	-	-
7	39906	399.86	PC Hardware	38,171	-	1,145	39,316	19,658	58,974
8	39907	399.87	PC Software	10,609	-	318	10,927	5,464	16,391
9	39908	399.88	Application Software	-	-	-	-	-	-
10			**MIS**	48,780	-	1,463	50,244	25,122	75,365
11									
12			**Equipment**						
13	37000	n/a	Communication Equipment - Transmission	-	-	-	-	-	-
14	37100	n/a	Other Equipment - Storage	-	-	-	-	-	-
15	38700	384.00	Other Equipment	2,387	-	72	2,459	1,229	3,688
16	39000	390.00	Structures and Improvements	-	-	-	-	-	-
17	39003	390.03	Improvements	-	-	-	-	-	-
18	39004	390.04	Air Conditioning	-	-	-	-	-	-
19	39009	390.09	Improvements-Leased Premises	10,609	-	318	10,927	5,464	16,391
20	39100	391.83	Office Furniture	-	-	-	-	-	-
21	39103	391.00	Office Machines	1,591	-	48	1,639	820	2,459
22	39300	n/a	Stores Equipment	-	-	-	-	-	-
23	39400	394.77	Tools, Shop & Equipment	4,244	-	127	4,371	2,185	6,556
24	39600	n/a	Power Operated Equipment	-	-	-	-	-	-
25	39603	396.93	Ditchers	-	-	-	-	-	-
26	39604	396.94	Backhoes	-	-	-	-	-	-
27	39605	396.95	Welders	-	-	-	-	-	-
28	39700	397.00	Communications - Telephones	42,436	-	1,273	43,709	21,855	65,564
29	39701	397.20	Communications - Mobile Radios	6,365	-	191	6,556	3,278	9,835
30	39702	397.20	Communications - Fixed Radios	-	-	-	-	-	-
31	39705	397.22	Communications - Telemetering	-	-	-	-	-	-
32	39800	398.00	Miscellaneous	-	-	-	-	-	-
33			**Equipment**	67,632	-	2,029	69,661	34,831	104,492
34									
35			**System Maintenance**						
36	36701-30	367.00	Transmission - Leakage	42,670	-	1,280	43,950	21,975	65,925
37	37601-30	376.00	Steel Mains - Leakage	422,796	-	12,684	435,479	217,740	653,219
38	37602-30	376.00	Plastic Mains - Leakage	221,320	-	6,640	227,960	113,980	341,940
39	38000-30	380.00	Services - Leakage	474,415	-	14,232	488,648	244,324	732,971
40	38200-30	382.00	Meter Loops - Leakage	7,171	-	215	7,387	3,693	11,080
41	3xxxx-98	Various	Retirements	458,222	-	13,747	471,969	235,984	707,953
42			**System Maintenance**	1,626,594	-	48,798	1,675,392	837,696	2,513,088
43									
44			**System Improvements**						
45	33400-20	334.00	Field Measurement & Regulation	-	-	-	-	-	-
46	35100-20	351.20	Storage Structures and Improvements	-	-	-	-	-	-
47	35200-20	352.01	Wells	-	-	-	-	-	-
48	35200-40	352.02	Wells	-	-	-	-	-	-
49	35300-10	353.10	Field Lines	36,591	-	1,098	37,689	18,844	56,533
50	35300-20	353.20	Gathering Lines	8,551	-	257	8,808	4,404	13,212
51	35400-20	354.00	Compressor Station Equipment	-	-	-	-	-	-
52	35500-20	355.00	Measuring and Regulating	-	-	-	-	-	-
53	35600-20	356.00	Purification Equipment	-	-	-	-	-	-
54	36510-20	365.10	Land and Land Rights	-	-	-	-	-	-
55	36600-20	366.20	Structures and Improvements	-	-	-	-	-	-
56	36700-40	367.00	Transmission Mains - Cathodic Protection	4,356	-	131	4,487	2,243	6,730
57	36701-20	367.00	Transmission Mains - System Improvements	13,591	-	408	13,999	6,999	20,998
58	36900-20	369.10	Measurement & Regulation Stations	8,547	-	256	8,803	4,402	13,205
59	37500-20	375.10	Structures - Public Improvements	-	-	-	-	-	-
60	37600-40	376.00	Mains - Cathodic Protection	102,551	-	3,077	105,627	52,814	158,441
61	37600-69	376.00	Mapping Conversion	143,428	-	4,303	147,730	73,865	221,595
62	37600-82	376.00	Aid-in-Construction	-	-	-	-	-	-
63	37601-20	376.00	Steel System Improvements	518,103	-	15,543	533,646	266,823	800,469
64	37602-20	376.00	Plastic System Improvements	49,160	-	1,475	50,635	25,317	75,952
65	37800-20	378.00	Measurement & Regulation - System Improvements	195,061	-	5,852	200,913	100,457	301,370
66	37900-20	379.00	Measurement & Regulation - Equipment	33,705	-	1,011	34,717	17,358	52,075
67	38000-20	380.00	Services - System Improvements	-	-	-	-	-	-
68	38100-20	381.00	Meters - System Improvements	-	-	-	-	-	-
69	38200-20	382.00	Meter Loops - System Improvements	182,817	-	5,485	188,302	94,151	282,452
70	38300-20	383.00	House Regulators - System Improvements	-	-	-	-	-	-
71	38500-20	385.00	Industrial Measurement & Regulation - System Impr.	140,559	-	4,217	144,776	72,388	217,164
72	3xxxx-98	Various	Public Works Reimbursements	(273,343)	-	(8,200)	(281,543)	(140,771)	(422,314)
73			**System Improvements**	1,163,678	-	34,910	1,198,588	599,294	1,797,882
74									
75			**Growth**						
76									
77	36701-10	367.00	Steel Transmission Mains	-	-	-	-	-	-
78	36900-10	369.00	Measurement & Regulation Stations	-	-	-	-	-	-
79	37600-81	376.00	Forfeitures	(401,700)	-	(12,051)	(413,751)	(206,876)	(620,627)
80	37601-10	376.00	Steel Revenue Mains	88,803	-	2,664	91,467	45,733	137,200
81	37602-10	376.00	Plastic Revenue Mains	1,436,084	-	43,083	1,479,167	739,583	2,218,750
82	37800-10	378.00	Measurement & Regulation - Revenue	11,978	-	359	12,337	6,168	18,505
83	37900-10	379.00	Measurement & Regulation - City Gate	70,019	-	2,101	72,120	36,060	108,180
84	38000-10	380.00	Services - Revenue	1,470,420	-	44,113	1,514,533	757,266	2,271,799
85	38100-10	381.00	Meters - Revenue	509,689	-	15,291	524,980	262,490	787,470
86	38200-10	382.00	Meter Loops - Revenue	319,277	-	9,578	328,855	164,428	493,283
87	38300-10	383.00	House Regulators - Revenue	113,022	-	3,391	116,413	58,206	174,619
88	38500-10	385.00	Industrial Measurement & Regulation - Revenue	-	-	-	-	-	-
89			**Growth**	3,617,592	-	108,528	3,726,120	1,863,060	5,589,179
90									
91			**Total WKG**	$ 6,524,276	$ -	$ 195,728	$ 6,720,004	$ 3,360,002	$ 10,080,006

WESTERN KENTUCKY GAS
Capital Budget Forecast and Test Year Calculation

Projected Overheads				50.000%
Projected Increase In Maintenance & Imporvements				0.000%
.Projected Price Increases				3.000%

Line #	Budg Stat #	Acct #	Budget Category	Fiscal Year 2003 2003 w/o O/H	Projects	Inflation	Direct Costs	O/H	2003
1			**Vehicles**						
2	39200	392.00	Transportation	-	-	-	-	-	-
3			**Vehicles**	-	-	-	-	-	-
4									
5			**MIS**						
6	3990x	399.00	Office Equipment	-	-	-	-	-	-
7	39906	399.86	PC Hardware	39,316	-	1,179	40,496	20,248	60,744
8	39907	399.87	PC Software	10,927	-	328	11,255	5,628	16,883
9	39908	399.88	Application Software	-	-	-	-	-	-
10			**MIS**	50,244	-	1,507	51,751	25,875	77,626
11									
12			**Equipment**						
13	37000	n/a	Communication Equipment - Transmission	-	-	-	-	-	-
14	37100	n/a	Other Equipment - Storage	-	-	-	-	-	-
15	38700	384.00	Other Equipment	2,459	-	74	2,532	1,266	3,799
16	39000	390.00	Structures and Improvements	-	-	-	-	-	-
17	39003	390.03	Improvements	-	-	-	-	-	-
18	39004	390.04	Air Conditioning	-	-	-	-	-	-
19	39009	390.09	Improvements-Leased Premises	10,927	-	328	11,255	5,628	16,883
20	39100	391.83	Office Furniture	-	-	-	-	-	-
21	39103	391.00	Office Machines	1,639	-	49	1,688	844	2,532
22	39300	n/a	Stores Equipment	-	-	-	-	-	-
23	39400	394.77	Tools, Shop & Equipment	4,371	-	131	4,502	2,251	6,753
24	39600	n/a	Power Operated Equipment	-	-	-	-	-	-
25	39603	396.93	Ditchers	-	-	-	-	-	-
26	39604	396.94	Backhoes	-	-	-	-	-	-
27	39605	396.95	Welders	-	-	-	-	-	-
28	39700	397.00	Communications - Telephones	43,709	-	1,311	45,020	22,510	67,531
29	39701	397.20	Communications - Mobile Radios	6,556	-	197	6,753	3,377	10,130
30	39702	397.20	Communications - Fixed Radios	-	-	-	-	-	-
31	39705	397.22	Communications - Telemetering	-	-	-	-	-	-
32	39800	398.00	Miscellaneous	-	-	-	-	-	-
33			**Equipment**	69,661	-	2,090	71,751	35,876	107,627
34									
35			**System Maintenance**						
36	36701-30	367.00	Transmission - Leakage	43,950	-	1,318	45,268	22,634	67,902
37	37601-30	376.00	Steel Mains - Leakage	435,479	-	13,064	448,544	224,272	672,816
38	37602-30	376.00	Plastic Mains - Leakage	227,960	-	6,839	234,799	117,399	352,198
39	38000-30	380.00	Services - Leakage	488,648	-	14,659	503,307	251,654	754,961
40	38200-30	382.00	Meter Loops - Leakage	7,387	-	222	7,608	3,804	11,412
41	3xxxx-98	Various	Retirements	471,969	-	14,159	486,128	243,064	729,192
42			**System Maintenance**	1,675,392	-	50,262	1,725,654	862,827	2,588,480
43									
44			**System Improvements**						
45	33400-20	334.00	Field Measurement & Regulation	-	-	-	-	-	-
46	35100-20	351.20	Storage Structures and Improvements	-	-	-	-	-	-
47	35200-20	352.01	Wells	-	-	-	-	-	-
48	35200-40	352.02	Wells	-	-	-	-	-	-
49	35300-10	353.10	Field Lines	37,689	-	1,131	38,820	19,410	58,229
50	35300-20	353.20	Gathering Lines	8,808	-	264	9,072	4,536	13,608
51	35400-20	354.00	Compressor Station Equipment	-	-	-	-	-	-
52	35500-20	355.00	Measuring and Regulating	-	-	-	-	-	-
53	35600-20	356.00	Purification Equipment	-	-	-	-	-	-
54	36510-20	365.10	Land and Land Rights	-	-	-	-	-	-
55	36600-20	366.20	Structures and Improvements	-	-	-	-	-	-
56	36700-40	367.00	Transmission Mains - Cathodic Protection	4,487	-	135	4,621	2,311	6,932
57	36701-20	367.00	Transmission Mains - System Improvements	13,999	-	420	14,419	7,209	21,628
58	36900-20	369.10	Measurement & Regulation Stations	8,803	-	264	9,067	4,534	13,601
59	37500-20	375.10	Structures - Public Improvements	-	-	-	-	-	-
60	37600-40	376.00	Mains - Cathodic Protection	105,627	-	3,169	108,796	54,398	163,194
61	37600-69	376.00	Mapping Conversion	147,730	-	4,432	152,162	76,081	228,243
62	37600-82	376.00	Aid-In-Construction	-	-	-	-	-	-
63	37601-20	376.00	Steel System Improvements	533,646	-	16,009	549,656	274,828	824,483
64	37602-20	376.00	Plastic System Improvements	50,635	-	1,519	52,154	26,077	78,230
65	37800-20	378.00	Measurement & Regulation - System Improvements	200,913	-	6,027	206,941	103,470	310,411
66	37900-20	379.00	Measurement & Regulation - Equipment	34,717	-	1,041	35,758	17,879	53,637
67	38000-20	380.00	Services - System Improvements	-	-	-	-	-	-
68	38100-20	381.00	Meters - System Improvements	-	-	-	-	-	-
69	38200-20	382.00	Meter Loops - System Improvements	188,302	-	5,649	193,951	96,975	290,926
70	38300-20	383.00	House Regulators - System Improvements	-	-	-	-	-	-
71	38500-20	385.00	Industrial Measurement & Regulation - System Impr.	144,776	-	4,343	149,119	74,559	223,678
72	3xxxx-98	Various	Public Works Reimbursements	(281,543)	-	(8,446)	(289,989)	(144,995)	(434,984)
73			**System Improvements**	1,198,588	-	35,958	1,234,545	617,273	1,851,818
74									
75			**Growth**						
76									
77	36701-10	367.00	Steel Transmission Mains	-	-	-	-	-	-
78	36900-10	369.00	Measurement & Regulation Stations	-	-	-	-	-	-
79	37600-81	376.00	Forfeitures	(413,751)	-	(12,413)	(426,164)	(213,082)	(639,245)
80	37601-10	376.00	Steel Revenue Mains	91,467	-	2,744	94,211	47,105	141,316
81	37602-10	376.00	Plastic Revenue Mains	1,479,167	-	44,375	1,523,542	761,771	2,285,312
82	37800-10	378.00	Measurement & Regulation - Revenue	12,337	-	370	12,707	6,353	19,060
83	37900-10	379.00	Measurement & Regulation - City Gate	72,120	-	2,164	74,284	37,142	111,425
84	38000-10	380.00	Services - Revenue	1,514,533	-	45,436	1,559,969	779,984	2,339,953
85	38100-10	381.00	Meters - Revenue	524,980	-	15,749	540,729	270,365	811,094
86	38200-10	382.00	Meter Loops - Revenue	328,855	-	9,866	338,721	169,360	508,081
87	38300-10	383.00	House Regulators - Revenue	116,413	-	3,492	119,905	59,952	179,857
88	38500-10	385.00	Industrial Measurement & Regulation - Revenue	-	-	-	-	-	-
89			**Growth**	3,726,120	-	111,784	3,837,903	1,918,952	5,756,855
90									
91			**Total WKG**	$ 6,720,004	$ -	$ 201,600	$ 6,921,604	$ 3,460,802	$ 10,382,406

Exhibit DHD-2
Page 1 of 8

WESTERN KENTUCKY GAS COMPANY
Special Service Charge Analysis

Line No.	Description	Work Codes	Total Orders Charged	Average Time To Complete (Minutes)	Service Technician Salary & Load Per Minute ($0.30)	Office Salary & Load Per Minute ($0.03)	Supervision Salary & Load Per Minute ($0.06)	Total Salary Load Per Order ($0.39)	Travel Cost Between Orders ($5.82 per order)	Service Cost Per Order	Preparation and Processing of Order	Total Cost To Perform	Current Rates (Business Hours)	Current Revenue if all done during Business Hours	Proposed Rates (Business Hours)	Proposed Rates (After Hours) [1]	Proposed Revenue if all done during Business Hours	Increase in Revenue if all done during Business Hours
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(14)	(15)	(16)
1	Meter Set	100	2,200	48	$ 14.74	$ 1.34	$ 2.97	$ 19.04	$ 5.82	$ 24.87	$2.53	$ 27.40	$ 28.00	$ 61,600.00	$28.00	$35.00	$61,600.00	$0.00
2	Turn On	120/123	15,500	30	$ 9.03	$ 0.82	$ 1.82	$ 11.67	$ 5.82	$ 17.49	$2.53	$ 20.02	$ 18.00	$ 279,000.00	$20.00	$25.00	$310,000.00	$31,000.00
2A	Turn On	120/123	500	30	$ 9.03	$ 0.82	$ 1.82	$ 11.67	$ 5.82	$ 17.49	$2.53	$ 33.53	$ 18.00	$ 9,000.00	$34.00	$40.00	$17,000.00	$8,000.00
	Turn Off for Non-Pay	913	1,000	13	$ 3.98	$ 0.36	$ 0.80	$ 5.15	$ 5.82	$ 10.97	$2.53							
3	Read	121	24,000	9	$ 2.82	$ 0.26	$ 0.57	$ 3.64	$ 5.82	$ 9.46	$2.53	$ 11.99	$ 10.00	$ 240,000.00	$12.00	$14.00	$288,000.00	$48,000.00
4	Seasonal Turn On	122	60	29	$ 8.88	$ 0.80	$ 1.79	$ 11.47	$ 5.82	$ 17.29	$2.53	$ 36.21	$ 25.00	$ 1,500.00	$65.00	$73.00	$3,900.00	$2,400.00
	Seasonal Turn Off	911	60	20	$ 6.22	$ 0.56	$ 1.25	$ 8.03	$ 5.82	$ 13.85	$2.53							
														$ 591,100.00			$680,500.00	$89,400.00

[1] The after hours rate is calculated using 1.5 times column (5), Service Technician Salary & Load, plus the remaining charges.

WESTERN KENTUCKY GAS COMPANY
Computation of Customer Service Payroll Loading
WKG Field

Line No.	Description	All Field Service Personnel
	(1)	(2)
1	Fiscal 1998 Total Yearly Salary [1]	$2,134,024
2	Times Benefits and Payroll Tax Loading Factor	1.3
3	Fiscal 1998 Avg. Monthly Salary with Benefits and Payroll Tax Loading	$2,774,231.46
4	Divided by Number of Employees	73
5	Average Salery per Employee with benefits	$38,003.17
6	Divided by Working Hours in a Year	2,080
7	Cost per Hour	$18.27
8	Divided by 60 Minutes per Hour	60
9	Employee Cost per Minute	$0.30

[1] Salaries adjusted to only include time charged to NARUC accounts for service work
90% of Service Techs salary charged to service.

WESTERN KENTUCKY GAS COMPANY
Computation of Customer Service Payroll Loading
WKG Field Office

Line No.	Description (1)	Operations Assistants (2)
1	Fiscal 1998 Total Yearly Salary [1]	$50,324
2	Times Benefits and Payroll Tax Loading Factor	1.3
3	Fiscal 1998 Avg. Monthly Salary with Benefits and Payroll Tax Loading	$65,421.72
4	Divided by Number of Employees	19
5	Average Salery per Employee with benefits	$3,443.25
6	Divided by Working Hours in a Year	2,080
7	Cost per Hour	$1.66
8	Divided by 60 Minutes per Hour	60
9	Employee Cost per Minute	$0.03

[1] Salaries adjusted to only include time charged to NARUC accounts for service work
10% of Office Assistants salary charged to service.

WESTERN KENTUCKY GAS COMPANY
Computation of Customer Service Payroll Loading
WKG Supervision

Line No.	Description	Supervisors
	(1)	(2)
1	Fiscal 1998 Total Yearly Salary [1]	$123,473
2	Times Benefits and Payroll Tax Loading Factor	1.3
3	Fiscal 1998 Avg. Monthly Salary with Benefits and Payroll Tax Loading	$160,514.77
4	Divided by Number of Employees	21
5	Average Salery per Employee with benefits	$7,643.56
6	Divided by Working Hours in a Year	2,080
7	Cost per Hour	$3.67
8	Divided by 60 Minutes per Hour	60
9	Employee Cost per Minute	$0.06

[1] Salaries adjusted to only include time charged to NARUC accounts for service work
10% of all Supervision charged to service.

WESTERN KENTUCKY GAS COMPANY
TRAVEL COST
BETWEEN ORDERS

Line No.	Description (a)	Cost per Order (b)
1	Estimated Average Speed (Miles per Hour)	35
2	Minutes per Mile [1]	1.71
3	Total Number of Service Miles Driven	1059499
4	Total Number of Service Orders Worked	152321
5	Miles Between Orders	7.0
6	Minutes Between Orders	11.9
7	Loaded Salary per Minute	$0.30
8	Employee Travel Cost per Order	$3.63
9	Vehicle Cost per Mile [2]	0.315
10	Vehicle Cost per Order	$2.19
11	Total Cost to Arrive	**$5.82**

[1] 60 Minutes Divided by 35 Mph

[2] IRS Rate for Expenses of Operating a Vehicle

WESTERN KENTUCKY GAS COMPANY
Computation of Customer Service Payroll Loading
Atmos Customer Support Center

Line No.	Description	Amount Allocated from CSC
	(1)	(2)
1	Annualized Allocated Cost	$403,525
2	Divided by Working Hours in a Year	8,760
3	Cost per Hour	$46.06
4	Divided by 60 Minutes per Hour	60
5	Cost per Minute	$0.77
6	Divided by 60 Seconds per Minute	60
7	Cost per Second	$0.012796
8	Average Talk Time in Seconds	198
9	Average Cost per Call/Transaction	$2.53

[1] The allocated dollars shown are 33% of the total, to reflect the percenatge of service charge orders to total orders.

[8] The average time to handle the call was 3:18 from the Aurthor Anderson study.

Fiscal Year 98(October 97 - September 98)
Taken from SOO150 Phase 3

Number of Orders Worked less Orders Worked at No Charge

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Yearly Total
meter set	100	634	519	326	190	138	165	105	93	106	84	87	147	2594
meter set	104	26	19	8	15	17	9	12	15	20	13	14	12	180
turn on	120	3072	1952	941	742	676	759	642	677	832	840	1013	1140	13286
read only	121	1630	1824	2203	2192	2065	2106	1434	1333	1556	1537	1632	1443	20955
turn on	122	13	2	1	2	2	2	5	4	7	4	6	10	58
turn on NP	123	220	91	124	409	559	322	365	56	1	30	138	228	2543
turn on Trf	130	185	138	58	61	63	80	122	141	143	137	144	151	1423
read only	131	231	202	215	229	276	280	271	253	252	225	230	250	2914
turn off cust	911	11	2	1	4	4	2	28	41	40	7	8	10	158
turn off NP	913	260	126	156	737	924	672	1028	72	33	116	896	1001	6021
												Total		50132

911 & 913 are at no charge, cost of service should be included in associated turn on

Calendar Year (March 98 - February 99)
Taken from SOO100 Phase 3

Average time to complete work orders

		Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Average	Avg. time + 2 min.
meter set	100	46	45	50	45	48	44	43	47	47	45	49	48	46	48
meter set	104	38	44	45	40	48	56	42	40	43	40	45	41	44	46
turn on	120	28	28	28	27	28	27	28	28	28	28	27	27	28	30
read only	121	8	7	7	7	7	8	7	7	8	7	7	7	7	9
turn on	122	43	38	20	21	28	17	22	33	32	26	27	19	27	29
turn on NP	123	27	29	28	28	30	29	28	28	27	27	28	28	28	30
turn on Trf	130	30	31	27	29	28	27	29	27	29	28	27	30	29	31
read only	131	7	6	7	6	7	7	6	6	7	7	7	6	7	9
turn off cust	911	51	20	13	14	13	16	17	23	9	13	22	10	18	20
turn off NP	913	12	11	10	10	12	7	10	10	13	16	12	10	11	13

WESTERN KENTUCKY GAS COMPANY
Returned Check Charge
Survey of Banks - April 1, 1999

Bank	CHARGE
Bank One Kentucky, NA	$ 25.00
Beaver Dam Deposit Bank	$ 20.00
Independence Bank	$ 20.00
Fifth Third Bank	$ 27.00
First Security Bank of Owensboro	$ 10.00
National City Bank	$ 25.00
Owensboro National Bank	$ 25.00
Star Bank	$ 27.50
Average Return Check Charge	**$ 22.44**

COMPARISON COST OF PURCHASING AND INSTALLING EFM EQUIPMENT

TYPE OF INSTALLATION	1998 COST
ONE PD/TURBINE/ROTARY	$6,142
ONE ORIFICE RUN	$10,627
TWO PD/TURBINE/ROTARY METERS	$12,917
ONE ORIFICE AND ONE PD METER	$13,390
TWO ORIFICE METERS	$12,129

WESTERN KENTUCKY GAS CO.

EFM INSTALLATION
MERCURY MINI AT WITH MERCURY MODEM

ITEM			COST
MERCURY MINI AT	REMOTE MOUNT W/PULSER		
	AC POWERED CORRECTOR		
	ALKALINE BATTERY W/RECEPTACLE (BACKUP)		
	THERMOWELL		
	SCI BOARD		
	AC/DC CONVERTER		$1,874.00
MERCURY MODEM			
	NEMA 4X ENCLOSURE		
	BATTERY BACKUP		
	AC/DC CONVERTER		$620.00
TRANSIENT, SURGE & GROUNDING PROTECTION (2)			$180.00
MISC. TUBING, VALVES, FITTINGS, WIRE AND CONDUIT			$300.00
LABOR ((18 HRS. LOADED)			$480.00
TRANSPORTATION	(600 MIL AT .31)		$186.00
TAX	6%		$178.44
WKG NSOCCC	34%		$1,298.27
		SUB-TOTAL (CUSTOMER REIMBURSEMENT)	$5,116.71
STORES EXPENSE	45%		$45.00
CORPORATE A&G	19%		$980.72
		SUB-TOTAL (STORE S AND A&G)	$1,025.72
TOTAL COST (WITH CUSTOMER REIMBURSEMENT)			$6,142.43

NOTE: INSTALLATION COSTS OF 120 VAC POWER AND TELEPHONE CIRCUIT ARE NOT INCLUDED.

EFM INSTALLATION - ONE ORIFICE RUN
FISHER ROC 306

11/3/98

ITEM	
FISHER ROC 306	
CMA 7, DC DIAL-UP INTERNAL MODEM	
RPSI1, ROC PAK	
FSA1-1, ANALOG INPUT MODULE (4 TOTAL)	
FSLPM-2, LIGHTNING PROTECTION MODULE (3)	
FSACC-1	
EN-35, ENCLOSURE	
PS 122, POWER SUPPLY	
B121, 30 AMP/HR BATTERY	
	$2,700
(1)-PRESS TRANSDUCER-(ROSEMONT 2088G-1-A-22-1-B4)	$668
(1)-TEMP. TRANSDUCER-(TELMAR 577006 W/THERMOWELL)	$380.00
(3)-TRANSIENT, SURGE & GROUNDING PROTECTION	$333
(1)-DP TRANSDUCER	$760
(1)- AGCO 5 VALVE MANIFOLD	$270
MISC. TUBING, VALVES, FITTINGS, WIRE AND CONDUIT	$250
LABOR- (40 HOURS AT $26.00/HR -LOADED)	$1,040
TRANSPORTATION (600 MI. AT .31 PER MILE)	$186
KY. SALES TAX 6%	$322
W.K.G.- NSOCC (34%)	$2,349
SUB-TOTAL (CUSTOMER REIMBURSEMENT)	$9,258
STORES EXPENSE (45%)	$56
COROPORATE A&G (19%)	$1,313.00
SUB-TOTAL (STORES &A&G	$1,369.00
TOTAL COST - WITH CUSTOMER REIMBURSEMENT	$10,627.00

EFM INSTALLATION - FOR TWO PD/TURBINE/ROTARY METERS
FISHER ROC 312

11/3/98

ITEM	
FISHER ROC 312	
CMA 7, DC DIAL-UP INTERNAL MODEM	
RPSI1, ROC PAK	
FSA1-1, ANALOG INPUT MODULE (4 TOTAL)	
FSLPM-2, LIGHTNING PROTECTION MODULE (6)	
FSACC-1	
EN-35, ENCLOSURE	
PS 122, POWER SUPPLY	
B121, 30 AMP/HR BATTERY	
	$3,049
(2)-PRESS TRANSDUCER-(ROSEMONT 2088G-1-A-22-1-B4)	$1,336
(2)-TEMP. TRANSDUCER-(TELMAR 577006 W/THERMOWELL)	$760.00
(6)-TRANSIENT, SURGE & GROUNDING PROTECTION	$666
(2)-MERCURY MODEL 212 PULSE TRANSMITTERS	$852
MISC. TUBING, VALVES, FITTINGS, WIRE AND CONDUIT	$250
LABOR- (32 HOURS AT $26.00/HR -LOADED)	$832
TRANSPORTATION (600 MI. AT .31 PER MILE)	$186
KY. SALES TAX 6%	$475
W.K.G.- NSOCC (34%)	$2,858
SUB-TOTAL (CUSTOMER REIMBURSEMENT)	$11,264
STORES EXPENSE (45%)	$56
COROPORATE A&G (19%)	$1,597.00
SUB-TOTAL (STORES &A&G	$1,653.00
TOTAL COST - WITH CUSTOMER REIMBURSEMENT	$12,917.00

EFM INSTALLATION - ONE ORIFICE RUN & ONE PD/TURBINE/ROTARY METER
FISHER ROC 312

ITEM	11/3/98
FISHER ROC 312	
CMA 7, DC DIAL-UP INTERNAL MODEM	
RPSI1, ROC PAK	
FSA1-1, ANALOG INPUT MODULE (5 TOTAL)	
FSLPM-2, LIGHTNING PROTECTION MODULE (6)	
FSACC-1	
EN-35, ENCLOSURE	
PS 122, POWER SUPPLY	
B121, 30 AMP/HR BATTERY	
	$3,221
(2)-PRESS TRANSDUCER-(ROSEMONT 2088G-1-A-22-1-B4)	$1,360
(1)-TEMP. TRANSDUCER-(TELMAR 577006 W/THERMOWELL)	$380.00
(6)-TRANSIENT, SURGE & GROUNDING PROTECTION	$666
(1)-DP TRANSDUCER	$760
(1)- AGCO 5 VALVE MANIFOLD	$270
(1)-MERCURY 212 PULSER	$426
MISC. TUBING, VALVES, FITTINGS, WIRE AND CONDUIT	$400
LABOR- (40 HOURS AT $26.00/HR -LOADED)	$1,040
TRANSPORTATION (600 MI. AT .31 PER MILE)	$186
KY. SALES TAX 6%	$428
W.K.G.- NSOCC (34%)	$2,696
SUB-TOTAL (CUSTOMER REIMBURSEMENT)	$11,833
STORES EXPENSE (45%)	$90
COROPORATE A&G (19%)	$1,467.00
SUB-TOTAL (STORES &A&G	$1,557.00
TOTAL COST - WITH CUSTOMER REIMBURSEMENT	$13,390.00

EFM INSTALLATION - TWO ORIFICE RUN
FISHER ROC 312

	11/3/98
ITEM	
FISHER ROC 312	
CMA 7, DC DIAL-UP INTERNAL MODEM	
RPSI1, ROC PAK	
FSA1-1, ANALOG INPUT MODULE (4 TOTAL)	
FSLPM-2, LIGHTNING PROTECTION MODULE (4)	
FSACC-1	
EN-35, ENCLOSURE	
PS 122, POWER SUPPLY	
B121, 30 AMP/HR BATTERY	
	$2,815
(1)-PRESS TRANSDUCER-(ROSEMONT 2088G-1-A-22-1-B4)	$668
(1)-TEMP. TRANSDUCER-(TELMAR 577006 W/THERMOWELL)	$380.00
(4)-TRANSIENT, SURGE & GROUNDING PROTECTION	$444
(2)-DP TRANSDUCER	$1,420
(2)- AGCO 5 VALVE MANIFOLD	$540
MISC. TUBING, VALVES, FITTINGS, WIRE AND CONDUIT	$400
LABOR- (40 HOURS AT $26.00/HR -LOADED)	$1,040
TRANSPORTATION (600 MI. AT .31 PER MILE)	$186
KY. SALES TAX 6%	$400
W.K.G.- NSOCC (34%)	$2,403
SUB-TOTAL (CUSTOMER REIMBURSEMENT)	$10,696
STORES EXPENSE (45%)	$90
COROPORATE A&G (19%)	$1,343.00
SUB-TOTAL (STORES &A&G	$1,433.00
TOTAL COST - WITH CUSTOMER REIMBURSEMENT	$12,129.00

9

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	)	
RATE APPLICATION BY	)	**Case No. 99-070**
WESTERN KENTUCKY GAS COMPANY	)	

TESTIMONY OF DONALD P. BURMAN

Q. Please state you name, business address and position.

A. My name is Donald P. Burman, my business address is 5430 LBJ Freeway, Dallas, Texas 75240. I am employed by Atmos Energy Corporation ("Atmos") as Assistant Controller. Atmos is a local distribution company, which serves over 1,000,000 gas consumers in twelve states. The Kentucky LDC operations are designated as Western Kentucky Gas Company ("Western " or "WKG").

Q. Please state your education and working experience.

A. I received a Bachelor of Science in Business Administration degree from Drake University. I am a certified public accountant in the states of Texas and Colorado.

I was appointed to my present position in December 1998. Prior to that time I was Treasurer since February 1997 and Assistant Treasurer since December 1995. Previously, I was Vice President and Controller of the Greeley Gas division. I joined Greeley Gas in 1976, after spending nine years with Arthur Young & Company (currently Ernst & Young LLP).

I am a member of American Institute of Certified Public Accountants and the Texas and Colorado Societies of Certified Public Accountants.

Q. What are your duties as Assistant Controller of Atmos?

A. As Assistant Controller of Atmos I am responsible for the presentation and maintenance of the accounting and financial records of the company, customer billing, gas purchase accounting, payroll accounting, accounts payable, accounting systems and financial reporting.

The Director of Utility Accounting Services, the Director of Gas Accounting Services and the Director of Financial Reporting and Payroll Services, all of who report to me, assist me in these tasks.

Q. Please briefly summarize the scope of your testimony.

A. My testimony sponsors all of the rate application amounts from the books and records of the company. In that regard, I am sponsoring the following filing requirements:

FR10(1)(b)2 Statement that annual reports are on file with the Commission;

FR10(9)(j) The prospectus of the most recent debenture offering;

FR10(9)(k) Calendar year 1998 FERC Form 2;

FR10(9)(l) Annual reports to shareholders for the preceding five years;

FR10(9)(m) Current chart of accounts;

FR10(9)(n) Monthly managerial reports providing financial results of operations for the twelve months ended March 31, 1999;

FR10(9)(p) The Securities and Exchange Commission filings on Form 10-K and Form 8-K for the prior two years and the Form 10-Q for the past six quarters;

FR10(9)(q) Independent auditors annual opinion report;

FR10(9)(r) Quarterly reports to stockholders for the most recent five quarters; and

FR10(9)(s) Summary of the most recent depreciation study.

Q. Do you adopt the Filing Requirements and Exhibits you just identified and do you make them part of your testimony?

A. Yes.

Filing Exhibits

Q. Are Western's annual reports on file with the Kentucky Public Service Commission? (Filing Requirement FR10(1)(b)2)

A. Yes. Western's annual reports including the annual report filed under the FERC Form 2 format for the calendar year 1998 are on file with the Kentucky Public Service Commission. The 1998 annual report is the most recent one to be filed with the Commission. Additional reporting to the Commission will be discussed later in my direct testimony.

Q. Please describe FR10(9)(j).

A. Filing Exhibit FR10(9)(j) is a copy of the prospectus of the Company's $150 million, 6 ¾% Debenture offering, which was completed in July 1998. The purpose of this offering was to convert short-term debt to long-term debt to take advantage of the lower rates on 30-year debt.

Q. Please explain FR10(9)(k)

A. Filing Exhibit FR10(9)(k) is the Company's annual FERC Form 2 report for the calendar year 1998 filed with the Commission. This report is the most recent report filing with the Commission.

Q. Please explain FR10(9)(l).

A. Filing Exhibit FR10(9)(l) is the Company's Annual Report to Shareholders for the preceding five years.

Q. Please explain FR10(9)(m).

A. Filing Exhibit FR10(9)(m) is the current chart of accounts for the Company which is more detailed than the Uniform Chart of Accounts prescribed by the Commission. The chart of accounts includes NARUC account number, additional detail account numbers for the Company and a description of each account.

Q. Please explain FR10(9)(n).

A. Filing Exhibit FR10(9)(n) includes monthly managerial reports providing results of operations for the twelve months ended March 31, 1999. These reports provide monthly and year-to-date comparisons to the Company's latest budget.

Q. Please explain FR10(9)(p).

A. Filing Exhibit FR10(9)(p) includes a copy of each of the Securities and Exchange Commission filings on Forms 10-K and Form 8-K for the prior two years and Form 10-Q for the past six quarters.

Q. Please explain FR10(9)(q).

A. Filing Exhibit FR10(9)(q) contains a statement that there have not been any written communications from the independent auditors which indicates the existence of a material weakness in the Company's internal controls. The independent auditor's annual opinion is included in the Company's Annual Report to Shareholder's and is included as part of Exhibit FR10(9)(l). The Company's independent auditing firm is Ernst & Young, LLP.

Q. Please explain FR10(9)(r).

A. Filing Exhibit FR10(9)(r) is the Company's Quarterly Report to Shareholders for the most recent five quarters.

Q. Please explain FR10(9)(s).

A. Filing Exhibit FR10(9)(s) is the most recent study of the depreciation rates used by Western. This study was conducted by Deloitte & Touche LLP and will be discussed later in my testimony.

Books and Records

Q. Are the books and records of the Company prepared by you or under your supervision?

A. Yes. The books and records of Atmos and its operating business units are prepared and maintained under my supervision

Q. Are the books and records of the Company audited by an independent auditing firm?

A. Yes. The independent accounting firm of Ernst & Young LLP has audited the financial statements of Atmos Energy Corporation for the year ended September 30, 1998. Their opinion regarding these financial statements is included in Filing Exhibit FR10(9)(l).

Q. Are the Company's annual reports on file with the Kentucky Public Service Commission?

A. Yes. The Company has filed monthly financial statements with the Commission and has also filed annual reports on FERC Form 2. The most recent FERC Form 2 on file with the Commission is for the calendar year 1998.

Depreciation Study

Q. Has the Company filed a depreciation study with the Commission?

A. Yes. Filing Exhibit FR10(9)(s) contains the most recent depreciation study which has been prepared for Western. This study was performed by the firm of Deloitte & Touche LLP and was completed in March 1999. In our last case, the Commission ordered that a depreciation study be made and filed in our next rate case.

Q. What was the purpose of this depreciation study?

A. The purpose of the depreciation study was to ensure that the depreciation cost is borne by the customers that benefit from the costs to be incurred and not by some earlier or later generation of customers. As part of a depreciation study, the depreciation component is increased by the cost to retire an asset and decreased by any salvage applicable to the disposal of the asset.

Q. What was the source of the data used in the depreciation study?

A. The data used in the study was obtained from the information contained in the Company's books and records. The data required for the study involved each depreciable property group.

Q. Did the results of the depreciation study recommend any changes to Western's current depreciation rates?

A. No. Although there are recommended changes in the rates of the various components with the fixed asset group, the overall rate remained at 3.71%.

Q. Have the rates supported by the depreciation study been included on the books and records of the Company?

A. Since the depreciation study was not completed until after the close of the Company's fiscal year the change in rates have been shown as a proforma adjustment in the accompanying financial statements.

<u>Pension Expense</u>

Q. Please discuss Western's accounting for pension expense.

A. Western follows Financial Accounting Standard Board (FASB) Statement No. 87, "Employers' Accounting for Pensions" for its accounting of pension expense. FASB 87 does not affect Western's pension plan assets, its obligations, or its funding. FASB 87 does, however, affect the manner in which Western recognizes the timing and accrual of pension expense for accounting purposes and the recognition of pension assets and obligations on its balance sheet.

Q. What level of pension expense did Western experience in the base period of this rate case?

A. Western experienced a net credit to book pension expense of $2,032,245 during the base period primarily due to an overfunded position of the plan resulting from: (1) a reduction in pension obligations due to a reduction in the number of eligible employees and (2) from the performance of pension assets.

Q. What level of pension expense did Western budget for the test year in this case?

A. Western budgeted a net credit of $853,000 for pension expense.

Q. Does this credit to expense mean that Western receives cash from the plan?

A. No. Western's pension assets are held in a trust for the benefit of Western's employees. Western will not and, under pension laws, cannot remove cash from the pension plan when the plan is overfunded.

Q. Please explain Western's test period adjustment to pension expense.

A. Western made an adjustment to test period expense to set its ratemaking pension expense to zero. This adjustment was made so that Western will not flow cash back to ratepayers in the form of reduced rates, as Western will receive no cash distribution from its pension plan. By setting ratemaking pension expense to zero, Western's ratepayers will receive benefit from the plan's overfunded position by not having to fund the plan through rates during the period when rates set in this proceeding are in effect, regardless of Western's book accounting pension expense during that time period.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 99-070
WESTERN KENTUCKY GAS COMPANY	)	

CERTIFICATE

I, Donald P. Burman, have answered the foregoing questions propounded to me in the above-enumerated Docket. These answers and exhibits constitute and I hereby adopt, under oath, these answers as my prefiled direct testimony in said case, which is true and correct to the best of my information and belief.

Donald P. Burman
Assistant Controller
Atmos Energy Corporation

STATE OF TEXAS)
) S.S.
COUNTY OF DALLAS)

SUBSCRIBED AND SWORN TO before me by Donald P. Burman, on this 6th day of May, 1999.

SHARON L. QUINN
Notary Public
State of Texas
Comm. Expires 3-06-2003

Sharon L. Quinn
Notary Public
State of Texas.

My Commission expires: May 6, 2003.

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BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 99-070
WESTERN KENTUCKY GAS COMPANY	)	

TESTIMONY OF JOHN P. REDDY

Q. Please state your name, business affiliation, and business address.

A. My name is John P. Reddy and I am the Vice President and Treasurer of Atmos Energy Corporation ("Atmos" or "the Company"). My business address is 5430 LBJ Freeway, Dallas, Texas.

Q. Please state your education and work experience.

A. I earned a Bachelor of Arts degree in Political Science and Economics from the University of California at Los Angeles in 1975 and an MBA (concentration in Finance) from the University of Southern California in 1979. I worked for Rockwell International as a financial analyst for four years beginning in 1976. In March 1980, I joined Southern California Gas Company in Los Angeles, California as financial administrator in the project finance department. I worked for Southern California Gas and its parent company, Pacific Enterprises, for eighteen years in positions of increasing responsibility in the areas of project finance, cash management, corporate finance, regulatory affairs, gas supply and marketing, and strategic and financial planning. I joined Atmos in August 1998 as Vice President, Corporate Development and assumed my current duties in December 1998.

Q. What are your duties as Treasurer of Atmos?

A. As Treasurer of the Company, I am responsible for the corporate treasury, credit and collections, purchasing, risk management and business insurance functions of the Company. My duties include planning, scheduling and administering the Company's financial requirements, including the sale and issuance of debt and equity securities. In addition to long-term financings, I am responsible for the Company's bank relations and short-term borrowing and investing activities. As a result of these activities, I am in frequent contact with financial institutions, security analysts and commercial and investment bankers.

Q. Have you ever submitted testimony before the Kentucky Public Service Commission?

A. No.

Q. Have you ever testified before any other regulatory body?

A. Yes. I have testified before the California Public Utilities Commission and the Federal Energy Regulatory Commission.

Q. Briefly summarize the scope of your testimony.

A. I will sponsor the proposed debt/equity ratio, the embedded cost of debt, and the specific return on equity component from the range sponsored by Dr. Murry.

Q. Which of the WKG filing requirements are you sponsoring?

A. I am sponsoring the following Filing Requirements:

FR 10(9)(h)11 Capital Structure Requirements; and

FR 10(10)(j) Cost of Capital Summary

Q. Do you adopt these Filing Requirements and make them part of your testimony?

A. Yes.

Q. Mr. Reddy, what is the capital structure that is appropriate for WKG in this proceeding?

A. The appropriate capital structure for each of the Atmos utility operating divisions is equivalent to the consolidated capital structure for Atmos as a whole, since Atmos provides the debt and equity capital for its subsidiary companies. The capital structure that is appropriate for WKG in this proceeding is set forth in my exhibit FR 10(9)(h)11. As shown in that exhibit, long-term debt comprises 40.4%, short-term debt comprises 9.4%, and equity is 50.2% of the Company's 13-month average capital structure for the forward-looking test period.

Q. How does this recommended capital structure compare to the actual capital ratios as of March 30, 1999?

A. Atmos' capital ratios at March 30, 1999 were as follows:

L-T Debt	S-T Debt	Total Debt	Shareholder Equity	Total
$405,636,000[1]	$112,147,000	$517,783,000	$409,931,000	$927,714,000
43.72%	12.09%	55.81%	44.19%	100.00%

[1] Includes current maturities portion of long-term debt.

Q. Please explain why the debt components of Atmos' current capital structure are higher than the capital structure that you believe to be appropriate for this proceeding.

A. Atmos' objective is to maintain a capital structure comprised of approximately 50% shareholder equity and 50% debt. This objective is in line with the average equity ratio of Atmos peer companies of 51% and is consistent with the objective of maintaining an "A" credit rating on Atmos senior debt.

A number of factors combined in 1998 to skew Atmos' capital ratios, producing debt to total capital ratios that were higher than the Company's stated objectives. In July 1998, Atmos issued $150 million of 30-year debentures and in October 1998, the Company commenced a commercial paper program under which it is authorized to issue up to $250 million of commercial paper backed by a committed bank credit facility. These credit facilities were undertaken partly in anticipation of the need to finance costs associated with various service initiatives described in Mr. Gruber's testimony, with the Company's investment in these initiatives totaling approximately $80 million as of September 30, 1998. As explained by Mr. Gruber, these initiatives are composed of a combination of customer service enhancements including a customer call center, a new customer information system on client server architecture, mobile data terminals in service trucks, ITRON electric meter reading technology, a network of third party bill payment centers, and implementation of utility industry best practices.

Other significant capital initiatives in 1998 included Y2K compliance efforts and the implementation of new Oracle based financial and human resources software. Also, in

1997 the Company established a reserve of $20 million ($13 million after-tax) to account for merger and integration costs associated with the United Cities Gas merger that may not ultimately be recovered in customer rates. The effect of this reserve is to reduce retained earnings and, in turn, the equity component of capital structure. Finally, retained earnings have been reduced as a result of the effects of weather that in 1998 was 3% warmer than 1997 (5% warmer than 30-year normals) and which in 1997 was 3% warmer than 1996. Normal weather conditions would have added approximately $3.3 million to retained earnings in 1998 and $3.5 million in 1997.

These factors have all contributed to the higher degree of leverage in Atmos' capital structure when compared to target levels. However, as explained below, the current capital structure is not appropriate for use in setting rates in this proceeding.

Q. What are Atmos' objectives for consolidated capital ratios and how does the Company plan to achieve them?

A. As stated in Atmos 1998 Annual Report to Shareholders, the Company plans to decrease the debt to capitalization ratio to nearer its target range of 50-52% over the next two fiscal years through cash flow generated from operations (reduces external financing requirements); issuance of new common stock under its Direct Stock Purchase Plan (DSPP) and Employee Stock Ownership Plan (ESOP) which in combination add approximately $20 million to shareholder equity annually; recovery in utility rates of costs related to implementing various service improvement initiatives; recovery in rates of merger and integration costs related to the Atmos/United Cities Gas merger (consistent with including merger benefits in reducing the revenue requirement for the Atmos utility divisions); and the possible sale of certain remaining real estate assets. Taken together, these measures will allow the Company to achieve its objective of a 50%/50% debt-to-equity ratio within the forecast period. The Company plans to fund future requirements through internally generated cash flows, credit facilities and its access to the public debt and equity capital markets.

Atmos' five-year financial plan shows that, in the absence of making any sizable acquisitions, the debt to capitalization ratio declines substantially as shown in my Exhibit FR 10(9)(h) 11, page three, and summarized below.

	Fiscal 2000	Fiscal 2001	Fiscal 2002	Fiscal 2003
Long-term Debt	40.2%	38.4%	36.8%	34.6%
Short-term Debt	10.0%	8.6%	6.3%	3.5%
Total Debt	50.2%	47.0%	43.1%	38.1%
Shareholders' Equity	49.8%	53.0%	56.9%	61.9%

The improvement in the capital ratios reflects the following assumptions: adoption of a weather normalization adjustment mechanism ("WNA") for Western Kentucky and a return to normal long-term weather patterns for the other Atmos utility divisions beginning in fiscal year 2000; the issuance of approximately $26 million of new equity in November 1999; raising $20 million of new equity annually under the Company's DSPP and ESOP plans; no significant acquisitions; sufficient levels of cash flow from depreciation to fund ongoing capital spending requirements; and no new long-term debt issues. The Company expects to seek approval of its Board of Directors later this year for the filing of a Universal Shelf Offering with the SEC which, when approved by the SEC and various state regulatory commissions (including the Kentucky PSC), will enable the Company to issue various equity and debt securities to meet its financial objectives.

Q. Please summarize your testimony regarding the appropriate capital structure for use in this proceeding.

A. Although Atmos' capital structure as of March 30, 1999 included approximately 55.8% debt, the measures I have described in my testimony will allow Atmos to achieve its objective of a 50% debt/50% equity ratio early in fiscal year 2000. Therefore, the capital structure that I have proposed is appropriate for use in this proceeding.

Q. What rates do you propose for the rate of return on equity capital and the embedded cost of debt capital in setting rates in this case?

A. I have reviewed the testimony of Dr. Murry and, supported by my own experience and judgment, recommend that the Commission approve a 12.25% return on the equity portion of Atmos' capital structure, adopt 8.06% as the weighted-average cost of long-term debt capital and 6.10% as the cost of short-term debt for the forecast period. These rates of return will permit Western to attract the capital necessary to continue to provide efficient, high quality customer service at the lowest possible cost.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 99-070
WESTERN KENTUCKY GAS COMPANY	)	

CERTIFICATE

I, John P. Reddy, have answered the foregoing questions propounded to me in the above enumerated Docket. These answers and exhibits constitute and I hereby adopt, under oath, these answers as my prefiled direct testimony in said case, which is true and correct to the best of my information and belief.

John P. Reddy

John P. Reddy
Vice President
Atmos Energy Corporation

STATE OF TEXAS)

COUNTY OF DALLAS)

SUBSCRIBED AND SWORN TO before me by John P. Reddy, on this 21st day of April, 1999.

JUDY AMOS
Notary Public
State of Texas
Comm. Exp. Oct. 21, 1999

Judy Amos

Judy Amos
Notary Public
State of Texas

My Commission expires: October 21, 1999

Western Kentucky Gas Company
Case No. 99-070
Capital Structure Summary
Base Year

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Line No.	Atmos Consolidated	9/30/98	10/31/98	11/30/98	12/31/98	1/31/99	2/28/99	3/31/99	4/30/99	5/31/99	6/30/99	7/31/99	8/30/99	9/30/99	13 MO. AVERAGE	13-MO. AVG CAP STRUCT	
1	Shareholders Equity:																
2	Common stock	151,992	152,197	152,598	153,122	153,249	153,364	154,139	154,497	154,855	155,186	155,493	155,789	156,076			
3	Paid in capital	271,637,624	272,821,596	275,210,978	278,173,251	278,952,207	279,590,719	283,061,974	284,781,026	286,500,078	288,219,157	289,938,259	291,657,373	293,376,496			
4	Retained earnings	99,368,877	97,292,171	91,621,540	106,509,126	120,040,472	118,070,884	128,715,184	129,056,486	119,568,760	117,006,082	114,772,404	106,032,352	105,859,994			
5	Total equity	371,158,493	370,265,964	366,985,116	384,835,499	399,145,928	397,814,967	409,931,277	413,992,009	406,223,693	405,380,425	404,866,157	397,845,514	399,392,566	394,449,047	42.7%	Equity
6	Long term debt	456,330,720	453,705,720	413,649,433	408,346,227	407,794,591	405,729,509	405,635,567	405,329,597	399,746,751	399,606,584	398,757,791	397,422,286	395,330,967	411,337,365	44.5%	LT Debt
7	Total capitalization	827,489,213	823,971,684	780,634,549	793,181,726	806,940,519	803,544,476	815,566,844	819,321,606	805,970,444	804,987,009	803,623,948	795,267,800	794,723,532			
8	Short term debt	66,400,000	89,730,500	144,190,110	167,993,587	159,597,825	125,926,367	112,147,281	89,580,325	101,279,650	113,048,328	116,294,005	121,841,683	126,824,361	118,065,694	12.8%	ST Debt
9	Total	893,889,213	913,702,184	924,824,659	961,175,313	966,538,344	929,470,843	927,714,125	908,901,931	907,250,094	918,035,337	919,917,954	917,109,483	921,547,894	923,852,106	100.0%	

ASSUMPTIONS:

1 All numbers are actual through March 1999
2 Assumes a base stock capital growth rate of $20 million per year via various plans
3 1999 monthly Net Income is per monthly budget
4 2000 monthly net income is patterned after 1999 budget
5 Net Income is adjusted monthly for 1) additional short-term interest based on 6% annual rate on $22,000,000 overall Net Income shortfall do to warm weather, 2) reduced short term interest due to any issuance of equity (assumed to pay down ST debt), and 3) additional deprecintion related to various service initiaves.
6 Dividends are adjusted to reflect any new issuance of equity; they are calculated on the monthly ending shares outstanding
7 Assumed div. rate is $1.10 for FY 1999, $1.14 for 2000, and $1.18 for 2001
8 Long-term debt balances are per financial plan, with no additional issuances for acquisitions
9 Short-term debt is per the 5-year financial plan, reduced for equity issuances, increased for Net Income shortfall due to warm weather in 1999, increased for additional dividends related to stock issuances, and increased or decreased for tax-effected change in short term interest (one iteration only)

Western Kentucky Gas Company
Case No. 99-070
Capital Structure Summary
Base Year

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Line No.	Atmos Consolidated	12/31/99	1/31/00	2/29/00	3/31/00	4/30/00	5/31/00	6/30/00	7/31/00	8/31/00	9/30/00	10/31/00	11/30/00	12/31/00	13 MO. AVERAGE	13-MO. AVG CAP STRUCTURE
1	Shareholders Equity:															
2	Common stock	161,270	161,557	161,844	162,131	162,418	162,705	162,992	163,279	163,566	163,853	164,140	164,427	164,714		
3	Paid in capital	324,529,532	326,248,655	327,967,777	329,686,900	331,406,023	333,125,146	334,844,269	336,563,392	338,282,515	340,001,637	341,720,760	343,439,883	345,159,006		
4	Retained earnings	120,217,152	139,702,074	146,177,984	156,548,906	159,485,828	149,161,735	146,407,658	144,005,580	132,403,483	129,342,405	129,617,327	128,654,384	145,519,306		
5	Total equity	444,907,954	466,112,286	474,307,606	486,397,937	491,054,269	482,449,586	481,414,918	480,732,250	470,849,563	469,507,895	471,502,227	472,258,694	490,843,026	475,564,478	50.2% Equity
6	Long term debt	387,523,571	386,994,023	385,924,288	385,827,611	385,731,941	383,519,517	383,374,590	382,890,775	381,550,450	379,454,280	376,854,735	376,781,276	369,632,467	382,004,579	40.4% LT Debt
7	Total capitalization	832,431,525	853,106,309	860,231,894	872,225,548	876,786,210	865,969,103	864,789,508	863,623,025	852,400,013	848,962,175	848,356,962	849,039,970	860,475,493		
8	Short term debt	116,519,195	94,873,273	75,727,351	70,709,429	65,693,507	71,259,584	81,977,662	84,878,740	89,349,818	93,843,896	95,229,974	111,298,718	104,868,796	88,940,765	9.4% ST Debt
9	Total	948,950,720	947,979,581	935,959,244	942,934,977	942,479,717	937,228,688	946,767,171	948,501,766	941,749,831	942,806,071	943,586,936	960,338,689	965,344,289	946,509,822	100.0%

ASSUMPTIONS:

1 All numbers are actual through March 1999
2 Assumes a base stock capital growth rate of $20 million per year via various plans
3 1999 monthly Net Income is per monthly budget
4 2000 monthly net income is patterned after 1999 budget
5 Net income is adjusted monthly for 1) additional short-term interest based on 6% annual rate on $22,000,000 overall Net Income shortfall do to warm weather, 2) reduced short-term interest due to any issuance of equity (assumed to pay down ST debt), and 3) additional depreciation related to various service initiaves.
6 Dividends are adjusted to reflect any new issuance of equity; they are calculated on the monthly ending shares outstanding
7 Assumed div. rate is $1.10 for FY 1999, $1.14 for 2000, and $1.18 for 2001
8 Long term debt balances are per financial plan, with no additional issuances for acquisitions
9 Short term debt is per the 5-year financial plan, reduced for equity issuances, increased for Net Income shortfall due to warm weather in 1999, increased for additional dividends related to stock issuances, and increased or decreased for tax-effected change in short term interest (one iteration only)

Western Kentucky Gas Company
Case No. 99-070
Capital Structure Summary
Base Year

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Atmos Consolidated

	FY 2000	FY 2001	FY 2002	FY 2003
Shareholders Equity:				
Common stock	163,853	163,970	164,109	164,305
Paid in capital	340,001,637	341,056,520	342,415,382	344,496,185
Retained earnings	129,342,405	158,516,405	194,655,405	237,367,405
Total equity	469,507,895	499,736,895	537,234,895	582,027,895
Long term debt	379,454,280	361,886,147	347,970,911	324,885,319
Total capitalization	848,962,175	861,623,042	885,205,807	906,913,214
Short term debt	93,843,896	81,201,896	59,869,896	33,350,896
Total	942,806,071	942,824,938	945,075,703	940,264,110

Ending Capital Structure:				
Equity %	49.8%	53.0%	56.8%	61.9%
LTD %	40.2%	38.4%	36.8%	34.6%
STD %	10.0%	8.6%	6.3%	3.5%
Total	100.0%	100.0%	100.0%	100.0%

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BEFORE THE KENTUCKY
PUBLIC SERVICE COMMISSION

WESTERN KENTUCKY GAS COMPANY
AN UNINCORPORATED DIVISION OF
ATMOS ENERGY CORPORATION

PREPARED DIRECT TESTIMONY
OF
DONALD A. MURRY, Ph.D.

June 1999

BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY
OF
DONALD A. MURRY, Ph.D.

On Behalf of
WESTERN KENTUCKY GAS COMPANY
AN UNINCORPORATED DIVISION OF
ATMOS ENERGY CORPORATION

Q. Please state your name and business address.

A. My name is Donald A. Murry. My address is 5555 North Grand Blvd. Oklahoma City, Oklahoma 73112.

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

A. I am an economist with C. H. Guernsey & Company in Oklahoma City. I am also a Professor Emeritus at the University of Oklahoma.

Q. What is your educational background?

A. I have a B. S. in Business Administration, and a M.A. and a Ph.D. in Economics from the University of Missouri - Columbia.

Q. Please describe your professional background that might be relevant to this proceeding.

A. From 1964 to 1974, I was on the faculty of the University of Missouri - St. Louis as an Assistant and Associate Professor and Director of Research. From 1974 through the present, I have been a Professor of Economics at the University of Oklahoma. Until 1978, I also served as Director of the Center for Economic and Management Research. In each of these positions, I directed and performed academic and applied research projects related to energy and regulatory policy. During this time, I also served on several state and national committees associated with energy policy and regulatory matters and published and presented a number of papers in the field of regulatory economics in the energy industries.

Q. What is your professional experience in regulatory affairs?

A. Since 1964, I have consulted for a number of private and public utilities, state and federal agencies, and other industrial clients regarding energy and regulatory matters in the United States, Canada and other countries. In 1971-72, I served as Chief of the Economic Studies Division, Office of Economics of the Federal Power Commission. From 1978 to early 1981, I was Vice President and Corporate Economist for Stone & Webster Management Consultants, Inc. and managed the Washington D.C. office. In both of these positions I directed and performed a wide variety of applied research projects and conducted other projects related to regulatory matters. Recently, I have assisted both private and public companies and government officials in areas related to regulatory, financial and competitive issues associated with the restructuring of the utility industry in the United States and other countries.

Q. Have you previously testified before or been an expert witness in proceedings before regulatory bodies?

A. Yes, I have appeared before the U.S. District Court-Western District of Louisiana, U.S. District Court-Western District of Oklahoma, District Court-Fourth Judicial District of Texas, U.S. Senate Select Committee on Small Business, Federal Power Commission, Federal Energy Regulatory Commission, Interstate Commerce Commission, Alabama Public

Service Commission, Alaska Public Utilities Commission, Arkansas Public Service Commission, Colorado Public Utilities Commission, Florida Public Service Commission, Georgia Public Service Commission, Illinois Commerce Commission, Iowa Commerce Commission, Kansas Corporation Commission, Louisiana Public Service Commission, Maryland Public Service Commission, Missouri Public Service Commission, New York Public Service Commission, Power Authority of the State of New York, Nevada Public Service Commission, North Carolina Utilities Commission, Oklahoma Corporation Commission, South Carolina Public Service Commission, Tennessee Public Service Commission, Texas Public Utilities Commission, the Railroad Commission of Texas, the State Corporation Commission of Virginia and the Public Service Commission of Wyoming.

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

A. I have been retained by Western Kentucky Gas Company ("Western Kentucky") which is a division of Atmos Energy Corporation, to develop a recommended cost of capital. This recommended cost of capital is appropriate for Western Kentucky's proposed tariffs in this proceeding.

Q. What is the nature of your analysis in developing your recommended cost of capital?

A. I determined the capital structure and the Atmos cost of debt and common stock appropriate for this proceeding. I devoted much of my effort to calculating the cost of the common stock equity component of Atmos' capital structure and determining a rate of return to recommend in this proceeding. I also evaluated my return recommendation in light of the ongoing restructuring of the natural gas industry, the special risk of Western Kentucky, and the need to maintain the financial integrity of Atmos' securities.

Q. Are you sponsoring any exhibits that accompany your testimony?

A. Yes. I am sponsoring the attached Exhibit DAM, which consists of 23 schedules.

Q. Were these schedules prepared by you or under your direction?

A. Yes.

Q. What is your rationale for regulation of public utilities and the setting of a rate of return?

A. Public utilities provide services which are virtually indispensable to current living standards and are part of the infrastructure supporting the modern economy. However, the role of regulation goes beyond the central role of utility service in the economy. Many analysts believe that competitive pressure alone will not necessarily produce the desired market efficiencies in these industries.

Economies of scale in delivery of the service are likely to lead to a single firm being the most efficient supplier in a service area. Although these competitive relationships are changing, duplication of the distribution facilities may be inefficient. Furthermore, communities grant utilities franchises, which, along with obligations to serve, usually give a company some exclusive rights to provide service in a given region. Thus, utilities are subject to price regulation designed to allow utilities to recover the costs of providing service and to earn a "fair" return on invested capital. Establishing this return is the purpose of my testimony.

Q. What is a fair rate of return for a regulated public utility?

A. A fair rate of return for a utility meets the standards of the United States Supreme Court decision in the *Bluefield Water Works and Improvement Company vs. Public Service Commission*, 262 U.S. 679 (1923) case (*Bluefield*), as further modified in the *Federal Power*

Commission vs. Hope Natural Gas Company, 320 U.S. 591 (1944) (*Hope*). Following these precedents, it is a rate of return which provides earnings to investors similar to the alternative investments in companies of equivalent risk. Such a rate of return will allow a company to maintain its present capital and to attract additional capital on reasonable terms.

Q. How did you determine the return necessary to attract and maintain capital?

A. I used standard methods for valuing common stock in the capital market and calculating the embedded cost of debt of common stock. These methods all use market information in some manner in estimating the cost of capital. This rationale is consistent with the economic rationale set forth in the *Hope* decision.

Q. Why is the *Hope* decision important?

A. That decision clarified the principle that a return should be set at a level that will instill investor confidence in the financial integrity of the company and provide a return sufficient to attract capital. A company will attract and maintain capital when the return on investment in the company is equal to the return from investment in businesses with comparable investment risks.

Q. In developing your analysis what were the steps that you followed?

A. First, I evaluated the capital structure of Atmos that is relevant for this proceeding. Because Western Kentucky is a division of Atmos, Atmos raises capital for Western Kentucky's operations. The investors acquire securities of Atmos, and the risks of Western Kentucky are, of course, evaluated by investors when they acquire an Atmos security. Consequently, it is correct analytically to use Atmos' capital structure as the relevant capital structure in this proceeding. The costs of the components of the capital structure of Atmos are also the analytically correct costs to apply in this proceeding.

Q. What is the capital structure for Western Kentucky that is appropriate for this proceeding?

A. As I stated, the cost of capital for Western Kentucky is the cost of capital of Atmos. Consequently, for this proceeding, the appropriate capital structure for Western Kentucky is the capital structure of Atmos. That is, $382,004,580 long-term debt, $88,940,765 short-term debt, and $475,564,478 in common stock equity. That results in a total capital of $946,509,822 for Atmos that is appropriate in this proceeding. I have illustrated this capital structure on Schedule DAM-1. This is the capital that is consistent with requirements for this proceeding. It is a representative, appropriate capital structure for ratemaking for Western Kentucky.

Q. What are the ratios of the capital components that you used in your analysis?

A. The long-term debt is 40.36 percent of the total capital. The short-term debt is 9.40 percent of total capital. Therefore, the common stock equity ratio is 50.24 percent. It is theoretically wrong to use short-term capital in the capital structure of a utility when it is not permanent capital, and it is not permanent capital in Atmos' case. It is Atmos' policy to use short-term capital for working capital purposes only. Moreover, in practice, Atmos is using short-term debt for working capital only.

Q. What is the Western Kentucky's embedded cost of short-term debt ?

A. The company has requested 6.10 percent for the cost of short-term debt. However, this cost is the most unstable component of the capital structure in this proceeding. As such, the Commission should make allowances for this added risk.

Q. What is Western Kentucky's embedded cost of its long-term debt for this proceeding?

A. Western Kentucky's cost of long-term debt , which is the weighted cost of long-term debt of Atmos, is 8.06 percent. The embedded cost of long-term debt, which is based on the annual cost of each of the outstanding issues, is shown in Schedule DAM-2. It is important that the total debt of Atmos has increased sharply since July 1998 because of the issuance of a $150 million long-term debenture. That had the consequence of reducing the percentage of common stock equity of Atmos temporarily to levels which are lower than its historical levels.

Q. What is the justification for the level of Atmos' common stock equity which you are recommending for use in this case?

A. The common stock equity, at December 31, 2000 includes components of capital stock, $162,992 additional paid-in capital, $334,844,269 and retained earnings of $140,557,217 I have listed the components of the common stock in Schedule DAM-3.

Q. How did you proceed to evaluate the cost of common stock of Atmos which you referred to previously?

A. I used two common methods for measuring the cost of common stock. Since the common stock of Atmos is publicly traded, I could rely on market-based evaluations for most of my analysis. For example, I used the Discounted Cash Flow (DCF) technique which relies on market prices and the stream of returns that an investor would anticipate when making an investment. I also used the Capital Asset Pricing Model (CAPM), which uses the current return to risk-free securities as an analytical basis and estimates the risk differential between that value and the security in question. Of course, I evaluated the risk of these analyses in the context of market conditions and the risks to investors in Atmos' securities.

Q. How did you evaluate the adequacy of your recommendation?

A. After completing my estimates of the cost of capital, I verified that my recommendation would be adequate to meet debt coverage requirements. Then I recommended a return for Atmos. Finally, I calculated the adequacy of my recommendation. Of course, the recommended return must be sufficient to maintain the financial integrity of the company.

Q. You described the use of a group of comparative companies in your analysis. What was the group of companies that you used in your comparative analysis of common equity costs?

A. The firms that I used as comparative companies are AGL Resources, Bay State Gas Company, Indiana Energy, KeySpan Energy, Laclede Gas, Northwest Natural Gas, Peoples Energy, Washington Gas Light. This is a group of gas distribution companies which I selected, in part, because they are the Moody's gas distribution companies, and the financial community already recognizes them as representative of companies in the gas distribution industry. However, I excluded KeySpan and Bay State from my cost of capital analyses.

Q. During your study did you compare the capital structures of this group of companies to the capital structure of Atmos?

A. Yes, I did. I have illustrated the results of that comparison in Schedule DAM-4.

Q. Did that comparison influence your evaluation of the cost of common stock of Atmos in this analysis?

A. Yes. As this schedule shows, according to *Value Line* Atmos' common stock equity ratio dropped sharply in 1998 from previous levels. These *Value Line* estimates show 48.2 percent for Atmos for 1998 which is much lower than the level for the previous four years for Atmos and the current capital structure. It is also much lower than the 56.5 percent average for the Moody's Distribution Companies.

Q. Do you know why *Value Line* shows such decline in the common stock equity of Atmos for 1998?

A. Atmos issued $150 million in long-term debt in July 1998. That level of funding is sufficient to reduce the common stock equity ratio to abnormally low levels, at least for a brief period of time. For ratemaking purposes the more recent, actual capital structure is important because it represents Atmos' current capital structure and Atmos' financial policy.

Q. In reviewing that schedule, it is apparent that the *Value Line* common stock equity ratio for Atmos in 1998 is lower than for all of these companies. Is that comparison important?

A. Yes. The average of the comparative companies is a useful representation of the common stock ratio in the gas distribution industry. It shows that Atmos' capital structure which I used in this proceeding is relatively low-cost. It also confirms that the capital structure that I am proposing is appropriate for setting rates for the future.

Q. Why is the common equity ratio of Atmos important?

A. Lower common stock equity ratios normally mean greater financial risk. With a low equity ratio, common stockholders' dividends are at greater risk. The dividend payment is less protected. Greater financial risk means that investors will view those stocks as less attractive; that, of course, raises the cost of common stock.

Q. Why did you exclude Bay State and KeySpan from your cost of capital analysis?

A. Bay State Gas has merged with NIPSCO and has ceased to exist as a stand-alone company and *Value Line* has dropped Bay State Gas from its analysis. *Value Line* has suspended its analysis and forecasts of KeySpan pending its problems associated with the Long Island Lighting Company acquisition. Consequently, neither of these companies can be used as a viable comparison at this time.

Q. You stated that you used the DCF method to estimate the cost of capital. What is the conceptual basis of the DCF method?

A. The Discounted Cash Flow method relies on market price information that reflects the value that investors place on an anticipated stream of returns. Those returns are expected dividends and any capital gains. By relating its value, or price, to the expected income stream, an analyst can estimate the cost of common stock equity. The present value of that stream of returns equals the price, at the margin, that an investor will pay for the security. Symbolically, if K is equal to the cost of common equity, $K = D/P + g$, where D = dividends, P = price per share, and g = rate of growth of dividends. That is, K is a capitalization rate that converts a stream of future returns (dividend and stock appreciation) to a current value.

Q. Is it your opinion that the DCF method is conceptually sound?

A. Yes, it is conceptually sound. Furthermore, analysts generally accept the theory. Although they are likely to agree that it is sound conceptually, analysts differ in how to apply the theory.

Q. In what ways do analysts differ when applying the DCF theory?

A. One area of controversy is the growth rate to represent the expectations by investors about future earnings streams. Because many factors may influence market price at any time, the estimate of the cost of capital is also sensitive to market changes. That creates a problem in interpreting the results for ratemaking purposes.

Q. You stated that the DCF method requires an analyst to evaluate the investor expectations of the earnings stream of a common stock investment. As an analyst, how do you estimate investor's expectations?

A. Investors develop expectations about future returns based on information that may come to them from various sources. We can review the data that are available to knowledgeable investors. This information may be historical; historical data reveals recent performance and trends. Information regarding projections of future earnings are also available to investors. For example, it is reasonable to assume that rational investors will review earnings forecasts when they are evaluating a common stock investment. I use all of the information as reflective of what investors rely upon as they develop their expectations.

Q. Is that the type of data that you used in your analysis of investor expectations?

A. Yes. For example, I used earnings growth and dividend growth data that are readily available to investors and which they commonly use. Earnings enable the payment of dividends, and a growth in earnings enables dividends to grow. Whether paid out in dividends or retained by a company, earnings growth will raise the value of a common stock. Both earnings growth and dividend growth are key variables that investors observe and financial analysts review as expected returns from an investment.

Q. How long was the period of time that you used to measure the earnings growth component of the DCF analysis?

A. I analyzed growth in earnings per share, dividends per share, and book values for the most recent five and ten-year periods and for near-term forecasts. However, the book value growth rates are somewhat remote to the returns to investors so I placed most of my emphasis on the earnings and dividend growth rates. The expected returns are most important to investors so I concentrated on the forecast as well.

Q. Do you believe that there is an analytical difference between the historical growth rates and the forecasted growth rates in your analysis?

A. I believe that they both have analytical value. However, the gas industry has undergone and is continuing to undergo significant restructuring with increasing competition in many markets. For that reason in particular, I believe that the forecasts are probably more meaningful that the historical growth rates. Stated somewhat differently, because investors evaluate these growth rates in formulating their expectations, I believe that the forecasted growth rates are likely to be more important for ratemaking purposes.

Q. What did your review of the growth in earnings and dividends show?

A. As shown in Schedule DAM-5, the earnings growth expectations for investors in Atmos' common stock are undoubtedly higher than for the investors in the common stock of the other Moody's companies.

Q. Did you compare the earnings growth to the dividend growth rates?

A. Yes, I did.

Q. What did that comparison of earnings growth and dividend growth show?

A. Each company studied had earnings growth rate forecasts that were much higher than their dividend growth rate forecasts. In addition, every one of the companies studied had much higher earnings growth rates over the most recent five years than their dividend growth rates.

Q. Can you explain the divergence in the earnings and dividend growth rates in recent years and in their forecasts?

A. This pattern appears to reflect prudent behavior. The increased competition in the natural gas industry has increased the gas distributors' market or business risk. With the increased competitive pressures on gas distribution companies and the uncertainties about the future market competition, this earnings-dividend pattern is not surprising. Considering this added business uncertainty, conservative boards of directors will conserve cash from earnings rather than raising cash dividends. Retaining cash and assets in the company would be financially prudent during a period of change and uncertainty.

Q. How does this relationship affect your analysis in this case?

A. It means that earnings growth is the more relevant measure for setting rates for the future. Notably, Atmos exhibits the same relationship between earnings growth and dividends. That is, investors expect Atmos' earnings to grow faster than dividends.

Q. What earnings and dividend forecasts did you use in your analysis?

A. I used forecasts from both the *Value Line* and *Standard & Poor's*, which reports the I/B/E/S forecasts, as representative of analysts' expectations for Atmos. Both are readily available and used by analysts and investors.

Q. How will the high growth rate in earnings forecasted for these companies by both *Value Line* and *Standard & Poor's* affect investors?

A. I believe the high growth rate in earnings forecasted by both *Value Line* and *Standard & Poor's* will attract investors looking for growth. Conversely, it may discourage investors seeking stability over time. These latter investors are the ones who have bought utility stocks historically. To some investors, this will likely diminish the relative attractiveness of gas distribution companies, including Atmos/Western Kentucky. Inevitably, investors in gas distribution companies will change from investors seeking dividends to investors seeking appreciation in value.

Q. In your opinion, is this change in investor profile important?

A. Yes. Investors looking for earnings growth and relying less on dividends are deferring their returns for the expected future return. In the long-term, they will demand a higher return as a tradeoff for giving up more stable near-term returns. In fact, the earnings-dividend growth differential means that the investors already are facing this tradeoff between growth and stable earnings.

Q. What price information did you use in your DCF analyses?

A. Recognizing the volatility of the securities markets, I took a longer view than looking just at current market conditions. I developed DCF estimates of the cost of common stock using the range of market prices since the beginning of 1999 and all of 1998. Also, to estimate the current cost of capital, I used price information from a recent two-week period.

Q. What growth ratios did you use in your DCF analysis?

A. As I stated previously, I concentrated on the earnings growth and the dividend growth in my DCF analysis because these are statistics familiar to knowledgeable investors. Because of the differential in the earnings per share and the dividend growth rates, my DCF calculations differed depending on which of the two growth rates that I used in my calculations. Of course, this is not surprising. However, the DCF results require interpretation because of this difference.

Q. What do you mean that the DCF results require interpretation because of the differential in the dividend and earnings growth rates?

A. Because the growth rate differential is so large, it is important to this analysis. Investors may be influenced more by one than the other. Comparing the DCF results using the dividend growth rate to the current return on utility debt demonstrates clearly the investors interest in earnings growth. In other words, the low dividend growth rate DCF results are so low they are not credible estimators of the cost of common stock for distribution companies.

Q. You say that the DCF results produced by the dividend growth rate are so low that they are not credible. What is the basis of that statement?

A. There is not a sufficient differential between the bond yields and dividend growth DCF calculations to compensate investors for the risk differential. For example, Moody's Bond Record reported the yield of Baa rated utility bonds was 7.53 percent.

Q. How did the dividend growth rate affect your DCF analysis?

A. My Schedules DAM-6 using 1998 yields, DAM-7 using 1999 yields, and DAM-8 using current yields, show the effects of these low dividend growth rates and current low dividend yields in the DCF calculations. If the investors were basing their decisions to buy the distribution companies' common stock exclusively on dividend growth, the DCF yield would be high enough to create a gap with the returns on bonds that compensated for the risk differential. As these low dividend growth results show, the cost of common stock calculations are so low that they call into question this phase of the analysis.

Q. Why are the dividend yields low?

A. The common stock market is currently at very high price-earnings levels, and when the companies are not raising dividends at the rate of earnings growth, and, at the same time, investors are buying the stock based on earnings growth, the dividend yields will be very low. That is the current situation for gas distributors. These low dividend growth rates and the current high level in the common stock prices, taken together, produce very low DCF results using the dividend growth rates.

Q. How do you interpret the DCF analysis using the earnings growth rate?

A. The DCF calculations of the cost of common stock using the earnings per share growth rate forecast by *Standard & Poor's* and *Value Line* are higher because of higher earnings forecasts. DCF calculations based on both *Value Line* and *Standard & Poor's* earnings growth estimates are shown in Schedules DAM-9, DAM-10, DAM-11, DAM-12, DAM-13, and DAM-14. DAM-15 is a schedule that summarizes all of the DCF results. Note that the DCF cost of capital using the earnings per share growth rates from these two sources were quite similar. Note also that all of these estimates have uniformly high cost of capital for Atmos.

Q. From your DCF analysis do you have any observations that pertain specifically to your Atmos cost of common stock calculations?

A. I have two observations concerning Atmos about these DCF analyses. First, the yields on Atmos' common stock have been very low. That is very apparent when one compares them to the yields of the Moody's Distribution Companies. As shown in the current cost of capital schedules, the yield for Atmos is much lower that the yield for the Moody's Companies. It is, at minimum, 70 basis points less than the average yield for the Moody's companies. Second, the forecasted earnings growth rate is much higher for Atmos than it is for the Moody's companies.

Q. Are the low yields for Atmos' common stock important in your interpretation of how to use this analysis for the setting of rates in this proceeding?

A. Yes. The low yields show that the market has responded to the high earnings forecasts for Atmos. Consequently, when determining the cost of common equity, we should be aware of the growth rate component in the DCF analysis because the high growth rate forecasts are important to investors. However, analyzing the earnings-growth DCF results and the dividend-growth DCF results guides us toward using the earnings growth rather than the dividend-growth DCF results for ratemaking. The dividend growth rate produces a return estimate that does not meet the test of a credible risk differential from current debt costs. This makes using the dividend-growth rate in a DCF analysis an unreliable estimate for ratemaking in today's markets. Therefore, the earnings-growth forecasts, which influence the equity investors of gas distribution companies, produce the most reliable cost of common estimates for ratemaking in this proceeding.

Q. What other factors, if any, influenced your interpretation of these DCF results?

A. I considered the theoretical basis of the DCF methodology in interpreting these results and using these calculations to reach my recommendation. In theory, the DCF calculation produces a marginal cost measure of the cost of common stock. Mechanically, this means that there is no calculated margin for misinterpreting the results. Therefore, the results of the mechanical calculations in light of the theoretical basis of the DCF are often adjusted by analysts. For example, some analysts compensate for this shortcoming by applying either a flotation or market pressure adjustment or both.

Q. Did you calculate a separate flotation or market pressure adjustment?

A. No, I did not. Instead, I considered the need to raise capital in the future in evaluating the DCF results, and I took this into consideration in reaching my recommended return.

Q. You stated that you used the Capital Asset Pricing Model or CAPM model. What is the CAPM model?

A. The CAPM model is based on an investor's ability to diversify by combining risky securities into an investment portfolio. The diversification of investments in this way reduces the overall risk to the investor. However, some risk is non-diversifiable, such as the market risk. Investors remain exposed to that market risk.

The formal CAPM model is expressed as:

$$K = R_F + \beta\,(R_M - R_F)$$

Where:
K = the required return.
R_F = the risk-free rate.
R_M = the required overall market return; and
β = beta, a measure of security risk relative to the overall market.

Note that the value of market risk is the differential between the market rate and the risk-free rate. Beta is the relative measure of this risk of securities. One can interpret beta as the relationship between an individual security and the market as a whole. The Capital Asset Pricing Model is useful because it can effectively link the incremental cost of capital of an individual company with the risk differential between that company and the market as a whole.

Q. How did you apply the theory of the CAPM model in your analysis?

A. I developed two different CAPM measures. Each has some special analytical benefits, and I used them to evaluate the results of my DCF analyses. First, I developed a rather standard historical CAPM analysis. Then, because of recognized biases in the CAPM method, I also developed a size-adjusted CAPM analysis. This second technique compensates for bias in company size.

Q. Why did you use a method that compensates for size bias?

A. That bias is important in ratemaking when comparing smaller companies to larger companies, and in this case Atmos is smaller than three of the Moody's companies. Excluding that adjustment will underestimate the true capital costs that will result from the traditional or simple CAPM analysis. This adjustment is also important in this proceeding because Western Kentucky is also much smaller than Atmos.

Q. You stated that you developed a standard historical CAPM analysis. What were the results of that analysis?

A. Using a risk-free rate of long-term government securities, the current betas, and the current market rate of 6.62 percent, this basic CAPM analysis estimates the cost of capital for Atmos of 11.68 percent. The results of that analysis are shown in Schedule DAM-16.

Q. You described a size-adjusted CAPM analysis. What were the results of that calculation?

A. Using a CAPM method that compensates for the risk associated with the size of a company, I calculated a cost of common equity for Atmos of 11.31 percent (see Schedule DAM-17).

Q. Does this size adjustment apply to Atmos or to Western Kentucky?

A. The size adjustment that I used applies to Atmos. If Western Kentucky were raising capital on its own, this CAPM method would produce cost of common equity of 12.81 percent.

Q. Were there additional factors that you considered in reaching your recommendation?

A. Yes. I considered the financial market's assessment of the shifting risks between the interstate transmission companies and the local distribution companies within the natural gas industry. Of course, these changes were brought about by the increasing competition faced by many companies in the industry.

Q. How does this increased competition affect your recommendation for a return on common stock?

A. The measured cost of capital in my market-based analyses reflect the investor evaluation of the companies' market structure. These are risks to investors, and I evaluated how investors were compensating for these risks. The risks of the local gas distribution companies are changing almost daily. First, there was the deregulation of pipelines, and for distributors, this increased the risks in acquiring gas and uncertainties about gas price passthroughs. As the investors are becoming aware of the implications of competition in the retail market, they assess the associated risks. Investors will embrace those risks by discounting their expected future returns in determining the current market values of securities.

Q. Has the market accounted for these risks by discounting the expected returns?

AFFIDAVIT

STATE OF OKLAHOMA)
) SS
COUNTY OF OKLAHOMA)

Before me, the undersigned Notary Public, personally appeared DONALD A. MURRY, who being duly sworn on oath deposes and says that the foregoing prepared testimony and statement of facts contained therein are true and correct to the best of his knowledge, information and belief.

D A Murry

Donald A. Murry

Subscribed and sworn to before me this 17 day of May, 1999.

Pat Burnett

Notary Public

My Commission Expires:

October 5, 2002

Western Kentucky Gas Company

A Division of Atmos Energy Corporation

Summary of Schedules

Western Kentucky Gas Company

A Division of Atmos Energy Corporation

Pro Forma Capital Structure

Thirteen Month Average as of December 31, 2000

Item		Amount	Share
Shareholders' Equity	$	475,564,478	50.24%
Long Term Debt	$	382,004,580	40.36%
Short Term Debt	$	88,940,765	9.40%
Total Capital	$	946,509,823	100.00%

Source:
Western Kentucky Gas Company Work Papers

Western Kentucky Gas Company

A Division of Atmos Energy Corporation

Pro Form Shareholders' Equity

Thirteen Month Average as of December 31, 2000

Item		Amount
Common Stock	$	162,992
Paid In Capital	$	334,844,269
Retained Earnings	$	140,557,217
Total Shareholders' Equity	$	475,564,478

Source:
Western Kentucky Gas Company Work Papers

Western Kentucky Gas Company

A Division of Atmos Energy Corporation

Pro Forma Long Term Debt

Thirteen Month Average as of December 31, 2000

Line No.	Issue		Amount Outstanding	Interest Rate	Effective Annual Cost	Composite Interest Rate
1	First Mortgage Bonds		$17,000,000	9.40%	1,598,000	
2	First Mortgage Bonds		153,846	8.69%	13,369	
3	First Mortgage Bonds		19,423,077	10.43%	2,025,827	
4	First Mortgage Bonds		20,000,000	9.75%	1,950,000	
5	First Mortgage Bonds		9,403,077	11.32%	1,064,428	
6	First Mortgage Bonds		18,000,000	9.32%	1,677,600	
7	First Mortgage Bonds		20,000,000	8.77%	1,754,000	
8	First Mortgage Bonds		10,000,000	7.50%	750,000	
9	Unsecured Senior Note		5,846,154	11.20%	654,769	
10	Unsecured Senior Note		14,769,231	9.76%	1,441,477	
11	Unsecured Senior Note		13,384,615	9.57%	1,280,908	
12	Unsecured Senior Note		6,615,385	7.95%	525,923	
13	Unsecured Senior Note		20,000,000	8.07%	1,614,000	
14	Unsecured Senior Note		20,000,000	8.26%	1,652,000	
15	Unsecured Note		1,151,654	10.00%	115,165	
16	Unsecured Note		1,151,654	10.00%	115,165	
17	Debentures		150000000	6.75%	10,125,000	
18	Medium Term Notes		10,000,000	6.67%	667,000	
19	Medium Term Notes		10,000,000	6.27%	627,000	
20	Medium Term Notes		1,846,154	6.20%	114,462	
21	First Mortgage Bonds		1,742,674	7.90%	137,671	
22	Unsecured Notes		0	7.50%	0	
23	Unsecured Notes		383,654	7.50%	28,774	
24	Unsecured Notes		603,365	7.00%	42,236	
25	Unsecured Notes		28,432	7.00%	1,990	
26	Unsecured Notes		115,423	6.00%	6,925	
28	Unsecured Notes		1,132,308	7.00%	79,262	
29	Unsecured Notes		1,112,212	6.99%	77,744	
30	Unsecured Notes		361,538	7.00%	25,308	
31	Unsecured Notes		819,231	8.50%	69,635	
33	Senior Secured Note		6,960,896	7.45%	518,587	
	Total LONG-TERM DEBT		382,004,580		30,754,224	
	Amortization of debt discount	$	394,837			
		$	381,609,744			8.06%

Source:
Western Kentucky Gas Company Work Papers

Western Kentucky Gas Company

A Division of Atmos Energy Corporation

Equity Ratio Comparison for the Past Five Years

	1994	1995	1996	1997	1998	Five Year Average
Atmos Energy Corporation	52.0%	54.7%	58.5%	51.9%	48.2%	53.1%
AGL Resources	45.8%	47.6%	48.9%	45.9%	47.1%	47.1%
Bay State Gas Company	52.3%	51.8%	53.1%	50.0%	NMF	51.8%
Indiana Energy	63.1%	61.4%	62.5%	65.0%	62.5%	62.9%
KeySpan Energy	52.2%	53.2%	55.8%	56.5%	60.0%	55.5%
Laclede Gas	55.5%	59.3%	57.1%	61.6%	58.6%	58.4%
Northwest Natural Gas	45.1%	50.3%	52.8%	49.0%	51.5%	49.7%
Peoples Energy	50.6%	50.8%	56.4%	57.6%	58.9%	54.9%
Washington Gas Light	56.7%	58.9%	59.4%	56.2%	57.1%	57.7%
Moody's Distribution Company Average	52.7%	54.2%	55.8%	55.2%	56.5%	54.9%

Note: NMF-No Meaningful Figure

Source: Value Line Investment Survey

Schedule DAM-5

Western Kentucky Gas Company

Comparable Local Distribution Companies

Growth Rate Summary

	1994 TO 2003 Estimate			Value Line Five Year Historical			Projections Value Line		S & P
	E/S	D/S	BK Value	E/S	D/S	BK Value	E/S	D/S	E/S
Atmos Energy Corporation	11.5%	4.3%	7.2%	9.5%	4.0%	4.0%	11.5%	4.5%	9.0%
AGL Resources	5.3%	1.6%	4.2%	5.0%	1.0%	2.5%	5.5%	2.0%	5.0%
Indiana Energy	6.9%	3.8%	4.4%	9.5%	4.0%	4.5%	6.0%	4.0%	6.0%
Laclede Gas Company	5.1%	1.9%	3.5%	5.5%	1.5%	3.5%	4.0%	2.0%	2.0%
Northwest Natural Gas	4.2%	1.6%	4.8%	12.0%	1.5%	4.5%	4.5%	1.5%	4.0%
Peoples Energy	5.7%	1.9%	3.8%	5.0%	1.5%	3.0%	3.5%	2.0%	4.0%
Washington Gas Light	5.7%	2.2%	4.9%	7.0%	2.0%	5.0%	4.5%	2.5%	5.0%
Moody's Companies' Average	5.49%	2.16%	4.28%	7.33%	1.92%	3.83%	4.67%	2.33%	4.33%

Sources : Value Line Investment Survey
Standard & Poor's Earnings Guide

Western Kentucky Gas Company

Comparable Local Distribution Companies

1998 Cost of Capital

	Share Prices		1998	1998 Yields		1993-95	2002-04E	Growth	Cost of Capital	
	High	Low	Dividend	High	Low	Dividend	Dividend	Rate	High	Low
Atmos Energy Corporation	32.30	24.80	1.06	4.27%	3.28%	0.89	1.30	4.34%	8.62%	7.63%
AGL Resources	23.40	17.70	1.08	6.10%	4.62%	1.04	1.20	1.60%	7.70%	6.22%
Indiana Energy	26.40	19.60	0.90	4.59%	3.41%	0.77	1.08	3.83%	8.42%	7.24%
Laclede Gas Company	27.90	22.40	1.32	5.89%	4.73%	1.23	1.45	1.88%	7.77%	6.61%
Northwest Natural Gas	30.80	24.30	1.22	5.02%	3.96%	1.17	1.35	1.57%	6.59%	5.53%
Peoples Energy	40.10	32.10	1.91	5.95%	4.76%	1.79	2.12	1.88%	7.83%	6.64%
Washington Gas Light	30.80	23.10	1.20	5.19%	3.90%	1.11	1.35	2.23%	7.43%	6.13%
Moody's Companies' Average	29.90	23.20	1.27	5.46%	4.23%	1.19	1.43	2.16%	7.62%	6.39%

Source : Value Line Investment Survey

Schedule DAM-6

Western Kentucky Gas Company

Comparable Local Distribution Companies

1999 Cost of Capital

	Share Prices		1999	1999 Yields		1993-95	2002-04E	Growth	Cost of Capital	
	High	Low	Dividend	High	Low	Dividend	Dividend	Rate	High	Low
Atmos Energy Corporation	33.00	23.00	1.10	4.78%	3.33%	0.89	1.30	4.34%	9.13%	7.68%
AGL Resources	23.40	18.30	1.08	5.90%	4.62%	1.04	1.20	1.60%	7.50%	6.22%
Indiana Energy	24.60	19.10	0.94	4.92%	3.82%	0.77	1.08	3.83%	8.75%	7.65%
Laclede Gas Company	27.00	20.80	1.34	6.44%	4.96%	1.23	1.45	1.88%	8.32%	6.84%
Northwest Natural Gas	27.00	22.10	1.23	5.57%	4.56%	1.17	1.35	1.57%	7.14%	6.13%
Peoples Energy	40.30	31.80	1.95	6.13%	4.84%	1.79	2.12	1.88%	8.01%	6.72%
Washington Gas Light	27.40	22.30	1.22	5.47%	4.45%	1.11	1.35	2.23%	7.70%	6.69%
Moody's Companies' Average	28.28	22.40	1.29	5.74%	4.54%	1.19	1.43	2.16%	7.90%	6.71%

Source : Value Line Investment Survey

Western Kentucky Gas Company

Comparable Local Distribution Companies

Current Cost of Capital

	Share Prices		Current	Current Yields		1993-95	2002-04E	Growth	Cost of Capital	
	High	Low	Dividend	High	Low	Dividend	Dividend	Rate	High	Low
Atmos Energy Corporation	23.80	23.16	1.10	4.75%	4.62%	0.89	1.30	4.34%	9.09%	8.97%
AGL Resources	19.01	18.56	1.08	5.82%	5.68%	1.04	1.20	1.60%	7.42%	7.28%
Indiana Energy	20.31	19.83	0.94	4.74%	4.63%	0.77	1.08	3.83%	8.57%	8.46%
Laclede Gas Company	22.33	21.78	1.34	6.15%	6.00%	1.23	1.45	1.88%	8.03%	7.88%
Northwest Natural Gas	24.52	23.60	1.23	5.21%	5.02%	1.17	1.35	1.57%	6.78%	6.59%
Peoples Energy	35.31	34.71	1.95	5.62%	5.52%	1.79	2.12	1.88%	7.50%	7.40%
Washington Gas Light	24.04	23.36	1.22	5.22%	5.07%	1.11	1.35	2.23%	7.46%	7.31%
Moody's Companies' Average	24.25	23.64	1.29	5.46%	5.32%	1.19	1.43	2.16%	7.63%	7.49%

Sources:
Value Line Investment Survey
Wall Street Journal

Schedule DAM-8

Western Kentucky Gas Company

Comparable Local Distribution Companies

1998 Cost of Capital

	Share Prices		1998	1998 Yields		1993-95	2002-04E	Growth	Cost of Capital	
	High	Low	Dividend	High	Low	EPS	EPS	Rate	High	Low
Atmos Energy Corporation	32.30	24.80	1.06	4.27%	3.28%	1.13	3.00	11.50%	15.77%	14.78%
AGL Resources	23.40	17.70	1.08	6.10%	4.62%	1.19	1.90	5.30%	11.41%	9.92%
Indiana Energy	26.40	19.60	0.90	4.59%	3.41%	1.07	1.95	6.90%	11.49%	10.31%
Laclede Gas Company	27.90	22.40	1.32	5.89%	4.73%	1.43	2.25	5.14%	11.03%	9.87%
Northwest Natural Gas	30.80	24.30	1.22	5.02%	3.96%	1.66	2.40	4.18%	9.20%	8.14%
Peoples Energy	40.10	32.10	1.91	5.95%	4.76%	2.01	3.30	5.68%	11.63%	10.45%
Washington Gas Light	30.80	23.10	1.20	5.19%	3.90%	1.39	2.30	5.73%	10.92%	9.62%
Moody's Companies' Average	29.90	23.20	1.27	5.46%	4.23%	1.46	2.35	5.49%	10.95%	9.72%

Source : Value Line Investment Survey

Schedule DAM-9

Western Kentucky Gas Company

Comparable Local Distribution Companies

1998 Cost of Capital

	Share Prices		1998	1998 Yields		EPS Estimates		Cost of Capital	
	High	Low	Dividend	High	Low	Value Line	S&P	High	Low
Atmos Energy Corporation	32.30	24.80	1.06	4.27%	3.28%	11.50%	9.00%	15.77%	12.28%
AGL Resources	23.40	17.70	1.08	6.10%	4.62%	5.50%	5.00%	11.60%	9.62%
Indiana Energy	26.40	19.60	0.90	4.59%	3.41%	6.00%	6.00%	10.59%	9.41%
Laclede Gas Company	27.90	22.40	1.32	5.89%	4.73%	4.00%	2.00%	9.89%	6.73%
Northwest Natural Gas	30.80	24.30	1.22	5.02%	3.96%	4.50%	4.00%	9.52%	7.96%
Peoples Energy	40.10	32.10	1.91	5.95%	4.76%	3.50%	4.00%	9.95%	8.26%
Washington Gas Light	30.80	23.10	1.20	5.19%	3.90%	4.50%	5.00%	10.19%	8.40%
Moody's Companies' Average	29.90	23.20	1.27	5.46%	4.23%	4.67%	4.33%	10.29%	8.40%

Sources : Value Line Investment Survey
Standard & Poor's Earnings Guide

Western Kentucky Gas Company

Comparable Local Distribution Companies

1999 Cost of Capital

	Share Prices		1999	1999 Yields		1993-95	2002-04E	Growth	Cost of Capital	
	High	Low	Dividend	High	Low	EPS	EPS	Rate	High	Low
Atmos Energy Corporation	33.00	23.00	1.10	4.78%	3.33%	1.13	3.00	11.50%	16.28%	14.83%
AGL Resources	23.40	18.30	1.08	5.90%	4.62%	1.19	1.90	5.30%	11.21%	9.92%
Indiana Energy	24.60	19.10	0.94	4.92%	3.82%	1.07	1.95	6.90%	11.82%	10.72%
Laclede Gas Company	27.00	20.80	1.34	6.44%	4.96%	1.43	2.25	5.14%	11.58%	10.10%
Northwest Natural Gas	27.00	22.10	1.23	5.57%	4.56%	1.66	2.40	4.18%	9.75%	8.74%
Peoples Energy	40.30	31.80	1.95	6.13%	4.84%	2.01	3.30	5.68%	11.81%	10.52%
Washington Gas Light	27.40	22.30	1.22	5.47%	4.45%	1.39	2.30	5.73%	11.20%	10.18%
Moody's Companies' Average	28.28	22.40	1.29	5.74%	4.54%	1.46	2.35	5.49%	11.23%	10.03%

Source : Value Line Investment Survey

Western Kentucky Gas Company

Comparable Local Distribution Companies

1999 Cost of Capital

	Share Prices		1999	1999 Yields		EPS Estimates		Cost of Capital	
	High	Low	Dividend	High	Low	Value Line	S&P	High	Low
Atmos Energy Corporation	33.00	23.00	1.10	4.78%	3.33%	11.50%	9.00%	16.28%	12.33%
AGL Resources	23.40	18.30	1.08	5.90%	4.62%	5.50%	5.00%	11.40%	9.62%
Indiana Energy	24.60	19.10	0.94	4.92%	3.82%	6.00%	6.00%	10.92%	9.82%
Laclede Gas Company	27.00	20.80	1.34	6.44%	4.96%	4.00%	2.00%	10.44%	6.96%
Northwest Natural Gas	27.00	22.10	1.23	5.57%	4.56%	4.50%	4.00%	10.07%	8.56%
Peoples Energy	40.30	31.80	1.95	6.13%	4.84%	3.50%	4.00%	10.13%	8.34%
Washington Gas Light	27.40	22.30	1.22	5.47%	4.45%	4.50%	5.00%	10.47%	8.95%
Moody's Companies' Average	28.28	22.40	1.29	5.74%	4.54%	4.67%	4.33%	10.57%	8.71%

Sources : Value Line Investment Survey
Standard & Poor's Earnings Guide

Western Kentucky Gas Company

Comparable Local Distribution Companies

Current Cost of Capital

	Share Prices		Current	Current Yields		1993-95	2002-04E	Growth	Cost of Capital	
	High	Low	Dividend	High	Low	EPS	EPS	Rate	High	Low
Atmos Energy Corporation	23.80	23.16	1.10	4.75%	4.62%	1.13	3.00	11.50%	16.25%	16.12%
AGL Resources	19.01	18.56	1.08	5.82%	5.68%	1.19	1.90	5.30%	11.12%	10.98%
Indiana Energy	20.31	19.83	0.94	4.74%	4.63%	1.07	1.95	6.90%	11.64%	11.52%
Laclede Gas Company	22.33	21.78	1.34	6.15%	6.00%	1.43	2.25	5.14%	11.29%	11.14%
Northwest Natural Gas	24.52	23.60	1.23	5.21%	5.02%	1.66	2.40	4.18%	9.39%	9.20%
Peoples Energy	35.31	34.71	1.95	5.62%	5.52%	2.01	3.30	5.68%	11.30%	11.20%
Washington Gas Light	24.04	23.36	1.22	5.22%	5.07%	1.39	2.30	5.73%	10.95%	10.80%
Moody's Companies' Average	24.25	23.64	1.29	5.46%	5.32%	1.46	2.35	5.49%	10.95%	10.81%

Sources:
Value Line Investment Survey
Wall Street Journal

Schedule DAM-13

Western Kentucky Gas Company

Comparable Local Distribution Companies

Current Cost of Capital

	Share Prices		Current	Current Yields		EPS Estimates		Cost of Capital	
	High	Low	Dividend	High	Low	Value Line	S&P	High	Low
Atmos Energy Corporation	23.80	23.16	1.10	4.75%	4.62%	11.50%	9.00%	16.25%	13.62%
AGL Resources	19.01	18.56	1.08	5.82%	5.68%	5.50%	5.00%	11.32%	10.68%
Indiana Energy	20.31	19.83	0.94	4.74%	4.63%	6.00%	6.00%	10.74%	10.63%
Laclede Gas Company	22.33	21.78	1.34	6.15%	6.00%	4.00%	2.00%	10.15%	8.00%
Northwest Natural Gas	24.52	23.60	1.23	5.21%	5.02%	4.50%	4.00%	9.71%	9.02%
Peoples Energy	35.31	34.71	1.95	5.62%	5.52%	3.50%	4.00%	9.62%	9.02%
Washington Gas Light	24.04	23.36	1.22	5.22%	5.07%	4.50%	5.00%	10.22%	9.57%
Moody's Companies' Average	24.25	23.64	1.29	5.46%	5.32%	4.67%	4.33%	10.29%	9.49%

Sources : Value Line Investment Survey
Standard & Poor's Earnings Guide
Wall Street Journal

Schedule DAM-14

Western Kentucky Gas Company

A Division of Atmos Energy Corporation

Summary of Discounted Cash Flow Analysis

	DCF Range	
	High	Low
DCF Using Dividend Growth Rates		
Atmos Energy Corporation	9.13%	7.63%
Moody's Companies' Average	7.90%	6.39%
DCF Using Earnings Growth Rates		
Atmos Energy Corporation	16.28%	12.28%
Moody's Companies' Average	11.23%	8.40%

Sources : Schedules DAM-6 through DAM-14

Western Kentucky Gas Company

Comparable Local Distribution Companies

Cost of Equity : Historical Capital Asset Pricing Model

	Market Total Returns	Long-Term Corporate Bonds Return	Risk Premium	Beta	Adjusted Risk Premium	Aaa Corporate Bonds Return	Cost of Equity
Atmos Energy Corporation	15.30%	6.10%	9.20%	0.55	5.06%	6.62%	11.68%
AGL Resources	15.30%	6.10%	9.20%	0.65	5.98%	6.62%	12.60%
Indiana Energy	15.30%	6.10%	9.20%	0.60	5.52%	6.62%	12.14%
Laclede Gas Company	15.30%	6.10%	9.20%	0.55	5.06%	6.62%	11.68%
Northwest Natural Gas	15.30%	6.10%	9.20%	0.60	5.52%	6.62%	12.14%
Peoples Energy	15.30%	6.10%	9.20%	0.75	6.90%	6.62%	13.52%
Washington Gas Light	15.30%	6.10%	9.20%	0.60	5.52%	6.62%	12.14%
Moody's Companies' Average	15.30%	6.10%	9.20%	0.63	5.75%	6.62%	12.37%

Sources :
Value Line Investment Survey
Ibbotson Associates 1998 SBBI Yearbook
Federal Reserve Statistical Release

Western Kentucky Gas Company

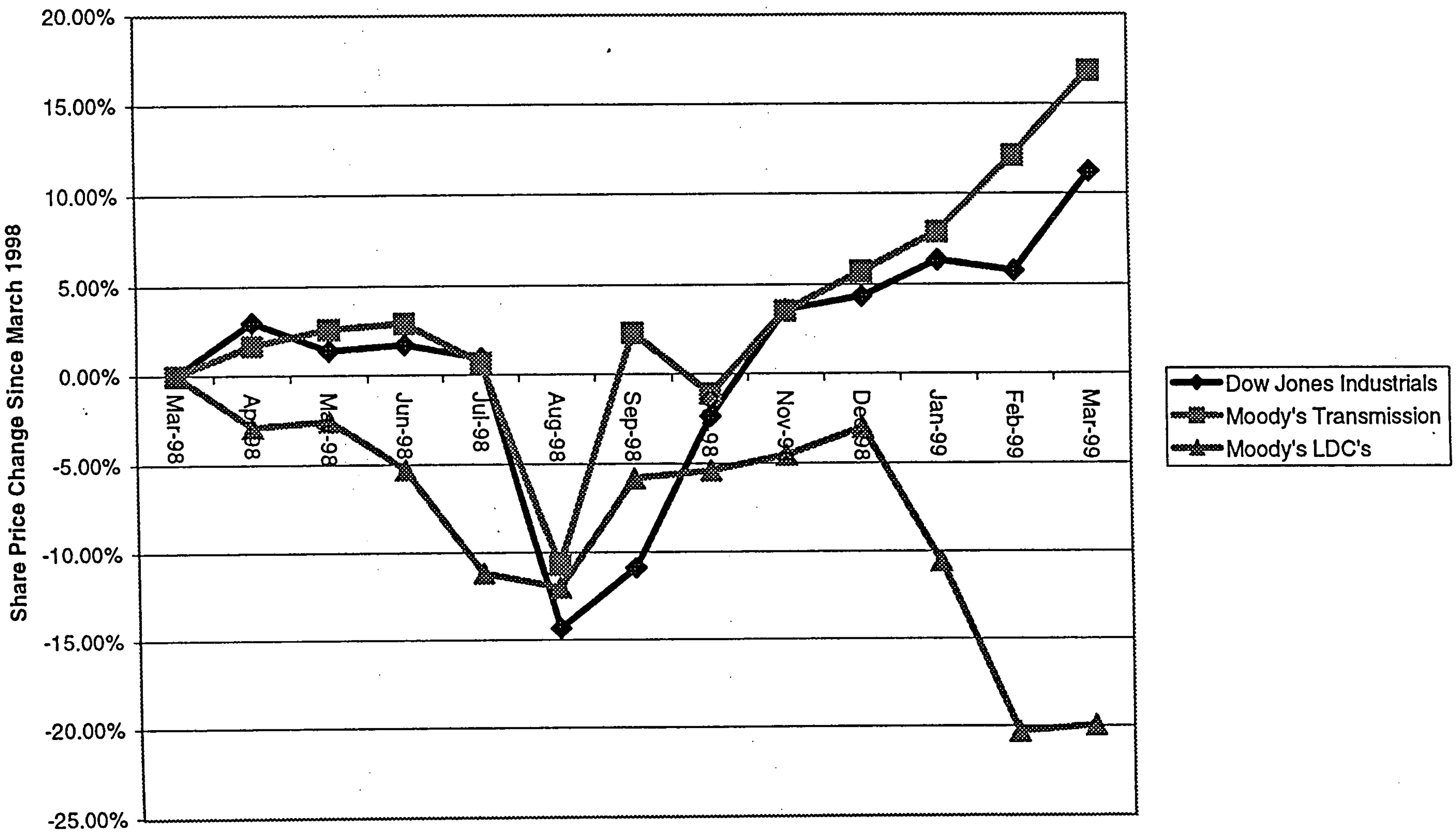
Comparable Local Distribution Companies

Cost of Equity : Size Adjusted Capital Asset Pricing Model

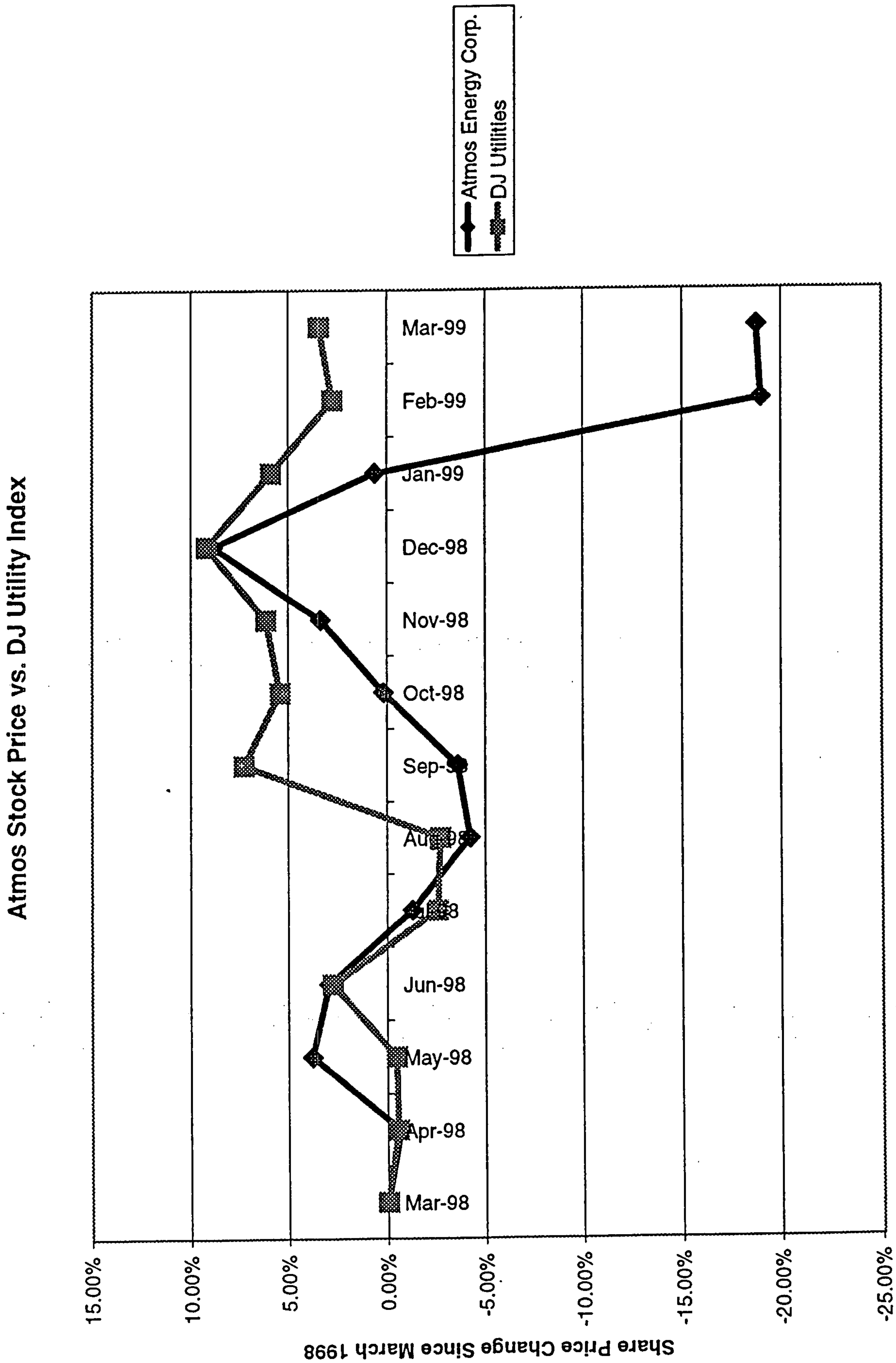
	Risk Free Return	Beta	Equity Risk Premium	Adjusted Equity Risk Premium	Size Premium	Cost of Equity
Atmos Energy Corporation	5.81%	0.55	8.00%	4.40%	1.10%	11.31%
AGL Resources	5.81%	0.65	8.00%	5.20%	0.50%	11.51%
Indiana Energy	5.81%	0.60	8.00%	4.80%	1.10%	11.71%
Laclede Gas Company	5.81%	0.55	8.00%	4.40%	1.10%	11.31%
Northwest Natural Gas	5.81%	0.60	8.00%	4.80%	1.10%	11.71%
Peoples Energy	5.81%	0.75	8.00%	6.00%	0.50%	12.31%
Washington Gas Light	5.81%	0.60	8.00%	4.80%	0.50%	11.11%
Moody's Companies' Average	5.81%	0.63	8.00%	5.00%	0.80%	11.61%

Sources :
Value Line Investment Survey
Ibbotson Associates 1998 SBBI Yearbook
Federal Reserve Statistical Release

Comparison of Price Appreciation for Moody's Gas Companies



Schedule DAM-19



Western Kentucky Gas Company

A Division of Atmos Energy Corporation

Comparison of Value Line's Timeliness Rank

	Timeliness Rank
Atmos Energy Corporation	5
AGL Resources	4
Indiana Energy	4
Laclede Gas	3
Northwest Natural Gas	4
Peoples Energy	3
Washington Gas Light	4
Moody's Distribution Company Average	3.67

Source: Value Line Investment Survey

Western Kentucky Gas Company

A Division of Atmos Energy Corporation

Comparison of Value Line's Safety Rank

	Safety Rank
Atmos Energy Corporation	3
AGL Resources	2
Indiana Energy	2
Laclede Gas	1
Northwest Natural Gas	2
Peoples Energy	1
Washington Gas Light	1
Moody's Distribution Company Average	1.5

Source: Value Line Investment Survey

Western Kentucky Gas Company

A Division of Atmos Energy Corporation

Proposed Cost of Capital

Thirteen Month Average as of December 31, 2000

Item		Amount	Share	Cost of Capital Low	Cost of Capital High	Weighted Cost of Capital Low	Weighted Cost of Capital High
Shareholders' Equity	$	475,564,478	50.24%	12.00%	12.50%	6.03%	6.28%
Long Term Debt	$	382,004,580	40.36%	8.06%	8.06%	3.25%	3.25%
Short Term Debt	$	88,940,765	9.40%	6.10%	6.10%	0.57%	0.57%
Total	$	946,509,823	100.00%			9.86%	10.11%

Source:
Western Kentucky Gas Company Work Papers

Western Kentucky Gas Company

Moody's Local Distribution Companies

Comparison of After-Tax Times Long Term Interest Earned Ratios

Atmos Energy Corporation	@12% ROE	2.86
AGL Resources		2.61
Indiana Energy		4.10
Laclede Gas		3.06
Northwest Natural Gas		2.03
Peoples Energy		2.90
Washington Gas Light		3.34
Moody's Companies' Average		3.01

Source : Value Line Investment Survey

6

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	)	
RATE APPLICATION BY	)	**Case No. 99-070**
WESTERN KENTUCKY GAS COMPANY	)	

TESTIMONY OF JOHN W. HACK

Q. Please state your name, business address and position.

A. My name is John W. Hack. My business address is 5430 LBJ Freeway, Suite 700, Dallas, Texas 75240. I am employed by Atmos Energy Corporation ("Atmos") as Director of Gas Supply Operations.

Q. Please briefly describe your education and work history.

A. I have earned a Bachelor of Arts degree in business administration from Kentucky Wesleyan College. I have been employed by the Company since 1969 and have held numerous positions both with Western and Atmos. During the time at Western (July, 1969 through October, 1990), I held positions of Gas Controller, Supervisor of Gas Control, Supervisor of Gas Control and Rates, Manager of Gas Rates, and Manager of Gas Supply Administration. Since transferring to Atmos, I have held the positions of Director of Gas Supply Kentucky, Director of Interstate Gas Supply and my current position of Director of Gas Supply Operations.

Q. Please describe your duties.

A. As Director of Gas Supply Operations for Atmos Energy Corporation, one of my principle duties is gas supply management for its Western Kentucky Gas ("Western") division. I am responsible for all gas supply and system supply transportation arrangements involving the interstate pipelines which deliver gas to the Western system. This includes pipeline capacity arrangements, gas supply acquisition planning, contract negotiations and day-to-day administration, including administration of the company's end-user transportation program.

Q. Have you ever-submitted testimony in a regulatory proceeding?

A. Yes. I have testified and/or submitted written testimony before the Kentucky Public Service Commission in Case No. 9556 (the Company's 1988 general rate case); Case No. 89-354 (Alternative Fuel Flex); Case No. 92-558 (Limited Rate Change); Case No. 95-010 (General Rate Case); and in Administrative Case No. 346. Also, I have submitted testimony to the Kansas Corporation Commission (Docket No. 99-UNCG-486-CON).

Q. What filing requirement schedules are you sponsoring?

A. I am sponsoring Filing Requirement FR 10(9)(h)8, mix of gas supply.

Q. What functions are included in Gas Supply Operations?

A. The Gas Supply Operations function consists of Gas Supply Administration, Gas Control and Third Party Nominations and Scheduling.

Q. What is the scope of your testimony in this proceeding?

A. My testimony will address Western's gas purchasing practices, pipeline capacity management, gas supply planning and acquisition, types of supply and capacity agreements and other gas supply related matters in the FERC Order 636 environment.

Q. Please provide an overview of Western's gas purchasing practices.

A. The mission of Western's Gas Supply Department is to develop and manage a gas supply portfolio that is reliable, competitively priced and appropriate for the market and customers we serve. The process we go through to achieve these goals involves constant, thorough appraisals of our needs, our resources, options and the performance of all of our suppliers and transporters. We utilize a competitive bidding process which begins with the identification of a need for either new or replacement supply. The Department prepares a detailed Request for Proposal (RFP) which we send to potential vendors who might both have an interest in bidding and are qualified to perform the requirements being bid. After the successful bidder is selected, an agreement is finalized. Western requires corporate warranties from its vendors to assure that the benefits for our customers will assuredly be achieved. We have also been able to obtain competitively priced, reliable gas supplies utilizing this process.

Q. What pipelines serve Western's thru-put requirements?

A. Historically, Western's requirements have been served through Texas Gas Transmission Corporation (Texas Gas), Trunkline Pipeline (Trunkline), ANR and Tennessee Gas Pipeline Company (Tennessee), except for a small quantity of locally produced supplies. Approximately 82% of the requirements are through Texas Gas, 4% through Trunkline, and about 12% is through Tennessee, with the remaining 2% of the requirements purchased from local producers that are connected directly to Western's system. The ANR interconnect is primarily utilized for storage refill in Western's Bon Harbor and Kirkwood storage fields. Western recently interconnected with Midwestern Gas Transmission (Midwestern) and will receive a small portion of its requirements from Midwestern in the future. The addition of the Midwestern will proportionally reduce the percentage reflected above through Texas Gas by a small percentage.

Q. Please summarize Western's pipeline transportation capacity.

A. Western maintains only enough capacity to meet firm requirements, and seeks to minimize demand costs by releasing any unused capacity that may be available from time-to-time. Since implementation of FERC Order 636, Western has sought to obtain a portfolio of reliable and competitive market-priced supply to meet its firm requirements. Western has done this through utilizing a competitive bidding process, which allows Western the opportunity to take advantage of changing market conditions.

Q. Does Western have pipeline storage on all of its interstate pipelines?

A. No. Western only has no-notice storage on Texas Gas and contract storage on Tennessee Pipeline. The transportation agreements on Trunkline and Midwestern are firm transportation only and the transportation on ANR Pipeline is interruptible.

Q. Explain the difference between the No-Notice Service on Texas Gas and the Contract Storage on Tennessee Gas.

A. The storage on Texas Gas is bundled with firm transportation to provide the No-Notice service. Whereas, on Tennessee Gas, Western had an option to contract for storage separately. Both services are very similar operationally.

Q. Are Western's firm pipeline capacity requirements adequate to serve Western's firm market requirements on peak day?

A. Yes. The Western system was designed to maximize efficient capacity utilization. An example is the Texas Gas Zone 3 area where Western provides approximately 26% of peak day supply from Company-owned storage fields. These storage fields are directly connected to Western's system, which eliminates the need for pipeline capacity equal to the deliverability of these storage quantities. This results in substantial pipeline demand cost savings. Also, this Company-owned storage provides excellent supply reliability because it is located on Western's system and in the market area.

Q. What are Western's current supply source arrangements?

A. Western's supply source arrangement consist of a "Natural Gas Sales, Purchase, Transportation, and Storage Agreement" with Reliant Energy Services (formerly NorAm Energy Services) and a small quantity of local production.

Atmos' Gas Supply Department oversees these responsibilities on a daily basis and retains operational control. These responsibilities include supply planning, capacity management, monitoring and changing daily supply and storage levels, monitoring pipeline electronic bulletin boards, and reviewing and complying with tariffs, etc.

Q. Please describe Western's gas storage fields and their function.

A. Western owns six underground storage fields. Four of the six fields are used for peak shaving purposes in the Owensboro area. The other two storage fields are used for peak shaving purposes in the Madisonville and Hopkinsville peak shaving areas. The utilization of these storage fields provides Western the opportunity to smooth out the low load factor usage of the residential and small commercial customers.

Q. Does this complete your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF RATE APPLICATION BY WESTERN KENTUCKY GAS COMPANY	§ § §	CASE NO. 99-070

CERTIFICATE

I, John W. Hack, have answered the foregoing questions propounded to me in the above-referenced Docket. Those answers constitute and I hereby adopt, under oath, those answers as my prepared direct testimony in said case, which is true and correct to the best of my information and belief.

John W. Hack

John W. Hack
Director of Gas Supply Operations

STATE OF TEXAS
COUNTY OF DALLAS

SUBSCRIBED AND SWORN TO before me by John W. Hack, on this fourteenth day of May, 1999.

MARIE E. WALTZ
Notary Public
State of Texas
Comm. Exp. 12-07-2002

Marie E. Waltz

Marie E. Waltz, Notary Public
State of Texas

My Commission Expires: 12/07/02

10

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	)	
RATE APPLICATION BY	)	**Case No. 99-070**
WESTERN KENTUCKY GAS COMPANY	)	

TESTIMONY OF THOMAS H. PETERSEN

Q. Please state your name, position and business address.

A. My name is Thomas H. Petersen. I am Director of Rates for Atmos Energy Corporation, 5430 LBJ Freeway, Dallas, Texas 75240. I am responsible for rate studies of the Company's gas utility operations in 12 states including Kentucky.

Q. What is your educational background and professional experience?

A. I received a Bachelor of Science degree in accounting from the University of Omaha and a Master of Arts degree with a major in finance from the University of Iowa. I am a Chartered Financial Analyst. From July, 1980 through March, 1989, I was employed in the Rates and Tariffs Division of the Kentucky Public Service Commission. I was Manager of Rates and Revenue Requirements for Atmos from April, 1989 through September, 1997. I was Director of Price Policy and Administration from October, 1997 through September, 1998. I have been in my current position since October, 1998.

Q. What is the scope of your testimony in this proceeding?

A. I am sponsoring the following:

FR 10(9)(v) Class Cost Service Study

FR 10(9)(t) List of Software

Q. Do you adopt these Filing Requirements and make them a part of your testimony?

A. Yes.

Class Cost of Service

Q. Please explain FR 10(9)(v), the class cost of service study.

A. The objective of the study was to distribute in a reasonable manner the Company's per books costs for the fiscal year ended September 30, 1998 among the following five rate classes: residential, commercial, firm industrial, interruptible and carriage customers using less than 200,000 Mcf per year, and interruptible and carriage customers using over 200,000 Mcf per year. The results of this distribution of embedded costs are useful to consider in designing rates when the limitations of this type of study are also considered. A substantial portion of the Company's cost of service is incurred in common for all customer classes. The distribution of these common costs among classes is done in a reasonable manner following a generally accepted methodology. However, an allocation of common costs among classes can never be as precise as the assignment of costs directly incurred to serve a particular class of customers. For example, commercial customers can be directly assigned their portion of the commodity cost of gas that they consume, but they must be allocated a reasonable portion of the cost of mains that serve multiple classes of customers. Also, an embedded cost of service study does not consider incremental costs of providing service or competitive market conditions for each of the customer classes. With these limitations in mind, the results of this embedded cost study are a useful guide in designing rates when considered along with incremental costs, competitive circumstances and gradualism in implementing changes.

Q. Why did you select these five rate classes?

A. These are the same rate classes used in the Company's previous class cost of service studies. They follow the current rate design and differ from one another in key load characteristics.

Q. Please compare the five rate classes with regard to annual use per customer, seasonality of use and load factor.

A. Page 2 of the study shows comparisons among the five rate classes on annual use per customer, seasonality of use, and load factor. Average annual use per customer varies from 86.2 Mcf for residential class to 1,000,011 Mcf for the large interruptible class. Winter season volumes as a percent of annual volumes varies from 73.8% for the residential class to 45.2% for the large interruptible class. Class load factor is the average daily use divided by either design day use or maximum daily contract level. Class load factors vary from 20.7% for the residential and commercial classes to 56.8% for the large interruptible class. Further, the interruptible and carriage customers have lower priority service than firm customers. They may be curtailed under system peak load conditions. The rate classes selected use available data and capture these differences in load characteristics.

Q. Briefly describe the methodology used in the class cost of service study.

A. Per books data for the fiscal year ended September, 1998 were used with an adjustment to reflect normal weather in revenues net of gas costs. The weather normalization is consistent with the determination of revenues for the forward looking test year. Revenues are included net of the gas cost recoveries embedded in rates. Gas costs recoverable through the Gas Cost Adjustment ("GCA") mechanism were excluded from this study. Another adjustment to per books data was an adjustment to customer accounts expense to reflect a more normal level of this expense than the amount expensed during the transition to a call center.

In distributing costs to rate classes, some costs could be and were directly assigned, but most had to be allocated. I applied a three step allocation process. First, costs were distributed among the functions of gas costs, storage, distribution, transmission and production. Second, the costs in each function were further classified by whether they were primarily related to the number of customers served, the amount of the commodity delivered, or the daily demands placed on the system. Finally each functionalized and classified cost was allocated among customer classes. The detail of how each allocation was made is displayed in the attached study and workpapers. The results are summarized on pages 1 and 2 of the study. Pages 3 through 5 show the allocation of rate base. Pages 6 through 15 show the allocation of costs. Pages 16 and 17 state the derivation of cost allocators. Page 18 shows the calculation of revenue net of gas cost by class from rates in effect during fiscal 1998. Page 19 summarizes monthly customer costs by rate class.

Q. Is this class cost of service study similar to the one the Company filed in its last Rate Case No. 95-010?

A. Yes, the methodology used in the study filed in Case No. 95-010 was used as a starting point in developing this study. However, as discussed above, this study is limited to the analysis of costs that are recoverable through base rates rather than through the GCA. Also, there have been refinements in the methodology. This study incorporates a method of allocating "Other Revenue" to customer classes that was proposed by Mr. David Brown Kinloch on behalf of the office of the Attorney General in Case No. 95-010. This method allocates "Other Revenue", except for industrial electronic flow measurement charge revenues, among customer classes on the basis of the number of customers, better matching these revenues to the classes that provided them. Also, since the last case there were significant additions of 6 inch and 8 inch mains. These additions were classified as distribution plant while earlier similar additions had been classified as transmission plant. To avoid distorting the distribution mains regression analysis on worksheet 7 of the study, these mains were reclassified as transmission for purposes of this study.

Q. What were the study's findings?

A. The total rate of return is 7.93%. The residential and commercial classes have lower rates of return on rate base of 7.06% and 6.22% respectively. The other classes have higher rates of return, 14.17% for firm industrial and 18.85% and 9.61% respectively for the smaller and larger interruptible and carriage customers.

Q. The study was performed using 1998 data. Have you considered how the results of the study would differ if the analysis had been performed on the forecasted test period in this case.

A. Yes, I reviewed Ms. Buchanan's calculation of the revenue deficiency in the forecasted period. I have also read Mr Gruber's discussion of the Company's various service improvement initiatives. Based on his discussion, it appears that much of the cost of the initiatives would be applicable to the residential class. Based on this review, it appears that the costs of providing service would be higher for all classes in the forecasted period, but that the relative levels of costs between classes would follow a pattern similar to the results of this study. Therefore, the implications of the study for rate design would be similar.

Q. Does that conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 99-070
WESTERN KENTUCKY GAS COMPANY	)	

CERTIFICATE

I, Thomas H. Petersen, have answered the foregoing questions propounded to me in the above enumerated Docket. These answers and exhibits constitute and I hereby adopt, under oath, these answers as my prepared direct testimony in said case, which is true and correct to the best of my information and belief.

Thomas H. Petersen

Thomas H. Petersen
Director of Rates
Atmos Energy Corporation

COMMONWEALTH OF KENTUCKY	)	
	)	S.S.
COUNTY OF DAVIESS	)	

SUBSCRIBED AND SWORN TO before me by Thomas H. Petersen, on this 11th day of May, 1999.

Pearl Ann Simon

Pearl Ann Simon
Notary Public
State of Kentucky At Large.

My Commission expires: September 26, 2001.

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BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	**)**	
RATE APPLICATION BY	**)**	**Case No. 99-070**
WESTERN KENTUCKY GAS COMPANY	**)**	

TESTIMONY OF GARY L. SMITH

Introduction

Q. Please state your name, position and business address.

A. My name is Gary L. Smith. I am Vice President - Marketing of Western Kentucky Gas Company ("Western" or "Company"). My business address is 2401 New Hartford Road, Owensboro, Kentucky, 42303.

Q. Please briefly describe your current responsibilities, and professional and educational background.

A. In my position as Vice President – Marketing, I am responsible for planning and directing the development and implementation of marketing plans and strategies for natural gas services to residential, commercial, and industrial sales and transportation markets. I am a 1983 graduate of the University of Kentucky, with a Bachelor of Science degree in Civil Engineering. I have been employed by Western since 1984, initially as Project Engineer. After serving in a variety of technical and supervisory engineering positions, I transferred into the Industrial Marketing department in 1990. I became Director of Large Volume Sales in 1991, and was named Vice President – Marketing in 1998.

Q. Have your ever submitted testimony before the Kentucky Public Service Commission?

A. Yes. On November 21, 1997, I participated as a witness in a hearing on the matter of "Petitions of Western Kentucky Gas Company for Approval and Confidential Treatment of a Special Contract Submitted to the Kentucky Public Service Commission", Case Numbers 96-096, 96-113, 96-185, 96-278, 96-295 and 96-424.

Q. Are you sponsoring any of the filing requirements and, if so, which?

A. I am sponsoring the following filing requirements:

FR 10(1)(b)7	Proposed Tariff in compliance with 807 KAR 5:011
FR 10(1)(b)8a	Present and Proposed Tariffs in Comparative Form
FR 10(9)(c)	Factors Used in Preparing the Utility's Forecast Period (Revenues/ Volumes)
FR 10(9)(h)14	Customer Forecast
FR 10(9)(h)15	Mcf Sales Forecast
FR 10(10)(l)	Narrative Description and Explanation of All Proposed Tariff Changes
FR 10(10)(m)	Revenue Summary for Both the Base Period and Forecasted Period
FR 10(10)(n)	Typical Bill Comparison Under Present and Proposed Rates for All Customer Classes

Q. Do you adopt these Filing Requirements and make them part of your testimony?

A. Yes.

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

A. The purpose of my testimony is fivefold: (1) to provide an overview of Western's service area and its customer base; (2) to describe the methods used to forecast Western's revenues and volumes as they relate to the base period and test period in this case; (3) to present the test period forecast of revenues and volumes; (4) to provide an overview of the financial problems caused by our current rate structures; and, (5) to present the rates and tariff changes we propose to restore Western's financial integrity going forward.

Overview of Western's Service Area and Customer Base

Q. Please describe the makeup of Western's current customer base.

A. Western currently serves 175,000 customers throughout its service area extending from western to central Kentucky. Residential class customers account for the vast majority of meters, at nearly 156,000. Western's natural gas deliveries totaled 48.8 Bcf per year during the 12-month period ending September 1998.

The Company is somewhat unique in its level of throughput to industrial class customers, with industrial sales and transportation volumes accounting for more than 60% of Western's annual throughput during that 12-month period. The region served by Western is somewhat economically dependent on the well-being of these industries, as is Western through its requirements for operating margin under current rate designs.

Although the industrial class accounts for the majority of total annual deliveries, it is important to note that it is the residential class that primarily drives Western's growth capital investment, constituting the vast majority of the Company's annual funding requirements for the extension of pipelines.

Q. What is the economic climate in the area served by Western?

A. Western serves a region that has traditionally exhibited low to moderate population growth. During the decade of the 1980's, counties served by Western experienced a population growth rate of only 1.5% for the ten year period. Although estimated population growth rates have increased in the 1990's, the annual growth rate is still less than 0.5% per year.

Q. What is Western's current level of annual meter growth?

A. New customer additions attributable to new residential developments have exhibited stable levels over recent years. Total customer growth has declined moderately over the past 1½ years, due to a diminishing number of nearby conversion candidates.

Western's current annual meter growth rate for all customer classes is slightly less than 2000, about a 1% growth in meter count per year.

Process of Forecasting of Revenues and Volumes

Q. Please describe your role in the forecasting of revenues and volumes for Western's budgets?

A. For the past three years, I have had primary responsibilities for forecasting the volumes and revenues in Western's annual budget. The process of developing these forecasts has become increasingly more refined over the three-year period.

Q. Please describe the goals of forecasting revenue and volumes?

A. The goal of revenue forecasting, fundamentally, is to provide an accurate assessment of expected revenues for business planning purposes. The primary emphasis of the "revenue" budgeting process is the estimate of the Company's gross margin, that portion of revenues excluding purchased gas costs. Purchased gas costs, recovered through the Company's Gas Cost Adjustment mechanism, are calculated only as a final step in the process, to forecast gross revenues.

Revenue forecasting is an essential element of Western's financial planning and affects our level of operating and maintenance expenses, capital investment, and cash flow requirements. Volumetric forecasts utilized in the budget are also utilized for gas supply planning purposes.

Q. What types of factors are considered in Western's revenue and growth forecasting process?

A. The forecast process can be segregated into two steps. The first step is an analysis of revenue trends over recent years to determine a baseline reference. The second step is consideration of factors and issues expected to affect the budget period.

First, the analysis of historical revenue trends quantifies the net customer additions and Mcf requirements, by customer class. Using heating degree day data for the respective periods, the Mcf requirements are "weather-normalized" for each customer class. Upon completing the analysis of historic data, customer growth and class usage trends may be identified.

Second, consideration is given to any factors that could either continue or alter historical trends. These factors include:

- changing local economic conditions that could influence customer growth;
- changes in marketing practices that could impact customer growth rates;
- major industrial additions or plant closings;
- price-restructuring with large customers that has occurred or is anticipated; and
- institutional or regulatory changes.

Considered individually, these factors may have either a positive or negative affect upon current revenue streams or the rate of growth.

Q. What time period typically forms the basis for revenue and volume forecasts?

A. Forecasts are typically prepared for Western's fiscal year, which runs from October 1 to the following September 30.

Q. What is the base period for this case?

A. The base period is our 1999 fiscal year (FY1999), which runs from October 1998 to September 1999. For purposes of this filing, the data submitted corresponds to the budgets in place for Western during FY1999, updated for actual results through March 1999.

Q. What is the forecast period for this case?

A. The forecasted test period for this case is January 1, 2000 to December 31, 2000. This period is largely determined by the date of our filing.

Q. Are the revenues for the forecasted test year representative of Western's budget for that time period?

A. Yes. The revenues shown on FR 10(9)(d) for the test year correspond to Western's budget for the period.

Q. Please describe in detail the base period revenue and volume forecasting process as well as the key assumptions included in those forecasts.

A. The revenue and volume forecasts for FY1999 were prepared in the manner described earlier in this testimony – the two step process of establishing a historical baseline reference and adjusting for unique factors influencing the budget period.

Financial statistics for three years were analyzed, noting the numbers of customers added during that time and the total volumetric requirements by customer class. Actual sales volumes were adjusted for variances from normal weather, based on the heating degree days reported in the Company's financial statistics. The methodology for determining composite degree days for Western was based on a process instituted several years ago, with the composite calculated weighting weather data from Paducah, Madisonville and Danville.

Based on the historical data, trends were noted for the following statistics:

- Total residential customer count and net annual growth,
- Total commercial customer count and net annual growth,
- Total public authority customer count and net annual growth,
- Annual changes in volumetric requirements for industrial sales and transportation deliveries, and
- The level of volume migration from sales to transportation service.

These items completed the first step – analyzing historical information. In the second step, applying adjustments to historical trends, a number of assumptions were made.

Q. Please discuss the assumptions used in the development of the FY1999 revenue budget.

A. Economic conditions in Western's service area have exhibited stable, though only moderate population growth rates for several years. However, for the FY1999 budget, we forecasted that residential growth would exceed the levels experienced in recent years - a net increase of 2500 residential customers, despite historical growth rates averaging slightly less than 2000 for the three prior years. For the previous five years, however, the average net residential growth had been nearly 2400 per year. The budgeted 2500 additional customers were comprised of 1700 additions to serve newly constructed homes and 800 for on-main conversions. On-main residential conversions had, in fact, averaged more than 900 per year for the five years ending FY1997. Marketing incentive programs had been targeted for on-main conversion candidates since the early 1990's, and the FY 1999 budget assumed the rate of growth from the conversion market would be sustained consistent with past trends.

Commercial and Public Authority customer gains were projected to continue at historical levels, at 285/year and 10/year respectively.

Annual volumetric growth in the industrial sales/transportation sector revealed an expected annual growth of 400,000 Mcf. Although this level of growth was forecast to continue in the FY 1999 budget, there were concerns that future growth rates could diminish since many of Western's active industrial development markets had slowed due to labor market saturation. Discounting of margins, necessary to retain large customers vulnerable to physical bypass of Western's system, has become an increasingly common occurrence over the past several years. Consequently, an adjustment was incorporated for expected transportation margin losses to retain competitively situated large industrial customers.

Q. Based on actual information now available for FY1999, were the forecasts of customer growth in the budget reasonably accurate?

A. Ultimately, the forecasted growth rates for FY 1999 have not materialized. Through March 1999, Western's total average monthly meters in service have increased by 2,132 over the same period in FY 1998. The budget forecast growth of 2,795. Industrial sales and transportation volumes have declined in FY1999, as opposed to the gains we forecasted.

Q. Were there any significant changes in the forecasting methods used to develop the test year forecast versus the base period budget?

A. Yes, although the two fundamental steps in the revenue forecasting process remained unchanged. The development of the test year forecast included a much more detailed historical analysis than previous budgets. For example, we studied the appropriateness of the weather stations comprising Western's composite heating degree day basis. We examined the long-term usage trends for residential and commercial customers as well. We also conducted a detailed analysis of individual industrial customer usage trends and contract service changes, typical of the thorough studies associated with a comprehensive rate case. Some key assumptions also changed, recognizing variations in market and economic conditions in the service area.

Q. Please summarize the revenue and volume forecasting process used for the test year.

A. In order to assure a solid, historical basis for the test year forecast, we gathered detailed information from a twelve-month "reference period" which coincides with Western's FY1998, October 1997 to September 30, 1998.

Several adjustments to the actual, per books results of the reference period were warranted to reflect changes expected to occur prior to or during the forward-looking test period. These adjustments included:

- a pro-forma adjustment to reflect changes in industrial sales and transportation deliveries due to customer additions, plant closings, expansions or reductions affecting gas requirements and contract reformations that have occurred or will occur prior to the test year,
- a weather adjustment to reflect performance during FY1998 if normal winter weather had occurred,

- an adjustment for expected meter growth per customer class from the reference period to the test year, and
- an adjustment to reflect declining normalized usage for residential and commercial customers.

Exhibit GLS-1 summarizes the actual, per books margins (revenues less purchase gas costs) for the reference period and each of the adjustments incorporated to determine the forecast for the test year.

Q. How was the data for the reference period gathered?

A. The unadjusted data for the reference period reflects the actual billing units and margins for all services during the FY1998. This data was gathered from billing system reports for the period. Exhibit GLS-2 details the actual billing units and volumes by class of service for FY1998.

Q. Please describe the adjustments to the reference period, including key assumptions, for industrial sales and transportation services.

A. The volume requirements in FY1998 for each industrial customer were reviewed, with adjustments made to account for expected changes by service type for future periods. For example, usage for a new customer added midway through the reference period would not be representative of its forecast test period requirements. Adjustments were also made for plant closings, expansions or reductions, and contract changes altering a customer's service type or rate schedule. These adjustments ensured that known, measurable and anticipated changes in industrial sales and transportation were reflected in our test period forecast. Exhibit GLS-3 summarizes the impact of industrial contract and volume changes, by service type.

Q. Please describe the process employed to determine the adjustment for weather variances during the reference period.

A. Adjusting for variances from normal weather is a common practice. In this case, we began by thoroughly analyzing the appropriateness of the weather stations utilized for the calculation of a composite number of heating degree days (HDDs) for Western's service area. The HDD is a measure of the difference between average daily temperature and a 65 degree Fahrenheit base. Western's service area covers a broad territory, and requires the application of multiple weather stations to determine a system average, or composite. Past procedures used by Western have included some secondary or tertiary stations manned by volunteers versus the first order stations maintained by the National Oceanic and Atmospheric Administration (NOAA). First order weather stations are those at commercial airports manned 24 hours a day and recording hourly weather data which NOAA holds to be the most reliable. Since Western was considering a possible Weather Normalization Adjustment in this case, we recognized that quality first order stations were necessary in the determination of HDDs.

Q. Which NOAA first order stations were utilized to determine Western's composite heating degree days?

A. Five first order stations in and around Western's service area were utilized for purposes of determining a system composite. Geographic proximity to communities we serve and the respective number of weather-sensitive customers (residential, commercial and public authority classes) in those communities established the respective weighting of each station. The resulting pro-rata allocation of data from each station is as follows:

NOAAFirst Order Weather Station	**Heating Degree Day Weighting Percentage**
Paducah, KY	37.9%
Evansville, IN	22.2%
Nashville, TN	21.5%
Louisville, KY	2.8%
Lexington, KY	15.6%

Actual HDD data was secured from NOAA for the above stations, and the benchmark of normal weather was determined using NOAA's report on "Climatography of the

United States No. 84, Daily Normals of Temperature, Heating and Cooling Degree Days and Precipitation 1961-1990".

Again, the additional research and assessment of the HDD composite was essential due to Western's consideration of a WNA in its proposed rate structure. The WNA proposal will be discussed more thoroughly later in my testimony.

Q. What was the composite normal heating degree days calculated for Western's system?

A. The composite normal for the Western system is 4340 HDDs.

Q. What was the actual composite degree days for the FY1998 reference period?

A. For the FY1998 period, actual HDDs were 4021.

Q. How was the potential for weather variances accounted for in the test period forecast?

A. The forecast volumes for the test year were based on achieving the composite normal of 4340 annual heating degree days. Exhibit GLS-4 summarizes the weather adjustment to the reference period resulting from the 7.4% warmer than normal period.

Q. How was the adjustment calculated for expected meter growth per customer class from the reference period to the test year?

A. Customer growth levels were evaluated over the past several years, using two sources – the Company's financial statistics and marketing reports tracking new customer additions. Through both resources, it was apparent that the level of customer growth has declined in recent years, and particularly during FY1999. The following table summarizes the number of active meters during the month of December for each of the past five years, as reported in financial statistics:

Fiscal Year	Residential Meters In Service	Net Change From Prior Year
1994	148,461	2,844
1995	151,311	2,850
1996	153,605	2,294
1997	156,057	2,452
1998	157,779	1,722

Similarly, marketing reports indicate a decline in the rate of adding new residential customers, more specifically in the category of on-main conversions.

Through an analysis conducted in the fall of 1998, Western determined that the number of homes located on the Company's distribution mains that do not receive gas service was only 2,150 - indicating a market saturation of over 98.5%. Clearly, our long-standing efforts to attract on-main conversion prospects had not only been effective, but also greatly diminished the number of remaining prospects from that market. In light of these observations, the forecasted growth for residential customers results in an annual net addition of 1700 customers.

Similar analysis in the commercial and public authority classes, resulted in a forecasted net annual growth rate of 230 commercial customers.

Exhibit GLS-5 summarizes the impact of growth on monthly billings and volumes by class.

Q. Are there any other significant adjustments from the reference period to the forecasted test year?

A. Yes. Another significant adjustment to the test year forecast addresses a trend of reduced usage per customer in both the residential and commercial class. We reviewed historical billing data and assessed the total weather-normalized throughput for Western over an eight-year period, from FY1990 to FY1998. The conclusions were striking.

Despite adding more than 22,000 residential customers during the period, Western's total weather normalized residential sales deliveries remained flat. Further analysis revealed that the average weather-normalized usage per residential customer had declined from 100 Mcf per year to 86 Mcf per year over the course of eight years. The rate of decline was constant, at about 1.73 Mcf each year.

An investigation into the commercial and public authority group yielded similar results. The combined average commercial/public authority weather normalized usage declined by more than 3 Mcf per year over the period from FY1990 to FY1998. This "efficiency and conservation" adjustment is applied on a forward-looking basis to reflect the expected average requirements per customer during the test year.

Exhibit GLS-6 summarizes the volume adjustment for declining usage per customer.

Test Period Forecasts of Revenues and Volumes

Q. Was the forecasting process previously described the best method to use for the development of the test year volume and revenue forecast?

A. Yes. The method of developing the forecast ensures a solid bridge of logical and measurable adjustments, building upon the actual performance of a recent, reference period.

Q. After adjustments from the reference period, what is the projected financial performance of the Company in the forecasted test year?

A. Western's forecast of total gross profit for the forecasted period is $43.1 million. At this level of revenue, the Company would earn a -0.54% return on shareholder equity, approximately 3.6% return on rate base. An additional gross profit of $14.1 million is required to achieve the rate of return proposed in this case.

Problems with Current Rate Structures

Q. What has been the trend in earnings for Western is recent years?

A. When effects of weather are factored out, it is apparent that the Company has experienced a consistent decline in its financial return since implementing its last rate increase. Rate increases have historically been necessary every three or four years to restore the Company's financial integrity. Continued investments for the maintenance and expansion of our system, margin losses due to competition in the large industrial market and declining usage levels for residential and commercial classes have substantially reduced the Company's return since the last rate case.

Q. What market factors are responsible for this trend?

A. Several factors contribute significantly to Western's declining rate of return:

(1) Western has experienced exceptional industrial competition. Subsequent to our last rate case, the re-negotiation of special contracts has resulted in a reduction in annual margins of more than $800,000 from the affected customers;

(2) Western has experienced the continued effects of energy efficiency improvements and conservation in our core markets - residential and commercial service. Since 1995, the reduction in average, weather normalized, residential and commercial requirements have reduced Western's annual margin by nearly $1,600,000;

(3) The extremely low residential margin under Western's current rate structures produces poor financial returns on our investment to extend service to new customers. Although Western's growth rate is not exceptionally high, adding unprofitable new customers dilutes our overall financial performance, even at moderate growth rates; and

(4) Warm weather has undermined Western's ability to earn a reasonable rate of return.

Q. Under these market conditions, what effect does the current rate design have on Western's financial performance?

A. To reiterate Mr. Gruber's point, Western's current rate structures have produced an environment of high risk and low reward. We are simply not achieving a fair return on our investment with the rates currently in place. Each of the issues referenced above pose a serious business challenge. These challenges are exacerbated when coupled with ineffective rate design. For example, competitive pressures in the industrial market are compounded by rate designs premised upon large, high load factor customers subsidizing smaller, low load-factor customers. Cross-class rate subsidies also lead to poor returns on new investments to serve the subsidized markets – the very markets that demand the largest share of our annual growth capital investment. Similarly, conservation and efficiency effects in the residential and commercial markets are magnified by a rate design that requires a disproportionate share of revenue requirements to be recovered in the commodity component. Effects of warmer than normal weather devastate the financial returns of a well-managed, cost-conscious gas utility absent weather normalized rates.

Q. What is Western's current strategy for the industrial market?

A. Western's current tariff strategy is to provide a variety of sales and transportation service options, allowing each customer a menu of choices to best meet their unique economic and operational needs. This strategy is well-reasoned both for service to existing customers and in Western's support of state and local economic development efforts to attract new manufacturers to our region. Western also works hard to maintain good relations with its industrial customers. Our strategy is cognizant of the alternative sources of energy available to our industrial customers, and the role our current rates and services play in determining the energy choices made by industrial customers.

Q. What is the effect of current rate structures on the industrial market?

A. Serving the industrial market carries substantial risks because industrial margins are designed to subsidize residential rates in our current rate structure. The revenue burden borne by industrial customers to keep residential rates lower has undermined Western's competitive position with its largest customers. While the industrial sales and transportation market comprises a significant portion of Western's annual deliveries, the difficulty lies in financial dependence on a relatively small number of industrial customers to provide this subsidy. The retention of these accounts provides long-term benefits to all of Western's customers. Even at rates which have been negotiated significantly below the standard tariffs to compete effectively with an industrial customer's energy service options, any retained contribution of the industrial customers to the Company's fixed costs of operation is beneficial – to all ratepayers. Negotiating discounted-rate contracts can help salvage system load, but, Western and its shareholders suffer exclusively from the loss of revenues. We have no method in our current rate structures to make up for this reduction in revenue – a deficiency in contribution relied upon in the setting of Western's rates in the prior rate case. Only during a subsequent rate case can Western recognize the reduced revenue, adjusting the revenue requirements of other customers going forward.

Q. Please elaborate on the problems of bypass.

A. Energy often represents a major component of industry's overall manufacturing costs. Our experience is that large volume customers inevitably choose to seek cost-competitive options to minimize their energy costs. Their significant level of natural gas requirements and high load factor makes this class of customers particularly vulnerable to competitive options and threatens the long-term economics and affordability of our fixed cost system. Certain large industrial customers have gas pipelines in close proximity, providing easy access to competing sources of natural gas. In these situations, Western's published tariffs do not satisfy the demands or needs of the customer – in effect, creating highly favorable economics of physically bypassing Western, and avoiding our transportation charges. In such situations, Western must seriously consider the merits of discounting its applicable rates to lessen the customers economic attraction to bypass. Retention of a contribution from such customers toward Western's fixed costs is of benefit to all of Western's ratepayers.

Western is at risk, even with customers not favorably situated to physically bypass our system. For example, an economic downturn, closing of a major plant or a shift in production to sister plants outside western Kentucky, can trigger significant financial consequences for the Company. If Western's rates to industries are higher than an appropriate level, the potential for reduced industrial requirements is aggravated and our excessive revenue requirement from this small market sector is placed at significant risk. An appropriate level of industrial rates would focus more on the incremental value of their contribution toward fixed system costs instead of burdening the class with an unreasonable share of fixed system costs attributable to other classes of customers.

Q. Can you quantify Western's vulnerability to bypass?

A. Western, to date, has entered into 13 special contracts, lowering the otherwise applicable tariff rates to mitigate the customer's economic attraction to physical bypass. These 13 customers combine to consume more than 13,300,000 Mcf per year, and contribute $1.7 million toward Western's annual gross profits. Under Western's tariff rates, physical bypass of Western's system would have been imminent – in some cases producing a simple payback of six months or less on the customer's bypass facilities costs. The current annual gross profits from this group of customers represents a total annual discount below the otherwise applicable tariff rates of more than $3.5 million. Western's vulnerability to bypass, however, extends beyond these 13 customers under existing special contracts.

Despite Western's proactive attempts to retain bypass-vulnerable accounts, we have suffered the loss of two former customers to physical bypass. It is also noteworthy that Western has failed in a handful of cases to compete successfully for initial service to new industrial facilities. These facilities established initial service through a direct connection with a nearby interstate pipeline or, in some cases, through a third party pipeline.

Q. Are there examples of competition in other markets, such as the residential and commercial classes?

A. Yes. Competition exists with electric utilities serving our market, particularly in the arena of residential and commercial new construction. Such competition is fierce and is highlighted by an array of electric utility marketing activities primarily targeted to builders and developers. Builders and developers usually determine which utility services are initially made available to end-use customers. Builders and developers are quite sensitive to "first-cost" differentials between fuel choices. Electricity is universally installed in all homes and businesses. Although gas is a superior and more affordable energy source for heating and other services, it is competitively disadvantaged simply because it is a discretionary service. The nature of competition is to leverage market power to gain an even greater competitive advantage. Electric providers are and will continue to have market power by sheer inertia. To ensure that energy users in western Kentucky continue to have an energy choice, gas must be aggressively marketed - priced in a manner to produce a reasonable return to the Company and a competitive option for the customer. Our intent in this case is to ensure the competitiveness of our Company as well as its financial health.

Q. What is the affect of current rate structures on the residential market?

A. Current rate structures send uneconomic price signals to the residential market. In particular, our prices do not track the substantial fixed costs we incur to provide residential gas service. Western's margin for service to residential class customers, $1.0615 per Mcf, is very low. Our residential margin is the lowest among Kentucky's five largest local distribution companies, and are among the lowest in the 12 states served by Atmos.

Q. Why is Western's residential margin so low?

A. Costs of providing residential service are subsidized with revenues from the industrial class, keeping residential rate as low as possible. In a closed system, with a captive industrial class willing to subsidize other customer classes, such subsidies would have a reasonable chance of success. Absent such captive industrial customers, however, and with the continued loss of industrial revenues, residential rates must carry a greater revenue burden.

Q. What problems do low residential margins create?

A. Existing residential customers pay well less than their fair share toward Western's substantial fixed cost investments – pipeline systems designed to ensure reliable service during extreme cold-weather conditions to human needs customers. Also, low residential margins provide an inadequate return on investments necessary to expand service to new residential customers.

Q. What are the cost implications of serving residential customers during cold weather?

A. Our compact with the customer is an assurance that we will prudently invest in peak load capacity to ensure that critical human services needs are met during times of extreme weather. We expect that the costs of the investment, including a fair return on the investment, is fully recoverable. Meeting critical human needs during the heating season requires a significant fixed cost investment by Western.

However, Western's low residential rates, specifically its' present low monthly base charge has created an environment which is highly dependent on normal winter weather. Nearly 37 percent of Western's current annual margin is weather sensitive. That is, present margins are greatly dependent upon on the commodity used for space heating.

Absent properly balanced rates, Western's substantial fixed costs would remain under-recovered during warm weather. Neither customers nor the Company benefit when rates are so sensitive to weather.

Q. Please elaborate on the problems Western has experienced in the expansion of service to new residential customers.

A. Although only moderate residential growth is available to Western, a significant component of the Company's capital funds is dedicated to the extension of service to new residential customers. The very low margin for residential service results in an unprofitable extension of service, even under main extension policies meeting only the minimum standards of Commission's regulations. The testimony of Mr. Daniel M. Ives details the financial impact of service to new residential customers. Inadequate financial return on investments to serve residential growth have hindered Western in achieving intended returns.

Q. Mr. Petersen's testimony touched on the fact that residential, commercial and industrial margins and service charges do not reflect their embedded class cost of service. What is the consequence of that?

A. The cross-class subsidies inherent in our present rates send uneconomic price signals to the market by undervaluing subsidized services and overvaluing those services used to provide a subsidy. Each service should be set to recover its own level of costs. Once the costs of services are properly aligned by class, the fixed and variable elements in our rates should be re-balanced to more accurately reflect the underlying cost characteristics of those services. That is, where possible, fixed rate elements should be designed to recover fixed costs and variable rate elements to recover variable costs.

As stated previously, we have also determined that there is depletion in revenue caused by changing customer usage patterns that must be recaptured. Re-balancing a greater portion of our revenues to be recovered from our fixed versus variable rate elements will help resolve this problem.

Q. What problems result from the combination of non-gas and commodity gas costs in Western's rates?

A. Most customers have a poor understanding of the underlying costs which rates reflect. They have no idea how much the cost of gas versus non-gas costs affects their monthly bill. Customers also have no understanding of which costs are fixed and which costs vary with usage. As we approach unbundling, it is appropriate to separate gas costs and non-gas costs on the customer's bill so they will better understand which costs would be subject to choice and which will not.

Q. Do you have any final comments on the problems associated with Western's current rates?

A. I would just reiterate our overall financial weakness at this time. This weakness is highlighted by our exposure to weather variations. Additionally, service charges provide inadequate revenue to cover the costs of special customer services. Elimination of cross-subsidization is an important step in the restructuring required for unbundling. In sum, inadequate financial return on capital required to expand residential service, vulnerability to margin degradation in the industrial market, reliance on sustained levels of residential and commercial customer demand despite energy efficiency improvements, and dependence on normal weather have created a series of years of financial under performance by Western.

Proposed Rates and Rate Structures

Q. What are the goals for Western's rate design in this case?

A. Western has several goals that guide the rate design proposed in this forward-looking case.

1) Revenue adequacy. Ensure that the revenue deficiency is corrected. This deficiency is based upon our most realistic estimates of costs, usage and customer growth.

2) Rate equity. We must equitably distribute cost responsibilities to each customer class and re-balance rates to better reflect the underlying cost characteristics of each service.

3) Economic efficiency. Western proposes to establish rate structures aligned with appropriate business objectives, including but not limited to – earnings stability, service reliability, and customer satisfaction.

4) Long-term price stability. Our proposals have been developed to reduce if not eliminate our reliance on frequent rate adjustments to sustain our long-term financial performance.

Q. What are the primary rate changes proposed by Western?

A. Western's rate design proposals are as follows:

1) Realign residential, commercial and industrial margins and service charges to eliminate existing cross-class subsidies.
2) Rebalance the fixed and variable elements in our rates to more accurately reflect the underlying cost characteristics of our service and mitigate the depletion in revenue caused by declining residential and commercial customer usage.
3) Properly segregate our gas costs from our distribution costs in our commodity rates.
4) Phase-in the restructuring of the collection of Gas Research Institute (GRI) Research and Development (R&D) costs from the GCA to the proposed Distibution Charge.
5) Establish a margin loss recovery mechanism to capture industrial margins lost as a result of contracts negotiated to avoid bypass.
6) Offer a new Alternate Receipt Point Service that provides more flexibility to meet the demands of Western's transportation customers.
7) Establish a surcharge to pay the costs of our Demand Side Management program (WKG CARES).
8) Weather normalize our rates.
9) Establish a new forward-looking rate element to sustain us as we add new customers.

Q. Western proposes certain changes to service charges in this filing. Please describe each of the rate changes set forth in the tariffs.

A. Our intent is to ensure that our service charges are equitable. To achieve this, Mr. Doggette prepared a study to identify the costs to provide each service (reference Exhibit DHD-2) and we have set the price for each service at or above that cost. In this way we ensure that the service cost is assigned to the cost causer so that other customers do not have to subsidize those causing the cost. We also want to send the correct price signals to customers to avoid incurring unnecessary costs and keep the overall cost of service to all customers lower. As such, our service charges have been designed to promote efficient usage of services and discourage unnecessary churn of customers' service being turned off and on.

Q. What changes to Western's special services and applicable service charges are proposed?

A. Western is aligning the charges for similar services to the costs to perform. This will simplify our administrative procedures and reduce customer confusion in performing similar service order activity. This philosophy also includes charging for turn-on from non-payment of service (reconnect delinquent service). Consistent with the Business Process Changes described by Mr. Gruber, including the availability of more locations and more convenient hours for customers to pay their bills, we are also proposing to eliminate the termination or field collection charge.

Q. Please discuss the service charges for Turn-on and Read (meter read-in/read-out) that Western is proposing to change.

A. Western is proposing to change the charges for Turn-on and Read-in/Read-out to ensure each service recovers its full costs to perform.

Q. The seasonal charge requested is substantially greater than the cost identified in Mr. Doggette's Exhibit DHD-2. Why is this?

A. This charge is designed to not only recover the costs of both turning the service off and then back on, it is also designed to discourage unnecessary churn. Unnecessary churn of service order activity drives up the cost of service to all other customers. Absent the appropriate disincentives, customers have little economic motivation to help Western avoid incurring uneconomic costs. The Commission has previously ruled, in the case of Columbia Gas, that such rationale is a valid basis for the setting of seasonal turn-on charges.

Q. Please describe the After Hours Charge proposed by Western?

A. The After Hours Charge is designed to assign specific cost responsibility to those customers who require service order activity outside normal business hours. Consequently, the After Hours Charge has been set to recover an additional 1.5 times (the overtime factor) the payroll loading costs for the service technician. This charge will be applied to any special service activity, including reconnects for delinquent service, <u>initiated at the customer's request</u> outside normal business hours such as at night, on weekends or holidays. The Company will advise the customer of the applicable After Hours Charge upon receipt of the service request, and offer the customer the alternative to perform the requested activity during normal business hours, including reconnects for delinquent service. This charge is designed to send proper economic signals to the customer and prevent other customers from absorbing these additional costs.

Q. What is Western's Returned Check Charge proposal?

A. We are requesting to increase this charge from $15.00 to $22.50 to reflect the findings of the survey of banking industry return check charges referred to in Mr. Doggette's testimony.

Q. Please discuss Western's proposal to implement a five percent (5%) Late Payment Charge?

A. This new charge is consistent with our philosophy that customers should be sent the correct economic signals in pricing. In this case, we are encouraging timely payments to reduce the administrative costs and align overall cash flow to more closely match cycle billing. Our proposal for a five percent (5%) Late Payment Charge matches that of several other LDC's in Kentucky. The Late Payment Charge is applicable to G-1 sales service volumes. Western proposes to implement the Late Payment Charge beginning April 1, 2000, to provide additional time for consumer education regarding this new provision.

Q. What is Western's proposal for its Electronic Flow Measurement (EFM) monthly facilities charges.

A. Consistent with Mr. Doggette's recommendations, we are proposing to maintain the Class 1 EFM equipment monthly charge at $105 for a five year period, and increase the monthly facilities charge for Class 2 EFM equipment to $245 to ensure recovery of costs over five years. Western will also maintain the one-time payment option for both classes of equipment with the stipulation that Western will service the equipment for five years.

Q. Please discuss the Customer Class Cost-of-Service study sponsored by Mr. Petersen in this case.

A. Mr. Petersen's study confirmed a couple of key points relevant to Western's rate strategies:

- Residential and commercial customer classes continue to be subsidized by industrial customers; and
- Fixed and variable rate elements are not aligned to reflect the underlying cost characteristics of services.

In the development of Western's proposed rate structures for sales and transportation services, the conclusions of Mr. Petersen's study were considered as a guide for the realignment of overall customer class revenue responsibilities, as well as the fixed and variable components of the rate structures. However, as Mr. Petersen states in his testimony, results of an embedded class cost of service study should be considered along with incremental costs and competitive circumstances for each class as well.

Q. Please summarize the changes to the monthly base charges for each service.

A. Western's proposed monthly base charge for G-1 sales service is $9.00 for residential customers and $24.00 for non-residential service. The monthly base charge for interruptible sales services G-2 and LVS-2 as well as for carriage transportation services T-3 and T-4 are proposed at $250.00.

Q. How will Western's higher monthly base charges benefit Western and its customers?

A. A higher base charge recognizes that a fixed-cost gas system requires a large common cost investment. Few, if any, costs of operating our distribution system are variable. Usage patterns for the vast majority of Western's customers exhibit a low load factor, as well as a declining level of annual usage over time. Higher monthly base charges will mitigate the problems above and provide rate stability and a more constant flow of revenues in support of our fixed system costs.

Q. Please summarize the changes to the distribution charges (simple margin) for each service.

A. The proposed distribution charges for each of Western's sales and transportation services are noted in FR 10(1)(b)7.

Q. Are there proposed rate changes in addition to the base monthly charges and distribution charges noted above?

A. Yes. Western's transportation administration fee is proposed to increase from $45.00 per month to $50 per month, and the charge for the new T-5 alternate receipt point service is $0.10 per Mcf.

Q. What is the resulting effect of Western's proposed rates compared to current rates for the average residential, commercial and industrial customers respectively?

A. Using the test year volumes and gas costs as the basis for comparison, the annual impact of Western's proposed rates is as follows. The average monthly charges for a residential customer under G-1 service increases $4.85, a 13.5% increase over current rates. Commercial class customers average monthly charges increase $14.57, a 9.9% increase over current rates, and the industrial sales and transportation class average monthly charges increase $209.46, a 6.4% increase over current rates. The test year revenues are summarized on Exhibit GLS-7.

Q. What proposal is Western making to "properly segregate its distribution costs from its commodity gas costs?"

A. We proposing a zero-based Gas Cost Adjustment (GCA).

Q. What is a zero-based GCA?

A. A zero-based GCA excludes the cost of gas from embedded volumetric base rates. The GCA is so-called zero-based because the GCA will be calculated from zero each month. The GCA will reflect only gas costs. The GCA will be recovered as a Gas Charge which customers will see as a separate line item on their bill.

Q. Will the GCA continue to change each month?

A. Yes. The GCA will change because it is intended to reflect the most current cost of gas. The GCA also includes pipeline transportation, pipeline capacity, pipeline refunds, any true-up adjustments from prior periods, and other costs usually included in the cost of gas, such as the pipeline-billed GRI surcharge.

Q. What happens to the base cost of gas previously built into the embedded base rates?

A. Since the cost of gas will be calculated from zero each month, there will no longer be a base cost of gas built into base rates. Consequently, no adjustment will be necessary each month to have it removed during the GCA calculation. This makes the calculation of the GCA simpler.

Q. What happens to the base rate?

A. The base rate, currently, is the sum of Western's simple margin (or "distribution charge") plus the base cost of gas. Customers billings reflect a seemingly ambiguous base rate less an adjustment factor. Under this proposal, the components will be much more meaningful, a separate distribution charge and gas charge.

Q. What is the purpose of the distribution charge?

A. The distribution charge simply recovers our margin on a volumetric basis. It will recover that portion of our margin that is not recovered by the monthly customer charge.

Q. Is the result the same to ratepayers?

A. Yes, but under a zero-based GCA, it is easier for the customer to see that the gas charge recovers gas costs and that the distribution charge recovers margin.

Q. Are there any other benefits to a zero-based GCA?

A. Yes, there are several. First, some confusion will be removed from the bill because it will no longer show a correction factor (gas cost amount). On a given month, this line item could be either positive or negative and is an essentially meaningless subtotal in the GCA calculation process – and, provides no beneficial information on the costs of gas to the customer. Secondly, the GCA also becomes easier to calculate once separated out from the embedded cost of gas. Thirdly, a zero-based GCA is a small, but first step toward retail gas choice. It is important during the transition toward unbundling that customers understand which costs will be subject to choice and which would remain embedded in our cost of service. A zero-based GCA better informs customers of the different costs of providing gas.

Q. Do any other gas companies regulated by this Commission have zero-based GCA's.

A. Yes, Columbia Gas for one.

Q. Do any other Atmos companies have zero-based GCA's?

A. Yes, most of the 11 other states in which Atmos operates allow zero-based GCA's.

Q. Please describe the phased-in restructuring of collecting Gas Research Institute (GRI) Research and Development (R&D) surcharge as proposed by Western.

A. Consistent with the settlement reached at the Federal Energy Regulatory Commission (FERC), interstate pipelines are phasing-out the billing of GRI R&D surcharge to local distribution companies like Western. As a result of this settlement, GRI will lose all of its funding by the year 2004 unless LDCs, in cooperation with their state regulatory commissions, establish alternative funding mechanisms to pick-up the difference. Western's proposal is to fully fund GRI in its rates consistent with its December 31, 1998 level of GRI R&D surcharge recovery.

Q. How will Western phase in its restructured collection of GRI costs?

A. Today, the GRI R&D surcharge is recovered through the GCA because it is billed a component of gas cost from the pipeline. Since pipelines will no longer include the GRI R&D surcharge per the FERC settlement, we will no longer bill these to the customer as gas costs. After discussions with representatives of GRI and the Commission, we have decided to go ahead in this case and directly fund the GRI R&D surcharge as a component of our distribution charge applicable to all gas sold and transported, other than Carriage Services Rate T-3 and Rate T-4. All funds collected under this rider will be remitted to GRI on a monthly basis. We will continue to collect the pipeline billed GRI R&D surcharge as gas costs during the transition to full direct funding by Western. The restructuring will be complete after 2004.

Q. When would Western propose to adjust its GRI R&D collections?

A. Western would propose to adjust it GRI R&D collections annually consistent with the GRI R&D surcharge level being collected through the pipelines as of December 31, 1998, in conjunction with the transition schedule outlined in the pipelines' tariffs.

Q. Please describe Western's proposed Margin Loss Recovery Rider.

A. The Margin Loss Recovery Rider is designed to keep Western largely whole when industrial margins are reduced as a result of contracts negotiated to avoid bypass. Our proposal will shift most but not all lost revenue to the Company's sales service customers. Western would retain a portion of the loss associated with a renegotiated contract as an incentive for Western to maximize contract revenues through the highest possible negotiated price.

Q. Please explain the risk sharing proposed by Western.

A. Our proposal is for a 90/10 sharing of the risk of negotiated contracts. Western will adjust the volumetric commodity rate of all sales customers by an amount equal to 90 percent of the associated annual revenue reduction, while absorbing the remaining 10 percent of the revenue reduction as an incentive.

Q. How would Western adjust its margins?

A. Our proposal is to adjust all sales service margins on a semi-annual basis for any lost industrial margins.

Q. Would Western be required to obtain Commission approval of its negotiated contract rate prior to making any margin loss adjustment?

A. Yes, just as Western is required to receive approval for any negotiated contract rate today.

Q. What are the benefits of this provision for other ratepayers who will have their rates adjusted upward?

A. As addressed earlier in this testimony, any contribution made by a major customer to the Company's fixed costs is better than none if the alternative is bypass.

Q. Will residential and commercial ratepayers be paying the costs of serving industrial customers under this provision?

A. No. Western will continue to recover as much of its cost as is equitable and economically viable from its industrial customers. In every circumstance the industrial customer will continue to pay its incremental cost of service and make at least some contribution to Western's fixed joint and common costs. In fact, the process of securing the Commission's acceptance of a special contract includes Western's submittal of an analysis of contribution to fixed costs under the pricing terms of the proposed agreement.

Certainly Western has found, as has other LDC's, that its ability to recover costs from industrial customers is constrained by competitors in its market. Bypass of Western's system has become a viable option for uniquely situated customers. Western recognizes that if the price of the alternative supply is below Western's incremental costs, then Western should not retain the deliveries at pricing structures below that floor. Under such a situation, the bypass would be economic and Western could compete only to the detriment of its other ratepayers. This situation would be highly unusual.

In most all cases, where Western's rate is above the competitor's price due to the over-assignment of fixed joint and common costs to the industrial class, then the bypass is uneconomic. In these situations, the reduction in Western's rate by the amount necessary to maintain service to the industrial customer actually protects the general customer body from absorbing, ultimately, the fixed joint and common costs that would be recovered from the industrial customer.

Q. Why shouldn't Western's shareholders bear that burden?

A. Western's shareholders are investors. They derive no service benefit from this system of common costs. However, for purposes of providing an incentive to Western to maximize the revenues generated from a negotiated contract, the Company proposes to absorb 10 percent of the loss in revenue.

Q. What benefits does this proposal achieve for Western?

A. This proposal addresses the inequity of margin losses associated with negotiated contracts. Without this provision, Western's shareholders will have to permanently absorb this loss year after year until the Company files another rate case to set rates for future periods. In essence it allows us to avoid filing case rates as frequently. This is one of the goals stated for our rate design. I should add that setting rates in a future rate case would not allow Western to recover previously lost margins.

Q. Do any other Atmos companies have a margin loss recovery mechanism?

A. Yes. Similar mechanisms are in place in Tennessee, Georgia and South Carolina.

Q. Please describe Western's proposal to offer an Alternate Receipt Point Service to transportation customers.

A. Currently, Western's transportation customers have a designated single location to which the Company must receive their gas supplies. This single receipt point represents the primary location through which Western has physically received the supply for redelivery to the plant site, the delivery point to the Customer. Over the course of recent years, Western has installed facilities permitting receipts of supply from additional interstate pipeline sources. Heretofore, the new interconnects have been utilized for receipt of Western's system supply dedicated to sales customer requirements.

Since establishing the interconnects with additional pipelines, Western has received inquiries from transportation customers and their agents about the possibility of using the new points as an alternative point of receipt for their supplies into Western's system.

This new service is proposed to establish a framework under which transporters could utilize an alternative receipt point into Western's system.

Q. Would all of Western's current transporters be able to utilize the alternative receipt point service?

A. No. The proposed tariff addresses the limited availability of this receipt point option. The customer's physical location, and whether Western's upstream facilities are integrated with multiple pipeline interconnects dictate whether alternate receipt point service is a possibility. Even if a customer is served through a Western system accessing multiple interstate pipelines, the availability of the service may be limited by physical restrictions at the interconnect or through the Company's pipeline system. If such capacity constraints are not a restricting factor for a specific transporter, the service could be limited by Western to avoid any detrimental impairment of the Company's receipts for core market sales customers.

Q. If Western approves a request by a transporter to utilize the Alternate Receipt Point Service, would there be any other standard conditions of service?

A. Upon Western's determination that the requested service is available, an amendment to the service agreement between the Company and the customer would be necessary. As stated in the proposed T-5 tariff, all volumes under this service would be delivered on a strictly interruptible basis.

Q. Would volumes delivered under the Alternate Receipt Point service be "interruptible" even when applied to Firm Carriage Service?

A. Yes. Western's obligation to the customer under Firm Carriage Service is that our system capacity is sufficient to redeliver their carriage volumes, up to the contract maximum daily demand, from the Company's traditional receipt point to the delivery point to the customer. This obligation remains unchanged, but does not apply to supply volumes the customer delivers to Western at the alternate receipt point.

Q. What is Western's proposal to recover a surcharge for its Demand-Side Management program (WKG CARES)?

A. WKG CARES provides weatherization for the homes of low income consumers. WKG CARES is a three-year pilot program begun in 1996 and developed by a collaborative of participants in direct response to the settlement reached in our last rate case. An expert consultant, Mr. Michael Marks, was hired by the collaborative to ensure that WKG CARES met its objectives and qualified for full cost recovery. Mr. Marks will testify that our DSM surcharge proposal recovers not only the costs of the three-year pilot program, but also those costs associated with continuing our program for another three years. Mr. Marks will also testify that WKG CARES meets the criteria necessary for statutory cost recovery. If WKG CARES qualifies on a going-forward basis, it qualifies on an after-the-fact basis as well, because the programs are the same. Our request is only to recover approved program costs. We would not intend to continue any program that the Commission decides does not to approve. We are not trying to recover any revenues lost as a result of WKG CARES or any DSM incentives. Revenue requirements associated with the DSM program are incremental to the Company's deficiency in this case; therefore, the DSM surcharge is excluded from the summary of proposed revenues in Exhibit GLS-7.

Q. Please describe the purpose of the Weather Normalization Adjustment Rider (WNA) proposed by Western.

A. The purpose of a WNA is to eliminate the effects of abnormal weather on customer bills and the Company's earnings. Since the Commission designs rates based on normal weather and the Company has no control over weather, a WNA is a logical extension of that methodology. The benefit of a WNA is that neither the customer nor the Company bears an advantage or disadvantage as a result of abnormal weather variations during any heating season.

Q. Why is a Weather Normalization Adjustment (WNA) appropriate?

A. During the rate case process, both costs and revenues are normalized for a test year. The process of normalizing revenues consists of either increasing or decreasing weather related sales volumes by the difference between normal heating degree days (HDDs) and actual HDDs occurring during the test period. Normalized sales are used to calculate the per unit rates for gas service. These per unit rates are designed to recover significant fixed costs. These costs do not change with changes in weather, or related variations in commodity requirements. When weather is normal during a given period, usage matches the weather used to normalize sales, and the revenues produced by the rates in effect for that period recover only those costs approved by the Commission.

In actuality, however, normal weather seldom occurs. This results in either an under- or over-collection of the distribution costs, or non-gas costs, which commodity gas rates are supposed to recover. These costs are largely fixed in nature. Examples of these costs include the embedded cost of pipe in the ground or property taxes. These costs cannot be avoided simply because the weather is warmer than normal. Nor do these costs increase as a result of cold weather. Hence, in the absence of normal weather, there is a chronic mismatch of fixed costs incurred to revenues recovered. Either customers are billed for more costs than the Company incurs in weather which is colder than normal or the Company under-recovers its fixed costs in warmer than normal weather. Neither situation is desirable or equitable. A WNA resolves both situations by eliminating the effects of abnormal weather on customer bills and the Company's earnings, and returning gas rates to a desirable state of equilibrium.

Q. Doesn't the effect of abnormal weather average out over time so that neither customers nor the Company is harmed?

A. That may be the theory, but during a given abnormal heating season either the customer or the Company may be harmed. That is not equitable. Moreover, during consecutive heating seasons of abnormally cold weather, customers may be substantially harmed for a prolonged number of years. Conversely, during consecutive warm heating seasons, the Company may be substantially harmed by abnormal weather for a prolonged number of years. Either we collect substantially more revenue from customers than intended by the Commission or we substantially under-collect. Again, neither situation is equitable.

Q. Would the WNA apply to the GCA or Gas Charge?

A. No, the WNA would only apply to the Company's margin or what we propose to call the Distribution Charge. The GCA through which the Company recovers its gas costs will be unaffected by the WNA.

Q. How would the proposed WNA benefit customers?

A. The proposed WNA would stabilize customer bills, making them more predictable during the heating season.

Q. How would the proposed WNA benefit the Company?

A. The Company would benefit from revenue stability, making its revenues more predictable during the heating season.

Q. Does a WNA reduce the Company's risk?

A. WNA reduces a downside risk only if actual weather is warmer than normal. It also removes an upside opportunity when weather is colder than normal.

Q. How does a WNA eliminate the effects of abnormal weather?

A. The WNA is an adjustment mechanism that computes the marginal change in fixed cost revenue associated with abnormal weather and spreads that revenue over actual sales.

Q. How will the WNA work?

A. The WNA shall be computed using the following formula:

$$WNA_i = R_i \frac{(HSF_i \quad (NDD - ADD))}{(BL_i + (HSF_i \times ADD))}$$

Where,

i = any rate schedule or billing classification within a rate schedule that contains more than one billing classification

WNA_i = Weather Normalization Adjustment Factor for the ith rate schedule or classification expressed as a rate per Mcf

R_i = weighted average rate (distribution charge) of temperature sensitive sales for the ith schedule or classification

HSF_i = heat sensitive factor for the ith schedule or classification used in normalizing test year sales

NDD = normal billing cycle heating degree days

ADD = actual billing cycle heating degree days

BL_i = base load for the ith schedule or classification used in determining normalized test year sales

Customer base loads and heating sensitive factors will be determined by class and computed annually.

Q. How does Western propose to administer its WNA?

A. Western's proposal mirrors that of its affiliate, United Cities Gas Company in Tennessee and Georgia. (This is also the same manner in which Nashville Gas and Chattanooga Gas administer their WNA programs.) The benefit of this is that the same successful administrative processes in use and functioning well for United Cities and its customers since 1990 would be applied to Western's WNA. No new computer programs or data collection systems would have to be developed. The same Atmos shared services accounting and billing personnel who administer United Cities' WNA would administer Western's WNA. This should ensure a smooth transition, a minimum of problems and virtually no start-up or incremental costs to be incurred for Kentucky customers.

Q. To which classes of service, and when will the WNA apply?

A. The WNA will apply to all residential, commercial and public authority bills under Rate G-1 Sales Service, based on meters read during the heating season months of November through April. The WNA will not be billed to reflect meters read during the months of May through October.

Q. Why not industrial customers?

A. Industrial customer usage is not highly sensitive to weather variations. Industrial volumes are usually tied to consumption related to the manufacturing process.

Q. When would Western propose to put its WNA in effect?

A. After approval by the Commission, Western proposes to put its WNA in effect at the beginning of the first complete heating season. That date would be November 1, 2000.

Q. What reports does Western propose to submit to the Commission on its WNA?

A. Western proposes to submit a monthly report to the Commission summarizing the effect of its WNA on customer bills by cycle for each customer class as well as actual and normal degree days and the number of days in a normal cycle. Western will also report a WNA factor and actual total revenues for each cycle.

Q. Have a number of other states approved a WNA?

A. Yes, in 1994, Columbia Gas presented evidence to this Commission that there were 13 states that had approved a WNA. This Commission then added itself to that list by approving a WNA for Columbia Gas.

Q. What proposal is Western making to address the financial problems related to residential main extensions which you previously discussed in your testimony?

A. We are proposing to establish a Premises Charge. The Premises Charge is designed to sustain us financially as we add new residential service connections on our system. This charge will allow us to avoid increasing the rates of current ratepayers to pay for the substantial fixed costs of adding new customers by allowing "growth to pay for growth." By design, the Premises Charge will help the Company avoid filing for rate increases in the future. Our proposal includes a request for deviation from certain Commission rules relative to new mains, service lines, regulators and meters. Mr. Daniel Ives, a consultant with the Lukens Groups, Inc., will discuss our proposal for a Premises Charge in more detail in his testimony, including the proposed tariff and rule changes.

Q. Are there any changes in the proposed tariff in addition to those related to the subjects noted above?

A. Yes. There are a number of tariff language changes that are proposed for purposes of improved clarity and consistency. All of these minor changes, as well as changes resulting from the rate changes and new services described previously, can be readily distinguished on the side-by-side tariff comparisons in FR 10(1)(b)8a. A few examples of the minor tariff changes include:

- the deletion of the minimum bill relating to maximum seasonal volumes. This clause is an outdated carry-over from the moratorium period in the late 1970's and early 1980's.
- standardization of curtailment/unauthorized overrun language in each of the tariffs subject to these provisions. Western has added several sales and transportation services through the years, and in doing so, failed to develop uniform curtailment language.
- added the Alternative Fuel Responsive Flex Provision to the Rate G-2 interruptible sales tariff. This change also is for purposes of standardization - the G-2 tariff is the only interruptible tariff that does not include the Flex provision.

Conclusion

Q. Are the forecasts of revenues and volumes you have prepared for the test period budget presented in this rate application the same forecasts which will be used by Western to operate the Company for the respective forecast period?

A. Yes. The forecasts of revenues and volumes I prepared for the test period budget presented in this case determines the forecast of costs, or budget, filed in this case.

Q. Do you believe that the forecasts you have prepared for the test period revenue budget and presented in this case represents the most reasonable basis of revenues and volumes for the setting of rates in this proceeding?

A. Yes. These are the very best estimates we have of Western's future revenues and volumes and I believe these are the projections to be relied upon in the setting of rates.

Q. Are the rates and rates structures proposed by Western those rates which will, in total, best serve the needs of Western's ratepayers and shareholders in continuing or improving the high quality and efficient service Western's customers now enjoy?

A. Yes. Our proposal is the best overall rate design to sustain Western financially in the years ahead and are the rates consistent with the highest quality and most efficient service we can provide.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 99-070
WESTERN KENTUCKY GAS COMPANY	)	

CERTIFICATE

I, Gary L. Smith, have answered the foregoing questions propounded to me in the above enumerated Docket. These answers and exhibits constitute and I hereby adopt, under oath, these answers as my prepared direct testimony in said case, which is true and correct to the best of my information and belief.

Gary L. Smith

Gary L. Smith
Vice President of Marketing
Western Kentucky Gas Company

COMMONWEALTH OF KENTUCKY	)	
	)	S.S.
COUNTY OF DAVIESS	)	

SUBSCRIBED AND SWORN TO before me by Gary L. Smith, on this 11th day of May, 1999.

Pearl Ann Simon

Pearl Ann Simon
Notary Public
State of Kentucky At Large.

My Commission expires: September 26, 2001.

EXHIBIT GLS-1
Schedule 1 of 1

Western Kentucky Gas Company
Summary of Revenue at Present Rates
Test Year Ending 12/31/2000

Line No.	Description	Block (Mcf)	Reference Period - Twelve Months Ending 9/30/98					Forward-looking Adjustments To Test Year		Total Test Year Volumes	Present Margin	Present Revenue
			Number of Bills, Units	Volumes As Metered	Contract Adj. Bills and Volumes	Weather Adj. Volumes	Total Volumes	Customer Growth Forecast	Conservation & Efficiency Adjustments			
	(a)	(b)	(c)	(d)	(f)	(e)	(g)	(h)	(i)	(j)	(k)	(l)
1	Sales											
2	Firm Sales (G-1, LVS-1)	Customer Chrg	1,855,928					45,900			$5.10	$9,699,323
3		Customer Chrg	231,782					6,281			13.60	3,237,657
4		0 - 300		18,553,788	(81,063)	1,079,624	19,552,349	481,208	(735,061)	19,298,496	1.0615	20,485,353
5		301 - 15,000		2,498,766	(638,339)	85,954	1,946,381	28,892	(20,410)	1,954,863	0.5585	1,091,791
6		Over 15,000		8,819	0	0	8,819	0	0	8,819	0.4085	3,603
7	Interruptible Sales (G-2, LVS-2)	Customer Chrg	414		(16)						150.00	59,700
8		0 - 15,000		1,406,428	(333,250)		1,073,178			1,073,178	0.4936	529,721
9		Over 15,000		376,956	(127,603)		249,353			249,353	0.3436	85,678
10	Overrun (T-4)	0 - 300		11,639	(11,639)		0			0	1.1677	0
11		301 - 15,000		25,410	(25,410)		0			0	0.6144	0
12		Over 15,000		0	0		0			0	0.4494	0
13	Overrun (T-3)	0 - 15,000		141,016	(141,016)		0			0	0.5430	0
14		Over 15,000		0	0		0			0	0.3780	0
15	Transportation											
16	Customer Charges (T2/G1)	Customer Chrg	[1]								13.60	
17	Customer Charges (T2/G2,T4,T3)	Customer Chrg	1,392		27						150.00	212,850
18	Transp. Adm. Fee	Customer Chrg	1,468		367						45.00	82,575
19	Parked Volumes [2]			526,520							0.10	52,652
20	Alternate Receipt Point											
21	Firm Transport (G-1)	0 - 300		30,455	252		30,707			30,707	1.0615	32,595
22		301 - 15,000		500,929	(24,009)		476,920			476,920	0.5585	266,360
23		Over 15,000		78,311	0		78,311			78,311	0.4085	31,990
24	Interruptible Transport (G-2)	0 - 15,000		786,564	(229,742)		556,822			556,822	0.4936	274,847
25		Over 15,000		148,134	(58,376)		89,758			89,758	0.3436	30,841
26	Firm Carriage (T-4)	0 - 300		168,705	104,683		273,388			273,388	1.0615	290,201
27		301 - 15,000		2,680,003	672,759		3,352,762			3,352,762	0.5585	1,872,518
28		Over 15,000		531,549	(310,532)		221,017			221,017	0.4085	90,285
29	Interruptible Carriage (T-3)	0 - 15,000		4,177,009	479,546		4,656,555			4,656,555	0.4936	2,298,476
30		Over 15,000		3,493,877	(860,790)		2,633,087			2,633,087	0.3436	904,729
31	Total Special Contracts [3]		156	13,230,373	101,730		13,332,103			13,332,103		1,692,428
32	Total Tariff		2,091,140	48,848,731	(1,482,799)	1,165,578	48,531,510	510,100	(755,471)	48,286,139		43,326,173
33	Additional Contract Reformations [4]											(1,100,000)
34	Other Revenue											755,000
35												
36	Total Revenue, excluding gas costs											$ 42,981,173
37												
38	Gas Costs											77,522,158
39	TOTAL REVENUE											$ 120,503,331
40												

41 [1] Number of Bills included in G-1 Sales.
42 [2] Parked Volumes not included in Total Deliveries.
43 [3] Information on individual Special Contracts is condential.
44 [4] Discount from proposed tariff rates. Based on confidential information.

EXHIBIT GLS-2
Schedule 1 of 1

WESTERN KENTUCKY GAS COMPANY
PER BOOKS BILL FREQUENCY ANALYSIS - MARGINS
TWELVE MONTHS ENDED SEPTEMBER 30, 1998

Line No.		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		RESIDENTIAL				FIRM COMMERCIAL				FIRM INDUSTRIAL			
		Number Of Bills	Mcf	Rate	Total Revenue	Number Of Bills	Mcf	Rate	Total Revenue	Number Of Bills	Mcf	Rate	Total Revenue
1	Total Firm Bills	1,855,928		$5.10	$9,465,233	229,012		$13.60	$3,114,563	2,770		$13.60	$37,672
2	Transport. Bills					0		45.00	0	713		45.00	32,085
3	Parking Fees												178
4	Sales: 1-300		12,561,177	1.0615	13,333,689		5,520,335	1.0615	5,859,836		465,304	1.0615	493,920
5	Sales: 301-15000		0	0.5585	0		1,206,676	0.5585	673,929		1,207,001	0.5585	674,110
6	Sales: Over 15000						0	0.4085	0		2,108	0.4085	861
7	Trans: 1-300						0	1.0615	0		30,455	1.0615	32,328
8	Trans: 301-15000						0	0.5585	0		500,929	0.5585	279,769
9	Trans: Over 15000						0	0.4085	0		78,311	0.4085	31,990
10	LVS: 1-300						0	1.0615	0		6,972	1.0615	7,401
11	LVS: 301-15000						0	0.5585	0		85,089	0.5585	47,522
12	LVS: Over 15000						0	0.4085	0		6,711	0.4085	2,741
13	Carriage:1-300						0	1.0615	0		168,705	1.0615	179,080
14	Carriage:301-15000						0	0.5585	0		2,680,003	0.5585	1,496,782
15	Carriage:Over 15000						0	0.4085	0		531,549	0.4085	217,138
16	T-4 Overrun 1-300						193	1.1677	225		11,446	1.1677	13,365
17	T-4 Overrun 301-15,000						0	0.6144	0		25,410	0.6144	15,612
18	T-4 Overrun Over 15,000						0	0.4494	0		0	0.4494	0
19	Special Contracts (Confidential)										3,003,136		370,428
20													
21	Total		12,561,177		$22,798,922		6,727,204		$9,648,553		8,803,129		$3,932,982
22													
23						INTERRUPTIBLE COMMERCIAL				INTERRUPTIBLE INDUSTRIAL			
24						Number Of			Total	Number Of			Total
25						Bills	Mcf	Rate	Revenue	Bills	Mcf	Rate	Revenue
26	Total Bills					158		$150.00	$23,700	1,648		$150.00	$247,200
27	Transport. Bills							45.00	0	755		45.00	33,975
28	Parking Fees												52,474
29	Interrupt Sales: 1-15000						199,751	0.4936	98,597		899,934	0.4936	444,207
30	Interrupt Sales: Over 15000						0	0.3436	0		152,485	0.3436	52,394
31	Interrupt Transport: 1-15000						0	0.4936	0		786,564	0.4936	388,248
32	Interrupt Transport: Over 15000						0	0.3436	0		148,134	0.3436	50,899
33	Interrupt LVS: 1-15000						157,176	0.4936	77,582		149,567	0.4936	73,826
34	Interrupt LVS: Over 15000						0	0.3436	0		224,471	0.3436	77,128
35	Carriage:1-15000						0	0.4936	0		4,177,009	0.4936	2,061,772
36	Carriage:Over 15000						0	0.3436	0		3,493,877	0.3436	1,200,496
37	T-3 Overrun 1-15,000						787	0.5430	427		140,229	0.543	76,144
38	T-3 Overrun Over 15,000						0	0.3780	0		0	0.378	0
39	Special Contracts (Confidential)										10,227,237		1,556,898
40													
41	TOTAL						357,714		$200,306		20,399,507		$6,315,661
42													
43													
44	GRAND TOTAL										48,848,731		$42,896,424

EXHIBIT GLS-3
Schedule 1 of 1

WESTERN KENTUCKY GAS COMPANY
INDUSTRIAL / LARGE COMMERCIAL CONTRACT ADJUSTMENTS - BILLS & VOLUMES
TWELVE MONTHS ENDED SEPTEMBER 30, 1998

Line No.		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		RESIDENTIAL				FIRM COMMERCIAL				FIRM INDUSTRIAL			
		Number Of Bills	Mcf	Rate	Total Revenue	Number Of Bills	Mcf	Rate	Total Revenue	Number Of Bills	Mcf	Rate	Total Revenue
1	Total Firm Bills	0		$5.10	$0	(119)		$13.60	($1,618)	190		$13.60	$2,584
2	Transport. Bills					0		45.00	0	296		45.00	13,320
3	Parking Fees												0
4	Sales: 1-300		0	1.0615	0		(32,338)	1.0615	(34,327)		(47,225)	1.0615	(50,129)
5	Sales: 301-15000		0	0.5585	0		(170,410)	0.5585	(95,174)		(403,366)	0.5585	(225,280)
6	Sales: Over 15000						0	0.4085	0		0	0.4085	0
7	Trans: 1-300						0	1.0615	0		252	1.0615	267
8	Trans: 301-15000						0	0.5585	0		(24,009)	0.5585	(13,409)
9	Trans: Over 15000						0	0.4085	0		0	0.4085	0
10	LVS: 1-300						0	1.0615	0		(1,500)	1.0615	(1,592)
11	LVS: 301-15000						0	0.5585	0		(64,563)	0.5585	(36,058)
12	LVS: Over 15000						0	0.4085	0		0	0.4085	0
13	Carriage:1-300						0	1.0615	0		104,683	1.0615	111,121
14	Carriage:301-15000						0	0.5585	0		672,759	0.5585	375,736
15	Carriage:Over 15000						0	0.4085	0		(310,532)	0.4085	(126,852)
16	T-4 Overrun 1-300						(193)	1.1677	(225)		(11,446)	1.1677	(13,365)
17	T-4 Overrun 301-15,000						0	0.6144	0		(25,410)	0.6144	(15,612)
18	T-4 Overrun Over 15,000						0	0.4494	0		0	0.4494	0
19	Special Contracts (Confidential)										1,714,106		54,610
20													
21	Total		0		$0		(202,941)		($131,344)		1,603,749		$75,341
22													

Line No.		(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
23		INTERRUPTIBLE COMMERCIAL				INTERRUPTIBLE INDUSTRIAL			
24		Number Of			Total	Number Of			Total
25		Bills	Mcf	Rate	Revenue	Bills	Mcf	Rate	Revenue
26	Total Bills	(16)		$150.00	($2,400)	27		$150.00	$4,050
27	Transport. Bills			45.00	0	71		45.00	3,195
28	Parking Fees								0
29	Interrupt Sales: 1-15000		(7,174)	0.4936	(3,541)		(245,800)	0.4936	(121,327)
30	Interrupt Sales: Over 15000		0	0.3436	0		(127,603)	0.3436	(43,844)
31	Interrupt Transport: 1-15000		0	0.4936	0		(229,742)	0.4936	(113,401)
32	Interrupt Transport: Over 15000		0	0.3436	0		(58,376)	0.3436	(20,058)
33	Interrupt LVS: 1-15000		(75,895)	0.4936	(37,462)		(4,381)	0.4936	(2,162)
34	Interrupt LVS: Over 15000		0	0.3436	0		0	0.3436	0
35	Carriage:1-15000		0	0.4936	0		479,546	0.4936	236,704
36	Carriage:Over 15000		0	0.3436	0		(860,790)	0.3436	(295,767)
37	T-3 Overrun 1-15,000		(787)	0.5430	(427)		(140,229)	0.543	(76,144)
38	T-3 Overrun Over 15,000		0	0.3780	0		0	0.378	0
39	Special Contracts (Confidential)						(1,612,376)		(289,507)
40									
41	TOTAL		(83,856)		($43,830)		(2,799,751)		($718,261)
42	Special Contract Renegotiations (Discount from Current Rates)								(1,100,000)
43									
44	GRAND TOTAL						(1,482,799)		($1,918,094)

WESTERN KENTUCKY GAS COMPANY
WEATHER ADJUSTMENT
TWELVE MONTHS ENDED SEPTEMBER 30, 1998

Line No.		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		RESIDENTIAL				FIRM COMMERCIAL				FIRM INDUSTRIAL			
		Number Of Bills	Mcf	Rate	Total Revenue	Number Of Bills	Mcf	Rate	Total Revenue	Number Of Bills	Mcf	Rate	Total Revenue
1	Total Firm Bills	0		$5.10	$0	0		$13.60	$0	0		$13.60	$0
2	Transport. Bills					0		45.00	0	0		45.00	0
3	Parking Fees												0
4	Sales: 1-300		763,462	1.0615	810,415		301,463	1.0615	320,003		14,699	1.0615	15,603
5	Sales: 301-15000		0	0.5585	0		57,422	0.5585	32,070		28,532	0.5585	15,935
6	Sales: Over 15000						0	0.4085	0		0	0.4085	0
7	Trans: 1-300						0	1.0615	0		0	1.0615	0
8	Trans: 301-15000						0	0.5585	0		0	0.5585	0
9	Trans: Over 15000						0	0.4085	0		0	0.4085	0
10	LVS: 1-300						0	1.0615	0		0	1.0615	0
11	LVS: 301-15000						0	0.5585	0		0	0.5585	0
12	LVS: Over 15000						0	0.4085	0		0	0.4085	0
13	Carriage:1-300						0	1.0615	0		0	1.0615	0
14	Carriage:301-15000						0	0.5585	0		0	0.5585	0
15	Carriage:Over 15000						0	0.4085	0		0	0.4085	0
16	T-4 Overrun 1-300						0	1.1677	0		0	1.1677	0
17	T-4 Overrun 301-15,000						0	0.6144	0		0	0.6144	0
18	T-4 Overrun Over 15,000						0	0.4494	0		0	0.4494	0
19	Special Contracts (Confidential)										0		0
20													
21	Total		763,462		$810,415		358,885		$352,073		43,231		$31,538
22													
23						INTERRUPTIBLE COMMERCIAL				INTERRUPTIBLE INDUSTRIAL			
24						Number Of			Total	Number Of			Total
25						Bills	Mcf	Rate	Revenue	Bills	Mcf	Rate	Revenue
26	Total Bills					0		$150.00	$0	0		$150.00	$0
27	Transport. Bills							45.00	0	0		45.00	0
28	Parking Fees												0
29	Interrupt Sales: 1-15000						0	0.4936	0		0	0.4936	0
30	Interrupt Sales: Over 15000						0	0.3436	0		0	0.3436	0
31	Interrupt Transport: 1-15000						0	0.4936	0		0	0.4936	0
32	Interrupt Transport: Over 15000						0	0.3436	0		0	0.3436	0
33	Interrupt LVS: 1-15000						0	0.4936	0		0	0.4936	0
34	Interrupt LVS: Over 15000						0	0.3436	0		0	0.3436	0
35	Carriage:1-15000						0	0.4936	0		0	0.4936	0
36	Carriage:Over 15000						0	0.3436	0		0	0.3436	0
37	T-3 Overrun 1-15,000						0	0.5430	0		0	0.543	0
38	T-3 Overrun Over 15,000						0	0.3780	0		0	0.378	0
39	Special Contracts (Confidential)										0		0
40													
41	TOTAL						0		$0		0		$0
42	Special Contract Renegotiations (Discount from Current Rates)												0
43													
44	GRAND TOTAL										1,165,578		$1,194,026

Western Kentucky Gas
Actual & Normal Degree Days
12 Months Ended 9/30/98

Line No.	Month (a)	Actual Ddays (b)	Normal Ddays (c)	Lagged Actual 50% Prior Mo. DDays (d)	Lagged Normal 50% Prior Mo. DDays (e)
1	Sep-97	18	29		
2	Oct-97	284	239	151.0	134.0
3	Nov-97	658	520	471.0	379.5
4	Dec-97	864	859	761.0	689.5
5	Jan-98	728	1,007	796.0	933.0
6	Feb-98	594	793	661.0	900.0
7	Mar-98	573	553	583.5	673.0
8	Apr-98	267	246	420.0	399.5
9	May-98	29	93	148.0	169.5
10	Jun-98	13	1	21.0	47.0
11	Jul-98	0	0	6.5	0.5
12	Aug-98	0	0	0.0	0.0
13	Sep-98	3	29	1.5	14.5
14					
15		4,013	4,340	4,021	4,340

Western Kentucky Gas Company
Normalization Of Volumes For Weather
Reference Period Ended September 30, 1998

Line No.	Month	Lagged Normal DDays	X Coefficient	Product	Constant	Normalized Usage per Customer	No. of Customers	Normalized Volumes	Actual Volumes	Weather Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Residential - Class 1 Rate 1									
1	Oct-97	134.0	0.0155	2.0706	1.5444	3.6150	150,484	544,003	325,214	218,789
2	Nov-97	379.5	0.0155	5.8640	1.5444	7.4084	153,862	1,139,875	1,179,797	(39,922)
3	Dec-97	689.5	0.0155	10.6541	1.5444	12.1985	155,921	1,902,006	2,019,864	(117,858)
4	Jan-98	933.0	0.0155	14.4167	1.5444	15.9611	156,448	2,497,086	2,258,954	238,132
5	Feb-98	900.0	0.0155	13.9067	1.5444	15.4511	156,450	2,417,328	2,090,356	326,972
6	Mar-98	673.0	0.0155	10.3992	1.5444	11.9436	156,963	1,874,707	1,796,088	78,619
7	Apr-98	399.5	0.0155	6.1730	1.5444	7.7174	156,414	1,207,113	1,242,796	(35,683)
8	May-98	169.5	0.0155	2.6191	1.5444	4.1635	155,280	646,512	642,746	3,766
9	Jun-98	47.0	0.0155	0.7262	1.5444	2.2706	154,408	350,602	290,969	59,633
10	Jul-98	0.5	0.0155	0.0077	1.5444	1.5521	153,621	238,438	250,082	(11,644)
11	Aug-98	0.0	0.0155	0.0000	1.5444	1.5444	153,212	236,624	223,798	12,826
12	Sep-98	14.5	0.0155	0.2241	1.5444	1.7685	152,865	270,345	240,513	29,832
13										
14	Total	4,340			1.5444		154,661	13,324,639	12,561,177	763,462
15										
16	Average Usage / Customer							86.15	81.22	

Western Kentucky Gas Company
Normalization Of Volumes For Weather
Reference Period Ended September 30, 1998

Line No.	Month	Lagged Normal DDays	X Coefficient	Product	Constant	Normalized Usage per Customer	No. of Customers	Normalized Volumes	Pro-Forma Actual Volumes	Weather Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Commercial - Class 2 Rate 1									
1	Oct-97	134.0	0.05845	7.8317	8.4203	16.2520	18,420	299,361	266,065	33,296
2	Nov-97	379.5	0.05845	22.1800	8.4203	30.6003	18,985	580,946	594,131	(13,185)
3	Dec-97	689.5	0.05845	40.2981	8.4203	48.7184	19,359	943,139	1,023,289	(80,150)
4	Jan-98	933.0	0.05845	54.5295	8.4203	62.9498	19,422	1,222,611	1,102,716	119,895
5	Feb-98	900.0	0.05845	52.6008	8.4203	61.0211	19,014	1,160,255	987,521	172,734
6	Mar-98	673.0	0.05845	39.3337	8.4203	47.7540	19,537	932,970	864,847	68,123
7	Apr-98	399.5	0.05845	23.3489	8.4203	31.7692	19,486	619,054	572,181	46,873
8	May-98	169.5	0.05845	9.9065	8.4203	18.3268	19,308	353,854	315,939	37,915
9	Jun-98	47.0	0.05845	2.7469	8.4203	11.1672	19,055	212,791	236,172	(23,381)
10	Jul-98	0.5	0.05845	0.0292	8.4203	8.4495	18,889	159,602	129,074	30,528
11	Aug-98	0.0	0.05845	0.0000	8.4203	8.4203	18,738	157,779	187,756	(29,977)
12	Sep-98	14.5	0.05845	0.8475	8.4203	9.2678	18,680	173,122	176,908	(3,786)
13										
14	Total	4,340			8.4203		19,074	6,815,484	6,456,599	358,885
15										
16	Average Usage / Customer							357.31	338.50	

Western Kentucky Gas Company
Normalization Of Volumes For Weather
Reference Period Ended September 30, 1998

Line No.	Month	Normal DDays	X Coefficient	Product	Constant	Normalized Usage per Customer	No. of Customers	Normalized Volumes	Pro-Forma Actual Volumes	Weather Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Industrial - Class 3 Rate 1									
1	Oct-97	239.0	0.60541	144.6929	199.8435	344.5364	221	76,142	98,950	(22,808)
2	Nov-97	520.0	0.60541	314.8130	199.8435	514.6565	221	113,739	150,456	(36,717)
3	Dec-97	859.0	0.60541	520.0468	199.8435	719.8903	218	156,936	158,632	(1,696)
4	Jan-98	1,007.0	0.60541	609.6474	199.8435	809.4909	220	178,088	137,122	40,966
5	Feb-98	793.0	0.60541	480.0898	199.8435	679.9333	226	153,665	123,997	29,668
6	Mar-98	553.0	0.60541	334.7915	199.8435	534.6350	220	117,620	121,465	(3,845)
7	Apr-98	246.0	0.60541	148.9307	199.8435	348.7742	216	75,335	69,335	6,000
8	May-98	93.0	0.60541	56.3031	199.8435	256.1466	216	55,328	38,775	16,553
9	Jun-98	1.0	0.60541	0.6054	199.8435	200.4489	214	42,896	43,242	(346)
10	Jul-98	0.0	0.60541	0.0000	199.8435	199.8435	215	42,966	52,164	(9,198)
11	Aug-98	0.0	0.60541	0.0000	199.8435	199.8435	213	42,567	33,369	9,198
12	Sep-98	29.0	0.60541	17.5569	199.8435	217.4004	215	46,741	31,285	15,456
13										
14	Total	4,340			199.8435		218	1,102,023	1,058,792	43,231
15										
16	Average Usage / Customer							5,057	4,859	

EXHIBIT GLS-5
Schedule 1 of 1

WESTERN KENTUCKY GAS COMPANY
CUSTOMER GROWTH FORECAST
TWELVE MONTHS ENDED SEPTEMBER 30, 1998

Line No.		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		RESIDENTIAL				FIRM COMMERCIAL				FIRM INDUSTRIAL			
		Number Of Bills	Mcf	Rate	Total Revenue	Number Of Bills	Mcf	Rate	Total Revenue	Number Of Bills	Mcf	Rate	Total Revenue
1	Total Firm Bills	45,900		$5.10	$234,090	6,210		$13.60	$84,456	0		$13.60	$0
2	Transport. Bills					0		45.00	0	0		45.00	0
3	Parking Fees												0
4	Sales: 1-300		329,524	1.0615	349,789		151,684	1.0615	161,013		0	1.0615	0
5	Sales: 301-15000		0	0.5585	0		28,892	0.5585	16,136		0	0.5585	0
6	Sales: Over 15000						0	0.4085	0		0	0.4085	0
7	Trans: 1-300						0	1.0615	0		0	1.0615	0
8	Trans: 301-15000						0	0.5585	0		0	0.5585	0
9	Trans: Over 15000						0	0.4085	0		0	0.4085	0
10	LVS: 1-300						0	1.0615	0		0	1.0615	0
11	LVS: 301-15000						0	0.5585	0		0	0.5585	0
12	LVS: Over 15000						0	0.4085	0		0	0.4085	0
13	Carriage:1-300						0	1.0615	0		0	1.0615	0
14	Carriage:301-15000						0	0.5585	0		0	0.5585	0
15	Carriage:Over 15000						0	0.4085	0		0	0.4085	0
16	T-4 Overrun 1-300						0	1.1677	0		0	1.1677	0
17	T-4 Overrun 301-15,000						0	0.6144	0		0	0.6144	0
18	T-4 Overrun Over 15,000						0	0.4494	0		0	0.4494	0
19	Special Contracts (Confidential)										0		0
20													
21	Total		329,524		$583,879		180,576		$261,605		0		$0
22													
23						INTERRUPTIBLE COMMERCIAL				INTERRUPTIBLE INDUSTRIAL			
24						Number Of			Total	Number Of			Total
25						Bills	Mcf	Rate	Revenue	Bills	Mcf	Rate	Revenue
26	Total Bills					0		$150.00	$0	0		$150.00	$0
27	Transport. Bills							45.00	0	0		45.00	0
28	Parking Fees												0
29	Interrupt Sales: 1-15000						0	0.4936	0		0	0.4936	0
30	Interrupt Sales: Over 15000						0	0.3436	0		0	0.3436	0
31	Interrupt Transport: 1-15000						0	0.4936	0		0	0.4936	0
32	Interrupt Transport: Over 15000						0	0.3436	0		0	0.3436	0
33	Interrupt LVS: 1-15000						0	0.4936	0		0	0.4936	0
34	Interrupt LVS: Over 15000						0	0.3436	0		0	0.3436	0
35	Carriage:1-15000						0	0.4936	0		0	0.4936	0
36	Carriage:Over 15000						0	0.3436	0		0	0.3436	0
37	T-3 Overrun 1-15,000						0	0.5430	0		0	0.543	0
38	T-3 Overrun Over 15,000						0	0.3780	0		0	0.378	0
39	Special Contracts (Confidential)										0		0
40													
41	TOTAL						0		$0		0		$0
42	Special Contract Renegotiations (Discount from Current Rates)												0
43													
44	GRAND TOTAL										510,100		$845,484

WESTERN KENTUCKY GAS COMPANY
RESIDENTIAL & COMMERCIAL CONSERVATION AND ENERGY EFFICIENCY ADJUSTMENTS
TWELVE MONTHS ENDED SEPTEMBER 30, 1998

Line No.		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		RESIDENTIAL				FIRM COMMERCIAL				FIRM INDUSTRIAL			
		Number Of Bills	Mcf	Rate	Total Revenue	Number Of Bills	Mcf	Rate	Total Revenue	Number Of Bills	Mcf	Rate	Total Revenue
1	Total Firm Bills	0		$5.10	$0	0		$13.60	$0	0		$13.60	$0
2	Transport. Bills					0		45.00	0	0		45.00	0
3	Parking Fees												0
4	Sales: 1-300		(627,923)	1.0615	(666,540)		(107,138)	1.0615	(113,727)		0	1.0615	0
5	Sales: 301-15000		0	0.5585	0		(20,410)	0.5585	(11,399)		0	0.5585	0
6	Sales: Over 15000						0	0.4085	0		0	0.4085	0
7	Trans: 1-300						0	1.0615	0		0	1.0615	0
8	Trans: 301-15000						0	0.5585	0		0	0.5585	0
9	Trans: Over 15000						0	0.4085	0		0	0.4085	0
10	LVS: 1-300						0	1.0615	0		0	1.0615	0
11	LVS: 301-15000						0	0.5585	0		0	0.5585	0
12	LVS: Over 15000						0	0.4085	0		0	0.4085	0
13	Carriage:1-300						0	1.0615	0		0	1.0615	0
14	Carriage:301-15000						0	0.5585	0		0	0.5585	0
15	Carriage:Over 15000						0	0.4085	0		0	0.4085	0
16	T-4 Overrun 1-300						0	1.1677	0		0	1.1677	0
17	T-4 Overrun 301-15,000						0	0.6144	0		0	0.6144	0
18	T-4 Overrun Over 15,000						0	0.4494	0		0	0.4494	0
19	Special Contracts (Confidential)										0		0
20											0		0
21	Total		(627,923)		($666,540)		(127,548)		($125,126)		0		$0
22													
23						INTERRUPTIBLE COMMERCIAL				INTERRUPTIBLE INDUSTRIAL			
24						Number Of			Total	Number Of			Total
25						Bills	Mcf	Rate	Revenue	Bills	Mcf	Rate	Revenue
26	Total Bills					0		$150.00	$0	0		$150.00	$0
27	Transport. Bills							45.00	0	0		45.00	0
28	Parking Fees												0
29	Interrupt Sales: 1-15000						0	0.4936	0		0	0.4936	0
30	Interrupt Sales: Over 15000						0	0.3436	0		0	0.3436	0
31	Interrupt Transport: 1-15000						0	0.4936	0		0	0.4936	0
32	Interrupt Transport: Over 15000						0	0.3436	0		0	0.3436	0
33	Interrupt LVS: 1-15000						0	0.4936	0		0	0.4936	0
34	Interrupt LVS: Over 15000						0	0.3436	0		0	0.3436	0
35	Carriage:1-15000						0	0.4936	0		0	0.4936	0
36	Carriage:Over 15000						0	0.3436	0		0	0.3436	0
37	T-3 Overrun 1-15,000						0	0.5430	0		0	0.543	0
38	T-3 Overrun Over 15,000						0	0.3780	0		0	0.378	0
39	Special Contracts (Confidential)										0		0
40											0		0
41	TOTAL						0		$0		0		$0
42	Special Contract Renegotiations (Discount from Current Rates)												0
43													
44	GRAND TOTAL										(755,471)		($791,666)

Western Kentucky Gas Company
Summary of Revenue at Proposed Rates
Test Year Ending 12/31/2000

Line No.	Description	Block (Mcf)	Reference Period - Twelve Months Ending 9/30/98: Number of Bills, Units	Volumes As Metered	Contract Adj. Bills and Volumes	Weather Adj. Volumes	Total Volumes	Forward-looking Adjustments To Test Year: Customer Growth Forecast	Conservation & Efficiency Adjustments	Total Test Year Volumes	Proposed Margin	Proposed Revenue
	(a)	(b)	(c)	(d)	(f)	(e)	(g)	(h)	(i)	(j)	(k)	(l)
1	Sales											
2	Firm Sales (G-1, LVS-1)	Customer Chrg	1,855,928					45,900			$9.00	$17,116,452
3		Customer Chrg	231,782					6,281			$24.00	5,713,512
4		0 - 300		18,553,788	(81,063)	1,079,624	19,552,349	481,208	(735,061)	19,298,496	1.2000	23,158,195
5		301 - 15,000		2,498,766	(638,339)	85,954	1,946,381	28,892	(20,410)	1,954,863	0.6946	1,357,848
6		Over 15,000		8,819	0	0	8,819	0	0	8,819	0.4299	3,791
7	Interruptible Sales (G-2, LVS-2)	Customer Chrg	414		(16)						250.00	99,500
8		0 - 15,000		1,406,428	(333,250)		1,073,178			1,073,178	0.5300	568,784
9		Over 15,000		376,956	(127,603)		249,353			249,353	0.3301	82,311
10	Overrun (T-4)	0 - 300		11,639	(11,639)		0			0	1.3200	0
11		301 - 15,000		25,410	(25,410)		0			0	0.7641	0
12		Over 15,000		0	0		0			0	0.4729	0
13	Overrun (T-3)	0 - 15,000		141,016	(141,016)		0			0	0.5830	0
14		Over 15,000		0	0		0			0	0.3631	0
15	Transportation											
16	Customer Charges (T2/G1)	Customer Chrg	[1]								24.00	
17	Customer Charges (T2/G2,T4,T3)	Customer Chrg	1,392		27						250.00	354,750
18	Transp. Adm. Fee	Customer Chrg	1,468		367						50.00	91,750
19	Parked Volumes [2]			526,520							0.10	52,652
20	Alternate Receipt Point (T-5) [2]									100,000	0.10	10,000
21	Firm Transport (G-1)	0 - 300		30,455	252		30,707			30,707	1.2000	36,848
22		301 - 15,000		500,929	(24,009)		476,920			476,920	0.6946	331,269
23		Over 15,000		78,311	0		78,311			78,311	0.4299	33,666
24	Interruptible Transport (G-2)	0 - 15,000		786,564	(229,742)		556,822			556,822	0.5300	295,116
25		Over 15,000		148,134	(58,376)		89,758			89,758	0.3301	29,629
26	Firm Carriage (T-4)	0 - 300		168,705	104,683		273,388			273,388	1.2000	328,066
27		301 - 15,000		2,680,003	672,759		3,352,762			3,352,762	0.6946	2,328,828
28		Over 15,000		531,549	(310,532)		221,017			221,017	0.4299	95,015
29	Interruptible Carriage (T-3)	0 - 15,000		4,177,009	479,546		4,656,555			4,656,555	0.5300	2,467,974
30		Over 15,000		3,493,877	(860,790)		2,633,087			2,633,087	0.3301	869,182
31	Total Special Contracts [3]		156	13,230,373	101,730		13,332,103			13,332,103		1,692,428
32	Total Tariff		2,091,140	48,848,731	(1,482,799)	1,165,578	48,531,510	510,100	(755,471)	48,286,139		57,117,566
33	Additional Contract Reformations [4]											(1,184,884)
34	Other Revenue											1,176,139
35												
36	Total Revenue, excluding gas costs											$ 57,108,821
37												
38	Gas Costs											77,522,158
39	TOTAL REVENUE											$ 134,630,979
40												

41 [1] Number of Bills included in G-1 Sales.
42 [2] Parked Volumes and Alternate Receipt Point Volumes not included in Total Deliveries.
43 [3] Information on individual Special Contracts is condential.
44 [4] Discount from proposed tariff rates. Based on confidential information.

12

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	**)**	
RATE APPLICATION BY	**)**	**Case No. 99-070**
WESTERN KENTUCKY GAS COMPANY	**)**	

TESTIMONY OF MICHAEL MARKS

Q. Please state your name and business address.

A. My name is Michael Marks. My business address is 490 Wheeler Road, Suite 100, Hauppauge, New York 11788.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Western Kentucky Gas Company (hereafter referred to as "Western").

Q. Please summarize your professional background.

A. I currently hold the position of Senior Partner and Secretary of Applied Energy Group, Inc. (AEG), a management and technical consulting firm that has served electric and gas utilities, both domestic and international, since 1982. I have twenty years of experience in the technical, management and consulting aspects of the utility industry, including demand side management program design, implementation, and evaluation; project management; statistical analysis; load forecasting; strategic issues consulting;

comparative economics; as well as the provision and support on expert testimony on all of the above.

Q. Can you please describe your qualifications as they relate to demand side management (DSM) programs?

A. I have been involved in the design, implementation, and evaluation of DSM programs since 1985. I have provided these services, as a consultant, to over 30 utility clients. I have provided design and evaluation services for well over 300 DSM programs over this time period. I have provided implementation services as a full-time contract employee for the New York Power Authority (NYPA), a large public power utility whose customers include the New York City schools, hospitals, all state and federal buildings, the Housing Authority, the Transit Authority and the Port Authority. Over a two-year period, I served as a NYPA Manager employee for this $100 million lighting retrofit program. I have also served as a contract employee for Bermuda Electric Light Company (BELCO). Over a two year period, I provided design, management and implementation services on-island in support of BELCO's energy services company subsidiary.

Q. What experience do you have specific to low-income DSM programs?

A. I have provided design and evaluation services for more than 10 different natural gas and electric utility low-income programs. Specific to natural gas local distribution companies, I consulted, this past year, on low-income programs for Minnegasco, Peoples

Natural Gas and Northern Minnesota Utilities. These three active programs are very similar in design to the WKG CARES program. I evaluated Atlanta Gas Light's first low-income DSM program during the 1995/96 timeframe. I also evaluated low income programs for four combination (gas/electric) utilities in New York State, specifically, Rochester Gas & Electric, New York State Electric & Gas, Long Island Lighting Company and Niagara Mohawk Company.

Q. Please outline your expert testimony experience in regulatory jurisdictions.

A. I have provided expert testimony in Missouri, Kansas, Texas, and South Carolina. These cases were on behalf of Kansas Gas & Electric and Kansas City Power & Light in Kansas (Nos. 84-KGE-197-R142,098 and 84-KCPL-198-R142,099-U), Kansas City Power & Light in Missouri (MPSC Case No. ER-128), El Paso Electric Company in Texas (Texas Public Utilities Commission Docket No. 8892) and South Carolina Pipeline in South Carolina (Docket No. 94-202-G).

I have also provided extensive support in the preparation of expert testimony on statistical and econometric studies related to electric and/or gas forecasts, weather normalization, power plant performance standards, power plant operations and maintenance costs, and demand side management program evaluation for the following companies: Arizona Public Service Company, Consolidated Edison of New York, El Paso Electric Company, Empire District, Freeport Electric, Georgia Power Company, Kansas City Power & Light Company, Kansas Gas & Electric Company, KeySpan, Long

Island Lighting Company, Minnegasco, Missouri Public Service Co., New York Power Authority, New York State Electric and Gas Corporation, Northeast Utilities, Town of Wellesley, TU Electric, and Western Resources.

Q. Please describe your educational background.

A. I received my B.S. in Mathematical Economics from the State University College of New York at Oswego and my M. A. in Applied Economics from Binghamton University in 1977 and 1979, respectively. A complete description of my qualifications is contained in Exhibit No. MM - 1.

Q. What role have you personally played in the WKG CARES program?

A. The concept for the WKG CARES program was developed as one element of a rate proceeding decided by the Kentucky Public Service Commission (hereafter referred to as the "Commission") in 1995 (Case No. 95-010). Central to the program are two important provisions of the agreement between Western and the Commission. These are, first, the delivery of program services should be coordinated through local Community Action Program Agencies (CAPs) and secondly, program oversight and guidance should be provided through a collaborative process. In July of 1996, I made a presentation to the WKG DSM Collaborative (hereafter referred to as the "Collaborative") on a proposal to design and evaluate a low-income DSM program (WKG CARES). The proposal was accepted by the Collaborative. Since that time, I have conducted and/or supervised most of this work.

Q. What is the purpose of your testimony?

A. I have been asked by Western to provide testimony on two related issues. I will first discuss the WKG CARES program and the results of a comprehensive process and impact evaluation that was performed by AEG. This discussion will support a proposal to continue the program for an additional three years. I will next describe a cost recovery proposal for both past and future costs related to the WKG CARES program.

Q. Please describe the WKG CARES program.

A. The WKG CARES Program was initiated as a pilot Demand Side Management/Low-income Customer Assistance Program. The program is directed at low-income customers who, for the most part, own their own homes. The program focuses on the delivery of weatherization measures to the homes of qualifying low-income residents and the reduction of their gas utility bill.

A total of 300 low-income residences were targeted initially for treatment during each year of the three-year program. The letter of stipulation and agreement called for a maximum of $1,500 to be expended per treated residence (the Collaborative subsequently modified this ceiling to an average of $1,500 per home, with a maximum of $2,000, provided that the *average* expense of all treated residences did not exceed $1,500) with a total program cost not to exceed $450,000 per year. Western agreed to commit to fund the pilot program for three years regardless of the cost recovery effectiveness, although all program elements were to be designed to qualify for full rate recovery.

The first year of the program spanned the period November 1, 1996, through October 31, 1997.

Q. How was the program managed?

A. Western provided a Program Manager. His role was to coordinate the day-to-day functioning of the program. The Collaborative provided additional oversight in the design and implementation of the program and ensured that the interests of all participants to the process were most effectively and most equitably served. Major policy decisions regarding the program are the responsibility of the Collaborative. The group comprising the Collaborative, as envisioned in the rate case, was to include representation from an internal team from Western, as well as representation from Kentucky Legal Services, Inc., the Attorney General's office, and either the Community Action agencies themselves or someone representing them. The Commission declined the opportunity to participate. Additionally, a representative was not available from Kentucky Legal Services, Inc. As a result, a representative from Cumberland Trace Legal Services (a regional legal service) was included in the Collaborative. A total of four representatives (one from each of the above mentioned organizations) comprised the voting membership of the Collaborative.

Q. Please describe the program design.

A. WKG CARES was designed as a piggy-back type of DSM program. This type of program overlays benefits and program measures supplied by the utility on top of benefits made available through other programs - in this case those provided by the CAPs. This program design has been successfully used in other states. There are a total of 26 CAPs in Kentucky. Western works with eight agencies in this group that cover 100% of its service territory. Western supplies funding to CAPs to augment CAP expenditures for weatherization services. Western does not install measures with its own staff, nor does it employ sub-contractors independent of the CAPs. The CAPs receive their normal funding generally from federal and state grant programs and provide a variety of services, one of which is weatherization. Examples of other services provided by CAPs include the qualification of potential recipients of Home Energy Assistance Program (HEAP) benefits that are made available annually to low-income households through this federal block-grant program, Meals on Wheels, aid to seniors, etc.

Q. How were the measures eligible for Western funding selected?

A. The selection of weatherization measures specifically authorized and funded by Western was the result of an analysis conducted by AEG as part of its services to the Collaborative. We also met with the CAPs to obtain their input as well. A series of measures were proposed by AEG for consideration. These potential program offerings were subjected to four specific benefit cost tests (as defined in the Standard Practice Manual: Economic Analysis of Demand-Side Management Programs developed by the

California PUC and the California Energy Commission). The ultimate choice of measures was based on a cost sharing arrangement between the CAPs and Western. This strategy enabled the installation of the widest range of measures, with each measure passing the Total Resource Cost Test (one of the four tests mentioned above). This test measures the costs and benefits of a conservation measure from the broadest perspective as it represents the net benefit to society, including benefits to both participants and non-participants. The measures ultimately selected for inclusion in the WKG CARES program were:

Attic insulation
Wall insulation
Floor insulation
Infiltration reduction
Water heater replacements/repairs
Duct insulation
Repair/replace furnace
Clean/repair furnace
Duct repair

Q. How were the process evaluation results determined?

A. AEG's process evaluation focused on program sponsors, implementors, and recipients through a variety of research tools including:

- Interviews with program management
- An Interview with the Executive Director of the Kentucky Association for Community Action
- Interviews with Community Action Program Agency directors
- Surveys of program participants
- Analysis of program data bases and reporting formats
- Reviews of relevant program documentation

The process evaluation covered the period from November 1, 1996, through January 31, 1998.

Q. Can you please summarize the results of the process evaluation that you conducted for WKG CARES?

A. The process evaluation found that the program is a good example of the way in which a DSM program can be designed that capitalizes on the strengths of a number of partners in the implementation process. The WKG CARES program design achieves the efficiencies and benefits accruing from piggy-back types of programs, while at the same time, maximizing the benefits that program participants could receive from both the CAP weatherization efforts, as well as Western's program expenditures. The program manifests a high degree of inherent efficiency as its infrastructure is already in place via the eight CAPs through which it operates.

A survey of low-income participants found that 90% of respondents indicated at least some improvement in comfort levels in the home, the ability to pay energy bills, home safety, and the overall condition of the home.

Q. Did the program meet its participation and budget goals?

A. The most up-to-date information on the program spans November 1996 through March 1999. Over this period, the WKG CARES program has provided services to 407 homes. Prorating the original goal of 300 homes per year results in a target of 725 homes for this period. Thus, the actual number of homes treated equates to 56.1% of the goal. Likewise, prorated program expenditure targets for the period total $1,087,500. Actual expenditures were $684,562 representing 62.9% of the goal. Even after adjusting for the fact that the first four months of the program were a "start-up" period in which no program activity took place, it is clear that these goals were not close to being achieved.

Q. Why weren't the participation goals achieved?

A. The 300 home per year goal arose from the settlement agreement. It was, in essence, an arbitrary number, in as much as it was not derived from market research. During the first six months of the program, it was clear that the CAPs would not be able to meet the established participation targets because they typically do not receive requests for assistance from 300 Western customers during the course of a year. This was brought to the attention of the Collaborative, and we were instructed to do the best we could given this limitation.

Q. How was the impact evaluation conducted?

A. To determine and analyze the quantitative results of the program, i.e., its impacts, AEG conducted a statistical billing analysis to estimate the gross and net energy Mcf savings associated with participation in the WKG CARES Program. AEG used the Princeton Scorekeeping Method (PRISM) to develop estimates of pre- and post-treatment normalized annual consumption values for a sample of program participants and non-participants. The resulting gross and net savings estimates were then projected to the program population. In addition, these energy savings estimates were used to develop estimated bill reductions for program participants. The net energy savings values were also integrated into a benefit-cost model to provide benefit-cost ratios from the societal, ratepayer, utility, and participant perspectives. AEG utilized a benefit-cost model (BENCOST) which was developed by the Minnesota Department of Public Service specifically for gas utility DSM programs. AEG is familiar with this model through the work it completed for three different Minnesota gas utilities.

Q. How were the net energy savings attributable to the program determined?

A. Estimates of pre- and post-treatment consumption were developed using PRISM for a sample of the program participants in order to calculate a gross energy savings. Mean estimates of pre- and post-treatment consumption were also developed for a sample of program non-participants in order to control non-programmatic influences on consumption. The final step in the development of net energy savings was to adjust the participant's mean pre-consumption to account for the "naturally-occurring" reduction in consumption experienced by the program non-participants.

Q. What were the results of the impact evaluation?

A. The net per-participant energy savings has been estimated as 16.8 Mcf for those Western customers who participated in the program between November 1996 and September 1997. This represents a reduction in energy consumption of approximately 19%. The annual bill reduction associated with this energy savings is $82, or 16.7%, of the average participant's annual natural gas bill.

Q. Are the savings estimates affected by customers that trade bill savings for increased comfort?

A. Yes they are. This phenomena, which is termed "Snap-Back" is generally defined as using increased amounts of energy once improvements in energy efficiency have been put into effect. As part of the participant survey, we asked customers if they increased the heating system thermostat setting after their home was weatherized. The survey found that 25% of the customers did in fact trade some bill savings for higher comfort levels in their homes. The occurrence of snapback serves to depress the energy savings attributable to any DSM program. However, in this instance, it could be argued that the higher heating levels that improved weatherization permits is a real benefit (e.g., from a health perspective) to the program regardless of the fact that it is not captured in the energy savings and benefit cost results.

Q. Why did you conduct a benefit-cost analysis?

A. Benefit-cost analysis provides a measurement of the dollar benefits relative to each dollar of cost. It is a standardized approach to summarizing impact evaluation results into a ratio of benefits-to-costs. Benefit-cost analysis is generally conducted over the life of the particular measure. All results are estimated in net present value (NPV) format. The Societal Test is modeled with and without an environmental externality adder. This adder accounts for environmental benefits associated with reduced natural gas consumption. The following were the results of the benefit-cost analysis:

Societal Test = 1.12 to 1.00

Societal Test = 1.17 to 1.00 (with environmental externality adder)

Ratepayer Impact Measure = 0.65 to 1.00

Utility Test = 0.66 to 1.00

Participant Test = 681.35 to 1.00

The specific benefit-cost test which the industry generally relies upon to determine the merits and cost effectiveness of a DSM program is the Societal Test. For WKG Cares, the Societal Test produces a positive result, that is, the program produces between 1.12 and 1.17 dollars in benefits for each dollar in cost.

Q. The Ratepayer Impact Measure (RIM) and Utility Test both show more cost than benefit. Why shouldn't these tests be relied upon to judge the cost effectiveness of the program?

A. The RIM and Utility Tests both show more cost than benefit because they account for participant bill savings as a negative, that is, as revenue erosion. However, since WKG is not attempting to recover the revenue erosion caused by the program, these measures are not really relevant to judge the WKG Cares program cost effectiveness. It should also be recognized that virtually no DSM program which results in energy savings will produce a positive benefit cost ratio under the RIM Test.

Q. Are there any benefits not captured in your benefit-cost results?

A. Yes. It is well known that low-income customers represent the highest relative percentage of uncollectibles for a utility. Programs like WKG CARES serve to materially reduce a customer's utility bill. Hence, it becomes easier for the customer to pay for the energy consumed, and to this extent, the program contributes to a reduction in uncollectibles. Since uncollectibles are a cost that is ultimately borne by all utility ratepayers, any reduction in uncollectibles that is experienced constitutes another direct benefit of the WKG CARES program.

Q. Why didn't you include uncollectibles in your benefit cost screening analysis?

A. An analysis of how WKG CARES impacted uncollectibles would have required a separate statistical study at a significant cost. The Collaborative did not believe the cost was justified.

Q. Why are you recommending that Western continue the WKG CARES program for an additional three years?

A. WKG CARES is an excellent example of the right way to design and operate a DSM program targeted towards low-income customers. WKG CARES functions effectively with minimal administrative support. The program capitalizes on the strengths of a number of partners in the implementation process. WKG CARES focuses on qualifying low-income residential homeowners that meet firm federal income guidelines. The program reaches these customers through promotional or marketing channels already established by the CAPs currently participating in the delivery of program services. Since the CAPs already have staffs that install weatherization measures, there is no need for Western to secure its own implementation contractor, or develop its own costly implementation infrastructure. As a result, the program manifests a high degree of inherent efficiency as the required infrastructure is already in place via the agencies. The CAPs are positive in their approach to serving low-income customers and appreciative of the opportunity to partner with Western in this effort. Although program parameters were established regarding allowable program measures, the agencies are afforded considerable latitude in the way in which they commit Western Program budgets. Overall, the average customer reaction to the various elements of the program, i.e., ease of scheduling, opinion of the workforce, quality, cost savings, etc., were very positive. The program delivers real and measurable benefit for participants in terms of actual energy-use reduction, coupled with improved comfort levels. The program passes the Societal benefit-cost test, with a score of 1.12 (excluding environmental externality benefits), which was a key target in the original program design.

Q. What are the estimated budget and participation targets for a second three-year term for the WKG CARES program?

A. We have estimated an annual budget of $200,000, or a total budget of $600,000 for the program cycle. This is far less than the $450,000 per year or $1.35 million that was allocated for the first three years of the program. This budget would support 400 participants assuming an average cost of $1,500 per customer.

Q. Why have you reduced the budget and participation targets from the pilot program levels?

A. The $600,000 budget reflects a realistic participation target based upon the first three years of experience during the initial pilot phase of the program. A total of 133 participants are targeted over each of the three years during the 1999 - 2002 period. This lower participation level reflects the fact that the CAPs funding has been significantly reduced over the past three years and they have had to trim their work forces and serve fewer customers accordingly. Fewer total jobs implies that fewer Western customers are served. Expenditure of the original $1.35 million budget in the pilot phase was not achievable even when the CAPs had increased Federal and State funding and larger work forces. We have found during the first three years of the program, as the CAPs' funding has been reduced, their WKG CARES participants have also lessened. The 133-per year customer participant target for the 1999 - 2002 period is in-line with the CAPs' expected work flow over that period. The budget can also be set lower because no provision has been made to include any Collaborative-related consulting (program design and evaluation) expenses.

Q. Are you recommending that no evaluation be conducted during the second three year period?

A. That is correct. Since the program will not be changed, the evaluation that was conducted in 1998 should be valid for the 1999 - 2002 period. While a new evaluation would provide additional evidence of program benefits, I do not believe it is the best use of the program funds. Furthermore, evaluation expenses depress the benefits of the program since there are no direct savings associated with their costs. However, should Western and/or the Commission desire to continue the program past 2002, I would recommend that an evaluation be conducted prior to making that decision.

Q. What are you going to cover in your discussion of cost recovery?

A. I will describe a cost recovery mechanism by which Western can recover its full costs associated with the implementation of the WKG CARES program. This mechanism can be used to recover both those costs associated with the three-year pilot program, as well as the three-year follow-on program presently being proposed.

Q. Is Western prepared to continue the WKG CARES program if it does not have an agreement up-front to recover all of its costs?

A. No. Western will only continue WKG CARES for a second three-year period if the Commission guarantees its cost recovery for all expenses associated with implementing the program. While Western believes this program benefits all of its customers, it is not prepared to pay for it out of stockholders' funds.

Q. Is there any state legislative foundation to support the recovery of utility DSM costs?

A. Yes there is. The Kentucky State Legislature in KRS 278.285 (2) states that the Commission may review and approve a demand-side management mechanism, which allows the utility to:

> [r]ecover the full-costs of commission–approved demand-side management programs and revenues lost by implementing these programs;
>
> [o]btain incentives designed to provide financial rewards to the utility for implementing cost-effective demand–management programs; or
>
> [b]oth of the actions specified.

According to the statute, these actions may occur as part of a proceeding to approve new rate schedules or as part of a separate proceeding limited to a review of demand-side management and related rate recovery issues.

Q. Does Western seek to recover revenues lost by the implementation of the WKG CARES program or to request that it be granted an incentive for implementing the program?

A. No. Western is seeking to recover only its full costs associated with the WKG CARES program. Western is seeking to recover those costs associated with the three-year pilot program which were approved by the Commission in Case No. 95-010, dated October 20, 1995, as well as those of the proposed 1999 - 2002 program.

Q. Please describe the nature of these costs.

A. Western is specifically seeking to recover only those payments made by Western to the program implementation contractors and those costs incurred by Western in the collaborative process, including costs for consultants.

Q. Please summarize the mechanism by which these costs will be recovered.

A. Western is proposing that a DSM cost recovery surcharge be approved which would allow Western to recover the full costs of the three-year pilot program and the three-year follow-on program. This surcharge would be included as a distinct and separate line item on the customer's bill and would begin with the first billing cycle in January 2000.

Q. Which revenue classes would be affected by this surcharge?

A. This surcharge would apply only to the residential rate class, specifically Rate G-1, General Sales Service.

Q. Please describe how the DSM cost recovery surcharge would be calculated.

A. The monthly amount computed under Rate G-1, General Sales Service, would be increased or decreased by the DSM Cost Recovery Component (DSMRC) at a rate per 100 cubic feet (Ccf) in accordance with the following formula:

$$DSMRC = DCRC + DCRP + DBA$$

Q. Please describe each component of the formula.

A. The DCRC, or DSM Cost Recovery-Current, would include all projected costs for the next-twelve month period. These costs would be limited to expected payments to program implementation contractors over that period, as well as any costs incurred by or on behalf of the collaborative process. These costs would be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DCRC. The DCRP, or DSM Cost Recovery-Pilot, would include all costs associated with the implementation of the three-year WKG CARES pilot program. These costs include payments to implementation contractors, as well as costs incurred on behalf of the collaborative process, including consultants. Western is proposing that these costs be amortized over the three-year follow-on period beginning in December 1999. These costs would be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DCRP.

The DBA, or DSM Balance Adjustment, would be calculated on a calendar year basis and be used to reconcile the difference between the amount of revenues actually billed through the DCRC, DCRP and previous applications of the DBA, and the revenues which should have been billed.

Q. Please describe in detail how the DBA would be calculated.

A. The DBA for the upcoming twelve-month period would be calculated as the sum of the balance adjustments for the DCRC, DCRP, and DBA. For the DCRC, the balance adjustment would be the difference between the amount billed in a twelve-month period from the application of the DCR unit charge and the actual cost of the WKG Cares program during the same twelve-month period.

For the DCRP, the balance adjustment would be the difference between the amount billed in a twelve-month period from the application of the DCRP unit charge and the actual cost of the three-year pilot WKG Cares program as amortized at no interest over three years.

For the DBA, the balance adjustment would be the difference between the amount billed in a twelve-month period from the application of the DBA unit charge and the balance adjustment amount established for the same twelve-month period.
The balance adjustment amounts calculated will include interest to be calculated at a rate equal to the average of "3-month Commercial Paper Rate" for the immediately preceding 12-month period. The balance adjustments plus interest shall be divided by the expected Ccf sales for the upcoming twelve-month period to determine the DBA.

Q. How often would the DSMRC be modified?

A. Western is proposing to file modifications to the DSMRC on an annual basis at least two months prior to the beginning of the effective period for billing.

Q. What information would be provided in these filings?

A. These filings would include detailed calculations of the DCRC, the DCRP, and the DBA, as well as data on the total cost of the WKG CARES program over the twelve-month period.

Q. Why have you selected this approach for cost recovery?

A. It is similar to an approach that the Commission has already approved for Louisville Gas & Electric. This cost recovery approach also spreads the costs in such a way as to have a very small impact on a typical residential customer's gas bill.

Q. What would be the dollar impact for a typical customer's gas bill?

A. I estimate that the cost recovery proposal to recover both historical and going forward costs for WKG Cares would cost the typical residential ratepayer approximately $0.25 (25 cents) per month over the three year period or about one-third of a cent (1/3 cent) per Ccf. My calculations are shown on Exhibit MM-2.

Q. The WKG CARES pilot program ends on October 31, 1999, but the rates Western has proposed would not go into effect prior to January 1, 2000. What happens to the funding of these low income weatherization programs during the intervening period?

A. The Company has advised the collaborative that it will extend the WKG CARES pilot for those additional months so as not to interrupt the low income weatherization activities underway during the first two busy months of the heating season.

Q. Why do you believe that Western is entitled to recover costs associated with the three-year pilot program?

A. It is evident from the following two citations that the Commission expected Western to file for DSM program cost recovery. In the October 20, 1995 decision, the Commission approved a unanimous settlement agreement that resolved all issues in Case No. 95-010. Page 6 of that setttement states, "To enhance the success of the program, Western agrees to work with a collaborative work group made up of an internal team and representatives of Kentucky Legal Services, Inc., the Attorney General's office and community action agencies having expertise at working with low-income customers' utility problems. The Commission shall be invited to participate also, at its discretion. The purpose of the Collaborative will be to establish a practical, detailed plan for implementing the DSM program. Unless otherwise agreed to by Western, ***all programs will be designed to qualify for full or partial rate recovery pursuant to KRS 278.285*** (emphasis added). Provided, however, Western will commit to fund the pilot programs for three years regardless of the effectiveness of cost recovery."

An October 30, 1996 letter sent by Mr. Don Mills, Executive Director of the Commission, stated that, "The Commission is interested in the current status of Western's efforts to develop possible programs and whether a general timetable exists for when Western expects to have programs in place and/or make a filing with the Commission for recovery of DSM program costs."

Q. What was the Company's response to the Commission's letter?

A. On November 15, 1996, Mr. Ben Boyd, Manager , Regulatory Affairs & Compliance, responded, "We presently plan to wait until the "Cares" program produces some data upon which to base a filing...We intend to file for cost recovery at the appropriate time, based on the [consultant's] recommendations."

Q. Did the Collaborative expect Western to file for cost recovery?

A. Yes. When we were hired by the Collaborative in 1996 to design the WKG CARES program, Western made it clear during a Collaborative meeting that designing a cost effective program was critical since Western would be seeking cost recovery toward the end of the three-year program period. There were no issues raised by other Collaborative members regarding this issue. A further indication that the Collaborative supported Western's efforts to recover costs was the fact that the last task in the request-for-proposal (RFP) issued by the Collaborative was to provide testimony to support cost recovery. I would therefore have to conclude that all Collaborative members were both aware of and in support of Western's efforts to seek cost recovery for expenses incurred during initial three year pilot phase of the program.

Q. Has Western successfully designed and implemented a cost effective program for which the Commission should grant full cost recovery?

A. Yes it has. Western has designed and implemented a program which produced a positive benefit cost result from a societal perspective, as previously discussed in my testimony, based on the results of our impact evaluation. It is therefore reasonable for Western to seek, and for the Commission to grant, cost recovery for this very successful and beneficial DSM program.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 99-070
WESTERN KENTUCKY GAS COMPANY	)	

CERTIFICATE

I, Michael Marks, have answered the foregoing questions propounded to me in the above enumerated Docket. These answers and exhibits constitute and I hereby adopt, under oath, these answers as my prefiled direct testimony in said case, which is true and correct to the best of my information and belief.

Michael Marks
Senior Partner
Applied Energy Group, Inc.

STATE OF NEW YORK	)	
	)	S.S.
COUNTY OF SUFFOLK	)	

SUBSCRIBED AND SWORN TO before me by Michael Marks, on this 21st day of April, 1999.

Jodi Nathan
JODI NATHAN
Notary Public, State of New York
No. 5044312
Qualified in Suffolk County
Commission Expires May 30, 1999

Exhibit MM-2

"WKG CARES" EXPENDITURES
Demand Side Management
Case No. 99 - 070

Annual Expenditure		Amount
Actual Expenses thru 10/31/98	$598,326.01	
Estimated Expenses 11/1/98 - 10/31/99	$218,000.00	
Estimated Expenses 11/1/99 - 12/31/99*	$50,000.00	
Subtotal - Pilot Program		$866,326.01
Estimated Expenses 1/1/00 - 12/31/00	$200,000.00	
Estimated Expenses 1/1/01 - 12/31/01	$200,000.00	
Estimated Expenses 1/1/02 - 12/31/02	$200,000.00	
Subtotal - Follow-On Program		$600,000.00
Total Expenditures		**$1,466,326.01**
Average residential customers in-service Jan 00 - Dec 02		160,186
Average annual Ccf per customer		804
WKG CARES cost/customer/month**		**$0.25427**
WKG CARES cost/ccf**		**$0.00380**

* two month pilot program extension to adjoin pilot and follow-on periods

** over 3 year period

MICHAEL S. MARKS
Senior Partner

SUMMARY OF QUALIFICATIONS

Twenty years of management consulting and decision making experience in the electric and gas industries. Specialization in the areas of energy services, business diversification, key customer retention, and strategic marketing.

Provided expert testimony, authored numerous articles, and made presentations on emerging utility related issues.

M.A. in Applied Economics with advanced course work reengineering, statistics, energy services, and computer science.

CURRENT POSITION

Since 1987, Mr. Marks has been an Officer and Senior Partner of Applied Energy Group, Inc. (AEG), a management consulting firm that serves the needs of the utility industries primarily in the areas of energy services, strategic planning, diversification studies, forecasting, innovative rate designs, customer service, reengineering, and business plan development.

PROFESSIONAL BACKGROUND

Applied Energy Group, Inc.	1982 - Present
Stone & Webster Management Consultants, Inc.	1980 - 1981
American Electric Power Service Corporation	1979 - 1980

CONSULTING PROJECTS

DIVERSIFICATIONS, BUSINESS PLANS, & BUSINESS PLAN IMPLEMENTATION

Bermuda Electric Light Company, Ltd. (BELCO) - Beginning in December 1995, AEG was retained by BELCO Energy Services Company (BESCO) to implement ESCO services throughout the island of Bermuda. The strategy that BELCO Holdings decided to employ was to have AEG function as BESCO management and field staff from 1996 throughout 1997. Mr. Marks provided overall management and implementation services on behalf of BELCO. On-site services were provided for a two year period of approximately one week per month. These services were directly linked to a business plan (developed by AEG) that was approved by the Board of Directors of BELCO.

Worked with senior management on opportunities for diversification and franchise protection, with emphasis on the formation of an Energy Service Company. This assignment is ongoing.

El Paso Electric Company (EPEC) - Directed the design and implementation of start-up strategies for a new utility ESCO (Energy Services Business Unit - ESBU) in 1997, including product/service identification, vendor negotiations, operational procedures and organizational restructuring. Particular emphasis was placed upon the institutional and governmental sectors. Designed and implemented a strategic ally program to provide technical and implementation resources for various ESCO services (e.g., lighting retrofits, HVAC designs and installation, backup generator installation, etc.). Developed a comprehensive third party financing program for the ESBU. Continue to provide on site and support services for the ESCO.

Hampton Strategies / R. J. Rudden Associates, Inc. - Formed Hampton Strategies in 1992 to expand AEG's markets into the gas utility business. Converted AEG's interest in Hampton Strategies in 1994 into an equity position in R. J.

Rudden Associates, Inc., a well-established consulting firm with skill sets that enhance AEG's ability to serve its changing domestic and international client base.

New York Power Authority (NYPA) - Worked as a full-time staff member over a two year period (1991 - 1992) in a management role in NYPA's DSM group on a $100 million dollar program which included a turnkey lighting retrofit program for large commercial and institutional customers throughout New York State. Responsibilities included program design, customer interface and supervision of all contractors. This program was and continues to be one of the largest DSM programs offered by a public authority in the United States.

Oglethorpe Power Corporation (OPC) - Prepared a Business Plan for EnerVision, a for-profit Company that OPC intended to create to separate the marketing functions from OPC. This plan described how EnerVision could successfully start-up and transition from the current marketing and economic development services at OPC.

Western Resources - Provided expert advisory services and research to assist in the development of a non-traditional Energy Service Company. A significant contribution was made by AEG to the business plan that was developed for this venture.

KEY CUSTOMER RETENTION

El Paso Electric Company (EPEC) - In 1998, developed and currently project manager for a business unit dedicated to key customer retention. The goal of this business unit is to develop innovative long-term rate contracts for many of EPE=s key customers. Designed time-of-use rate design, indexing, marginal cost pricing, load factor targeting and other rate strategies. Continue to negotiate and develop long term contracts directly with key customers on EPE=s behalf.

ENERGY SERVICES & DEMAND-SIDE MANAGEMENT (Selected Projects)

Atlanta Gas Light Company (AGLC) - Responsible officer and project manager for a multi-year (1993-1996) $700,000 DSM evaluation project. Responsibilities included preparation of evaluation plans, evaluating seven programs and interacting with and advising senior management.

Bermuda Electric Light Company, Ltd. (BELCO) - Designed and evaluated three pilot DSM programs that were implemented during 1993. The programs included a C&I Cooperative, a medium commercial audit and a residential direct install. This project was the first of its kind in the Caribbean.

Detroit Edison Company - Responsible officer and project manager for a process and impact evaluation of all 1994 and 1995 residential and low income DSM programs. The contract was administered through the Evaluation Collaborative (EC). The project involved research with trade allies, utility staff, implementation contractors, vendors, and participating and non-participating customers.

Iowa Power Company - Evaluated Iowa Power's first DSM program, a residential central A/C rebate program.

Long Island Lighting Company (LILCO) - Managed a comprehensive study of the persistence of equipment installed as a result of LILCO's C&I rebate and audit programs. This was one of the largest and most comprehensive studies on persistence ever conducted in the United States.

Served on a task force with LILCO management to develop state-of-the-art program tracking procedures and DSM program designs. Was the only non-LILCO employee on the task force.

Had overall responsibility for the evaluation of LILCO's 1987-1991 DSM programs. Over these years, LILCO had one of the most comprehensive DSM programs in the country with system coincident peak reductions of over 120 MW and annual expenditures of over $35 million. This project contributed to the generic DSM evaluation guidelines established by the NYPSC. Made presentations to the NYPSC during various stages of each evaluation.

Minnegasco -Conducted a competitive solicitation for implementation services related to three projects: C&I Multifamily Audit, Residential Home Energy Audit, and the Low-Income Weatherization Project for 1999. The scope of work included fully developing the RFP document for each project.

Provided contractor procurement services. Conducted a competitive solicitation for implementation services related to the Low-Income Weatherization Project for 1998.

Provided overall support and acted as an on-site technical advisor over the 1992-1994 period to develop a comprehensive DSM Plan. Responsibilities include all up-front planning, development of RFPs for multiple R&D projects with an over two million dollar budget, managed R&D projects, technical support on all activities, and the development of the comprehensive DSM Plan filing in July of 1994.

New York State Electric and Gas Corporation (NYSEG) - Had overall responsibility for a multi-million dollar impact evaluation of NYSEG's C/M/I DSM programs for the 1991 and 1992 calendar year.

Rochester Gas & Electric Corporation (RG&E) - Prepared RG&E's 1991-1993 compliance filings which were filed with the NYPSC to recover lost revenues and claim incentives for DSM activities.

Responsible Officer for the evaluation of RG&E's 1990-1993 DSM programs. Provided a comprehensive report filed with the NYPSC. Presentations were made to the NYPSC during various stages of each evaluation.

Western Kentucky Gas - Responsible Officer for the designing of 1997 WKG CARES Program and the evaluation of the 1997 Process and Impact Programs for this low Income Program. Presentations were made to the Western Kentucky Gas Collaborative and the CAP Agencies supporting the WKG program detailing the report findings.

INNOVATIVE MARKET SEGMENTATION & PROFITABILITY STUDIES

CINergy - Was selected in 1995 for a multi-phase project that had as its objective the meaningful (from a risk-profit perspective) segmentation of CINergy's key non-residential customer markets and the analysis of profitability of the segments. This was followed by the development of strategies to optimize the use of CINergy's marketing resources to maximize shareholder returns while ensuring the long-term viability of the company.

MARKET ASSESSMENT

Bermuda Electric Light Company, Ltd. (BELCO) - Developed an assessment of the potential for DSM including on-site interviews with most of the Island's largest customers.

Conducted an assessment of the potential revenue by specific product & service for a BELCO owned ESCO.

Electrical Generating Authority of Thailand (EGAT) - Was the responsible officer and project manager for this project funded by the World Bank to estimate the potential for DSM in the industrial sector in the country of Thailand. As part of this project, AEG retained in-country subcontractors to conducts audits and market research for primary data collection.

Western Resources - Conducted a market assessment of the potential revenue and earnings from 11 different ESCO products and services.

MARKET TRANSFORMATION

Consolidated Edison Company of New York, Inc. - Managed a market transformation study which attempted to measure the direct and in-direct impacts of information and free drivers during the 1990 - 1994 period. Study reviewed all programs and customer classes.

Long Island Lighting Company (LILCO) - Participated in a study to "right size" DSM for LILCO. Project involved a review of the current market and how LILCO's DSM programs, along with other factors may have "moved the market". The study included a repackaging of LILCO's program to more effectively spend DSM resources.

PLANNING & FORECASTING (Selected Projects)

El Paso Electric Company (EPEC) - Developed econometric load forecasts for ten residential classes of service. Separate models were developed for customers and use per customer by service class. Prepared revised forecasting methodology document to be used in Company planning for regulatory proceedings. Developed a number of adjustment factors to normalize monthly energy sales by rate class for billing cycle, number of customers, weather and customer growth. These adjustment factors were used to improve the sales data that were used in the Company's forecasting models, which AEG had previously developed.

Kansas City Power and Light Company (KCP&L) - Developed and implemented a residential econometric end use analysis. This analysis was the basis for Rebuttal Testimony filed on behalf of KCP&L.

Kansas Gas and Electric Company (KG&E) - Developed and implemented econometric end use load forecasts for the residential and commercial classes for use in the Company's long term planning process.

Iowa Power Company - Prepared a peak demand forecast and peak weather normalization for Iowa Power Company. This project included two separate analyses utilizing econometric models to normalize ten years of annual peaks and to forecast system peak over a ten-year period.

Minnegasco - Performed short term sales load forecast using Box Jenkins Time Series Analysis. Models were developed by rate group for customers and use per customers. Forecast was used as part of direct testimony filed on behalf of Minnegasco.

The Village of Rockville Centre - Developed and implemented the 1997 Power Supply Planning Study for the Village of Rockville Centre which depicted a forecast analysis for a 15-year period. This study included a scenario in which a new customer with a 3.4 to 4.2 MW load was added to the system. Such a customer had been identified by the Village, although their identity was kept confidential for this study.

Saudi Arabia - In 1995, selected from an international list of experts to perform a comprehensive review of Saudi Arabia's largest utility's overall planning and forecasting procedures, methodologies, and results. This two-phase project called for the reengineering of these processes once the analytical and fact-finding phase was completed.

South Carolina Pipeline Corporation - Performed a five-year forecast for SCPC by class and customer type as part of an IRP filing. This forecast was the first ever performed for this intra-state gas pipeline which serves 17 LDCs and directly serves hundreds of industrial customers.

UtiliCorp United - Responsible Officer for the development of UtiliCorp=s 1999-2000 Conservation Improvement Program (CIP) filing for People=s Natural Gas and Northern Minnesota Utilities. Project tasks included program development and benefit-cost analyses. Responsibilities included coordination with utility and regulatory staff.

Vanceburg Electric Light Heat and Power System - Performed a twenty-year Energy and Peak Load Forecast in connection with the proposed Hydro-Electric Dam on the Ohio River.

Vermont Gas - Performed a ten-year sales forecast using Box Jenkins Time Series Analysis and multiple regression analysis. Models were developed by rate group for customers and use per customers. Estimates were provided for base and heat loads. High/low scenarios were developed as well. Forecast was used as part of an IRP filing.

Western Resources - Provided all statistical analysis to weather normalize test year sales as part of an overall rate case filing. Analysis was used as part of direct and rebuttal testimony.

STRATEGIC MARKETING & MARKET POTENTIAL ASSESSMENTS

New York Power Authority (NYPA) - Was retained in late 1994 by NYPA to conduct a customer satisfaction and needs study, the first ever conducted by NYPA. Results of this assignment will be used to develop new programs and economic development initiatives.

Day and Zimmermann, Inc. - Responsible for the preparation of a report for Day and Zimmermann, Inc. on the market potential for cogeneration technologies. This report included technical information, a marketing strategy, and review of all current forecasts for cogeneration.

Kansas Gas & Electric Company - Performed a market potential analysis. The study assessed the utility cost/benefits in relation to current and new customers using cogeneration with sensitivities on fuel type and rate design.

NYNEX Corporation - Assisted in the evaluation of the market potential for Automatic Meter Reading Systems, including preliminary cost/benefit evaluations.

Orange & Rockland Utilities - Responsible for a market potential analysis. The study assessed the utility cost/benefits in relation to current and new customers using cogeneration with sensitivities on fuel type and rate design.

EXPERT TESTIMONY & REGULATORY SUPPORT ASSIGNMENTS

Kansas City Power and Light Company / Kansas Docket #84-KG&E-197-R-142, O98-U / Missouri Docket #ER-85-128, EO-85-185 - Provided rebuttal testimony in the Wolf Creek Nuclear Plant rate case regarding forecasting related issues on behalf of KCP&L in both Kansas and Mossouri.

South Carolina Pipeline - Prepared direct testimony on a five-year load forecast which was performed in support of the Company's first IRP.

El Paso Electric Company - Testified on behalf of El Paso Electric Company on the issues of load forecasting in Case No. 7460.

Arthur Kill, Prattsville, Indian Point - Assisted in the preparation of direct testimony, rebuttal testimony, and cross-examination in the Prattsville Pump Storage Project licensing procedure for NYPA, Case No.'s 50-247-SP, and 50-286-SP, Arthur Kill licensing proceeding for NYPA, Indian Point 3 Nuclear Power Plant Shutdown proceeding for the NYPA and the Indian Point 2 Nuclear Power Plant Shutdown proceeding for Con Edison.

Texas Utilities - Provided consulting services to Texas Utilities during the Comanche Peak Unit 1 and Unit 2 Rate Cases on the issues of need to build and prudence. Assisted in the preparation of testimony on the issue of nuclear performance standards. Managed the effort and wrote a comprehensive report entitled "The Lignite Utilization Report". This report covered TU's history regarding the use of lignite as a generating fuel, including exploration, acquisition criteria, recovery and generation.

Provided assistance in Unit 2 rate case including review of intervenor testimony regarding performance standards. Provided analysis used in Company testimony regarding the bias of the performance standards testimony being recommended by the intervenors.
Empire District Electric Company - Assisted in the preparation of testimony on the issue of weather normalization of energy sales in Case No. ER-90-138.

KeySpan - Performed statistical analysis in support of testimony before FERC on projections for fixed and variable O&M for KeySpan=s generating plants.

Missouri Public Service - Assisted in the preparation of testimony of the issue of weather normalization of energy sales in Case No. ER-90-101.

Palo Verde Units 1 and 2 - Assisted in the preparation of rebuttal testimony and cross-examination on the subject of comparative economics of generation alternatives in the Palo Verde Unit 1 and Unit 2 Rate Case, No.'s U- 1345-85-156, and U-1345-85-367, before the Arizona Corporation Commission on behalf of Arizona Public Service Company, and before the Public Utility Commission of Texas on behalf of El Paso Electric Company for the Unit 2 Rate Case. Testimony concentrated on Nuclear O&M, Capacity Factor, and Capital Additions.

Assisted in the preparation of testimony on Nuclear performance standards on behalf of El Paso Electric in Case No.'s 8892, 9069, and 9165.

Shoreham - Prepared cross-examination for the Long Island Lighting Company in the Shoreham Nuclear Power Plant Abandonment proceeding before the New York Public Service Commission in Case No. 28252.

Wolf Creek / Kansas Gas and Electric Company / Kansas City Power and Light Company / Kansas Docket #84-KG&E-197-R-142, O98-U / Missouri Docket #ER-85-128, EO-85-185 - Assisted in the development of rebuttal testimony on lifecycle economics of nuclear vs. coal alternative. Provided first-year and lifecycle estimates of Wolf Creek's Operation and Maintenance Costs and Capital Additions Costs. Provided first-year and lifecycle estimates of Wolf Creek's Capacity Factors. Participated in the preparation of KG&E witnesses on the subjects of statistics, econometrics, forecasting, and engineering economics.

EDUCATION

State University of New York at Binghamton, M.A., Applied Economics, 1979.
State University College of New York at Oswego, B.S., Mathematical Economics, 1977.

Areas of study include mathematics, economics, statistics, econometrics, computer science, matrix theory, and linear programming.

Academic Honors

Fellowship, SUNY Binghamton

Advanced Education

ACertificate of Mastery@ in Reengineering from the Hammer Institute=s Center for Reengineering Leadership.

Seminar in Box-Jenkins Time Series Analysis equivalent to the one-semester graduate level course. Seminar included the methodology and applications of Univariate Stochastic Models, Transfer Function Models, Multivariate Stochastic Models, Multivariate Transfer Function Models, and Intervention Analysis.

Seminar on Lighting Design (Efficient Lighting Solutions) - 1990.

AFFILIATIONS

American Statistical Association
American Economic Association
ASHRAE
The Association of Energy Engineers
Association of Energy Services Professionals

ARTICLES & PUBLICATIONS

Co-Authored, "Market Transformation - Can It Be Measured"; presented at the AESP Annual Conference; Phoenix, Arizona; December 5, 1995.

Co-Authored, "Comprehensive DSM Planning: A Gas Utility's Experience"; presented at the ADSMP "Demand-Side Marketing: The Competitive Face of DSM" Conference; Orlando, Florida; December 5-7, 1994.

"Where Do We Go, Based Upon What We Know?"; NYPA's Demand Side Management Customer Conference; April 22-23, 1993.

Co-Authored with Joseph T. Stanish, "DSM Bidding: A Formula for Success"; presented at the 6th National DSM Conference; Miami, Florida; March 1993.

"Implementing DSM for Public Sector Customers NYPA's High Efficiency Lighting Program"; Implementation of Demand-Side Management; June 23-24, 1992.

"DSM Evaluation The Role of Load Research"; AEIC Load Research Conference; September 12-14, 1990.

"Is There a Place for Microcomputers in Electric Utilities"; Public Utilities Fortnightly; December 8, 1983.

"Impact of Weather on Power System Loads"; Proceedings of the American Power Conference; 1980.

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BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	)	
RATE APPLICATION BY	)	**Case No. 99-070**
WESTERN KENTUCKY GAS COMPANY	)	

TESTIMONY OF DANIEL M. IVES

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BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	**)**	
RATE APPLICATION BY	**)**	**Case No. 99-070**
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TESTIMONY OF DANIEL M. IVES

Q. Please State Your Name, Position, And Business Address.

A. My name is Daniel M. Ives. I am a Consultant and Vice President with Lukens Consulting Group, Inc., under engagement with Western Kentucky Gas Company. My business address is 1100 Louisiana, Suite 2750, Houston, TX 77002.

I. Qualifications

Q. What Is Your Background And Experience In The Gas Industry?

A. I have been employed by Lukens Consulting Group, Inc. since January 1999. Prior to joining Lukens, I was employed by ANR Pipeline Company, Detroit, MI, as Vice President-Rates and Regulatory Affairs from 1995-1998; Algonquin Gas Transmission Company, Boston, MA, as General Manager-Rates and Billing from 1992-1995; and Washington Gas Light Company, Washington, DC, as Director of Maryland Rates and Regulatory Affairs from 1985-1992, and as Director of Federal Regulation from 1982-1985. From 1976-1982 I held various positions in non-utility operations, auditing and accounting at Washington Gas.

Q. What Are Your Educational And Professional Qualifications?

A. In 1970 I received a B. A. and in 1975 a B. S. from the University of Maryland. In 1979, I became a Certified Public Accountant in the State of Maryland. I am a member of the American Institute of Certified Public Accountants and I am Past Chair of the American Gas Association's Rate and Strategic Planning Committee.

I have testified before the Public Service Commission of Maryland, the New York Public Service Commission, and the Federal Energy Regulatory Commission. Summaries of my testimony are contained in my Curriculum Vitae, which is appended to this testimony.

II. Purpose of Testimony

Q. What Is The Purpose Of Your Testimony In This Proceeding?

A. I have been engaged by Western Kentucky Gas Company to determine the need for and design and describe a proposed Premises Charge for new residential hook-ups. The proposed charge is similar to the System Development Charge currently being investigated by the Commission for use by water and sewer utilities in Kentucky. My testimony also describes and explains an incremental cost study that was prepared in support of the proposed charge. Further, I address the regulatory authority for Western Kentucky's proposed charge, the estimated revenue impact, the proposed accounting and reporting requirements, and other applicable policy issues raised by the Commission in its investigation.

III. Identification of Exhibits

Q. What Exhibits Do You Sponsor In Support Of Your Testimony?

A. I sponsor Exhibits DMI - 1 through Exhibit DMI - 7, which are attached to this testimony. I prepared this testimony and the exhibits were prepared by me or under my direction and supervision.

IV. Identification of Problem

Q. Please Discuss The Earned Return Problem That The Company Has Been Experiencing.

A. Western Kentucky Gas has been earning less than its authorized overall rate of return. Witness Petersen's Class Cost of Service Study indicates that the company under-earned its allowed rate of return during the twelve months ended September 30, 1998. This return deficiency is, in large part, due to underrecovery of an allowed rate of return from residential customers – an underrecovery that is expected to continue beyond the test period.

Q. What Are The Reasons For The Residential Return Underrecovery?

A. The reasons for the residential class' return underrecovery are many, in my opinion. The overall residential margin is less than system average due, among other things, to: 1) a cross-class subsidy in the allocation of costs; 2) a rate design that has placed too much – almost 60% - of fixed cost recovery in the commodity rate; 3) incremental facility costs that exceed facility costs embedded in rates; and 4) tariff requirements for the installation of 100 feet of main, service line, and meter at no charge.

A study performed for the company in 1998 by The Economics Resource Group, Inc. (predecessor to the Lukens Consulting Group, Inc.) indicates that the company failed to recover its cost of capital on virtually every new residential hook-up in the study's sample. Additionally, as this testimony will demonstrate, new residential customer attachment costs (including mains, meters, services and regulators) are more than twice the embedded costs upon which rates are set. Consequently, the company will not earn a return, or recover other associated costs such as depreciation and property tax, on that portion of new customer investment that exceeds the level upon which rates are set. The return and other costs that are forgone on these investments, if not recovered by other means, may cause the company's overall return to fall below authorized levels and may drive the company to once again seek rate relief.

Q. What Changes Are Proposed To Remedy This Problem?

A. Several approaches to help resolve this problem are being taken in this rate case. Witness Smith has proposed that an increased share of costs be allocated to the residential class so as to reduce the cross-class subsidy and he also proposes an increase to the residential Base Charge to better assure collection of non-gas margins. Witness Smith also proposes a weather normalization mechanism that, if approved, should ameliorate the impact of weather on non-gas revenues collected in the commodity charge. My testimony demonstrates the need for and proposes a Premises Charge for new residential hook-ups that will allow the company to recover the amount by which incremental facility costs exceed embedded facility costs ("Excess Investment") for the main extension and the meter, service line and regulator; and return and tax on these costs during the periods over which the charge is collected.

V. Current Premises Connection Policies

Q. Please Describe The Commission's Current Premises Connection Policies.

A. The Commission's regulations generally require Kentucky utilities to furnish and install meters and appurtenances, service lines, and up to 100 feet of distribution main at their expense to customers who apply for new service. Below are excerpts from the Commission's regulations:

Service Lines: The Commission's regulations currently require gas utilities to "furnish and install *at its own expense*...that portion of the service pipe from its main to the property line or to and including the curb stop and curb box if used." [807 KAR 5:022, Section (9) (17) (a) 1.] (*Emphasis added*)

Meters: The regulations state that "the utility shall make *no charge* for furnishing and installing any meter or appurtenance necessary to measure gas furnished, except by mutual agreement as approved by the commission in special cases or except where duplicate or check meters are requested by the customer." [807 KAR 5:022, Section (8) (2) (c)] (*Emphasis added*)

Distribution Main: The regulations state that, for a normal extension: "An extension of 100 feet or less shall be made by a utility to an existing distribution main *without charge* for a prospective customer who shall apply for and contract to use service for one (1) year or more and provides guarantee for such service." [807 KAR 5:022, Section (9) (16) (a)] (*Emphasis added*)

Q. Does Western Kentucky Gas Company's Current Tariff Comply With The Commission's Regulations?

A. Yes, in my opinion. Section 21 of the company's tariff provides that the company will furnish, install and maintain at its expense the meter, regulator and connections, and the service line. Section 28 of the company's tariff provides that the company will extend without charge an existing distribution main 100 feet for each customer provided that the existing main is of sufficient capacity to provide service, the customer contracts to use gas on a continuous basis for one year or more, and "the potential consumption and revenue will be of such amount and permanence as to warrant the capital expenditures involved to make the investment economically feasible." [P.S.C. No. 20, Original SHEET Nos. 80 and 82] The Commission has accepted the company's tariff pages.

Q. May The Commission Permit Deviation From Its Rules?

A. Yes, it may. Section 18, "Deviations from Rules," provides that "[I]n special cases for good cause shown the commission may permit deviations from these rules." [807 KAR 5:022, Section (18)]

Q. If A Utility's Costs To Serve A Customer Exceed The Amount The Utility Collects In Rates To Provide Such Service, Could The Utility Make A Special Charge For Such Excess Costs?

A. Yes, upon Commission approval of such charge. For example, in addition to the Deviation provisions which would permit waiver of the "no charge provisions" for hook-ups, the Commission's regulations also provide that a utility may make "special nonrecurring charges to recover customer-specific costs incurred which would otherwise result in monetary loss to the utility or increased rates to other customers to whom no benefits accrue from the service provided or action taken." A utility must apply for commission approval of such charge and the charge "shall yield only enough revenue to pay the expenses incurred in rendering the service." [807 KAR 5:006, Section (8) (1) and (2)]

Q. Does Your Proposed Premises Charge Comport With The "Deviation" And "Special Charge" Provisions Of The Regulations?

A. Yes, in my opinion. This testimony will demonstrate that new residential hook-ups generally result in a monetary loss to the company and they ultimately may cause rate increases to other customers. The economics upon which new service connections "without charge" and "at its own [the company's] expense" were founded no longer work. Because the company proposes to credit plant accounts with the amount of Excess Investment recovered in the proposed charge, and retain only return and tax, it is effectively only seeking enough revenue to pay for the expense associated with the new hook-up. For these reasons it is appropriate for the company to seek Commission approval of the proposed Premises Charge.

VI. Western Kentucky's Embedded Facility Costs

Q. Why Is It Important To Review The Company's Embedded Facility Costs?

A. The company's rates are set based on embedded plant costs even though the company utilizes a forecasted Test Year. Embedded plant costs, as will be demonstrated in this testimony, have increased since the company's last rate filing, yet remain less than the incremental costs of new meters, services, regulators and distribution main. Rates set on embedded costs are not sufficient to recover the costs associated with new business investments that are installed at higher incremental facility costs.

Q. What Are The Company's Relevant Embedded Costs For New Residential Investment?

A. Exhibit DMI –1 shows a comparison of embedded distribution facility costs for all customers as reflected in Western Kentucky's 1994 Class Cost of Service that was filed in its 1995 rate case and in its 1998 Class Cost of Service filed in this rate case. The costs were retrieved from the company's "Walker" plant accounting system and do not reflect depreciation expense. The major cost components for a new customer hook-up are meter, regulator and service line costs, installed, and the cost of distribution main, installed. As shown in this exhibit, the average embedded facility costs for all customers rose $231, or 39%, from September 30, 1994 to September 30, 1998.

Exhibit DMI – 2, Schedule 1, reflects this same comparison, but for embedded costs for the residential customer class only as of September 30, 1994 and September 30,1998. The average increase in embedded facility costs is $173 per residential customer, or an increase of 41%.

Q. What Is The Significance Of The Residential Class' Embedded Cost Increase?

A. The residential class' embedded cost increase is significant because it indicates that new facility additions have caused rate base to increase substantially, notwithstanding continued rate base depreciation. And, it is indicative that rates that are set on embedded facility costs will not be adequate to recover the costs associated with new hook-ups. Further, as shown on Schedule 2 of Exhibit DMI – 2, most, 84%, of the company's customer growth is in the residential class, compounding the problem even more.

VII. Western Kentucky's Incremental Facility Costs

Q. Please Define Incremental Facility Costs.

A. Incremental facility costs, as used in this testimony, refer to the facility costs that will most likely be incurred by the company for new plant investments made during the test year. Fiscal 1998 plant addition unit cost data from the Walker System was used as a basis for incremental costs in this study and for the company's test year investments.

Q. Have You Quantified Incremental Costs For New Residential Service Connections?

A. Yes. Exhibit DMI – 3 identifies the incremental costs of facilities by component for new residential service hook-ups. The current incremental installed cost of a new residential meter, service and regulator (with main extension) is $1,476, as shown on the exhibit.

Q. Do Incremental Facility Costs Exceed Embedded Facility Costs?

A. Yes. Exhibit DMI – 4, Schedule 1, compares residential incremental facility costs, as reflected in Exhibit DMI – 3, with embedded facility costs, as contained in Exhibit DMI – 2, Schedule 1. The exhibit indicates that incremental residential facility costs exceed embedded residential facility costs by $878 per hook-up as of September 30, 1998.

Q. What Are The Reasons For The Difference Between Incremental And Embedded Costs?

A. There are many reasons for the differences, most obvious of which is the element of time. Embedded costs reflect a range of historical price levels, which are aggregated and averaged in the embedded cost data. On a rate base basis, embedded costs also reflect the accumulation of depreciation over time. (This study utilizes embedded costs, before depreciation, for comparability purposes.) Incremental costs reflect the most recent cost levels to be utilized for test year plant additions.

Q. What Is The Significance Of This Cost Differential?

A. The company's rates are set based on an average rate base methodology; regardless of whether a forecasted Test Period is used. The Test Period rate base includes historical installed facilities and facilities estimated to be installed during the test year. Facilities estimated to be installed during the test year are priced at incremental unit costs, but the bulk of the rate base is priced as recorded on the books, at historical cost. When added together, the adjusted rate base is still an average that contains mostly outdated costs. This is demonstrated in Exhibit DMI – 4, Schedule 2. The exhibit demonstrates that when budgeted new residential hook-ups in the test year, priced at incremental residential facility costs of $1,476 per hook-up, are added to the embedded residential costs of $598, the embedded cost level increases to $618 and the Excess Investment is reduced to $858.

Base tariff rates set on the test year embedded cost level of $618 clearly will not be sufficient to fully recover the allowed rate of return on new, higher cost facilities. Each unit of new growth inherently cannot fully earn an allowed rate of return because rates are only designed to recover a return on the embedded level of investment.

Q. Would Imposition Of A Premises Charge Result In An Overrecovery Of The Company's Authorized Return?

A. No. In order for such an overrecovery to occur, all elements of the ratemaking model (revenues, expenses, rate base, capital costs, billing determinants and test year adjustments) must occur exactly as estimated when the Commission sets rates. Only if all these variables are met exactly could a Premises Charge allow the company to generate earnings in excess of the authorized level. Such a scenario is unlikely.

Further, rates set on a projected test year rate base will only recognize plant additions budgeted to be in service in that test year. The incremental cost of plant additions the year following the test year will not be recognized in rates. Thus, the company will not begin to recover those costs unless or until it files another rate case or is authorized to implement a Premises Charge. For this reason, the company proposes to implement the Premises Charge effective for new residential service connections made on and after January 1, 2001, which commences the year following the test year.

Additionally, as will be discussed later in this testimony, the company proposes to credit to rate base that portion of its proposed Premises Charge related to Excess Investment. The company also would agree to an annual reporting requirement so that the Commission may monitor the impact of the charge upon customers and upon earnings.

Q. Is The Need For A Premises Charge Demonstrated?

A. Yes. The incremental cost study contained in Exhibit DMI – 4, Schedule 2, demonstrates that new service hook-ups cost more than twice the cost of embedded plant. Rates are set on embedded plant. Growing rate base at a loss does not make economic sense. To do so only foists the cost of growth onto customers and Western Kentucky's shareholders.

VIII. Proposed Premises Charge

Q. Please Describe Your Proposed Premises Charge.

A. To ameliorate the earnings erosion caused by new residential growth, I propose that a special charge be implemented on new residential service connections made on and after January 1, 2001. The proposed Premises Charge I have designed will recover the Excess Investment and return and tax on these costs during the collection period. The charge will be computed separately for new services that require main extension and those that do not require main. Both the "return of investment" and "return on investment" pieces of each proposed charge are grossed-up for income taxes as they are taxable income to the company. All of the components of each charge will be consolidated into a single rate that will be billed monthly for 180 months (15 years).

Q. Why Do You Propose A 15-Year Recovery Period For The Charge?

A. A 15-year recovery period recognizes the competitiveness of today's energy markets. A shorter recovery period would result in a higher, less competitive, rate while a longer collection period may exceed the economic life of the facilities. (The IRS has recognized that economic lives may be shorter than physical lives, for its MACRS depreciation system allows for accelerated depreciation cost recovery, utilizing 15 and 20 year lives for utility property.) Additionally, a fifteen-year recovery period is consistent with that being used elsewhere in the industry.

Q. Please Describe The Computation Of The Charge.

A. The computations of the proposed charges are set forth on Exhibit DMI – 5. The "return on investment" portion has been computed at the rate of return requested in this case, adjusted to a before-tax basis. The "return of investment" piece has been grossed-up for tax utilizing the company's composite Federal and state tax rate. Without main extension, the proposed charge is $11.25 per month, for 180 months. With main extension, the proposed charge is $13.05 per month, for 180 months.

Q. Why Do You Not Propose A Premises Charge For New Commercial Or Industrial Customers?

A. As discussed in Section IV of my testimony, the residential customer class is principally responsible for the company's earnings deficiency; thus, a Premises Charge is not necessary or appropriate for the other customer classes.

Q. Why Should The Charge Provide For Recovery Of Investment?

A. Recovery of the Excess Investment helps ensure that growth pays for itself and is not a constant driver of rate cases. The embedded cost of distribution facilities will not be increased as a result of new additions, as the company will credit plant for amounts recovered as a return of capital. Hence, existing customers' rates will not increase as a direct result of growth and all customers' future rates will be lower to the extent the proposed Premises Charge is authorized and implemented. It is possible that certain costs associated with growth, such as transmission main reinforcements, may ultimately be reflected in all customers' rates, but the increased costs of hook-ups (meters, regulators, service lines and distribution main) will be paid-for directly by the customer.

Q. How Did You Design The Premises Charge?

A. I designed the Premises Charge to be simple to compute, understandable to customers and regulators, and easy to administer.

In terms of simplicity, I propose that the Premises Charge be a "one size fits all" rate that reflects the average Excess Investment, except that a separate charge will be computed for hook-ups requiring main extension. This distinction is equitable so that customers only pay for main extension if they use it. The Premises Charge should remain with the Premises for the later of 180 months or until the charge is fully collected, regardless of service address ownership changes. The charge should be assessed commencing with the permanent occupancy of the dwelling, such that builders and developers are not assessed the charge on interim service for new construction.

Customers should find the charge understandable in that today's existing customers and will not be asked to pay for tomorrow's new customers. When properly communicated, customers should understand that the charge only allows the company an opportunity to recover the costs of investment and a fair return. A "one size fits all" charge should prevent confusion amongst customers in that they all pay the same charge for the same type of hook-up as opposed to different rates for each new service on the street or in the subdivision or community.

The administrative burdens associated with the proposed charge should be minimal, as the company informs me that its systems are capable of flagging the service addresses, assessing the charge, and keeping track of revenues recovered. Computation of the level of the charge is easy, as aggregate annual cost data may be utilized rather than job-specific data.

Q. Should The Company Update The Charge Annually?

A. The amount of each charge (with or without main installation) should be updated annually and the revised charge implemented prospectively for the next year's new residential customer additions. Premises Charges levied upon existing customers should not be changed, as those charges are based on cost levels applicable at the time of service installation.

Additionally, I recommend that the company be given the authority to not change the level of the prospective charge if the increase or decrease is less than 10%. This will allow a tolerance for small cost changes or data aberrations.

Q. Do You Propose Any Other Exceptions To The Charge?

A. Yes. I propose that the charge not be imposed on new service connections where the service holder is LIHEAP-qualified. These exemptions would serve the public policy objective of not unduly burdening those who can least afford energy costs, while not materially shifting costs to other customers or the company.

IX. Revenues, Accounting and Reporting, and Tariff Authority

Q. What Is The Anticipated Annual Growth Rate For New Residential Customers On The Company's System?

A. Growth on the company's system is moderate for new residential services. For fiscal years 2001-2005, the company is forecasting an average of 1700 hook-ups per year, about a 1 % annual growth rate. Exhibit DMI – 6 reflects estimated new service connections for each of the calendar years 2001-2005 and associated Premises Charge revenues.

Q. How Will This Growth Be Financed?

A. This growth is budgeted to be financed through a combination of internally generated funds, debt, and equity offerings by the company's parent, Atmos Energy Company. To the extent that the growth does not provide sufficient revenue to cover the company's operating costs and provide a return, the company may be forced to file general rate increases and assess all customers, through higher rates, for the cost of growth.

Q. Will The Proposed Premises Charge Help Offset The Revenue Deficiency Associated With Growth?

A. Yes, to the extent the charge is authorized and collected.

Q. What Amount Is Expected To Be Collected Through The Proposed Premises Charge?

A. Exhibit DMI – 6 contains a tabulation of the expected collections by type of charge, for the period 2001-2005. Revenue has been computed for new services without main additions and for new services with main additions, based upon the proposed amounts of the charges and the budgeted number of service additions by type. Customer additions are expected to be made equally over each of the summer months of April through October. Premises Charges are estimated to be collected over each month, for 180 months. As you will note from the exhibit, total annual Premises Charge collections are estimated to range from $ 130,438 per year to $ 1,173,718 per year.

Q. How Do You Propose That The Company Account For The Premises Charge Revenues?

A. I propose that the revenues be accounted-for as follows:

- That portion of each type of charge that represents a return of "Excess Investment" be credited to the appropriate plant accounts, similar to the accounting for contributions in aid of construction. This will lower the net plant balance included in subsequent rate filings, resulting in lower rates for customers. As Exhibit DMI – 6, Schedule 1, indicates, the estimated credit to plant ranges from $ 47,629 to $ 428,581 annually over the five-year period.
- That portion of each type of charge that represents a return on the investment be separately identified and credited to miscellaneous utility operating income. Exhibit DMI – 6, Schedule 1 indicates that the estimated miscellaneous income will range from $ 30,160 to $ 271,389 per year.
- That portion of each type of charge that represents the gross-up for Federal and state income tax be credited to income tax expense. Tax expense associated with the proposed charge ranges from $ 52,649 to $ 473,748 per year.

Q. What Is The Estimated Annual Earnings Impact Of The Proposed Charge?

A. As noted above, Schedule 1 of Exhibit DMI – 6 provides an estimate of revenues by component for each of the years 2001-2005. Revenues associated with the company's recovery of carrying costs, net of tax, are estimated to range from $30,160 to $ 271,389 per year. As previously noted, these revenues would commence in the year following the test year.

Q. Should These Revenues Be Credited To The Company's Cost Of Service For Ratemaking Purposes?

A. Absolutely not. As the company proposes to implement the Premise Charge effective the first of the year following the test year (one year after new rates adjudicated in this case go into effect) there will be no "excess" revenues associated with the charge. The earnings that do materialize will be related to new services that are connected after, and not included in, test year plant additions. Thus, the earnings will not be "excess", as the underlying plant will not have been considered in development of base rates.

Q. Should The Company Be Required To Report Activities Under The Premises Charge To The Commission?

A. The company should file a report annually with the Commission disclosing the following information about the program:

- Numbers of charges levied by type
- Costs recovered and earnings generated
- Accounting for the costs and revenues

Q. What Tariff Authority Does The Company Request In This Rate Case?

A. The company seeks authority to implement the proposed tariff provisions described in Exhibit DMI – 7, Schedule 1, and sponsored by tariff Witness Smith. The tariff provisions describe the Premises Charge, its applicability, and the Premise Charge rates for new residential connections commencing on and after January 1, 2001.

Q. What Other Authority Does The Company Seek In This Proceeding?

A. The Company seeks Commission waiver of any and all of its regulations necessary for the company to implement its proposed Premises Charge.

X. Other Considerations

Q. If The Commission Requires Annual Planning Studies As A Prerequisite To The Assessment Of A Premises Charge, What Information Should Be Required?

A. The company should provide an estimate of annual customer additions by customer class. The company should also discuss the estimated number and cost of meters, services, regulators and distribution main to be installed and demonstrate the extent to which incremental facility costs will exceed embedded facility costs. The company should also provide an estimate of revenues and earnings to be generated by the proposed Premises Charge.

Q. Should Premises Charges Be Developed And Assessed Upon Discreet Geographical Segments Of A Service Area, Rather Than On A Systemwide Basis?

A. Area development charges may be appropriate for certain geographical areas when the cost of expansion to those areas greatly exceeds the costs recovered in the proposed system-wide Premises Charge. Such instances may include expansions with long runs of distribution and/or transmission main, the cost of which may not be recoverable directly from customers or developers. Examples of this type of development would include expansion to new towns and/or along transportation corridors to distant high-growth areas. In those circumstances it may be appropriate for the company to apply for Commission approval of area-specific surcharges that recover the incremental costs applicable to those areas, in addition to the costs recovered in the New Premises Charge. However, I have not proposed area-specific charges in this testimony for the reasons previously discussed.

Q. What Facility Size Measures Should Be Considered In The Design Of The Charge?

A. The proposed charge considers the incremental costs of meters, regulators, service lines, and distribution main needed to serve residential customers, including Class 1 meters, service lines1" or less, and distribution mains 2" or less.

Q. Has The Company Had Any Discussions With Customers Or Builders And Developers Regarding Its Proposed Premises Charge?

A. The company informs me that it has had discussions with builders and with its Consumer Advisory Panel regarding the concept of this proposal and the need for such a charge.

Q. What Affect, If Any, Would The Imposition Of The Proposed Premises Charge Have Upon Economic Development In The Company's Service Area?

A. Although I have not done a study to address the impact of the charge on economic development and on low and moderate-income housing, it is likely that the charge will not have significant impact. This is because the company's rates are competitive with electricity and are amongst the lowest in the state for residential gas service. Imposition of a Premises Charge will help keep the company's rates low and competitive. This should benefit the economy in general and help keep utility costs affordable. As the company proposes certain low-income exemptions from the charge, there may be a resultant favorable impact on low-income customers and housing stock.

Q. Have You Considered Other Models For A Premises Charge?

A. Yes. I reviewed area expansion charges utilized by several other gas companies, including Minnegasco, Questar, and Michigan Gas Utilities (MGU). Each of the charges that I reviewed was area-specific, assessed monthly, and ran for periods of up to 15 years. The amounts of the charges ranged from $1.10-4.61 per Mcf for gas sold over a three to five year period at MGU, to $30 per month out to year 2013 for certain Questar customers. Minnegasco's tariff provides for a project-specific charge of up to 15 years, with residential charges ranging from $4.75-8.00 per month.

My approach of using a system average rate that is billed monthly results in a charge that, on average, is equitable to new customers; is understandable; and is easy to administer. Existing customers and new customers benefit because growth as a driver for rate cases will be minimized.

Q. What If The Commission Rejects The Concept Of Growth Paying For Growth?

A. If the Commission rejects the concept of new customers paying for the incremental cost of growth, then it should allow the company to implement a facilities adjustment charge over all residential customers, commencing in January 2001. The Excess Investment and tax related to the estimated 1700 annual residential customer additions would be collected from all residential customers either through an annual base rate adjustment or through a separate billing charge. Such an adjustment would initially approximate $15.44/year, or $1.29/month, per residential customer (based on an estimated 155,220 residential customers) and could be adjusted annually for cost changes and the number of customer additions. Initially, the charge would generate approximately $2.4 million in pre-tax revenues. The accounting and reporting requirements would be similar to those proposed for the Premises Charge.

Q. Would A Facilities Adjustment Charge Applicable To All Residential Customers Accomplish The Same Objectives As The Proposed Premises Charge?

A. Yes, except that all residential customers would fund residential growth. The earnings erosion associated with new residential investment would be eliminated.

XI. Summary

Q. Please Summarize Your Testimony.

A. The proposed Premises Charge should be approved by the Commission as filed for the following reasons:

- The proposed charge is equitable. Rates designed on embedded costs do not recover the incremental cost of growth. This testimony has demonstrated that costs for new residential facilities far exceed the embedded costs used to set rates. Further, the residential class has been earning less than its authorized rate of return due to growth and other factors. The company should be allowed to recover the costs of growth, and a return on those costs, from the customers that cause the costs.
- Collection of Premises Charges will reduce growth's impact on rate base, as rate base will be credited for the return of investment portion of the charge. This will help keep future tariff rates low to the benefit of both old and new customers.
- Imposition of a Premises Charge will help mitigate earnings erosion associated with residential growth. By being allowed to recover and earn on its incremental costs, the company will have a better opportunity to earn its authorized overall rate of return. This should help reduce the need for new rate case filings that would otherwise be driven by new growth.
- The proposed Premises Charge is reasonable when compared to other charges in the industry and the company's low base rates make it the most competitive gas distribution company in the state. The proposed Premises Charge should not have a material adverse impact on economic development or housing stock. Low-income customers are proposed to be exempted from the charge.
- The proposed Premises Charge is similar to the system development charge envisioned by the Commission in its current investigation into the need for such a charge by water companies in the state. The company has addressed the relevant issues of that proceeding in this filing.

- The Commission's regulations give it the authority to approve deviations from its new service connection policies and to approve a utility's imposition of special charges, such as the company's proposed Premises Charge.

For good cause and the reasons shown, the Commission should approve the proposed Premises Charge and the proposed tariff provisions. In the alternative, the Commission should approve a facilities adjustment charge applicable to all residential customers and the proposed alternate tariff provisions.

Q. Does This Conclude Your Prepared Direct Testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
RATE APPLICATION OF	)	Case No. 99-070
WESTERN KENTUCKY GAS COMPANY	)	

CERTIFICATE

I, Daniel M. Ives, have answered the foregoing questions propounded to me in the above enumerated Docket. These answers and exhibits constitute and I hereby adopt, under oath, these answers as my prepared direct testimony in said case, which is true and correct to the best of my information and belief.

D. M. Ives

Daniel M. Ives
Lukens Consulting Group, Inc.
On behalf of
Western Kentucky Gas Company

COMMONWEALTH OF KENTUCKY)
) S.S.
COUNTY OF DAVIESS)

SUBSCRIBED AND SWORN TO before me by Daniel M. Ives, on this 11th day of May, 1999.

Pearl Ann Simon

Pearl Ann Simon
Notary Public
State of Kentucky At Large.

My Commission expires: September 26, 2001.

Western Kentucky Gas Company

Overall Embedded Facility Costs[1]

At September 30, 1994

	Total Facility Investment	Total Customers[2]	Investment/ Customer
Mains	$ 49,208,047	161,314	$ 305.05
Services	$ 24,200,567	161,314	$ 150.02
Meters	$ 11,007,336	161,314	$ 68.24
Meter Install	$ 7,961,105	161,314	$ 49.35
Regulators	$ 2,598,120	161,314	$ 16.11
Total	$ 94,975,176	161,314	**$ 588.76**

At September 30, 1998

	Total Facility Investment	Total Customers[2]	Investment/ Customer
Mains	$ 65,290,250	171,195	$ 381.38
Services	$ 40,472,761	171,195	$ 236.41
Meters	$ 17,386,195	171,195	$ 101.56
Meter Install	$ 13,351,635	171,195	$ 77.99
Regulators	$ 3,910,536	171,195	$ 22.84
Total	$ 140,411,377	171,195	**$ 820.18**

Change 1994 to 1998 **$ 231.42**

Notes:

1. Costs retrieved from Western Kentucky "Walker System."
   Costs do not reflect depreciation expense.
2. Twelve-month rolling average customer count at September 30, 1994 and 1998, from company's financial statements.

Western Kentucky Gas Company

Residential Embedded Facility Costs[1]

At September 30, 1994

	Total Applicable Facility Investment[2]	Customers[3]	Investment/ Customer
Mains	$ 27,417,429	151,801	$ 180.61
Services	$ 22,334,292	151,801	$ 147.13
Meters	$ 7,302,542	151,801	$ 48.11
Meter Install	$ 5,281,596	151,801	$ 34.79
Regulators	$ 2,174,047	151,801	$ 14.32
Total	$ 64,509,906	151,801	$ **424.96**

At September 30, 1998

	Total Applicable Facility Investment[2]	Customers[3]	Investment/ Customer
Mains	$ 34,182,659	162,487	$ 210.37
Services	$ 37,106,369	162,487	$ 228.37
Meters	$ 12,771,576	162,487	$ 78.60
Meter Install	$ 9,807,863	162,487	$ 60.36
Regulators	$ 3,313,005	162,487	$ 20.39
Total	$ 97,181,473	162,487	$ **598.09**

***Change 1994 to 1998* $ 173.12**

Notes:

1. Costs retrieved from Western Kentucky "Walker System."
   Costs do not reflect depreciation expense.
2. Year End Balances at Septemeber 30 for each type of property:
   Mains - Plastic or Steel of size 2" or less
   Services - Plastic or Steel of size 1" or less
   Meters - with capacity of 250 cf per hour or less
   Regulators - of size 1" or less.
3. Twelve-month rolling average residential customer count at September 30 was increased to include 8,326 and 10,667 small commercial customers in 1994 and 1998 respectively to account for small commercial facility investment included in the plant balances for the above-sized facilities.

Western Kentucky Gas Company

Customer Growth

	Number of Customers1/			
	1994	1998	Growth	% of Total Growth
Residential	143,475	151,820	8,345	84.46%
Commercial	17,451	18,985	1,534	15.52%
Industrial	388	390	2	0.02%
Total	161,314	171,195	9,881	100.00%

Notes:

1. Twelve-month rolling average customer count at September 30, from the company's financial statements.

Western Kentucky Gas Company

Residential Incremental Facility Costs[1]

Fiscal Year 1998 Costs

	Footage/Units Installed[2]	Total Cost of Installed Units[3]	Incremental Cost Per Customer[4]
Mains	208,884	$ 994,069	$ 331.36
Services	3,263	$ 2,959,356	$ 906.94
Meters	13,538	$ 926,230	$ 68.42
Meters Install	9,042	$ 1,301,389	$ 143.93
Regulators	6,665	$ 170,726	$ 25.62
Overall Total			**$ 1,476.26**

Notes:

1. Data retrieved from Western Kentucky "Walker System" and include replacements and retirements. Cost data does not reflect depreciation expense.
2. Mains is installed footage. All others are units installed.
3. Total costs for each type of property:
   Mains - Plastic or Steel of size 2" or less
   Services - Plastic or Steel of size 1" or less
   Meters - with capacity of 250 cf per hour or less
   Regulators - of size 1" or less.
4. Mains is equal to the FY 1998 cost per foot multiplied by the end of year embedded footage of main per residential/small commercial customer (69.63 feet per residential/small commercial customer).

Western Kentucky Gas Company

Residential Incremental Costs vs. Embedded Costs

At Sepember 30, 1998

	Incremental Cost Basis[1]		Embedded Cost Basis[2]		Differential	
Mains	$	331.36	$	210.37	$	120.99
Services	$	906.94	$	228.37	$	678.58
Meters	$	68.42	$	78.60	$	(10.18)
Meter Install	$	143.93	$	60.36	$	83.57
Regulators	$	25.62	$	20.39	$	5.23
Total	$	1,476.26	$	598.09	**$**	**878.17**

Notes:

1. From Exhibit DMI-3, Schedule 1.
2. From Exhibit DMI-2, Schedule 1.

Western Kentucky Gas Company

Residential Incremental Costs vs. Embedded Costs

At September 30, 2000

	Embedded Cost 1998[1]	Customer Additions 1999 and 2000[2]	Incremental Cost Per Customer[3]	Estimated Incremental Cost Added	Estimated Embedded Cost 2000[4]	Estimated Customers 2000[5]	Estimated Embedded Cost Per Customer	Excess Investment[6]
Mains	$ 34,182,659	3,360	$ 331.36	$ 1,113,366	$ 35,296,025	165,847	$ 212.82	$ 118.54
Services	$ 37,106,369	3,860	$ 906.94	$ 3,500,801	$ 40,607,170	166,347	$ 244.11	$ 662.83
Meters	$ 12,771,576	3,860	$ 68.42	$ 264,090	$ 13,035,665	166,347	$ 78.36	$ (9.95)
Meter Install	$ 9,807,863	3,860	$ 143.93	$ 555,559	$ 10,363,422	166,347	$ 62.30	$ 81.63
Regulators	$ 3,313,005	3,860	$ 25.62	$ 98,875	$ 3,411,881	166,347	$ 20.51	$ 5.10
Total Mains	$ 210.37		$ 331.36				$ 212.82	$ 118.54
Total MSR	$ 387.72		$ 1,144.90				$ 405.29	$ 739.61
Overall Total	$ 598.09		$ 1,476.26				$ 618.11	**$ 858.15**

Notes:

1. From Exhibit DMI-2, Schedule 1.
2. Budgeted new residential customer additions of 1700/year of which 1450/year require main addition, plus budgeted commercial additions of 230 per year.
3. From Exhibit DMI-3, Schedule 1.
4. Embedded Cost 1998 plus Estimated Incremental Cost Added.
5. September 30, 1998 residential/small commercial customer count from Exhibit DMI-2, Schedule 1, plus estimated residential and commercial customer additions in 1999 and 2000.
6. Incremental Cost Per Customer less Estimated Embedded Cost Per Customer.

Western Kentucky Gas Company

Computation of Proposed Premises Charge

Assumptions		
Excess Investment in Main	$118.54	Per Customer[1]
Excess Investment in MSR	$739.61	Per Customer[1]
Total Excess Investment	$858.15	Per Customer[1]
Recovery Period	180	Months
Pre-Tax Rate of Return	14.06%	As Requested[2]
Composite Tax Rate	40.36%	State and Federal Tax

	Demand Charge Per Month		
	Return of Excess Investment[3]	**Carrying Cost on Excess Investment[4]**	**Return of Excess Investment plus Carrying Cost**
Main-Only	$1.10	$0.70	$1.80
MSR-Only	$6.89	$4.36	**$11.25**
Main & MSR	$7.99	$5.06	**$13.05**

Notes:

1. From Exhibit DMI-4, Schedule 2, "Excess Investment" column.
2. Pre-tax return calculated from Witness Murry's cost of capital exhibit.
3. Return of Excess Investment has been grossed up for taxes:
   [Excess Investment/(1-Tax Rate)]/180 months.
4. Carrying Costs assume equal monthly repayment of the Excess Investment over the Recovery Period.
   Carrying costs are computed on Exhibit DMI-5, Schedule 2.
   Total cumulative carrying costs/180 months = carrying cost per month.

Western Kentucky Gas Company

Computation of Proposed Premises Charge

Recovery Term 15 yrs

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Carrying Cost on Unpaid Excess Investment [1]															
Main-Only															
Average Annual Balance	$114.92	$107.02	$99.11	$91.21	$83.31	$75.40	$67.50	$59.60	$51.70	$43.79	$35.89	$27.99	$20.09	$12.18	$4.28
Annual Carrying Cost	$16.16	$15.05	$13.94	$12.83	$11.72	$10.60	$9.49	$8.38	$7.27	$6.16	$5.05	$3.94	$2.82	$1.71	$0.60
Cumulative Carrying Cost	$16.16	$31.21	$45.15	$57.98	$69.69	$80.30	$89.79	$98.17	$105.44	$111.60	$116.65	$120.59	$123.41	$125.13	$125.73
MSR-Only															
Average Annual Balance	$717.01	$667.70	$618.40	$569.09	$519.78	$470.47	$421.17	$371.86	$322.55	$273.24	$223.94	$174.63	$125.32	$76.02	$26.71
Annual Carrying Cost	$100.84	$93.90	$86.97	$80.03	$73.10	$66.17	$59.23	$52.30	$45.36	$38.43	$31.49	$24.56	$17.62	$10.69	$3.76
Cumulative Carrying Cost	$100.84	$194.74	$281.71	$361.74	$434.85	$501.01	$560.24	$612.54	$657.90	$696.33	$727.82	$752.38	$770.01	$780.70	$784.45
Main & MSR															
Average Annual Balance	$831.93	$774.72	$717.51	$660.30	$603.09	$545.88	$488.67	$431.46	$374.25	$317.04	$259.83	$202.62	$145.41	$88.20	$30.99
Annual Carrying Cost	$117.00	$108.95	$100.91	$92.86	$84.82	$76.77	$68.72	$60.68	$52.63	$44.59	$36.54	$28.50	$20.45	$12.40	$4.36
Cumulative Carrying Cost	$117.00	$225.95	$326.86	$419.72	$504.54	$581.31	$650.03	$710.71	$763.35	$807.93	$844.47	$872.97	$893.42	$905.82	$910.18

Notes:

1. Assumes that Balance of Excess Investment is paid down with monthly Premise Charge payment.

Western Kentucky Gas Company

Estimated Revenue Impact of 15-Year Premises Charge

Year	2001	2002	2003	2004	2005	Total
New Residential Customers[1]						
New-Main	1,450	1,450	1,450	1,450	1,450	1,450
Existing-Main	250	250	250	250	250	250
Total	1,700	1,700	1,700	1,700	1,700	1,700
New-Main Charge Revenue[2]						
Return of Excess Investment	$ 69,489	$ 208,515	$ 347,541	$ 486,567	$ 625,593	$1,737,705
Carrying Cost	$ 44,007	$ 132,051	$ 220,095	$ 308,139	$ 396,183	$1,100,474
Total	$ 113,496	$ 340,566	$ 567,636	$ 794,706	$ 1,021,776	$2,838,179
Existing-Main Charge Revenue[2]						
Return of Excess Investment	$ 10,376	$ 31,046	$ 51,716	$ 72,386	$ 93,056	$ 258,582
Carrying Cost	$ 6,566	$ 19,646	$ 32,726	$ 45,806	$ 58,886	$ 163,631
Total	$ 16,943	$ 50,693	$ 84,443	$ 118,193	$ 151,943	$ 422,213
Total Charge Revenue						
Return of Excess Investment	$ 79,865	$ 239,561	$ 399,257	$ 558,953	$ 718,649	$1,996,287
Carrying Cost	$ 50,573	$ 151,697	$ 252,821	$ 353,945	$ 455,069	$1,264,105
Total	$ 130,438	$ 391,258	$ 652,078	$ 912,898	$ 1,173,718	$3,260,392
Accounting for Charge Revenue						
Estimated Credit to Plant	$ 47,629	$ 142,867	$ 238,105	$ 333,343	$ 428,581	$1,190,526
Estimated Credit Misc. Income	$ 30,160	$ 90,468	$ 150,775	$ 211,082	$ 271,389	$ 753,874
Estimated Credit to Taxes	$ 52,649	$ 157,924	$ 263,198	$ 368,473	$ 473,748	$1,315,992
Total	$ 130,438	$ 391,258	$ 652,078	$ 912,898	$ 1,173,718	$3,260,392

Notes:

1. As budgeted by the company.
2. As calculated in Exhibit DMI - 6, Schedules 2 and 3.
   Ratio of "Return of Excess Investment" and "Carrying Cost" revenues derived from Exhibit DMI-5, Schedule 1.
   "Return of Excess Investment" column divided by "Return of Excess Investment Plus Carrying Cost" column.

Western Kentucky Gas Company

Estimated Revenue Impact of New-Main Customers[1]

($s)

Month-Year	Customer Additions[2]	2001[3]	2002	2003	2004	2005	Total
Apr-2001	207	24,312	32,416	32,416	32,416	32,416	153,977
May-2001	207	21,611	32,416	32,416	32,416	32,416	151,276
Jun-2001	207	18,909	32,416	32,416	32,416	32,416	148,574
Jul-2001	207	16,208	32,416	32,416	32,416	32,416	145,873
Aug-2001	207	13,507	32,416	32,416	32,416	32,416	143,172
Sep-2001	207	10,805	32,416	32,416	32,416	32,416	140,470
Oct-2001	208	8,143	32,573	32,573	32,573	32,573	138,434
Apr-2002	207		24,312	32,416	32,416	32,416	121,561
May-2002	207		21,611	32,416	32,416	32,416	118,859
Jun-2002	207		18,909	32,416	32,416	32,416	116,158
Jul-2002	207		16,208	32,416	32,416	32,416	113,457
Aug-2002	207		13,507	32,416	32,416	32,416	110,755
Sep-2002	207		10,805	32,416	32,416	32,416	108,054
Oct-2002	208		8,143	32,573	32,573	32,573	105,862
Apr-2003	207			24,312	32,416	32,416	89,145
May-2003	207			21,611	32,416	32,416	86,443
Jun-2003	207			18,909	32,416	32,416	83,742
Jul-2003	207			16,208	32,416	32,416	81,041
Aug-2003	207			13,507	32,416	32,416	78,339
Sep-2003	207			10,805	32,416	32,416	75,638
Oct-2003	208			8,143	32,573	32,573	73,289
Apr-2004	207				24,312	32,416	56,728
May-2004	207				21,611	32,416	54,027
Jun-2004	207				18,909	32,416	51,326
Jul-2004	207				16,208	32,416	48,624
Aug-2004	207				13,507	32,416	45,923
Sep-2004	207				10,805	32,416	43,222
Oct-2004	208				8,143	32,573	40,716
Apr-2005	207					24,312	24,312
May-2005	207					21,611	21,611
Jun-2005	207					18,909	18,909
Jul-2005	207					16,208	16,208
Aug-2005	207					13,507	13,507
Sep-2005	207					10,805	10,805
Oct-2005	208					8,143	8,143
Total	**7,250**	**113,496**	**340,566**	**567,636**	**794,706**	**1,021,776**	**2,838,179**

Notes:

1. Charge Revenues are calculated for customers connecting in each of the listed months (# months x # customers x $ surcharge).
2. From Exhibit DMI -6, Schedule 1. Customers assumed to connect ratably over the non-winter months.
3. Charge assumed to be in effect January 1, 2001.

Western Kentucky Gas Company

Estimated Revenue Impact of Existing-Main Customers[1]

($s)

Month-Year	Customer Additions[2]	2001[3]	2002	2003	2004	2005	Total
Apr-2001	36	3,645	4,860	4,860	4,860	4,860	23,085
May-2001	36	3,240	4,860	4,860	4,860	4,860	22,680
Jun-2001	36	2,835	4,860	4,860	4,860	4,860	22,275
Jul-2001	36	2,430	4,860	4,860	4,860	4,860	21,870
Aug-2001	36	2,025	4,860	4,860	4,860	4,860	21,465
Sep-2001	36	1,620	4,860	4,860	4,860	4,860	21,060
Oct-2001	34	1,148	4,590	4,590	4,590	4,590	19,508
Apr-2002	36		3,645	4,860	4,860	4,860	18,225
May-2002	36		3,240	4,860	4,860	4,860	17,820
Jun-2002	36		2,835	4,860	4,860	4,860	17,415
Jul-2002	36		2,430	4,860	4,860	4,860	17,010
Aug-2002	36		2,025	4,860	4,860	4,860	16,605
Sep-2002	36		1,620	4,860	4,860	4,860	16,200
Oct-2002	34		1,148	4,590	4,590	4,590	14,918
Apr-2003	36			3,645	4,860	4,860	13,365
May-2003	36			3,240	4,860	4,860	12,960
Jun-2003	36			2,835	4,860	4,860	12,555
Jul-2003	36			2,430	4,860	4,860	12,150
Aug-2003	36			2,025	4,860	4,860	11,745
Sep-2003	36			1,620	4,860	4,860	11,340
Oct-2003	34			1,148	4,590	4,590	10,328
Apr-2004	36				3,645	4,860	8,505
May-2004	36				3,240	4,860	8,100
Jun-2004	36				2,835	4,860	7,695
Jul-2004	36				2,430	4,860	7,290
Aug-2004	36				2,025	4,860	6,885
Sep-2004	36				1,620	4,860	6,480
Oct-2004	34				1,148	4,590	5,738
Apr-2005	36					3,645	3,645
May-2005	36					3,240	3,240
Jun-2005	36					2,835	2,835
Jul-2005	36					2,430	2,430
Aug-2005	36					2,025	2,025
Sep-2005	36					1,620	1,620
Oct-2005	34					1,148	1,148
Total	**1,250**	**16,943**	**50,693**	**84,443**	**118,193**	**151,943**	**422,213**

Notes:

1. Charge Revenues are calculated for customers connecting in each of the listed months (# months x # customers x $ surcharge).
2. From Exhibit DMI -6, Schedule 1. Customers assumed to connect ratably over the non-winter months.
3. Charge assumed to be in effect January 1, 2001.

Western Kentucky Gas Company

Proposed Tariff Provisions – Premises Charge

Sheet No. 13

8. Premises Charge

New residential service connections on and after January 1, 2001 hereunder are subject to the Premises Charge described on SHEET No. 67.

Sheet No. 51

Premises Charge for new residential service connections on and after January 1, 2001 requiring main extension. *	$ 13.05/month
Premises Charge for new residential service connections on and after January 1, 2001 not requiring main extension. *	$ 11.25/month

* Waived for qualified low-income customers ("LIHEAP participants").

Sheet No. 67

Premises Charge. A charge to recover Excess Investment associated with new residential service connections, along with carrying costs and related taxes. The following terms and conditions are applicable to the charge:

i) The charges are applicable to new residential service connections in all towns, commencing with connections made on and after January 1, 2001.

ii) Separate charges shall be computed and applied for those service connections requiring main extension and for those connections not requiring main extension.

iii) The charge shall be payable for one hundred eighty (180) months and is applicable to the service address, regardless of changes in ownership, commencing with the first occupant of the address following service connection.

iv) Premises Charge shall not be applicable to LIHEAP-qualified customers at any service address.

v) The company shall update the amounts of the charges annually and, upon Commission approval, implement such new charges prospectively for new residential service connections in the ensuing year. If the amount of increase or decrease to the Premises Charge is less than 10%, the company may waive implementation of such increase or decrease and charge the existing Premises Charge for new connections made in the ensuing year.

vi) The company shall file a report with the Commission annually, not later than 120 days after the close of the Company's fiscal year, listing the number and type of Premises Charges levied during the fiscal year and the financial accounting entries for the disposition of revenues, cost recovery, and taxes.

DANIEL M. IVES

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PROFESSIONAL EXPERIENCE
Lukens Consulting Group, Inc., Houston, TX
Vice President, January 1999-present

Consultant with experience in business and regulatory strategy for natural gas pipelines and distributors, and energy marketing firms. Areas of expertise include tariff and rate design, competitive analysis, litigation support, and energy project evaluation. Provides expert testimony on rate, tariff and certificate matters.

ANR Pipeline Company, Detroit, MI
Vice President-Rates and Regulatory Affairs, 1995-1998

Directed ANR's rate and regulatory activities before the Federal Energy Regulatory Commission (FERC). Settled a major ANR rate case and an Empire State Pipeline (an ANR subsidiary) rate case, achieving company financial and regulatory objectives. Achieved regulatory approval for the profitable sale and spin-down of ANR's Southwest gathering assets. Successfully completed applications for several major pipeline projects, including the Independence Pipeline project, Carisbrook to Horsham (Australia) pipeline, and a major Wisconsin expansion. Designed and implemented new gas transportation, parking and lending, and storage services to meet competitive market needs.

Algonquin Gas Transmission Company, Boston, MA
General Manager-Rates and Billing, 1992-1995

Directed Algonquin's transmission and storage company rate activities before the FERC. Filed and settled a major rate case, implementing FERC Order No. 636 and resolving inter-customer rate design issues. Testified on rate design policy and the company's design of "backhaul" transportation rates. Achieved resolution of a court remand case by proposing and obtaining inter-customer payment of refund obligations through a global rate settlement. Developed rate studies for market analysis and regulatory filing of the company's Northeast and Maritimes Pipeline project.

Washington Gas Light Company, Washington, DC
Director-Maryland Rates and Regulatory Affairs, 1985-1992

Responsible for the company's revenue requirements, tariff administration, general regulatory matters and Commission relations in Maryland. Filed, litigated and/or settled four rate cases for company and subsidiary Frederick Gas Company, Inc. Testified and implemented natural gas transportation rates. Designed and implemented a forward-looking quarterly purchased gas adjustment mechanism. Testified on gas supply, rate design and cost of service matters.

Director-Federal Regulation, 1982-1985

Represented the company in pipeline supplier negotiations and rate cases before the FERC. Testified on pipeline cost allocation, rate design, gas supply, and transportation matters.

Secretary and Treasurer, Davenport Insulation subsidiary, 1979-1982

Supervised the subsidiary's accounting, finance, treasury, computer operations, and corporate record functions. Prepared monthly financial reports and audited Annual Report for Davenport and three subsidiary companies. Restored profitability through sale or closure of unprofitable plants and branches, tightening of cost controls, and implementation of computerized accounting and cash management systems.

Various Accounting & Auditing positions, 1976-1979

Worked as a staff accountant and internal auditor. Prepared tax and insurance reports, journal entries, and special reports. Audited construction projects and bids. Participated on development task force for major accounting database system.

Firestone Tire and Rubber Company, Akron, OH
Field Auditor, 1975-1976

Performed audits of retail tire stores and distribution facilities.

Leaseway Transportation Corporation, Baltimore, MD
Various positions, 1968-1975

Worked as Branch Manager in truck rental and leasing and contract carriage trucking operations, supervising up to 80 drivers and helpers.

EDUCATION and CERTIFICATION

University of Maryland, College Park, MD
B. S., Accounting, 1975
B. A., Sociology, 1970

Certified Public Accountant, Maryland, 1979-present

TESTIMONY

Empire State Pipeline Company

State of New York before the Public Service Commission, Empire State Pipeline Case 95-G-1002. Prepared direct testimony on behalf of Empire State Pipeline Company supporting the general policy issues of the rate filing and introducing company witnesses, adopted July 16, 1996 at evidentiary hearing. Case settled and Commission approval order issued effective September 24, 1996.

Algonquin Gas Transmission Company

United States of America before the Federal Energy Regulatory Commission, Algonquin Gas Transmission Company, Docket No. RP 93-14-000. Prepared Direct Testimony on behalf of Algonquin filed on November 6, 1992. Policy testimony on rate design and the proposed rate increase and introduction of Algonquin's other witnesses. Supplemental Direct Testimony filed on behalf of Algonquin reviewing Commission policy on the showings necessary in order to roll-in incremental rates. Rebuttal Testimony filed in response to various depreciation, cost classification, cost allocation, rate design and tariff matters, including the design of backhaul rates-a limited issue which was set for hearing. Additional Rebuttal Testimony filed on rolled-in rate issues.

Washington Gas Light Company

United States of America before the Federal Energy Regulatory Commission, Transcontinental Gas Pipe Line Corporation, Docket No. RP83-137-000. Prepared Direct Testimony on behalf of Washington Gas Light Company filed on December 13, 1984. The testimony supported fully allocated cost-based rates for firm transportation service within a customer's contract entitlement and discounted interruptible transportation rates for service in excess of a customer's firm contract level. Rebuttal Testimony filed January 24, 1985.

United States of America before the Federal Energy Regulatory Commission, Transcontinental Gas Pipe Line Corporation, Docket No. RP82-55-000. Prepared Direct Testimony on behalf of Washington Gas Light Company filed on December 9, 1983. The testimony addressed Transco's proposed minimum commodity bill, its proposed Fixed-Variable rate design, and its proposed redesign of small customer rates.

Before the Public Service Commission of Maryland, Case No. 7962. Oral presentation made before the Commission at public hearings on gas transportation September 25-26, 1986. Prepared Direct Testimony on behalf of Maryland Natural Gas, a division of Washington Gas Light Company (WGL), and on behalf of Frederick Gas Company, Inc., a WGL subsidiary, filed on April 22, 1987. The testimony describes and supports proposed tariff provisions for firm and for interruptible delivery service by the companies and a proposed special purchases/sales rider for Frederick's low-priority interruptible gas sales. Rebuttal testimony subsequently filed as the case progressed.

Before the Public Service Commission of Maryland, Case No. 8060. Prepared Direct Testimony on behalf of Maryland Natural Gas, a division of Washington Gas Light Company, filed on March 1, 1988. The testimony describes and supports proposed tariff provisions and rates for interruptible delivery service and a margin-sharing tariff provision.

Before the Public Service Commission of Maryland, Case No. 8119. Prepared Direct Testimony on behalf of Maryland Natural Gas, a division of Washington Gas Light Company, filed on March 7, 1988. The testimony describes and supports a proposed declining block rate design with a monthly customer charge in the company's general rate case. The testimony also describes and supports proposed tariff changes to change or initiate turn-off and reconnection charges, service initiation fees, and rates and charges for unmetered gaslights. Rebuttal testimony was subsequently filed in the proceeding.

Before the Public Service Commission of Maryland, Case No. 8191. Prepared Direct Testimony on behalf of Maryland Natural Gas, a division of Washington Gas Light Company, filed on March 31, 1989. The testimony describes and supports a proposed declining block rate design with a monthly customer charge in the company's general rate case. The testimony also describes and supports proposed rate revisions for delivery service and for unmetered gaslight service and a proposal to retain margins on new interruptible services pending recovery of investment. Supplemental Direct Testimony was filed on June 16, 1989 to reflect actualized data for the test year.

Before the Public Service Commission of Maryland, Case No. 7131, Phase XIII. Prepared Direct Testimony filed on behalf of Washington Gas Light Company and Frederick Gas Company, Inc. Hearing Date of December 6, 1983. The testimony describes the companies' participation in the special gas transportation programs of its pipeline suppliers during the period June 1983-November 1983 and the resultant cost savings to consumers.

Before the Public Service Commission of Maryland, Case No. 7131, Phase XIV. Prepared Direct Testimony filed on behalf of Washington Gas Light Company and Frederick Gas Company, Inc. Hearing Date of June 20, 1984. The testimony describes the companies' participation in the special gas transportation programs of its pipeline suppliers during the period December 1983-May 1984 and the resultant cost savings to consumers. The testimony also discusses the companies' activities before the FERC involving its pipeline suppliers.

Before the Public Service Commission of Maryland, Case No. 7131, Phase XV. Prepared Direct Testimony filed on behalf of Washington Gas Light Company and Frederick Gas Company, Inc. Hearing Date of December 11, 1984. The testimony describes the companies' participation in pipeline suppliers' special marketing programs and direct producer purchases during the period June 1984-November 1984. The testimony also discusses the companies' activities before the FERC involving its pipeline suppliers.

Before the Public Service Commission of Maryland, Case No. 8509. Prepared Direct Testimony filed on behalf of Maryland Natural Gas, a division of Washington Gas Light Company. Hearing Date of December 6, 1985. The testimony identifies all gas purchases included in the company's Purchased Gas Adjustment during the period June 1985-November 1985, the costs of which supplies were not determined by regulation. The testimony also identifies the benefits from special contract sales credited to firm customers through the Firm Credit Adjustment.

Before the Public Service Commission of Maryland, Case No. 8509(a). Prepared Direct Testimony filed on behalf of Maryland Natural Gas, a division of Washington Gas Light Company. Hearing date of June 11, 1986. The testimony identifies all gas purchases included in the company's Purchased Gas Adjustment during the period December 1985-May 1986, the costs of which were not determined by regulation. The testimony also identifies the benefits from special contract sales credited to firm customers through the Firm Credit Adjustment and the testimony identifies and describes the company's participation in cases before the FERC.

Before the Public Service Commission of Maryland, Case No. 8509(c). Prepared Direct Testimony filed on behalf of Maryland Natural Gas, a division of Washington Gas Light Company. Hearing Date of May 7, 1987. The testimony identifies all gas purchases included in the company's Purchased Gas Adjustment during the period December 1986-May 1987, the costs of which were not determined by regulation.

Before the Public Service Commission of Maryland, Case No. 8509(d). Prepared Direct Testimony filed December 3, 1987 on behalf of Maryland Natural Gas, a division of Washington Gas Light Company. The testimony identifies all gas purchases included in the company's Purchased Gas Adjustment during the period June 1987-November 1987, the costs of which were not determined by regulation.

Before the Public Service Commission of Maryland, Case No. 8509(j). Appeared as a supplemental direct witness at the hearing on November 30, 1990 to present oral testimony regarding the operation of the Firm Credit Adjustment mechanism and the computation of margins, particularly with respect to sales to Potomac Electric Power Company.

Frederick Gas Company, Inc.

Before the Public Service Commission of Maryland, Case No. 8213. Prepared Direct Testimony filed on October 6, 1989 on behalf of Frederick Gas Company, Inc. in its general rate case. The testimony describes a stipulation and Agreement reached by the parties to the proceeding and provides supporting information for the settlement rates.

Before the Public Service Commission of Maryland, Case No. 8510. Prepared Direct Testimony filed December 3, 1985 on behalf of Frederick Gas Company, Inc. The testimony describes cost savings to firm customers as a result of Frederick's spot market gas purchases and the continued benefit of Frederick's special contract interruptible sales program.

TRAINING AND TEACHING EXPERIENCE

American Gas Association's "Gas Rates Course", University of Wisconsin, Madison, WI

"Introduction to Regulation and the Ratemaking Process," a lecture, followed by a "Ratemaking Workshop," presented annually in June, 1991-1998.

"Pipeline Cost Allocation and Rate Design," a lecture and hands-on computer demonstration presented June 6, 1995.

American Gas Association/Edison Electric Institute's "Introduction to Public Utility Accounting Course," Virginia Commonwealth University, Richmond, VA

"Introduction to Regulation and the Ratemaking Process," a lecture, followed by a "Ratemaking Workshop," presented annually in May, 1991-1995.

American Gas Association's "Advanced Regulatory Seminar," University of Maryland, College Park, MD

"Current Rate Design Issues," a speech presented September 28, 1995.

"Local Distribution Rate Design Trends and Opportunities," a speech presented in October 1990 and updated and presented in 1991.

"Current Pricing Issues," a speech presented October 6, 1989.

"Can America Unbundle and Still Keep Warm?" a speech presented October 7, 1988.

"Flexibility in the Changing Market," a speech presented October 5, 1984.

OTHER PRESENTATIONS AND SPEECHES

American Gas Association Rate Committee Meetings

"Market Hubs – Operation, Economics & Rate Implications," a speech presented August 29, 1994.

"Implications of Capacity Release," a speech presented March 7, 1994.

"Implementing Restructuring," a speech presented March 15, 1993.

"Integrated Resource Planning Theory and Practice," a speech presented in April 1992.

American Gas Association's Seminar "Competing in a Restructured World," Arlington, VA

"Separation of Functions and Accounting Cost Standards," a speech presented July 9, 1998.

NARUC Gas Subcommittee Teleconference on Gas Rate Issues

"Design of Pipeline Rates," a speech concerning the design of rates for short-term service given by teleconference, May 29, 1998.

"Natural Gas Pricing and Rate Design in the 1990s," Seminar in Houston, TX

"Rate Design Trends and Opportunities," a speech presented September 13, 1990.

"Pricing and Rate Strategies for Unbundled Services," Seminar in Houston, TX

"Local Distribution Rate and Regulatory Trends and Opportunities," a speech presented October 30, 1990.

PAPERS

"The Electric Heat Pump," an analysis of the electric heat pump's competitive impacts in the metropolitan Washington, DC heating markets and competitive strategies, June 28, 1985.

OTHER PROFESSIONAL ACTIVITIES

American Gas Association Rate and Strategic Planning Committee

Chairman	1997
Vice Chair	1995-1996
Member	1998, and prior to 1995

American Institute of Certified Public Accountants, Member

MAIN CASE FILE
CASE NO. 99-070
CORRESPONDENCE FOR
3/1/99 thru 10/1/99

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

October 1, 1999

To: All parties of record

RE: Case No. 99-070

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,

Stephanie Bell

Stephanie Bell
Secretary of the Commission

SB/sa
Enclosure

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF WESTERN KENTUCKY GAS COMPANY FOR AN ADJUSTMENT OF RATES	)))	CASE NO. 99-070

O R D E R

On September 20, 1999, the Commission entered an Order directing Western Kentucky Gas Company ("Western") to respond to requests for information by October 4, 1999. On Friday, September 24, 1999, Western requested clarification on two of the requests; namely, requests 6 and 57. The Commission finds that requests 6 and 57 of its September 20, 1999 Order should be amended. It further finds that granting Western an extension of time to respond to the two amended requests should not result in prejudice to the intervening parties.

IT IS THEREFORE ORDERED that:

1. Request 6 of the September 20, 1999 Order is amended as follows:

6. Refer to the response to Item 48 of the Commission's August 19, 1999 Order and Revised Exhibits GLS-1 and GLS-2.

a. If Western's application did not employ a forecasted test year, but employed the reference period ending September 30, 1998 as a historical test year, normalized to reflect known and measurable adjustments, would Column (g) "Total Volumes" be the adjusted billing units on which rates would be calculated? If no, provide the adjusted billing units and explain how they would be determined.

b. Refer to part (b) of the response. Explain how the 180,576 Mcf attributable to commercial customer growth was split between the "0 to 300 Mcf" rate block and the "301 to 15,000 Mcf" rate block.

2. Request 57 of the September 20, 1999 Order is amended to read as follows:

57. Western's previous responses to data request questions regarding the justification of assumptions underlying the forecast of operating and maintenance expenses, as well as identifying and explaining differences in assumptions and methodologies used in those forecasts, indicate a lack of documentation for the budgetary process and management reporting for budgetary variances. An additional approach to evaluating the forecasted expenses would be to consider the reasonableness of the forecasted amounts based on known and measurable adjustments that Western would have proposed if it had used a historic test year.

a. If Western's application did not employ a forecasted test year, but employed the reference period ended September 30, 1998, as a historical test year, normalized to reflect known and measurable adjustments, would the type of adjustments termed "utility budget adjustments, SSU billing adjustments, and rate making adjustments" on Schedule C-2 be the same? Provide a detailed explanation.

b. What would the dollar amounts of the adjustments be from the standpoint of normalizing known and measurable adjustments?

3. Western shall have to and including October 8, 1999 to provide responses to the amended data requests.

4. Responses to all other data requests contained in the September 20, 1999 Order shall be due October 4, 1999 as previously ordered.

Done at Frankfort, Kentucky, this 1st day of October, 1999.

By the Commission

ATTEST:

Executive Director

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
OCT 01 1999
PUBLIC SERVICE COMMISSION

In the Matter of:	)	
THE APPLICATION OF WESTERN	)	Case No. 99-070
KENTUCKY GAS COMPANY	)	
FOR AN ADJUSTMENT OF RATES	)	

SUPPLEMENTAL REQUEST FOR INFORMATION
BY THE ATTORNEY GENERAL
FOR THE APPLICANT'S SUPPLEMENTAL RESPONSES

Comes now the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and submits this Supplemental Request for Information for the Applicant's supplemental responses of 21 September 1999.

(1) In each case where a request seeks data provided in response to a staff request, reference to the appropriate request item will be deemed a satisfactory response.

(2) Please identify the company witness who will be prepared to answer questions concerning each request.

(3) These requests shall be deemed continuing so as to require further and supplemental responses if the company receives or generates additional information within the scope of these requests between the time of the response and the time of any hearing conducted hereon.

(4) If any request appears confusing, please request clarification directly from the Office of Attorney General.

(5) To the extent that the specific document, workpaper or information as requested does not exist, but a similar document, workpaper or information does exist, provide the similar document, workpaper, or information.

(6) To the extent that any request may be answered by way of a computer printout, please identify each variable contained in the printout which would not be self evident to a person not familiar with the printout.

(7) If the company has objections to any request on the grounds that the requested information is proprietary in nature, or for any other reason, please notify the Office of the Attorney General as soon as possible.

(8) For any document withheld on the basis of privilege, state the following: date; author; addressee; indicated or blind copies; all persons to whom distributed, shown, or explained; and, the nature and legal basis for the privilege asserted.

(9) In the event any document called for has been destroyed or transferred beyond the control of the company state: the identity of the person by whom it was destroyed or transferred, and the person authorizing the destruction or transfer; the time, place, and method of destruction or transfer; and, the reason(s) for its destruction or transfer. If destroyed or disposed of by operation of a retention policy, state the retention policy.

Supplemental Requests for Information

1. With reference to the supplemental response to AG 1-181,

   A. Please provide the number of contract employees instead of the contractor companies for each period listed.

   B. Please explain the increase in contractor O&M labor during 1998.

2. With reference to the supplemental response to AG 1-182(e), please explain what is meant by "[t]he increase in the O&M payroll took into consideration this [$67,750] amount." Please provide a workpaper illustrating how the amount was taken into consideration.

Respectfully submitted,

A.B. CHANDLER III
ATTORNEY GENERAL

David Edward Spenard

David Edward Spenard
Assistant Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601-8204
(502) 696.5457

CERTIFICATE OF SERVICE AND FILING

Counsel hereby certifies that an original and ten (10) photocopies of the foregoing Supplemental Request by the Attorney General for the Applicant's Supplemental Responses were served and filed by hand delivery to the Hon. Helen C. Helton, Executive Director, Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky 40601; furthermore, it was served by mailing a true and correct copy of the same, first class postage prepaid, to William J. Senter, Western Kentucky Gas, 2401 New Hartford Road, Owensboro, KY 42303 1312, Mark R. Hutchinson, Sheffer, Hutchinson & Kinney, 115 East Second Street, Owensboro, KY 42303, John N. Hughes, 124 West Todd Street, Frankfort, KY 40601, Douglas Walther, Atmos Energy Corporation, P.0. Box 650205, Dallas, TX 75265, and Robert M. Watt, Jr., J. Mel Camenisch, Jr., 201 E. Main Street, Suite 1000, Lexington, KY 40507-1380, all on this 1st day of October 1999.

David Edward Spenard
Assistant Attorney General

99-070_SR1

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ALL OTHERS ADMITTED IN KY ONLY

September 21, 1999

RECEIVED
SEP 22 1999
PUBLIC SERVICE COMMISSION

Kentucky Public Service Commission
730 Schenkel Lane
Frankfort, Kentucky 40602

Attention: Helen Helton, Executive Director

RE: Western Kentucky Gas - Case No. 99-070

Dear Ms. Helton:

Please find enclosed an original, plus ten (10) copies of the Supplemental Responses of Western Kentucky Gas Company to the Attorney General's Initial Data Requests Nos. 181 and 182. I am also serving copies of these Supplemental Responses to the Intervenors.

If there are any questions or if additional information is needed. Thanks.

Very truly yours,

SHEFFER HUTCHINSON KINNEY

Mark R. Hutchinson

MRH:bkk

cc: Intervenors

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 1[illegible]99
Supplemental Response to DR Item 181
Witness: Betty Adams

<u>**Data Request**</u>:

Please provide workpaper that presents the following annual data for the contract labor for FY 1994 through the forecasted test year. Provide actual monthly data for the available months during the base period.

a. Number of contractors;
b. Total contract labor payroll broken down by O&M, capital and non-O&M accounts; and
c. Contract labor overtime payroll broken down by O&M, capital and non-O&M accounts.

<u>**Response:**</u>

a. The total number of contractors used during the requested number of years is listed by contractor companies and not by individuals. This is shown on Schedule 1. The actual monthly data for October through May for the base period is shown on Schedule 2.
b. See attached schedule 1.
c. The contractors are not utilized on an overtime basis.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
Supplemental Response to DR Item 181
Schedule 1

Fiscal Year	1994	1995	1996	1997	1998	8 mos. 1999
No. of Contractor Companies	4	5	7	9	9	9
O&M Labor	$ 11,421	$ 240,814	$ 6,306	$ 2,181	$ 1,182,836	$ 67,750
Capital Labor	1,365,308	1,686,588	2,061,935	2,046,909	1,973,254	558,928
Non-O&M Labor	230,913	240,203	337,014	359,558	266,442	177,173
Total Contract Labor	$ 1,607,642	$ 2,167,605	$ 2,405,255	$ 2,408,648	$ 3,422,532	$ 803,851

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
Supplemental Response to DR Item 181
Schedule 2

Fiscal Year 1999 - Base Year	October	November	December	January	February	March	April	May	Total
No. of Contractor Companies	6	6	7	5	6	1	9	9	9
O&M Labor	$ 34,705	$ 15,599	$ 5,864	$ 4,778	$ 6,804	$ -	$ -	$ -	$ 67,750
Capital Labor	225,412	123,292	133,745	33,021	42,738	720	-	-	558,928
Non-O&M Labor	80,721	38,640	29,388	12,603	15,821	-	-	-	177,173
Total Contract Labor	$ 340,838	$ 177,531	$ 168,997	$ 50,402	$ 65,363	$ 720	$ -	$ -	$ 803,851

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
Supplemental Response to DR Item 182 e
Witness: Betty Adams

Data Request:

With reference to the discussion on labor beginning on page 8, line 22, of Ms . Adams' testimony:

a. Please explain why there would be an increase in O&M payroll costs if the employees hired are replacing contractors who were performing mostly construction activities.
b. According to page 8, lines 28 to 30 of Ms. Adams testimony, the Company "did not budget to reflect a full complement of employees for FY 1999 because we were substituting contract labor for Western's own employees." In response to KPSA 1-69e, it is stated that "[n]one of our planned positions to be filled were previously held by contractors." Please explain the apparent inconsistency in the two statements.
c. When did the Company begin its practice of using contractors instead of employees?
d. Please provide the date on which the Company plans to begin hiring employees to replace contractors.
e. Please explain how the costs of contractors were removed from the cost of service. Include in your response the amount removed and documentation supporting that amount.

Response:

e. For the base year only $67,750 was spent on O&M activities as shown on AG request 181, schedule 1. The increase in the O&M payroll took into consideration this amount.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF WESTERN KENTUCKY GAS COMPANY FOR AN ADJUSTMENT OF RATES	)))	CASE NO. 99-070

O R D E R

IT IS ORDERED that Western Kentucky Gas Company ("Western") shall file with the Commission the original and 15 copies of the following information, with a copy to all parties of record. The information requested herein is due no later than October 4, 1999. Each copy of the data requested should be placed in a bound volume with each item tabbed. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 1(a), Sheet 2 of 6. Include with each response the name of the witness who will be responsible for responding to questions relating to the information provided. Careful attention should be given to copied material to ensure that it is legible. Where information requested herein has been previously provided, in the format requested herein, reference may be made to the specific location of said information in responding to this information request. When applicable, the information requested herein should be provided for total company operations and jurisdictional operations, separately.

1. Refer to the response to Item 42 of the Commission's August 19, 1999 Order. The original agreement between Western and Reliant Energy Services ("Reliant") had been filed with the Commission by Western.

a. Has Western filed the replacement agreement of Woodward Marketing, LLC ("Woodward") with the Commission at this time?

b. When does Western expect to file the new agreement with the Commission?

c. Provide a detailed explanation for why Western decided to go with the next best proposal from the original vendors rather than re-open the process by requesting new bids.

d. Explain whether Western could have re-opened the process by requesting new bids from vendors other than Woodward, and then gone back to Woodward if its original proposal was still better than the new bids.

e. What is the corporate relationship between Western and Woodward?

f. The original agreement between Western and Reliant was terminated by mutual agreement of the parties. Provide the terms of the termination of the agreement and the impact that the termination has had, or will have, on the costs recovered through Western's Gas Cost Adjustment ("GCA") clause.

2. Refer to the response to Item 43 of the Commission's August 19, 1999 Order and the proposed Weather Normalization Adjustment ("WNA") tariff at Tab 6 in Volume 1 of 10 of the application.

a. Clarify the response to Item 43. Would Western be opposed to its WNA being implemented on a pilot basis?

b. As stated in the prior request, Western's proposed WNA tariff differs from the WNA tariff of Columbia Gas of Kentucky ("Columbia") in some respects. Provide an example calculation, based on the formula in the proposed tariff, of the impact of the WNA on a representative residential customer's bill, during both a colder-than-normal month and a warmer-than-normal month.

3. Refer to the response to Item 44 of the Commission's August 19, 1999 Order. The comparison of December 1998 to December 1999 meters in service and the comparison of June 1998 to June 1999 meters in service both reflect larger increases than the March 1998 to March 1999 comparison included in the Direct Testimony of Gary L. Smith.

a. Explain why the March 1998 to March 1999 comparison of meters in service was chosen to be included in Mr. Smith's testimony.

b. As soon as available, provide a September 1998 to September 1999 comparison of meters in service in the same format as the other comparisons that have been provided. Indicate in this response the date the information will be filed.

c. The response to Item 44 shows a change of 1,983 residential customers from December 1997 to December 1998, while the table on page 12 of Mr. Smith's testimony shows a change of 1,722. Explain the reasons for these differences and explain how "Average meters in service fiscal year to date" as shown in the response differs from "Residential meters in service," which is the heading in the table in Mr. Smith's testimony.

4. Refer to the response to Item 46 of the Commission's August 19, 1999 Order.

a. Provide an explanation for the decline in the number of Public Authority customers from fiscal year 1998 to the 12 months ended June 30, 1999.

b. As soon as available, provide an updated version of the response to Item 46(a), which substitutes fiscal year 1999 for the 12 months ended June 30, 1999. Indicate in this response the date the information will be filed.

c. The response to Item 46(b) provides weather-adjusted volumes by customer class, with Sheet 2 of 2 providing supporting calculations for the information shown on Sheet 1 of 2. Refer to the volumes for fiscal year 1996. Should the weather adjustment have resulted in a decrease from actual volumes rather than the increase shown when comparing responses 46(a) and 46(b)? If yes, provide Sheet 1 of 2 with the necessary revisions to the fiscal year 1996 volumes.

d. As soon as available, provide an updated version of response 46(b) that substitutes fiscal year 1999 for the 12 months ended June 30, 1999. Indicate in this response the date the information will be filed.

5. Refer to the response to Item 47(c) of the Commission's August 19, 1999 Order.

a. The response indicates that 13 customers, with adjusted volumes totaling 13,332,103 Mcf, will generate total net revenues of $1,692,428 under present margins (contract rates). Identifying them as Customer A, Customer B, etc., provide for each customer the net revenues it would provide Western if it were billed Western's tariffed rates, at both the existing rates and the proposed rates.

b. For the 13 customers as a group, provide the total volumes of 13,332,103 Mcf separated into the categories of Firm Carriage Service and Interruptible Carriage Service.

c. Based on the response to part (b) of this request, provide the total net revenues, under present margins, generated by Firm Carriage Service and Interruptible Carriage Service.

d. Based on the response to part (b) of this request, provide the total net revenues that this group of customers would provide for Firm Carriage Service and for Interruptible Carriage Service if they were billed Western's tariffed rates, at both the existing rates and the proposed rates.

6. Refer to the response to Item 48 of the Commission's August 19, 1999 Order and Revised Exhibits GLS-1 and GLS-2.

a. If Western's application did not employ a forecasted test year, but employed the historical test year ended September 30, 1998, normalized to reflect known and measurable adjustments, would Column (g) "Total Volumes" be the adjusted billing units on which rates would be calculated? If no, provide the adjusted billing units and explain how they would be determined.

b. Refer to part (b) of the response. Explain how the 180,576 Mcf attributable to commercial customer growth was split between the "0 to 300 Mcf" rate block and the "301 to 15,000 Mcf" rate block.

7. Refer to the response to Item 49 of the Commission's August 19, 1999 Order and Exhibits GLS-2, GLS-4, GLS-5 and GLS-6 of the Direct Testimony of Gary L. Smith.

a. Item 49, Sheets 1, 2, and 3 of 9, were provided to support the declining trend in residential usage per customer. Is it correct that the total for Column (h), "Normalized Volumes," on each of these sheets reflects total volumes for the fiscal year identified at the top of the page?

b. Is it correct that the 13,034,849 Mcf at the top of Sheet 3, above Column (h), "Normalized Volumes," reflects the total volumes for the forecasted test year, calendar year 2000?

c. Refer to the aforementioned exhibits to Mr. Smith's testimony at Column (b), "Residential Mcf." These columns show, respectively, per book volumes, volume increases for weather, volume increases for customer growth, and volume decreases for conservation and energy efficiency. The net total, beginning with GLS-2 and going through GLS-6, is 13,026,240 Mcf. Explain why this number for residential Mcf for the forecasted test year does not match the 13,034,849 Mcf shown in the response on Sheet 3.

8. Refer to the response to Item 51 of the Commission's August 19, 1999 Order. Given Western's GCA tariff provision requiring annual Balancing Adjustment filings in February, would it be preferable for Western to make its February filing and then begin a quarterly GCA filing schedule with a filing schedule of February, May, August, and November?

9. Refer to the response to Item 52 of the Commission's August 19, 1999 Order and Exhibits GLS-2 and GLS-3 of the Direct Testimony of Gary L. Smith.

a. Part (b) of the response identifies 16,113,322 Mcf as being under special contract and indicates this amount represents 57 percent of Western's total industrial sales and transportation deliveries during the test year. Identify, in Exhibits GLS-2 and GLS-3, the Mcf levels that, when summed, produce the total industrial sales and transportation deliveries that were used as the denominator to derive the result of 57 percent.

b. Refer to the response to part (a) of this request. Using the volumes included in that response, provide the amount of net revenues that would be generated under both existing rates and proposed rates and the calculations performed to derive these revenue amounts.

10. Refer to the response to Item 53 of the Commission's August 19, 1999 Order.

a. Identify the periods that were covered by the field arrears reports that were reviewed.

b. If implemented as proposed, the Late Payment Charge would be effective April 1, 2000 and would remain in effect permanently on a going forward basis. Explain why Western believes it is appropriate to include only nine months of Late Payment Charge revenues in the forecasted test year.

11. Refer to the response to Item 55(d) of the Commission's August 19, 1999 Order.

a. Provide the basis for the allocation of new connections of 1,700 between "Main and MSR" and "MSR Only."

b. Would the allocation ratio between "Main and MSR" and "MSR Only" remain the same if the number of connections were an amount larger or smaller than the 1,700 used in the calculation? If no, explain why it would be different.

c. The "Number of Customers – 2001" reflects additions of 1,700 for each of the calendar years 1999 and 2000 to the customer count as of September 30, 1998. Explain why no customer additions were reflected for the last three months of calendar year 1998.

12. Refer to the response to Item 56 of the Commission's August 19, 1999 Order. Historically, Commission approval of returned check charges has required cost support on a utility-by-utility basis. The intent of such charges is to charge the costs incurred by the utility to process the bad check to the cost-causer rather than to the entire body of ratepayers. Provide the cost calculations necessary to support a returned check charge based on Western-specific costs.

13. Refer to lines 22 through 24 on page 4 of the Direct Testimony of Earl Fischer. Describe how Western's return on new investments compares with those of Atmos's other business units.

14. Refer to pages 19 and 20 of the Direct Testimony of Dr. Donald Murry, to Schedules DAM–16 and DAM-17, and to Items 32 and 33 of the response to the Commission's August 19, 1999 Order.

a. Reconcile the response in Item 32(c) with the description of Schedule DAM-16 that begins at line 18 on page 19 of the testimony.

b. Fully describe, compare, and contrast the CAPM methodologies employed in Schedules DAM-16 and DAM-17. Include a more thorough explanation of the responses given in Items 32(e) and 33(d), as well as a full description of each variable used in each equation, its specific source, the time period covered by each variable, and its purpose in the specific equation that it is used.

c. If not fully explained in part (b) above, explain why the simple extension of the standard CAPM methodology to account for company size necessitates the use of different input values for those inputs that are common to both sets of calculations in Schedules DAM-16 and DAM-17.

d. Provide copies of the relevant sections from academic texts, such as Morin's Regulatory Finance, which justify the use of different input values in place of the same inputs used in similar calculations when the time periods used in the calculations do not change.

e. Provide all the calculations and results of any sensitivity analysis that Western has conducted supporting the CAPM calculations in Schedules DAM-16 and DAM-17. For each variable whose input value was changed from one set of calculations to the other, explain the rationale behind the range of input values used.

15. Refer to the response to Item 12 of the Attorney General's ("AG") Data Request of August 19, 1999. The page provided from Ibbotson Associates SBBI 1999 Yearbook includes government as well as corporate bond Total Return rates. Explain why a government bond rate was not used as the risk-free rate in the CAPM calculation in Schedule DAM-16.

16. Refer to the response to Item 9 of the AG's Data Request of August 19, 1999.

a. Table 8-1 of the SBBI 1999 Yearbook sets out the Equity Risk Premium and the Size Premia used in Schedule DAM-17 of Dr. Murry's testimony. Explain why the risk-free rate was not taken from Table 8-1 as well.

b. Were the size premia set out in Table 8-1 developed from utility stock returns? If not, identify which companies' returns were used and explain how those returns are applicable to gas utilities.

c. Provide a detailed explanation of how the size premia set out in Table 8-1 are calculated.

17. If Morin's <u>Regulatory Finance</u>, which is mentioned in response to Item 13 of the AG's Data Request of August 19, 1999, contains a discussion of the use of size premia for utilities, provide a copy of that discussion.

18. Refer to Schedules DAM-18 and DAM-19 of Dr. Murry's Testimony.

a. The Dow Jones Utilities' price appreciation does not deviate from those of the Dow Jones Industrials and Moody's Transmission companies to the extent that Moody's LDCs do, and in fact, for a period of time it exceeds them. To the extent that competition and deregulation are increasing in the majority of utility industries, provide Dr. Murry's assessment of the shift in risk for the utility industry as a whole as perceived by investors.

b. The Atmos price appreciation does not deviate from the Dow Jones Industrials and Moody's Transmission companies to the extent that Moody's LDCs do, and in fact, for periods of time it exceeds them. Provide Dr. Murry's assessment of investors' perceived shift in risk due to deregulation and increasing competition for Atmos relative to Moody's LDCs.

c. To what would Dr. Murry attribute the sudden stock price depreciation for Atmos, the Moody's LDCs, and the Dow Jones Utilities beginning in December 1998?

19. Refer to the response to Item 16 of the AG's Data Request of August 19, 1999. The studies and articles provided in the response to Item 16, which questioned how the financial markets assess the shift of risk between interstate transmission companies and LDCs, were published between 1993 and 1996. Schedule DAM-18, which supports Dr. Murry's testimony that investors are able to distinguish between the risks and returns of gas distribution and transmission companies, depicts price appreciation for Dow Jones Industrials, Moody's Transmission companies, and Moody's LDCs for March 1998 through March 1999. Page 20 of Dr. Murry's Testimony discusses investors' assessment of changing risks for LDCs brought about by deregulation of pipelines and increasing competition.

a. Explain why Dr. Murry assumes that the relatively lower price appreciation of LDC stocks for March 1998 through March 1999 is a result of the pipeline deregulation and emerging competition discussed in the studies published during the period 1993-1996.

b. Could LDC price appreciation be impacted by the warmer than normal weather experienced during March 1998 through March 1999? Explain the answer in detail.

c. Would investors assess transmission companies, with their Straight Fixed Variable rate design, to be as risky as LDCs during a warmer than normal winter? Explain the answer in detail.

d. Would investors assess the Dow Jones Industrials to be as risky as LDCs during a warmer than normal winter? Explain the answer in detail.

e. If Western's WNA is approved as proposed, would Western be assessed by investors as having closer to the same level of risk as the other two groups depicted in Schedule DAM-18? Explain the answer in detail.

20. Refer to the Direct Testimony of Betty L. Adams and the forecasted test period filing requirements at Volume 7 of 10 of the Application, Tab 4, exhibit FR 10(9)(o). The referenced "monthly budget variance reports provided in response to FR (9)(n)" do not satisfy the filing requirement. The reports supplied in FR (9)(n) have no further breakdown of expenses beyond operations and maintenance. Additionally, no narrative explanations were provided, as required by 807 KAR 5:001, Section 10(9)(o). Ms. Adams' testimony indicates Western's operating budget is prepared by cost center and individual functional expense. The response to the AG's August 19, 1999 Data Request, Item 175, Schedule A, Page 1 of 1, provides a comparison of budgeted operations and maintenance ("O&M") expenses (without employee benefits) by responsibility area for Western. The response to Item 176, in that same data request, states that "variance explanations are communicated verbally." However, Ms. Adams' testimony at page 6 states that Ms. Adams reviews variance reports for cost centers which "exceed the monthly budget by five percent (5%) or more," then "document[s] for future budgeting purposes, known changes in current operational spending from budget."

a. Explain whether the testimony is correct in stating certain variances of operational spending from budget are documented, or merely communicated verbally.

b. Western's response to the AG's August 19, 1999 Data Request, Item 175, states that the "threshold below which O&M budget variances are evaluated is 10 percent." Is 10 percent or the 5 percent referenced in Ms. Adams' testimony the threshold for evaluation of variances? Explain the response.

21. The response to the AG's August 19, 1999 Data Request, Item 175, Schedule A, Pages 1, 8, 13, 18, 22, 26, 30, and 33 of 33 provides monthly O&M budget to actual variances for October 1998 through May 1999.

a. Provide narrative explanations by cost center and functional expense of variances in these reports as required by 807 KAR 5:001, Section 10(9)(o). A narrative explanation for employee benefit variances may be provided on a monthly basis for Western in total. Use 10 percent as the minimum threshold to determine the variances requiring explanation. Additionally, provide these variance analyses and narrative explanations of variances greater than 10 percent for the months of June 1999 through September 1999 by November 15, 1999.

b. Provide the variance analyses with narrative explanations for variances greater than 10 percent, as referenced in (a) above for the 12 months immediately prior to the base period, as required in 807 KAR 5:001, Section 10(9)(o).

22. Refer to the Direct Testimony of Betty L. Adams and the forecasted test period filing requirements at Volume 9 of 10 of the Application, Tab 2, Exhibits FR 9(u)1, and Schedules 1-3 and Exhibit A. The referenced Schedules 1-3 and Exhibit A do not satisfy the filing requirement of providing a detailed description of the amounts allocated. Furthermore, the answers to the Commission's July 16, 1999 Order, Items 34(a) and 83(a) were non-responsive. It appears, based on the information in the

record at this point, that the recording of the $9,050,095 of Shared Services cost allocated to Western in Account 922 "Administrative Expenses Transferred – Credit" is not in accordance with the FERC USoA.

a. Explain how the use of Account 922 for Shared Services costs allocated to Western complies with the FERC definition that Account 922 is for "administrative expenses . . . [from] Accounts 920 and 921 which are transferred to construction costs or non-utility accounts."

b. The schedule of Shared Services "Combined Direct & Billed" total monthly expenses as allocated by division on the exhibit in response to DR Item 83a, "April's Financial Statements," bottom of the page marked "(33),(34) and (35)" appears to represent a detailed statement of operating expenses. Prepare this detailed statement of operating expenses showing the total six months actual activity and the projected six months total in the base period. Additionally, prepare a similar detailed statement of operating expenses showing total balances for the forecasted test year. Be sure that the amounts are reconciled to the amounts included on the FR 10(9)(h)1 and FR 10(10)(i)1 as described in (c) below.

c. The answer to the Commission's August 19, 1999 Order, Item 57, is non-responsive. A reconciliation should consist of detailed items comprising the approximate $953,000 difference for "Shared Services Billing" on DR 67(f) of $10,003,000 and Administrative Services Transferred on DR 67(g), Schedule C-2.1, Sheet 4 of 10, account 922, in the amount of $9,050,095. Provide a list of the items posted to different accounts that make up this difference.

d. Refer to the detailed statement of operating expenses in (b) above. Provide detailed descriptions of the types of expenditures and amounts for the base period and forecasted test year, for items the lesser of $10,000 or 10 percent of the account total. For all lesser amounts provide explanations of the various types of expenditures comprising the remainder.

e. Provide the Shared Services detailed statement of operating expenses cross-referenced to corresponding FERC account numbers.

23. Refer to the response to the Commission's August 19, 1999 Order, Item 1(c). The response states that no assets, liabilities, capital, or personnel of Western or Atmos Energy Corporation ("Atmos") were directly transferred to either WKG Storage, Inc. or WKG Energy Services, Inc. Were any of Western's assets, liabilities, capital, or personnel indirectly transferred to either of these affiliates? If yes, explain the nature of the transfer.

24. Refer to the response to the Commission's August 19, 1999 Order, Item 2. Based on the definition of "affiliate" in 807 KAR 5:001, Section 10(1)(b)10 and (1)(b)11, the five unincorporated divisions of Atmos are considered to be affiliates. Based on this clarification, and excluding those shared services transactions already described in this record, provide the information originally sought by this request.

25. Refer to the response to the Commission's August 19, 1999 Order, Item 3. Entry number 2 is shown as two debits, without a corresponding credit. Indicate whether the entry shown is correct or, if in error, provide the correct entry.

26. Refer to the response to the Commission's August 19, 1999 Order, Item 4(c). Explain in detail why information on Western's post-retirement employee benefits is not available for years prior to the fiscal year ending September 30, 1996.

27. Refer to the response to the Commission's August 19, 1999 Order, Item 6. The second paragraph of this response makes reference to an adjustment to the "test year" in this case. Clarify whether this reference is to the base period or the forecasted period.

28. Refer to the response to the Commission's August 19, 1999 Order, Item 6. In this response, Western has filed an update to its original weather adjustment schedules Exhibit GLS-4, using billing information through May 1999. KRS 278.192(2)(b) states that the actual results for the estimated months of the base period shall be filed no later that 45 days after the last day of the base period. 807 KAR 5:001, Section 10(8)(d) states that after an application based on a forecasted test period is filed, there shall be no revisions to the forecast, except for the correction of mathematical errors, unless such revisions reflect statutory or regulatory enactments that could not have been included in the forecast on the date it was filed.

a. If the update to Exhibit GLS-4 is related to the base period, explain why this information was filed covering a period other than the end of the base period.

b. If the update to Exhibit GLS-4 is related to the forecast period, explain in detail why Western is not in violation of 807 KAR 5:001, Section 10(8)(d).

29. Refer to the response to the Commission's August 19, 1999 Order, Item 7. Indicate where in this record Western has provided an analysis showing that the results of the "baseline" forecasting of the capital budget correlates with prior years budgeted

and actual amounts. If such an analysis has not been submitted, provide such an analysis.

30. Refer to the response to the Commission's August 19, 1999 Order, Item 9 and the supplemental response to the Commission's July 16, 1999 Order, Item 10, filed on August 18, 1999. Western was requested to provide the workpapers and assumptions used to determine that the projected increase in maintenance and improvements should be 36.25 percent for the FY 2000 capital budget. Western has not provided the requested workpapers nor adequately explained the assumptions used to make the 36.25 percent determination. Provide the originally requested information; this is the third request for this information.

31. Refer to the response to the Commission's August 19, 1999 Order, Item 9(b).

a. Provide the supporting workpapers for the $2,048,660 in maintenance and improvements for 1993.

b. Explain the reason(s) for the increases and decreases experienced by Western for maintenance and improvements for 1996, 1997, and 1998.

32. Refer to the response to the Commission's August 19, 1999 Order, Item 12.

a. Explain why it is reasonable to assume that by the forecasted period, Western's number of employees will represent 20 percent of the number of employees for Atmos's total regulated operations.

b. The response indicates that historically, Western's percentage of the total number of employees has been slightly lower than its percentage of the total number of customers. Explain why Western expects this relationship to change in both the base period and the forecasted period.

c. Do the responses to parts (d), (g), and (h) for the forecasted period reflect the impact of the proposed revenue increase? Explain the response.

d. Explain in detail why Western's percentages of net operating income and net income are expected to decrease significantly in the base period and forecast period. Include a discussion as to how this can be expected to happen, given the corresponding percentages shown for parts (d), (e), and (f).

33. Refer to the response to the Commission's August 19, 1999 Order, Item 13(g). Western stated that the reasonableness of the assumptions used in the five-year plan is evaluated against historical occurrences and anticipated future operating conditions. Provide a further explanation of how Western performs this type of evaluation and indicate whether the evaluation is presented in writing or orally.

34. Refer to the response to the Commission's August 19, 1999 Order, Item 14. Western contends that it is reasonable to assume that the employee stock plans will continue to add roughly $20 million annually to Atmos's equity base.

a. Based on the information in this response, it would appear that Atmos and Western have based this assumption solely on the employee stock plan activity during FY 1999. Does Western agree with this conclusion? Explain the response.

b. The average dollar amount of the increase in Atmos's equity balance associated with the employee stock plans for the five previous fiscal years is approximately $10.5 million. Given this historic information, explain in detail why it is reasonable to assume that $20 million annually will be added to Atmos's equity base.

35. Refer to the response to the Commission's August 19, 1999 Order, Item 15.

a. In the response to Item 15(d), Western states "it was our understanding that there were already guidelines in place based upon prior policy and regulatory rulings from the Kentucky Commission." Identify the guidelines, policies, and rulings this response is referencing.

b. In the response to Item 15(d), Michael Marks makes reference to several representations that were relayed to him concerning the WKG CARES program. Keeping in mind that the Commission speaks only through its Orders, do either Mr. Marks or Western have in their possession any Commission Orders that approved the WKG CARES program? If yes, provide copies of those Orders.

c. In the response to Item 15(k), it is stated that normal weather was based on actual weather for the 1980 – 1991 time frame as recommended in the Princeton Scorekeeping Methodology ("PRISM") software manual.

(1) Explain why the software manual recommended a 10-year period to use for the weather normalization.

(2) Explain why a 30-year period was not used for the weather normalization in the PRISM analysis, which is the time period normally used in weather normalization adjustments.

(3) Explain why Western believes the use of a 10-year period produces reasonable results for its PRISM analysis.

36. Refer to the response to the AG's Data Request dated August 19, 1999, Volume 2 of 3, Item 145.

a. Who performed the analysis and developed the expense estimates shown on Exhibit MM-2 of the testimony of Michael Marks?

b. Explain why Western concluded that these estimated expenses did not need to be documented with supporting workpapers.

c. The schedules of actual DSM program expenditures show that for the period from December 1996 through October 1998, Western expended $598,326. Using this historic information, explain in detail how Western and its DSM collaborative arrived at an estimated expense level of $268,000 for the period November 1998 through December 1999 and an estimated expense level of $200,000 per year for each of the following three calendar years.

37. Refer to the response to the AG's Data Request dated August 19, 1999, Volume 3 of 3, Item 230.

a. During the planning stage of the WKG CARES program, did Western and its DSM collaborative consult with other utilities in Kentucky that had approved DSM cost recovery mechanisms, especially those approved under KRS 278.285?

b. If yes to part (a), explain how Western incorporated that information into WKG CARES. If no to part (a), explain why Western and its DSM collaborative did not undertake such a consultation.

c. Explain how Western determined that the use of a deferred debit account was the most appropriate method to record WKG CARES program expenses.

38. Refer to the response to the AG's Data Request dated August 19, 1999, Volume 3 of 3, Items 176 and 192. Western has stated that for both its O&M budget variance analysis and the capital budget variance reports, variance explanations are communicated verbally during top management staff meetings and no written explanations are provided. Explain in detail why Western believes it is a sound and proper business practice not to document these budget variance explanations.

39. Refer to the response to the Commission's August 19, 1999 Order, Item 19.

a. In response to Item 19(d), Western states that it is not required to maintain records documenting capital project budgeted starting and ending dates nor capital project actual starting and ending dates. Based on this response, does Western mean that it does not keep any information concerning the starting or ending dates for its individual capital projects? Explain the response.

b. Would Western agree that the maintenance of such capital project information would be a sound business practice? Explain the response.

c. In response to Item 19(e), Western states that it does not record whether a capital project is completed ahead of schedule, on schedule, or behind schedule. Explain in detail why Western does not record such information. Also explain whether Western would agree that the recording of such information would be a sound business practice.

d. In the response to Item 20 of this data request, Western has stated that all capital projects were completed in the fiscal year in which they were budgeted. If Western does not record information concerning the beginning and ending construction dates or information on whether the project was completed on schedule, explain in detail how Western can conclude that all capital projects are completed within the fiscal year they were budgeted.

40. Concerning Western's capital projects included in the base and forecasted periods,

a. Western has assumed that the budgeted amounts for the capital projects and the final actual expenditure for those projects will be the same. Explain in detail why this is a reasonable assumption.

b. When determining the amounts to recognize for its budgeted capital projects in the estimated portion of the base period or in the forecasted period, does Western agree that it would be reasonable to adjust the budgeted amounts, using the historic completion percentage, in order to more accurately reflect actual expected capital additions? Explain the response.

41. Refer to the response to the Commission's July 16, 1999 Order, Item 28, and the August 19, 1999 Order, Item 18.

a. In five of the eight fiscal years that Western reported capital budget project information for the WKG Company Office operating area, the expenditure amount exceeded the budget amount. For those eight fiscal years, the WKG Company Office's total of all expenditures exceeded the total of all budgeted amounts by approximately 163 percent. Explain in detail why actual capital project expenditures have been exceeding the capital budgets for this operating area.

b. In seven of the nine fiscal years that Western reported capital budget project information for the Owensboro Operations operating area, the expenditure amount exceeded the budget amount. For those nine fiscal years the Owensboro Operations' total of all expenditures exceeded the total of all budgeted amounts by approximately 114 percent. Explain in detail why actual capital project expenditures have been exceeding the capital budgets for this operating area.

42. Refer to the response to the Commission's August 19, 1999 Order, Item 21(a). Western was requested to provide a summary for pages 1 through 4 of 6 of Exhibit DHD-1, listing the additions by plant account number. The summary was to also show how amounts for retirements and public works reimbursements were allocated to the particular plant accounts. Western's response, which included citations to workpapers "B-2 B 09" and "B-2 F 09," does not adequately address the question, in that the cited workpapers do not show how the amounts for retirements and public works reimbursement were allocated to the plant accounts. Provide the information originally requested.

43. Refer to the response to the Commission's August 19, 1999 Order, Item 21(b).

a. In this response, Western states "These variations are mainly attributed to the line items 41 'retirements' and 72 'public works retirements' on Exhibit DHD-1 not being assigned to the asset accounts on this exhibit." Explain in detail what asset accounts line items 41 and 72 were being assigned to if not Exhibit DHD-1.

b. If line items 41 and 72 were not being assigned to asset accounts on Exhibit DHD-1, explain why these line items were included on Exhibit DHD-1 originally.

c. In this response, Western states "Finally, there were slight variations in how inflation and overhead rates were applied and to how line 79 'Forfeitures' (asset account 376 Mains) was handled on DHD-1 as compared to on the workpapers WP B-2 B 09 and WP B-2 F 09." Explain in detail the nature of the "slight variations" referenced in this response. Also explain why Western would handle the Forfeitures amount differently.

44. Refer to the response to the Commission's August 19, 1999 Order, Item 22. It appears that the estimated monthly plant account additions result from a determination of the total increase, which is then divided into equal amounts to be added during the base or forecasted periods.

a. Explain in detail why Western believes this to be a reasonable method to recognize the estimated additions to its utility plant accounts.

b. Does the approach described by Western in this response represent its normal method of reflecting estimated plant additions as part of its normal budgetary process? Explain the response.

c. Explain why Western did not recognize seasonal factors when determining when to record the estimated plant additions.

45. Refer to the response to the Commission's August 19, 1999 Order, Item 23.

a. In the response to Item 23(a), Western stated that the depreciation allocation problem in the original base period was due to a misallocation of the reserve balances that occurred prior to 1996. Explain how and when Western determined that there had been a misallocation of the depreciation reserve balances.

b. In the same response, Western states that the major category accumulated depreciation balance was spread among the individual accounts within the specific category pro-rata, according to the related plant investment balance as compared to the total investment for that asset category at September 30, 1998. Explain how and when Western determined this was the appropriate methodology to use when allocating the accumulated depreciation balance to individual accounts.

c. Concerning the allocation of the accumulated depreciation balance, explain in detail why Western's approach is reasonable.

d. Under Western's allocation of the accumulated depreciation balance, doesn't this approach eliminate the possibility that Western could have over-depreciated an asset group? Explain the response.

46. Refer to the response to the Commission's August 19, 1999 Order, Item 24(e). The response to this request was inadequate. For each of the consulting services described below, explain in detail why the associated costs have been included as part of the rate case expenses.

a. October 20, 1998 – Met with West Kentucky Gas to discuss . . . other PSC related activities.

b. November 20, 1998 – Reviewed Court decision and agreement with Hopkinsville concerning franchise tax.

c. December 18, 1998 – Reviewed information on CIAC and discussed with PSC Staff.

d. December 23, 1998 – Continued to work on CIAC.

e. March 1, 1999 – Work on testimony.

f. April 20, 1999 – Work on testimony.

47. Refer to the response to the Commission's August 19, 1999 Order, Item 24(f). Provide a description of the "certain matters" that the firm of Ward and Anderson provided legal research in conjunction with this rate case.

48. Refer to the response to the Commission's August 19, 1999 Order, Item 28. For the organizations listed in parts (c), (d), (e), and (g), provide a description of the nature of the organization, a listing of the benefits Western receives from being a member, and a description of the education and training programs that Western employees have attended within the last two years that have been sponsored by the organization.

49. Refer to the filing requirements at Volume 10 of 10 of the Application, Tab 6, Exhibit FR 10(10)(f), Schedule F-1, Pages 1 through 6, membership dues for the base period and forecasted test year. Explain the nature of the organizations listed below and why the membership dues should be included for ratemaking purposes.

a. Club or organization from the base period – Associated Industries of KY, Ky., Labor-Management Conference, Green River Home Builders Association, Owensboro Home Builder Association, Hopkins County Home Builders, Henderson Home Builders, Association of U.S. Army, Hopkinsville Home Builders, Military Affairs Committee, Paducah Home Builders, Builders Association of Bowling Green, Russellville Home Builders, Danville-Boyle County Home Builders, Kiwanis Club, Lions Club and Civitan Club.

b. Club or organization from the forecasted test year – Associated Industries of KY, Ky. Labor-Management Conference, Green River Home Builders

Association, Owensboro Home Builder Association, Hopkins County Home Builders, Henderson Home Builders, Association of U.S. Army, Hopkinsville Home Builders, Military Affairs Committee, Paducah Home Builders, Builders Association of Bowling Green, Russellville Home Builders, Danville-Boyle County Home Builders, Kiwanis Club, Lions Club and Civitan Club.

50. Refer to the response to the AG's August 19, 1999 Data Request, Item 206. A standard business year includes 52 weeks with 40 hours of regular work time per week. This results in 2,080 hours per year.

a. Explain in detail why Western believes it is reasonable to normalize payroll expenses using 2,088 hours. If Western is proposing 2,088 hours because the year 2000 is a leap year, explain why the normalization should recognize an event that occurs only once every four years.

b. Revise all applicable schedules in this response to include a 2,080 per employee, regular time work year (FR 10(10)(g)).

c. If Western based its payroll hours on the year 2000 being a leap year, explain why it did not also adjust its sales and transportation delivery volumes to reflect an additional day's operations.

51. Refer to the response to the AG's August 19, 1999 Data Request, Item 165. Explain the amortized merger and acquisition costs and expenses applicable to Western.

52. Refer to the response to the AG's August 19, 1999 Data Request, Item 179. Explain how the $4,536 total medical costs per employee per year in part (c) is

determined, i.e., $X for medical per month, $Y for dental per month, and any distinction between single employee costs versus married employee costs.

53. Refer to the response to the AG's August 19, 1999 Data Request, Item 216. Are there any indirect lobbying activity expenses allocated to Western from Atmos or Shared Services in the forecasted test year? Explain the response in detail.

54. Are any non-recurring expenditures included in operating and maintenance expenses for the base period or forecasted test year? Explain and describe the nature and amounts of these non-recurring expenditures.

55. Refer to the response to Item 61(b) of the Commission's August 19, 1999 Order. If FR 10(10)(c) 2, at Volume 10 of 10 of the Application, Tab 3 of the Application addresses the amounts of functional expense for directors retirement benefits, community trade relations and trade shows, and sports activities, specify the amounts and explain or describe the nature of the expenditures. Western's response to the Commission's August 19, 1999 Order appears to be non-responsive to these items of expense. If the above-mentioned expenses are not addressed in FR 10(10)(c)2, resubmit the response to Item 61(b).

56. As stated in 22(b), the schedule of Shared Services "Combined Direct & Billed" total monthly expenses as allocated by division on the exhibit in response to DR Item 83a, "April's Financial Statements," bottom of the page marked "(33), (34) and (35)" appears to represent a detailed statement of operating expenses. Additionally, this statement allocates total Shared Services costs to the divisions to which Shared Services costs apply.

a. Explain whether any Shared Services costs are allocable to Atmos as parent company expenses.

b. Describe how applicable costs are allocated to Atmos as parent company expenses.

c. Are any of the Shared Services costs and expenses allocated to the gas operating divisions of Atmos "below the line" expenses according to FERC, i.e., investor relations, new business ventures, and directors retirement? Explain the response in detail.

57. Refer to the filing requirements at Volume 10 of 10 of the Application, Tab 3, Exhibit FR 10(10)(c), Schedule C-2.

a. If Western's application did not employ a forecasted test year, but employed the historical test year ended September 30, 1998, normalized to reflect known and measurable adjustments, would the type of adjustments termed "utility budget adjustments, SSU billing adjustments, and rate making adjustments" on Schedule C-2 be the same? Provide a detailed explanation.

b. What would the dollar amounts of the adjustments be from the standpoint of normalizing known and measurable adjustments?

58. Concerning the capital budget projects included in the estimated portion of the base period and the forecasted period, Western has assumed the actual expenditures on these projects will be equal to the budgeted amounts. Based on the nine fiscal years of information provided by Western concerning its capital budget

projects' completion percentage, Western's historic completion percentage is 94 percent.[1]

a. Restate all capital project budget amounts shown on Exhibit DHD-1 for the estimated months of the base period and for the entire forecasted period, reflecting the historic 94 percent completion factor.

b. Recalculate Western's base period rate base, balance sheet, and operating income statement reflecting the impact of applying the 94 percent completion factor. Include all workpapers, assumptions, and calculations used to determine the recalculated amounts. Provide this information on diskette using Excel spreadsheets as was done in responses to previous data requests.

c. Recalculate Western's forecasted revenue requirement, rate base, balance sheet, and operating income statement reflecting the impact of applying the 94 percent completion factor. Include all workpapers, assumptions, and calculations used to determine the recalculated amounts. Provide this information on diskette using Excel spreadsheets as was done in responses to previous data requests.

d. Western has also identified corrections and revisions to other financial information, which it has submitted in conjunction with its responses to various data requests. An example of such a revision is contained in the response to the AG's Initial Data Request, Volume 3 of 3, Item 206. When preparing the recalculation of the information required in parts (b) and (c) above, recognize and incorporate the impact of all corrections and revisions submitted by Western since the filing of its application.

[1] Total capital project expenditures for the nine fiscal years equals $101,474,634; total capital project budgets for the same nine fiscal years equals $107,992,213. Dividing the expenditures by the budget equals 94 percent.

Include in the workpapers, assumptions, and calculations the appropriate cross-references to the location in the record of these corrections and revisions.

Done at Frankfort, Kentucky, this 20th day of September, 1999.

By the Commission

ATTEST:

Helen C Helton

Executive Director

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
SEP 20 1999
PUBLIC SERVICE COMMISSION

In the Matter of: THE APPLICATION OF WESTERN KENTUCKY GAS COMPANY FOR AN ADJUSTMENT OF RATES	))))	Case No. 99-070

SUPPLEMENTAL REQUEST FOR INFORMATION
BY THE ATTORNEY GENERAL

Comes now the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and submits this Supplemental Request for Information by the Attorney General.

(1) In each case where a request seeks data provided in response to a staff request, reference to the appropriate request item will be deemed a satisfactory response.

(2) Please identify the company witness who will be prepared to answer questions concerning each request.

(3) These requests shall be deemed continuing so as to require further and supplemental responses if the company receives or generates additional information within the scope of these requests between the time of the response and the time of any hearing conducted hereon.

(4) If any request appears confusing, please request clarification directly from the Office of Attorney General.

(5) To the extent that the specific document, workpaper or information as requested does not exist, but a similar document, workpaper or information does exist, provide the similar document, workpaper, or information.

(6) To the extent that any request may be answered by way of a computer printout, please identify each variable contained in the printout which would not be self evident to a person not familiar with the printout.

(7) If the company has objections to any request on the grounds that the requested information is proprietary in nature, or for any other reason, please notify the Office of the Attorney General as soon as possible.

(8) For any document withheld on the basis of privilege, state the following: date; author; addressee; indicated or blind copies; all persons to whom distributed, shown, or explained; and, the nature and legal basis for the privilege asserted.

(9) In the event any document called for has been destroyed or transferred beyond the control of the company state: the identity of the person by whom it was destroyed or transferred, and the person authorizing the destruction or transfer; the time, place, and method of destruction or transfer; and, the reason(s) for its destruction or transfer. If destroyed or disposed of by operation of a retention policy, state the retention policy.

Supplemental Requests for Information by the Attorney General

1. With reference to the response to Kentucky Public Service Commission Data Request (KPSC) 2-2(c), please explain in detail how the estimate for the affiliate transaction is determined, and provide a workpaper supporting the forecasted test year amount.

2. With reference to the response to KPSC 2-2(a), please provide the schedule as requested.

3. With reference to the response to KPSC 2-4:

   a. Do the amounts presented in item (a) include only amounts paid out in claims and administrative costs? Do they include contributions to a trust fund?

   b. Does Western maintain an external trust fund such as a VEBA trust in which it is currently contributing cash towards its OPEB liability? If so, please provide the balance in that fund for each of the years shown in the response to KPSC 2-4 (a & b), and provide the annual amount contributed each year.

4. With reference to the response to KPSC 2-9(a), if there are no similar amounts for 96, 97 and 98, how does the Company assure itself that the 36.25 percent factor is a reasonable amount? Please explain fully.

5. With reference to the development of the 36.25 percent factor and the supplemental response to KPSC 1-10:

   a. Are the projects that equate to 36.25 percent of the 1999 maintenance budget additional projects to those which are anticipated and presented on Exhibit DHD-1, page 2, or are they the same projects that are presented on lines 36 through 41 of Exhibit DHD-1?

   b. Was the 36.25 percent factor used as a proxy for maintenance and system improvements based upon the identifiable projects in the maintenance budget?

   c. Do all the projects listed in the supplemental response to KPSC 1-10 belong in the classification of maintenance, system improvements or both?

   d. Given that the 36.25 percent factor is applied to FY 1999 capital budget amounts as the baseline, please explain fully how the FY 1999 capital budget was developed. Indicate whether it was developed using the bottom-up approach or FY 1998 as capital budget a baseline.

   e. Doesn't the FY 1999 capital budget include the costs associated with similar maintenance and improvement projects? Explain fully why the Company believes that the projects in the maintenance and improvement section of the FY 1999 budget are not representative of the projects to be performed during FY 2000. Provide workpapers and documentation that demonstrate this assumption.

6. Please provide the "Approved Authorization for Expenditures" for each of the projects listed in supplemental response to KPSC 1-10.

7. With reference to the response to KPSC 2-66, please provide a detailed explanation of the nature of the lawsuit settlement amortization, the excess property damage, and the prepaid liability amortization. Your response should also indicate the cause of the charges, the length of the amortization period, and indicate any Commission approvals for the amortization.

8. With reference to the response to Attorney General Data Request (AG) 1-165:

   a. Please identify the components and explain the nature of the costs which are being amortized over a 7-year period.

   b. Please identify and explain how any one-time or non-recurring cost savings from the Atmos/United Cities merger have been passed back to customers or handled for ratemaking purposes in Kentucky.

   c. Cite the Commission Order authorizing the recovery of merger-related costs.

9. With reference to the response to AG 1-166:

   a. Did the Commission approve the changes requested by the Commission Staff? If so, please cite the Order.

   b. The response to KPSC 1-77 shows the $319,730 expected savings. Please provide the expected savings after reflecting the Commission Staff's changes to the program. Please include supporting documentation in your response.

10. With reference to AG 1-169, please explain the negative depreciation expense during May 1999.

11. With reference to the response to AG 1-198 and 1-199:

   a. By setting pensions expense to $0, does the Company believe that pensions expense, for ratemaking purposes, should be based upon the amount contributed to the pension plan? Please explain.

   b. If pensions expense is set at $0 when the expense level is negative, will the Company agree to give ratepayers a credit when the expense becomes positive? If no, please explain.

12. With reference to the attachment to AG 1-197:

   a. Please explain what $(11,703,506) amount in the "Balance Sheet Accrued (Prepaid) Cost as of 10/1/98" column represents.

b. Please provide a breakdown showing the year-by-year accumulation of \$(11,703,506) that indicates the amount collected in rates, the benefits paid out, and the amount contributed to the pension plan fund.

c. Please provide the accrued/(prepaid) cost as of the end of the forecasted period. Include workpapers.

d. Please provide the level of accumulated deferred income taxes associated with the \$(11,703,506), and the end of the forecasted period amount. Indicate if the deferred taxes have been included in rate base.

13. With reference to the response to AG 1-199, reference is made to cases in Michigan and FERC. Subsequent to the dates of the cited orders, please explain how pensions expense has been set for ratemaking in those jurisdictions when the pensions expense per books is negative.

14. With reference to the response to AG 1-206, Schedule A, pages 1 and 3, please provide documentation supporting the amounts in the "Total Payroll" column.

15. According to the response to AG 1-208 the level of SFAS 106 expense included in the forecasted test year expenses is \$1,433,000, however, the response to KPSC 2-4 indicates the annual OPEB cost is \$1,583,200. Please explain the difference. If the difference is due to the application of the O&M percentage, please explain why that percentage differs from the percentage used for the payroll. Include any supporting data.

16. With reference to the response to AG 1-221:

a. Please provide a workpaper showing the buildup of the \$5,511,500 OPEB liability. Indicate the OPEB amount allowed in rates, the amount paid out in claims and administrative costs, etc.; and the amount contributed to the OPEB external fund.

b. Please update the OPEB liability to reflect the balance as of the end of the forecasted test year.

c. Please provide the level of accumulated deferred income taxes associated with the \$5,511,500 OPEB liability, and the similar amount as of the end of the forecasted test period. Indicate if the deferred taxes were included in rate base.

17. With reference to the response to AG 1-217:

a. Please provide the level of amortized injuries and damages included in the forecasted test period. Separately identify each claim being amortized and indicate when the amortization ends.

b. Please state the basis upon which claims over \$50,000 are deferred and amortized.

c. Is the General Liability Reserve only used to hold funds relating to injuries and damages? Please identify the other components of the reserve and the associated amounts that makeup the $455,000 balance.

18. With reference to the response to AG 1-217(d), please clarify the response. Does the response mean that other reserve accounts have been included (either as an addition or deduction) in rate base but not the pension reserve. Please identify the various reserve accounts and indicate whether they are excluded from or included in rate base.

19. With reference to the response to AG 1-235:

    a. If the National Bank of Texas amount is related to fees for a credit facility for the 8/7/98 to 8/6/99 period, and was being amortized over the life of the facility, why is there still a balance during the forecasted test year? When does the amortization end?

    b. Please explain how the fees relating to the National Bank of Texas credit facility is reflected in the cost of capital calculation by the Company.

    c. With reference to Oracle Data Base Main. and CIS Project, if these costs are related to maintenance contracts and technical support contracts which are being amortized, why do the balances fluctuate rather than steadily declining? Identify the total costs incurred for each of these items and provide the monthly amortization amount.

20. With reference to the response to AG 1-201, the referenced response indicates that "... budgeted additions are projected as a net amount less retirements" and that "Western does not budget for plant retirements since they are not known at the time of budget preparation".

    a. If Western does not budget for retirements what do the amounts in the "Retirements" column of Schedule B-2.2 pages 1 through 3 represent?

    b. Please explain how the budgeted additions can be projected net of retirements when the projected balance is based upon the applying the inflation and other cost rates to the previous year's balance.

21. With reference to the response to KPSC 1-10, an explanation is given for the 50 percent overhead rate. Please provide similar data for FY 1996 through 1998.

22. Please provide a copy of the source of the 3 percent inflation rate as stated on page 10, line 15 of Mr. Doggette's testimony.

23. Reference response to AG 1-34(d). Please generally describe the reason for the low pressure-caused interruptions. Was this a local area problem? A general area problem? Were interruptible customers located elsewhere on the system unaffected? Why have there been no more interruptions due to low system pressure since 1995? Has the problem been fixed? If so, how?

24. Reference response to AG 1-45. Please provide the referenced cost allocation guidelines in the Commission's Administrative Case No. 297.

25. Reference response to AG 1-139. The load data requested in parts (a), (b), (c), and (e) was customer class load data, not system data. Please provide the originally requested Item 139 data, by customer class.

26. Using the format of Schedule B, provided in the response to KPSC 1-69(b), please provide the actual monthly level of employees during the base period for Western. For each month indicate the number of authorized positions.

27. Please provide the actual monthly level of employees during the base period for Shared Services. For each month indicate the number of authorized positions.

28. With reference to the response to AG 1-241, both the referenced testimony and Schedule C-2.2 appear to indicate that the base year data and the forecasted period data are presented on the NARUC account basis. If both periods are presented on the same basis, please explain why the account fluctuations noted in Items (h) through (t) can be the result of converting from O&M budget cost elements to NARUC accounts. Given that the accounts are present on the same basis, wouldn't the differences between the periods result from actual changes in activities? Please explain fully.

Respectfully submitted,

A.B. CHANDLER III
ATTORNEY GENERAL

David Edward Spenard

David Edward Spenard
Assistant Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601-8204
(502) 696.5457

CERTIFICATE OF SERVICE AND FILING

Counsel hereby certifies that an original and ten (10) photocopies of the foregoing Supplemental Request for Information by the Attorney General were served and filed by hand delivery to the Hon. Helen C. Helton, Executive Director, Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky 40601; furthermore, it was served by mailing a true and correct copy of the same, first class postage prepaid, to William J. Senter, Western Kentucky Gas, 2401 New Hartford Road, Owensboro, KY 42303 1312, Mark R. Hutchinson, Sheffer, Hutchinson & Kinney, 115 East Second Street, Owensboro, KY 42303, John N. Hughes, 124 West Todd Street, Frankfort, KY 40601, Douglas Walther, Atmos Energy Corporation, P.0. Box 650205, Dallas, TX 75265, and Robert M. Watt, Jr., J. Mel Camenisch, Jr., 201 E. Main Street, Suite 1000, Lexington, KY 40507-1380, all on this 20th day of September, 1999.

David Edward Spenard

Assistant Attorney General

99-070_SR1

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

September 20, 1999

To: All parties of record

RE: Case No. 99-070

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,

Stephanie Bell

Stephanie Bell
Secretary of the Commission

SB/sa
Enclosure

William J. Senter
V.P. Rates & Regulatory Affairs
Western Kentucky Gas Company
2401 New Hartford Road
Owensboro, KY 42303 1312

Honorable Mark R. Hutchinson
Attorney at Law
Sheffer Hutchinson Kinney
115 East Second Street
Owensboro, KY 42303

Honorable John N. Hughes
Attorney for Western KY Gas
124 West Todd Street
Frankfort, KY 40601

Mr. Douglas Walther
Atmos Energy Corporation
P.O. Box 650205
Dallas, TX 75265

Honorable David E. Spenard
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY 40601 8204

Hon. Robert M. Watt,
Hon. J. Mel Camenisch, Jr.
STOLL, KEENON & PARK, LLP
201 E. Main Street, Suite 1000
Lexington, KY 40507 1380

Mr. Keith Tiggelaar
Manager-Regulatory Affairs
WBI Southern, Inc.
P.O. Box 5601
Bixmark, ND 58506 5601

COMMONWEALTH OF KENTUCKY
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September 15, 1999

Mark R. Hutchinson
Sheffer-Hutchinson-Kinney
115 East Second Street
Owensboro, KY 42303

RE: Western Kentucky Gas Company
Case No. 99-070
Petition for Confidential Protection

Dear Mr. Hutchinson:

The Commission has received the petition filed September 3, 1999, on behalf of Western Kentucky Gas Company to protect as confidential information containing volumes and discount levels for each special contract customer for whom a discount has been negotiated. A review of the information has determined that it is entitled to the protection requested on the grounds relied upon in the petition and it shall be withheld from public inspection.

If the information becomes publicly available or no longer warrants confidential treatment, you are required by 807 KAR 5:001, Section 7(9)(a) to inform the Commission so that the information may be placed in the public record.

Sincerely,

Helen C. Helton

Helen C. Helton
Executive Director

cc: All parties of record

FILE COPY

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
SEP 1 5 1999
PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF WESTERN)
KENTUCKY GAS COMPANY) CASE NO. 99-070
FOR AN ADJUSTMENT OF RATES)

MOTION TO FILE DATA REQUESTS UPON WESTERN KENTUCKY GAS COMPANY

Comes now the Intervener, WBI Southern, Inc., and requests that it be permitted to file and serve upon Western Kentucky Gas Company ("Western Kentucky") its Data Requests which have been filed with the Public Service Commission simultaneously with this Motion. In support of this Motion, WBI Southern states that it acquired a storage facility, known as Kentucky Pipeline and Storage Company, Inc. ("KYPSCO"), on July 16, 1999, which was after the May 28, 1999 filing of Western Kentucky's Application for Adjustment of Rates. Accordingly, since it had not acquired KYPSCO by the time of the Application, WBI Southern did not receive notice of the filing of the Application. Upon learning of the Application, Western Kentucky moved to intervene in this action on August 17, 1999 and the Public Service Commission granted the Motion on September 1, 1999. However, by the time WBI Southern was granted the right to intervene in these proceedings, the deadlines for requests for initial information to Western Kentucky, as set forth in the Public Service Commission's Order dated July 2, 1999, had already expired. That Order did, however, provide a September 20, 1999 deadline for all "supplemental requests for information" to Western Kentucky. WBI Southern submits that it should be entitled to file requests for information just as all other interested parties in these proceedings and that its late intervention in the proceeding should not affect that right.

Accordingly, WBI Southern requests that the Public Service Commission will accept for filing WBI Southern's Data Requests to Western Kentucky Gas Company which are filed simultaneously herewith and that the Public Service Commission will treat those Requests as "supplemental requests" under its July 2, 1999 Order, with Western Kentucky's response being due by October 4, 1999 as provided in the Order.

Respectfully Submitted,

J. Mel Camenisch, Jr.
STOLL, KEENON & PARK, LLP
201 East Main Street
Suite 1000
Lexington, Kentucky 40507
(606) 231-3000
COUNSEL TO WBI SOUTHERN, INC.

CERTIFICATE OF SERVICE AND FILING

Undersigned counsel hereby certifies that an original and ten (10) photocopies of the foregoing Data Requests to Western Kentucky Gas Company by WBI Southern, Inc. was served and filed by hand delivery on September 15, 1999, to:

Hon. Helen C. Helton
Executive Director
Public Service Commission
730 Schenkel Lane
Frankfort, Kentucky 40601

and served by mailing on September 14, 1999 a true and correct copy of the same, first class postage prepaid, to:

William J. Senter
Western Kentucky Gas Company
2401 New Hartford Road
Owensboro, Kentucky 42303

Mark R. Hutchinson
Sheffer, Hutchinson & Kinney
115 East Second Street
Owensboro, Kentucky 42303

John N. Hughes
124 West Todd Street
Frankfort, Kentucky 40601

Douglas Walther
Atmos Energy Corporation
P.O. Box 650205
Dallas, Texas 75265

Counsel to WBI Southern, Inc.

(320)S:\069\Data Motion

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF WESTERN	)	
KENTUCKY GAS COMPANY	)	CASE NO. 99-070
FOR AN ADJUSTMENT OF RATES	)	

DATA REQUESTS TO
WESTERN KENTUCKY GAS COMPANY BY
WBI SOUTHERN, INC.

Comes now the Intervener, WBI Southern, Inc., and submits these Data Requests to Western Kentucky Gas Company ("Western Kentucky"), to be answered by October 4, 1999, the date specified for responses to requests for information in the Commission's Order of Procedure dated July 2, 1999, and in accord with the following:

1. In each case where a request seeks data provided in response to a staff request, reference to the appropriate request item will be deemed a satisfactory response.

2. Please identify the Western Kentucky witness who will be prepared to answer questions concerning each request.

3. These requests shall be deemed continuing so as to require further and supplemental responses if Western Kentucky receives or generates additional information within the scope of these requests between the time of the response and the time of any hearing conducted hereon.

4. If any request appears confusing, please request clarification directly from counsel for WBI Southern at the address and phone number listed herein.

5. To the extent that the specific document, workpaper or information as requested does not exist, but a similar document, workpaper or information does exist, provide the similar document, workpaper, or information.

6. To the extent that any request may be answered by way of a computer printout, please identify each variable contained in the printout which would not be self evident to a person not familiar with the printout.

7. If Western Kentucky has objections to any request on the grounds that the requested information is proprietary in nature, or for any other reason, please notify counsel to WBI Southern at the address and phone number listed herein as soon as possible.

8. For any document withheld on the basis of privilege, state the following: date; author; addressee; indicated or blind copies; all persons to whom distributed, shown, or explained; and, the nature and legal basis for the privilege asserted.

9. In the event any document called for has been destroyed or transferred beyond the control of Western Kentucky state: the identity of the person by whom it was destroyed or transferred, and the person authorizing the destruction or transfer; the time, place, and method of destruction or transfer; and, the reason(s) for its destruction or transfer. If destroyed or disposed of by operation of a retention policy, state the retention policy.

10. As used herein, the term "Document" shall mean all writings and records in the possession, control, and custody of the party to whom the request is made, including but not limited to, memoranda, correspondence, reports, studies, workpapers, comparisons, tabulations, charts, books, pamphlets, bulletins, minutes, notes, diaries, log sheets, ledgers, transcripts, microfilm, computer data, files, tapes, inputs, outputs, printouts, accounting statement, mechanical and electrical recordings, telephone and telegraphic communications, speeches, and drafts of any of the above, Every copy of a document that contains handwritten or other notation or that otherwise does not exactly duplicate is a separate document.

11. When the party to whom the request is made is requested to provide a study, schedule or analysis, it should also provide the workpapers, underlying facts, inferences, suppositions, estimates and conclusions necessary to support such study, schedule or analysis.

12. Whenever the terms "affiliated company" and/or "operating division" are used in the attached data requests, such terms refer to any affiliate, howsoever designated, of Western Kentucky.

DATA REQUESTS

1. Provide a listing of all receipt points, including those with local producers of natural gas and all interstate pipelines, under all currently effective Rate T-2, T-3, and T-4 service contracts whereby the terms and conditions of Rate T-5 would not apply to such receipt point for any reason. Please provide this listing by customer name, contract number, and receipt point.

2. Provide a listing of all locations, including those with local producers of natural gas and all interstate pipelines, where alternate receipt points under currently effective Rate T-2, T-3, and T-4 service contracts would be required to follow the terms and conditions of Rate T-5. Please provide this listing by customer name, contract number, and locations.

3. Provide a listing of all local producers, interstate pipelines, Western Kentucky customers and other parties with whom Western Kentucky has entered any agreement, or has discussed any agreement, whereby Rate T-5 would not apply to such producer, pipeline or other customer in the manner provided in the Application. This response should include a description of the manner in which Rate T-5 would apply to such persons and Western Kentucky's justification for modifying the application of Rate T-5 to such persons.

4. Provide all projections, studies, documents and analyses used by Western Kentucky in the preparation of Rate T-5. In addition, include any correspondence from customers requesting that Western Kentucky provide such a service and any internal studies or correspondence showing the financial and operational effects on Western Kentucky as a result of it providing such a service.

5. WBI Southern has been informed that in the event eligible Western Kentucky customers elect to utilize the proposed interconnect between Western Kentucky and WBI Southern at the East Diamond Storage Field as a designated point of receipt, such service would be subject to the terms and conditions of Rate T-5. Explain why such interconnect does not currently qualify as Western Kentucky's interconnection with the pipeline as defined in Section 2(a) of Rate T-5?

6. Please provide all engineering and operational studies, including system flow diagrams, utilized by Western Kentucky to determine the location of all receipt points relative to its customers' premises and those points that would be considered "upstream" to specific customer service areas.

7. Explain Western Kentucky's justification for imposing an additional charge for an alternate receipt point? Are costs allocated to such Rate T-5? If so, why? If not, why not?

8. Explain from an operational standpoint, why it is necessary to implement Rate T-5?

9. Explain how Western Kentucky determined that a $0.10 Mcf rate is appropriate to Rate T-5? Please provide all workpapers, studies, cost/revenue projections, and analyses relied upon in any such determination.

10. Explain why volumes delivered by Western Kentucky under the Alternate Receipt Point Service may be subject to imbalance restrictions in addition to those specified in the Rate T-2, T-3, or T-4 tariffs?

11. Explain why Banking or Parking allowances for volumes delivered under the Alternate Receipt Point Service under Rate T-5 may be limited or restricted altogether, at Western Kentucky's sole judgment?

12. Section 2(c) of Rate T-5 allows Western Kentucky to determine, in its sole judgment, whether access will be allowed to any alternate receipt point. Provide all policies, processes, and procedures Western Kentucky has developed to prevent the use of such authority in a discriminatory manner?

13. Explain how the proposed Rate T-5 service will not discriminate against production and storage operators with properties located entirely within the Commonwealth of Kentucky in the form of restricted access and incremental service costs?

14. Explain why charging an additional $0.10 per Mcf for new supply sources of gas on Western Kentucky's system would not be discriminatory to such sources.

15. Explain why Rate T-5 is termed a "service" when it consists of only additional charges and limitations to services already being provided under Rates T-2, T-3, and T-4?

Respectfully Submitted,

J. Mel Camenisch, Jr.
STOLL, KEENON & PARK, LLP
201 East Main Street
Suite 1000
Lexington, Kentucky 40507
(606) 231-3000
COUNSEL TO WBI SOUTHERN, INC.

CERTIFICATE OF SERVICE AND FILING

Undersigned counsel hereby certifies that an original and ten (10) photocopies of the foregoing Data Requests to Western Kentucky Gas Company by WBI Southern, Inc. was served and filed by hand delivery on September 15, 1999, to:

Hon. Helen C. Helton
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730 Schenkel Lane
Frankfort, Kentucky 40601

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Counsel to WBI Southern, Inc.

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