CASE NUMBER:

99-070

HISTORY INDEX FOR CASE: 1999-070
KY. PUBLIC SERVICE COMMISSION
AS OF : 02/07/00
WESTERN KENTUCKY GAS COMPANY
Rates - General
FULLY-FORECASTED TEST PERIOD

IN THE MATTER OF RATE APPLICATION OF WESTERN KENTUCKY GAS COMPANY

SEQ NBR	ENTRY DATE	REMARKS
0001	03/01/1999	Notice of Intent.
M0001	04/14/1999	JACK HUGHES WESTERN KY GAS-COPY OF DRAFT NOTICE
M0002	04/28/1999	MARK HUTCHINSON WESTERN KY GAS CO.-SUPPLMENTAL NOTICE OF INTENT TO FILE RATE APPLICATION
0002	05/05/1999	Order denying motion to use an abbreviated form of notice
M0003	05/12/1999	WESTERN KY GAS CO. JOHN HUGHES-MOTION FOR RECONSIDERATION
0003	05/28/1999	Application.
0004	05/28/1999	Acknowledgement letter.
0005	05/28/1999	Order approving use of amended proposed abbreviated notice form submitted 5/12.
M0004	06/04/1999	DAVID SPENARD AG-MOTION TO INTERVENE
M0006	06/04/1999	EDWARD THOMASON CITIZEN-LETTER OF CONCERN TO RATE INCREASE
M0005	06/08/1999	JOHN HUGHES WESTERN KY GAS CO-CORRECTIONS TO APPLICATION FILED ON MAY 28,99
0006	06/10/1999	Order granting motion to intervene filed by Attorney General.
0007	06/16/1999	Order rejecting application; statutory time period to commence with req.info.
M0007	06/16/1999	JOHN N. HUGHES/ATTORNEY-MISSING APPLICATION PAGES, REPLACEMENT COPIES.
M0008	06/23/1999	JACK HUGHES WESTERN KY GAS-MOTION FOR RECONSIDERATION
0008	07/02/1999	Order suspending rates to Jan. 23, 2000; sets procedural schedule; info due 7/12
M0009	07/08/1999	JOHN HUGHES WESTERN KY GAS-RESPONSE TO ORDER OF JULY 2,99 COPIES OF PUBLICATION
M0010	07/12/1999	JOHN BAIRD/ATTORNEY AT LAW-OBJECTION TO RATE INCREASE
0010	07/15/1999	Letter to Jack Hughes regarding electronic filings
0009	07/16/1999	Data Request Order; response due 7/30
0011	07/22/1999	Response sent to John Baird letter of concern to rate increase.
0012	07/29/1999	Order scheduling 12/14 hearing; supplemental procedural schedule set forth
M0011	07/30/1999	JOHN HUGHES WESTERN KY GAS-RESPONSE TO FIRST REQ FOR INFO & PETITION FOR CONFIDENTIALITY
M0012	08/13/1999	JOHN HUGHES WESTERN KY GAS-SUPPLEMENTAL RESPONSE TO ITEMS 47F & 60 C-E
0013	08/16/1999	Letter granting petition for conf. filed 7/30/99 by Western Kentucky Gas.
M0013	08/17/1999	MEL CAMENISCH WBI SOUTHERN INC-MOTION FOR FULL INTERVENTION
M0015	08/18/1999	JOHN HUGHES WESTERN KY GAS-RESPONSE TO ITEMS 6,10,12,19,23,24D,25,42C,& 71
0014	08/19/1999	Data Request Order; response due 9/3
M0014	08/19/1999	AG DAVID SPENARD-INITIAL REQUEST FOR INFORMATION BY THE AG
0015	09/01/1999	Order granting WBI Southern, Inc. intervention
0016	09/03/1999	Memorandum regarding application for adjustment of rates
M0016	09/03/1999	JOHN HUGHES WESTERN KY GAS-RESPONSES TO PSC SECOND REQUEST FOR INFO TO AG FIRST REQ FOR INF
0017	09/15/1999	Letter granting petition for conf. filed 9/3/99 on behalf of Western Ky. Gas.
M0017	09/15/1999	MEL CAMENISCH WBI SOUTHERN INC-MOTION TO FILE DATA REQ UPON WESTERN KY GAS
M0018	09/15/1999	WBI SOUTHERN INC MEL CAMENISCH-DATA REQ TO WESTERN KY GAS BY WBI SOUTHERN INC
0018	09/20/1999	Order issuing data request; response due 10/4
M0019	09/20/1999	DAVID SPENARD AG-SUPPLEMENTAL REQUEST FOR INFORMATION
M0020	09/22/1999	MARK HUTCHINSON WESTERN KY GAS-RESPOSNE TO AG INITIAL DATA REQ NO 181 & 182
0019	10/01/1999	Data Request Order; response due 10/8
M0021	10/01/1999	AG DAVID SPENARD-SUPP REQ FOR INFO BY THE AG FOR THE APPLICANT SUPP RESPONSE
M0022	10/04/1999	JOHN HUGHES WESTERN KY GAS-RESPOSNES TO PSC THIRD REQ FOR INFO,AG SUPP REQ,WBI SUPP REQ,& P
0020	10/07/1999	Letters granting petitions for conf. filed 10/4/99 by Western Kentucky Gas.
M0023	10/07/1999	JOHN HUGHES WESTERN KY GAS-UPDATED RESPONSE TO PSC INITIAL DATA REQ ITEM 39C
M0024	10/07/1999	MARK HUTHINSON WESTERN KY GAS-REVISED RESPONSES TO DATA REQ ITEMS 49 & 153 OF AG INITIAL DA
M0025	10/07/1999	JOHN HUGHES WESTERN KY GAS-REVISED SCHEDULES & DATA REQ RESPONSES TO FILING OF SPECIAL CONT
M0026	10/08/1999	JOHN HUGHES WESTERN KY GAS-RESPONSE TO ORDER OF OCT 1,99 TO MODIFY ITEMS 6 & 57 & 58
M0027	10/11/1999	JOHN HUGHES WESTERN KY GAS-RESPONSE TO PSC ORDER OF OCT 1,99 ITEMS 57 & 58
M0028	10/14/1999	JOHN HUGHES WESTERN KY GAS-RESPONSE TO AG VERBAL REQ FOR ADDITIONAL INFO TO SUPPORT ITEM 14
M0029	10/18/1999	MEL CAMENISCH WBI SOUTHERN INC-VERIFIED TESTIMONY OF KEITH TIGGELAAR

1999-070

V1-C-64

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Box 12

WESTERN KENTUCKY GAS COMPANY
Rates - General
FULLY-FORECASTED TEST PERIOD

IN THE MATTER OF RATE APPLICATION OF WESTERN KENTUCKY GAS COMPANY

SEQ NBR	ENTRY DATE	REMARKS
M0030	10/18/1999	DAVID SPENARD AG-NOTICE OF FILING & CERTIFICATE OF SERVICE
0021	10/21/1999	Order revising procedural schedule
0022	10/29/1999	Letter granting WKGS's petition for confidentiality filed 10/7/99.
M0031	11/03/1999	MARK HUTCHINSON WESTERN KY GAS-UPDATED RESPONSE TO INITIAL DATA REQ ITEM 39C
0023	11/04/1999	Order entered; info due 12/6
0024	11/05/1999	Data Request Order; response due 11/22
M0032	11/08/1999	WESTERN KY GAS JOHN HUGHES-WESTERNS DATA REQUEST TO THE AG
M0033	11/15/1999	JOHN HUGHES WESTERN KY GAS-UPDATED EXHIBITS TO COMMISSION DATA REQ
M0034	11/15/1999	JOHN HUGHES WESTERN KY GAS-UPDATED SCHEDULES FOR FORCASTED MONTHS
M0035	11/22/1999	AD DAVID SPENARD-RESPONSE TO DATA REQ OF THE PSC
M0036	11/22/1999	AG DAVID SPENARD-RESPONSE TO WESTERNS DATA REQ TO THE AG
0026	12/03/1999	Letter granting petition for conf. filed 11/15/99 on behalf of Western Ky. Gas.
M0037	12/03/1999	JOHN HUGHES WESTERN KY GAS-JOINT STIPULATION & SETTLEMENT
0025	12/06/1999	Order requesting direct testimony due 12/9/99.
M0038	12/06/1999	WESTERN KY GAS-REBUTTAL TESTIMONY
M0039	12/09/1999	AG DAVID SPENARD-RESPONSE TO DEC 6,99 ORDER
M0040	12/09/1999	JOHN HUGHES WESTEN KY GAS-AFFIDAVITS VERIFYING REBUTTAL TESTIMONY OF WESTERNS WITNESSES
M0041	12/09/1999	JOHN HUGHES WESTERN KY GAS-RESPONSE TO DEC 6,99 ORDER
M0043	12/09/1999	ROBERT WATT WBI SANITATION-SETTLEMENT TESTIMONY OF DALE LAWRENCE
0027	12/10/1999	Order cancelling 12/14 hearing; case is submitted to Commission for a decision.
M0042	12/10/1999	ROBERT WATT WBI SOUTHERN-AFFIDAVIT OF DALE R LAWRENCE
M0044	12/13/1999	WALLY BRYAN CITIZEN-LETTER OF CONCERN TO RATE INCREASE
0028	12/21/1999	Acknowledgment to William Wallace Bryan, Jr. former mayor re: rate increase.
0029	12/21/1999	FINAL ORDER; APPROVES TERMS AND CONDITIONS OF SETTLEMENT
M0045	01/07/2000	WESTERN KY GAS WILLIAM SENTER-COMPLIANCE TARIFF FILING PER ORDER OF DEC 21,99

Tariffs sent to Tariff Branch.
SH
1/25/2000

Western Kentucky Gas Company

WESTERN
KENTUCKY
GAS

RECEIVED

JAN 7 2000

PUBLIC SERVICE
COMMISSION

January 6, 2000

Honorable Helen C. Helton
Executive Director
Kentucky Public Service Commission
730 Schenkel Drive
Frankfort, Kentucky 40602

Subject: The Application of Western Kentucky Gas Company for an Adjustment of Rates - Case No. 1999-070

Filing of Compliance Tariffs

Dear Ms. Helton:

Enclosed is the Compliance Tariff Filing ordered by the Commission on December 21, 1999 in the above-referenced docket, Western's rate case. The tariff pages reflect those submitted in Joint Stipulation and Settlement filed on December 3, 1999 and approved in the December 21, 1999 Order.

Please note that there are two technical corrections to the tariffs approved by the Commission included in this compliance filing. The tariff pages in question, 17 and 30D, were submitted with the proposed Settlement package on December 3, 1999.

The first correction is an error on page 17. This correction deletes the erroneous inclusion of item "e) Demand Side Management (DSM) Cost Recovery Mechanism" in the service components of the Net Monthly Rate applicable to Rate G-2 as listed on pages 16 and 17. DSM is only applicable to Residential Rate G-1 as indicated on page 30A, Section 1, and Rate G-2 is only applicable to commercial and industrial customers as indicated on page 15, Section 2.a). This correction is consistent with the proof of rates, testimony, and data request responses submitted in this case, as well as the statutes related to the DSM surcharge.

The second correction clarifies that the GRI R&D Unit Charge on page 30D changes in subsequent years. The transition schedule in the pipelines' tariffs is from 1998 to 2004, with 1998 being the baseline year. This correction is consistent with the proof of rates, testimony, and data request responses submitted in this case. In light of the Commission's letter of December 29, 1999 on GRI funding, I am also attaching workpapers demonstrating how multiple pipelines' rates were converted into one GRI rate for each year of the transition schedule based on December 1998 supply requirements. This clarification and these workpapers may be helpful to other companies wanting to better understand our approach.

We believe this filing concludes all matters pertaining to the rate case. We appreciate the professional and constructive manner by which the Commission, Staff and intervenors have participated in this proceeding.

Thank you for your assistance in this matter. If you have any questions, please feel free call me at 270-685-8072.

Sincerely yours,

William J. Senter

William J. Senter
VP Rates & Regulatory Affairs

cc: Mr. David Spenard, Office of Attorney General
Mr. Mel Caminish, Counsel for WBI Southern
Mr. M. Randy Hutchinson, Counsel for WKG
Mr. John N. Hughes, Counsel for WKG
Mr. Mark A. Martin, Senior Rate Analyst

JOHN N. HUGHES
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Professional Service Corporation
124 WEST TODD STREET
FRANKFORT, KENTUCKY 40601

Telephone:
(502) 227-7270

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(502) 875-7059

December 9, 1999

RECEIVED
DEC 09 1999
PUBLIC SERVICE
COMMISSION

Ms. Helen Helton
Executive Director
Kentucky Public Service Commission
730 Schenkel Lane
Frankfort, KY 40602

Re: Case No. 99-070

Dear Ms. Helton:

Please file the attached Response to the Commission's Order of December 6, 1999.

Thank you for your assistance, and if there are any questions about this matter or if additional information is needed, please contact me.

Sincerely Yours,

John N. Hughes

John N. Hughes
Attorney for Western Kentucky
Gas Company

cc: Intervenors

Gruber

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF)

RATE APPLICATION BY) Case No. 99-070

WESTERN KENTUCKY GAS COMPANY)

DIRECT TESTIMONY OF CONRAD E. GRUBER IN SUPPORT OF THE JOINT STIPULATION AND SETTLEMENT

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. What is the purpose of your direct testimony?

A. My testimony is in response to the Order issued on December 6, 1999 by the Kentucky Public Service Commission ("Commission") in this proceeding. The Commission's Order, issued in response to the Joint Stipulation and Settlement ("Settlement") filed by the parties in this proceeding on December 3, 1999, requested each party to the Settlement submit testimony which explains how, in each party's opinion, that the Settlement is fair, just and reasonable.

Q. As requested in the Order, please explain how the total amount of the increase in revenues proposed in the Settlement can be considered fair, just and reasonable when the total amount of increase proposed in Western's original testimony was also presented as being fair, just and reasonable.

A. Whether the amount of increase in revenues is fair, just and reasonable is a somewhat subjective determination. It is not a mathematical formula, and is a matter on which reasonable minds (and experts) can differ. The initial proposal by each party in this proceeding represented the best possible outcome based on the facts as they were understood by each of the parties at the commencement of this case. Since that time substantial data has been exchanged and the parties have engaged in extensive negotiations in an attempt to arrive at an outcome that is fair, just and reasonable to Western's ratepayers and its shareholders and an outcome which the Commission would, and should, approve. The compromise of revenues and rates which have resulted from these negotiations reflect the present best judgment of the parties (including their respective outside experts) as to what is fair, just and reasonable for Western's ratepayers and shareholders. These rates will produce sufficient revenue for Western to operate and provide the high level of service it strives for and its customers expect, while significantly modifying the financial impact on those customers.

Western's position remains that the entire increase originally filed by the Company is appropriate to restore its earnings to a level which will allow Western an opportunity to earn a fair, just and reasonable return on its investment. Nonetheless, the nature of the ratemaking process is such that a Settlement reached by the various parties in the proceeding can produce a fair, just and reasonable outcome as a result of the compromise reached by the parties.

Q. Why would the parties be willing to reach a compromise?

A. Each of the parties to the Settlement has vigorously pursued his respective positions in testimony, exhibits and responses to data requests. However, despite the sincerity of these individual positions, each party recognizes that the final outcome in this proceeding would likely result in a decision with which neither it nor the other parties would be totally satisfied. By reaching this compromise, each party has determined that the proposed Settlement outcome is preferable to other, less favorable outcomes which could result. Through negotiation each party was able to prioritize its goals in this proceeding and ensure that those priorities are reflected in the final settlement.

Q. But how does a compromise produce a fair, just and reasonable increase in revenues?

A. Each of the parties represents a unique constituency or unique combination of constituencies. By vigorously pursuing the positions of the respective constituencies in negotiation, each party has ensured that the priorities of its constituency have been recognized and protected in the Settlement. It is the vigorous representation of all constituencies in negotiations, with each party freely and voluntarily agreeing to the concessions it has made in order to guarantee its priorities are reflected in the Settlement which provides for a fair, just and reasonable increase in rates. In other words, this Settlement is a fair, just and reasonable settlement because each constituency has been vigorously represented in the negotiations and, through representation or direct involvement, has freely agreed to the final Settlement.

Q. What evidence is there for the Commission that each constituency was vigorously represented in the negotiations which led to this settlement?

A. The Settlement outcome itself reveals the sincerity of the negotiations on all sides. The record in this proceeding clearly states the positions of the parties. The Commission need only review the positions taken by the parties in this case and compare those positions to the final Settlement to determine if each constituency was vigorously represented in negotiations and made appropriate concessions to ensure its priorities were reflected in the final Settlement.

Q. Can you give an example?

A. Yes. The baseline litigation positions of the Attorney General and Western as stated in testimony were a recommended $7.4 million increase versus a proposed $14.1 million increase in revenues, respectively. While the overall increase in the final Settlement is much closer to the Attorney General's baseline litigation position than Western's, Western was able to secure some, but not all, aspects of its proposed rate design, even though much of that rate design was opposed by the Attorney General in its direct testimony. That is one example. Any settlement must be viewed in its entirety rather than evaluated on the basis of any of its individual components. This Settlement was negotiated in the context of its overall result and impact on ratepayers and shareholders, not any one particular rate issue.

Q. Are there any particular measures by which the Commission can be further assured that the increase in revenues proposed in the Settlement are fair, just and reasonable?

A. Yes. Western has submitted evidence in this proceeding demonstrating that its operating costs are the lowest in Kentucky. For example, in my original direct testimony I point out that Western's O&M costs per meter and our number of employees per 1000 customers are well below the industry average. In one of our data request responses we also point the data available on the Commission's website which demonstrates the relative efficiency of Western's operations compared to the other major gas utilities in Kentucky (KPSC DR 3-38, Schedule A). In another data request response, Western demonstrates how its recently implemented service and productivity improvement programs, investments which are an important aspect of Western's growth in rate base, produce immediate and sustainable savings for customers (Supplemental Response to KPSC DR 1-6). Given the efficiency with which Western operates and given the fact that the proposed rates are approximately 30 percent less than the increase originally proposed by Western, the Commission can be confident that the proposed rates are fair, just and reasonable.

Q. As requested in the order, please explain why the tariffs that have been included, excluded, or modified by virtue of the Settlement, are fair, just and reasonable.

A. The answer to this inquiry is largely the same as that indicated above. The tariffs reflected in the Settlement reflect a compromise between the vigorous positions taken by the parties in this case. The compromise reached ensures that the interests of the constituencies represented by each party have been prioritized and protected in the Settlement. The tariffs themselves are the means by which Western can produce the level of revenue necessary to meet its obligations. For the convenience of the Commission, a summary of the tariff changes is included with the side-by-side tariff comparisons provided as an attachment to Mr. Smith's direct testimony in support of the Joint Stipulation and Settlement.

Q. As requested in the order, please explain how the amounts proposed in the Settlement for the individual rate classes can be considered fair, just and reasonable when the distribution of the increase proposed in Western's original testimony was also presented as being fair, just and reasonable.

A. The answer to this question is the same as above. The amounts proposed in the Settlement for individual rate classes reflect a compromise between the vigorous positions taken by the parties in this case. In addition, we incorporated the tariff changes suggested in the data requests received from the Commission. For example, the Weather Normalization Adjustment is now proposed as a five-year pilot. The compromise reached ensures that the interests of the constituencies represented by each party have been prioritized and protected in the Settlement.

Q. Does this conclude your 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, 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 support of the Joint Stipulation and Settlement 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 8th day of December, 1999.

Pearl Ann Simon

Pearl Ann Simon
Notary Public
State of Kentucky At Large.

My Commission expires: September 26, 2001.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF)

RATE APPLICATION BY) Case No. 99-070

WESTERN KENTUCKY GAS COMPANY)

DIRECT TESTIMONY OF GARY L. SMITH
IN SUPPORT OF THE JOINT STIPULATION AND SETTLEMENT

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

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

Q. What is the purpose of your direct testimony?

A. My testimony is in response to the Order issued on December 6, 1999 by the Kentucky Public Service Commission ("Commission") in this proceeding. At the end of the referenced Order, the Commission requested that Western provide side-by-side comparisons of Western's tariffs proposed in its Application and the proposed tariffs included in the Settlement, and to address two additional issues relating to the proposed late payment charge.

Q. Has Western provided the requested side-by-side comparison of tariffs proposed in the Application versus those proposed in the Settlement?

A. Yes. The requested side-by-side comparison is included as Attachment GLS-A to my testimony. For the convenience of the Commission, a summary of the tariff changes is included with, and precedes, the side-by-side tariff comparisons.

Q. Please discuss the appropriateness of applying a late payment charge to only one customer classification.

A. The proposed late payment charge would not be applicable to only one customer classification. Western's late payment charge, as included in its Application and in the Settlement, applies to all customer classes served under Rate G-1 - including residential, commercial, public authority and industrial service under the referenced tariff.

Western's Firm General Sales Service, Rate G-1, is utilized by all but 188 of the customers served during the test year in this case. While Rate G-1 service is billed in conjunction with meter reading cycles throughout the month, Western's interruptible sales, transportation and carriage services are hand-billed on a calendar month basis. The Company has effectively managed the timely remittance of billing for this limited number of large consumers under services other than Rate G-1.

Q. Please discuss Western's timeliness in sending out customers' bills and whether customers should be reasonably able to remit payment within the time prescribed on their bills.

A. As stated in my pre-filed, direct testimony, Western proposes to defer implementation of the Late Payment Fee until April 2000. The rationale for the implementation timeframe was for purposes of consumer education regarding this new provision, and to afford appropriate review by the Company of its billing processes prior to implementation. The Company's sole intent for the proposed Late Payment Fee is to encourage prompt payment for services provided, and procedures will be established to ensure that this fee is applied only to those customer's whose payment is not received within a reasonable and specified time.

Under current billing processes, on the date the customer's bill is generated, a date 15 days thereafter is stated as the date payment is due to the Company. Under Western's proposed application of the Late Payment Fee, this charge "may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill." The Company would waive the assessment of the Late Payment Fee in any instance where it's billing or remittance processes were contributory to customer payments made after the due date specified on the bill. I would like to explain also that the due date specified on the bill has a very practical purpose that benefits both the Company and the customer. The Company's receipt of the customer's payment by the due date provides reasonable assurance that the payment can be processed and credited to the customer's account prior to the issuance of the subsequent month's billing.

Q. Does this conclude your 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, 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 support of the Joint Stipulation and Settlement in said case, which is true and correct to the best of my information and belief.

Gary L Smith
Gary L. Smith
Vice President, 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 8th day of December, 1999.

Pearl Ann Simon
Pearl Ann Simon
Notary Public
State of Kentucky At Large.

My Commission expires: September 26, 2001.

Attachment
GLS-A: Tariffs

WESTERN KENTUCKY GAS COMPANY
CASE NO. 99-070

SUMMARY OF TARIFF CHANGES
FROM ORIGINAL FILING TO JOINT STIPULATION AND SETTLEMENT

TARIFF SHEET	REMARKS
1	Capitalization of sub-page numbering (e.g., 29a to 29A)
4	Updates rates including current gas costs; adds footnote
5	Updates for current gas costs
6	Updates rates; revises footnote 1
11	Updates rates; adds references for application of riders
13	Deletes proposed Premises Charge
16	Updates rate
17	Updates rates; adds references for application of riders
21	Updates rates
22	Adds reference for application of MLR rider
26	Updates to reflect five-year WNA pilot
27	Changes from monthly to quarterly GCA filings
29	Changes existing page 29: quarterly GCA; adds footnote
29L	Updates MLR formula, language and clarifies applicability
30A-C	Deletes cost recovery of DSM pilot
30D	Adds actual rate with note; clarifies waiver
34	Updates rates
40	Updates rates
46	Updates rates
49	Updates rates; updates availability of service language
50	Adds waiver provision; updates imbalances language
51	Deletes proposed Premises Charge
52	Reflects new bill format; deletes proposed Premises Charge
67	Deletes proposed Premises Charge
67A	Deletes proposed page 67A

Note: All other pages remained the same as originally filed.

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Fourth Revised SHEET No. 1
Cancelling
Third Revised SHEET No. 1

WESTERN KENTUCKY GAS COMPANY

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ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter
Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Fourth Revised SHEET No. 1
Cancelling
Third Revised SHEET No. 1

WESTERN KENTUCKY GAS COMPANY

Rate Book Index

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Experimental Performance Based Rate Mechanism (PBR)	29A to 29K	
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ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter
Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Fourth Revised SHEET No. 2
Cancelling
Third Revised SHEET No. 2

WESTERN KENTUCKY GAS COMPANY

Rate Book Index

The following pages have been reserved for future use: 8-10, 14, 33, 39, 53-60 (T)

SUED: June 23, 1999 EFFECTIVE: July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Fourth Revised SHEET No. 2
Cancelling
Third Revised SHEET No. 2

WESTERN KENTUCKY GAS COMPANY

Rate Book Index

The following pages have been reserved for future use: 8-10, 14, 33, 39, 53-60 (T)

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

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PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 3
Cancelling
Original SHEET No. 3

WESTERN KENTUCKY GAS COMPANY

Towns and Communities in Service Area

The Service Area of the Company includes the following towns and their environs:

Adairville	Dennis	Hartford	Munfordsville	Sebree	
Aetnaville	Depoy	Hawesville	Niagara	Sedalia	(N)
Alton	Dermont	Heath	Nortonville	Shelby City	
Anthoston	Dixon	Hendron	Oak Ridge	Shelbyville	
Anton	Earlington	Herbert	Oakdale	Slaughters	(N)
Auburn	Eddyville	Hickory	Oakland	Smiths Grove	
Baskett	Elkton	Hill-n-dale	Oklahoma	Sorgho	
Beadlestown	Ellmitch	Hiseville	Owensboro	So. Henderson	(N)
Beaver Dam	Empire	Hopkinsville	Paducah	So. Highland	
Beda	Epley	Horse Cave	Park City	So. Union	
Beulah	Epperson	Hustonville	Perryville	Spottsville	
Boston	Evergreen	Junction City	Philpot	Springfield	
Bowling Green	Farmdale	Knottsville	Pleasant Hill	St. Charles	
Bremen	Fearsville	Lake City	Pleasant Ridge	St. Joseph	
Briartown	Feliciana	Lancaster	Plum Springs	Stanford	
Browns Valley	Finley	Lawrenceburg	Poole	Stanley	
Buck Creek	Fordsville	Lebanan	Powderly	Stringtown	
Buford	Franklin	Livia	Princeton	Summersville	
Burgin	Fredonia	Logantown	Pritchardsville	Sutherland	
Cadiz	Fruit Hill	Lone Oak	Pryorsburg	Symsonia	
Calhoun	Gilbertsville	Luzerne	Reidland	Thurston	
Calvert City	Gishton	Maceo	Reidville	Utica	
Calvary	Glasgow	Madisonville	Reynolds Sta.	Waddy	(N)
Campbellsville	Glenville	Mannington	Robards	Water Valley	
Carbondale	Grahamville	Marion	Rocky Hill	West Louisville	
Cave City	Grand Rivers	Masonville	Rome	Whitesville	
Central City	Greensberg	Mayfield	Rowletts	Wingo	
Charleston	Greenville	McGowan	Rumsey	Woodburn	
Cloverport	Habit	Memphis Junc.	Russellville	Woodlawn	
Crayne	Hanson	Midland	Sacramento	Woodsonville	
Crofton	Hardeman	Milledgeville	Salmons	Yelvington	
Danville	Hardinsburg	Moreland	Saloma	Zion	
Dawson Springs	Harned	Mortons Gap	Schochoh		
Deanfield	Harrodsburg	Mosleyville			

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 3
Cancelling
Original SHEET No. 3

WESTERN KENTUCKY GAS COMPANY

Towns and Communities in Service Area

The Service Area of the Company includes the following towns and their environs:

Adairville	Dennis	Hartford	Munfordsville	Sebree	
Aetnaville	Depoy	Hawesville	Niagara	Sedalia	(N)
Alton	Dermont	Heath	Nortonville	Shelby City	
Anthoston	Dixon	Hendron	Oak Ridge	Shelbyville	
Anton	Earlington	Herbert	Oakdale	Slaughters	(N)
Auburn	Eddyville	Hickory	Oakland	Smiths Grove	
Baskett	Elkton	Hill-n-dale	Oklahoma	Sorgho	
Beadlestown	Ellmitch	Hiseville	Owensboro	So. Henderson	(N)
Beaver Dam	Empire	Hopkinsville	Paducah	So. Highland	
Beda	Epley	Horse Cave	Park City	So. Union	
Beulah	Epperson	Hustonville	Perryville	Spottsville	
Boston	Evergreen	Junction City	Philpot	Springfield	
Bowling Green	Farmdale	Knottsville	Pleasant Hill	St. Charles	
Bremen	Fearsville	Lake City	Pleasant Ridge	St. Joseph	
Briartown	Feliciana	Lancaster	Plum Springs	Stanford	
Browns Valley	Finley	Lawrenceburg	Poole	Stanley	
Buck Creek	Fordsville	Lebanan	Powderly	Stringtown	
Buford	Franklin	Livia	Princeton	Summersville	
Burgin	Fredonia	Logantown	Pritchardsville	Sutherland	
Cadiz	Fruit Hill	Lone Oak	Pryorsburg	Symsonia	
Calhoun	Gilbertsville	Luzerne	Reidland	Thurston	
Calvert City	Gishton	Maceo	Reidville	Utica	
Calvary	Glasgow	Madisonville	Reynolds Sta.	Waddy	(N)
Campbellsville	Glenville	Mannington	Robards	Water Valley	
Carbondale	Grahamville	Marion	Rocky Hill	West Louisville	
Cave City	Grand Rivers	Masonville	Rome	Whitesville	
Central City	Greensberg	Mayfield	Rowletts	Wingo	
Charleston	Greenville	McGowan	Rumsey	Woodburn	
Cloverport	Habit	Memphis Junc	Russellville	Woodlawn	
Crayne	Hanson	Midland	Sacramento	Woodsonville	
Crofton	Hardeman	Milledgeville	Salmons	Yelvington	
Danville	Hardinsburg	Moreland	Saloma	Zion	
Dawson Springs	Harned	Mortons Gap	Schochoh		
Deanfield	Harrodsburg	Mosleyville			

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EFFECTIVE: December 15, 1999

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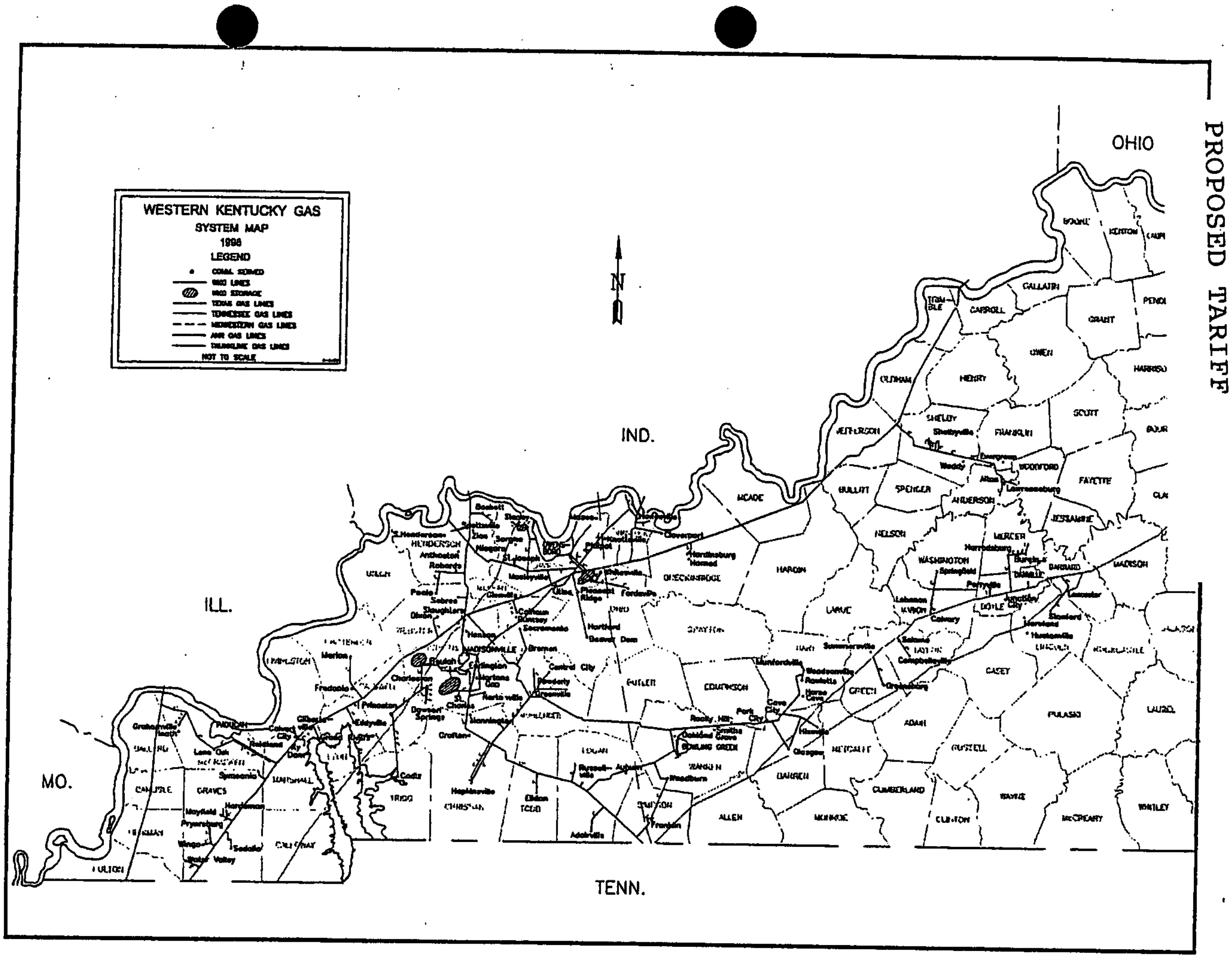
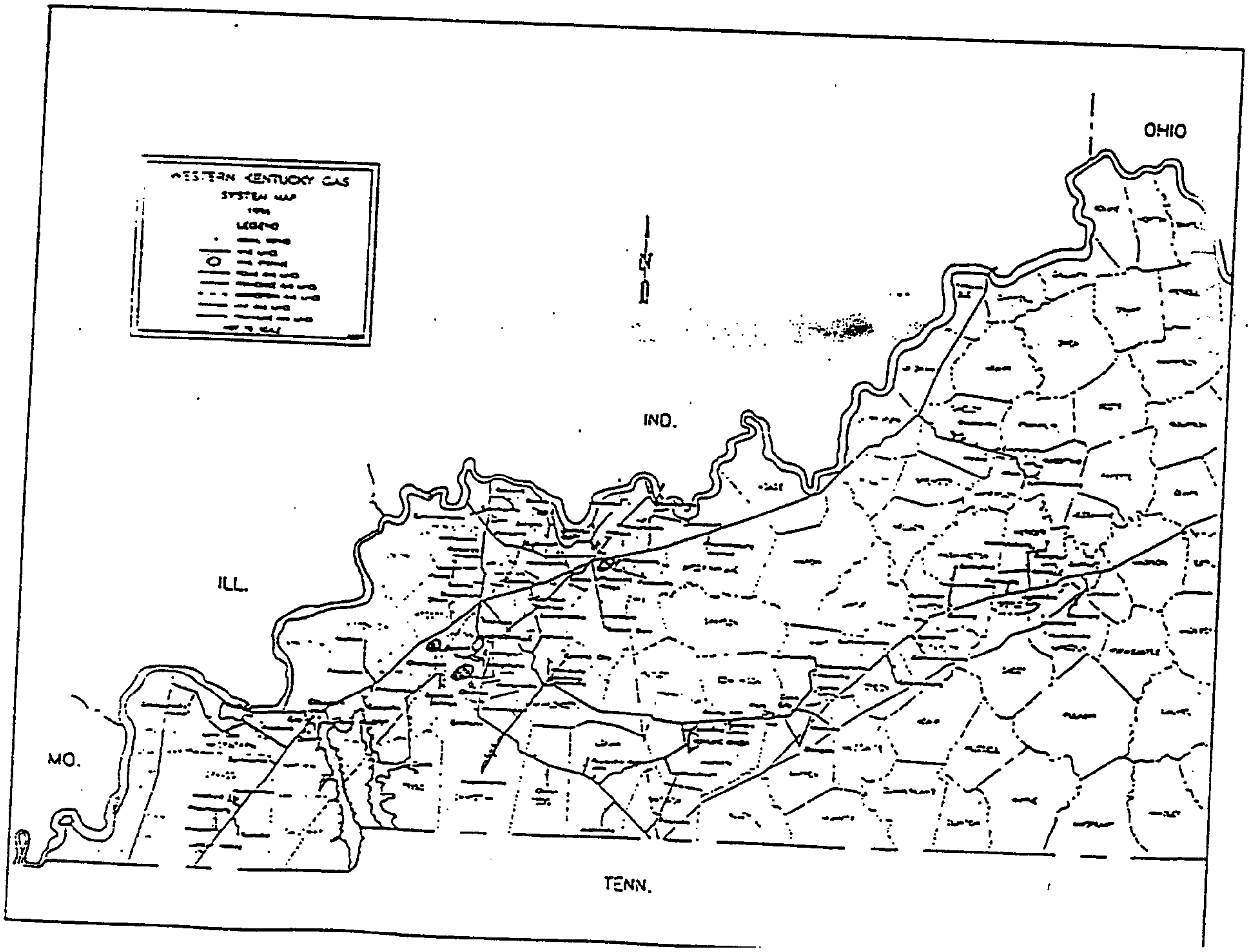
Vice President – Rates & Regulatory Affairs



PROPOSED TARIFF



SETTLEMENT TARIFF

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Seventy-First SHEET No. 4
Cancelling
Seventieth SHEET No. 4

WESTERN KENTUCKY GAS COMPANY

Current Rate Summary
Case No. 99-070

Firm Service

Base Charge:

Residential	-	$ 9.00 per meter per month	(I)
Commercial	-	24.00 per meter per month	(T,I)
Carriage (T-4)	-	250.00 per delivery point per month	(I)
Transportation Administration Fee	-	50.00 per customer per meter	(I)

Rate per Mcf			Sales (G-1)	Transport (T-2)	Carriage (T-4)	
First	300 [1]	Mcf	@ $3.7045 per Mcf	@ $1.9287 per Mcf	@ $1.2000 per Mcf	(R,I,I)
Next	14,700 [1]	Mcf	@ 3.1991 per Mcf	@ 1.4233 per Mcf	@ 0.6946 per Mcf	(R,I,I)
Over	15,000	Mcf	@ 2.9344 per Mcf	@ 1.1586 per Mcf	@ 0.4299 per Mcf	(R,I,I)

High Load Factor Firm Service

HLF demand charge/Mcf @ $4.2809 @ $4.2809 per Mcf of daily Contract Demand

Rate per Mcf					
First	300 [1]	Mcf	@ $3.1496 per Mcf	@ $1.3738 per Mcf	(R,I)
Next	14,700 [1]	Mcf	@ 2.6442 per Mcf	@ 0.8684 per Mcf	(R,I)
Over	15,000	Mcf	@ 2.3795 per Mcf	@ 0.6037 per Mcf	(R,I)

Interruptible Service

Base Charge	-	$250.00 per delivery point per month	(I)
Transportation Administration Fee	-	50.00 per customer per meter	(I)

Rate per Mcf			Sales (G-2)	Transport (T-2)	Carriage (T-4)	
First	15,000 [1]	Mcf	@ $2.5120 per Mcf	@ $0.7362 per Mcf	@ $0.5300 per Mcf	(R,I,I)
Over	15,000	Mcf	@ 2.3121 per Mcf	@ 0.5363 per Mcf	@ 0.3301 per Mcf	(R,R,R)

[1] All gas consumed by the customer (sales, transportation, and carriage; firm, high load factor, and interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

SUED: June 23, 1999 EFFECTIVE: July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Seventy-seventh SHEET No. 4
Cancelling
Seventy-sixth SHEET No. 4

WESTERN KENTUCKY GAS COMPANY

Current Rate Summary
Case No. 99-070

Firm Service

Base Charge:

Residential	-	$ 7.50 per meter per month	(I)
Non-Residential	-	20.00 per meter per month	(T,I)
Carriage (T-4)	-	220.00 per delivery point per month	(I)
Transportation Administration Fee	-	50.00 per customer per meter	(I)

Rate per Mcf[2]			Sales (G-1)	Transport (T-2)	Carriage (T-4)	
						(T)
First	300 [1]	Mcf	@ $4.6455 per Mcf	@ $1.9086 per Mcf	@ $1.1900 per Mcf	(I,I,I)
Next	14,700 [1]	Mcf	@ 4.1145 per Mcf	@ 1.3776 per Mcf	@ 0.6590 per Mcf	(I,I,I)
Over	15,000	Mcf	@ 3.8855 per Mcf	@ 1.1486 per Mcf	@ 0.4300 per Mcf	(I,I,I)

High Load Factor Firm Service

HLF demand charge/Mcf @ $4.2945 @ $4.2945 per Mcf of daily Contract Demand

Rate per Mcf[2]					
					(T)
First	300 [1]	Mcf	@ $4.0888 per Mcf	@ $1.3519 per Mcf	(I,I)
Next	14,700 [1]	Mcf	@ 3.5578 per Mcf	@ 0.8209 per Mcf	(I,I)
Over	15,000	Mcf	@ 3.3288 per Mcf	@ 0.5919 per Mcf	(I,I)

Interruptible Service

Base Charge	-	$220.00 per delivery point per month	(I)
Transportation Administration Fee	-	50.00 per customer per meter	(I)

Rate per Mcf[2]			Sales (G-2)	Transport (T-2)	Carriage (T-3)	
						(T)
First	15,000 [1]	Mcf	@ $3.4590 per Mcf	@ $0.7221 per Mcf	@ $0.5300 per Mcf	(I,I,I)
Over	15,000	Mcf	@ 3.2881 per Mcf	@ 0.5512 per Mcf	@ 0.3591 per Mcf	(I,I,I)

[1] All gas consumed by the customer (sales, transportation, and carriage; firm, high load factor, and interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

[2] DSM, GRI and MLR Riders may also apply, where applicable. (N)

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

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PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Seventy-First SHEET No. 5
Cancelling
Seventieth SHEET No. 5

WESTERN KENTUCKY GAS COMPANY

Current Rate Summary
Case No. 99-070

Applicable

For all Mcf billed under General Sales Service (G-1) and Interruptible Sales Service (G-2). (T)

Gas Charge = GCA (D)

GCA = EGC + CF + RF + PBRRF

Gas Cost Adjustment Components	G-1	HLF G-1	G-2	
EGC (Expected Gas Cost Component)	$2.7334	$2.1785	$2.1785	(R)
CF (Correction Factor)	(0.1882)	(0.1882)	(0.1882)	
RF (Refund Adjustment)	(0.0654)	(0.0654)	(0.0330)	
PBRRF (Performance Based Rate Recovery Factor)	0.0247	0.0247	0.0247	
GCA (Gas Cost Adjustment)	$2.5045	$1.9496	$1.9820	(R)

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Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Seventy-seventh SHEET No. 5
Cancelling
Seventy-sixth SHEET No. 5

WESTERN KENTUCKY GAS COMPANY

Current Gas Cost Adjustments
Case No. 99-070

Applicable

For all Mcf billed under General Sales Service (G-1) and Interruptible Sales Service (G-2). (T)

Gas Charge = GCA (D)

GCA = EGC + CF + RF + PBRRF

Gas Cost Adjustment Components	G-1	HLF G-1	G-2	
EGC (Expected Gas Cost Component)	$3.6999	$3.1432	$3.1432	(N)
CF (Correction Factor)	(0.2239)	(0.2239)	(0.2239)	
RF (Refund Adjustment)	(0.0452)	(0.0452)	(0.0150)	
PBRRF (Performance Based Rate Recovery Factor)	0.0247	0.0247	0.0247	
GCA (Gas Cost Adjustment)	$3.4555	$2.8988	$2.9290	(N)

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ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Seventy-First SHEET No. 6
Cancelling
Seventieth SHEET No. 6

WESTERN KENTUCKY GAS COMPANY

Current Rate Summary
Case No. 99-070

The General Transportation Rate T-2 and Carriage Service (Rates T-3 and T-4) for each respective service net monthly rate is a follows:

System Lost and Unaccounted gas percentage: 1.9%

			Distribution Charge		Non Commodity		Transportation Charge	(T)
Transportation Service (T-2)[1]								
a) Firm Service								
First 300 [2]	Mcf	@	$1.2000	+	$0.7287	=	$1.9287 per Mcf	(I)
Next 14,700 [2]	Mcf	@	0.6946	+	0.7287	=	1.4233 per Mcf	(I)
Over 15,000 [2]	Mcf	@	0.4299	+	0.7287	=	1.1586 per Mcf	(I)
b) High Load Factor Firm Service (HLF)								
Demand		@	$0.0000	+	4.2809	=	$4.2809 per Mcf of daily contract demand	
First 300 [2]	Mcf	@	$1.2000	+	$0.1738	=	$1.3738 per Mcf	(I)
Next 14,700 [2]	Mcf	@	0.6946	+	0.1738	=	0.8684 per Mcf	(I)
Over 15,000	Mcf	@	0.4299	+	0.1738	=	0.6037 per Mcf	(I)
c) Interruptible Service								
First 15,000 [2]	Mcf	@	$0.5300	+	$0.2062	=	$0.7362 per Mcf	(I)
All Over 15,000	Mcf	@	0.3301	+	0.2062	=	0.5363 per Mcf	(R)
Carriage Service[3]								
a) Firm Service (T-4)								
First 300 [2]	Mcf	@	$1.2000	+	$0.0000	=	$1.2000 per Mcf	(I)
Next 14,700 [2]	Mcf	@	0.6946	+	0.0000	=	0.6946 per Mcf	(I)
Over 15,000 [2]	Mcf	@	0.4299	+	0.0000	=	0.4299 per Mcf	(I)
b) Interruptible Service (T-3)								
First 15,000 [2]	Mcf	@	$0.5300	+	$0.0000	=	$0.5300 per Mcf	(I)
All Over 15,000	Mcf	@	0.3301	+	0.0000	=	0.3301 per Mcf	(R)

[1] Includes standby sales service under corresponding sales rates.

[2] All gas consumed by the customer (sales and transportation; firm, high load factor, interruptible, and carriage) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

[3] Excludes standby sales service.

ISSUED: June 23, 1999 EFFECTIVE: July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Seventy-seventh SHEET No. 6
Cancelling
Seventy-sixth SHEET No. 6

WESTERN KENTUCKY GAS COMPANY

Current Transportation and Carriage
Case No. 99-070

The General Transportation Rate T-2 and Carriage Service (Rates T-3 and T-4) for each respective service net monthly rate is a follows:

System Lost and Unaccounted gas percentage: 1.9%

			Distribution Charge		Non Commodity		Transportation Charge	(T)
Transportation Service (T-2)[1]								
a) Firm Service								
First 300 [2]	Mcf	@	$1.1900	+	$0.7186	=	$1.9086 per Mcf	(I)
Next 14,700 [2]	Mcf	@	0.6590	+	0.7186	=	1.3776 per Mcf	(I)
Over 15,000 [2]	Mcf	@	0.4300	+	0.7186	=	1.1486 per Mcf	(I)
b) High Load Factor Firm Service (HLF)								
Demand		@	$0.0000	+	4.2945	=	$4.2945 per Mcf of daily contract demand	
First 300 [2]	Mcf	@	$1.1900	+	$0.1619	=	$1.3519 per Mcf	(I)
Next 14,700 [2]	Mcf	@	0.6590	+	0.1619	=	0.8209 per Mcf	(I)
Over 15,000	Mcf	@	0.4300	+	0.1619	=	0.5919 per Mcf	(I)
c) Interruptible Service								
First 15,000 [2]	Mcf	@	$0.5300	+	$0.1921	=	$0.7221 per Mcf	(I)
All Over 15,000	Mcf	@	0.3591	+	0.1921	=	0.5512 per Mcf	(I)
Carriage Service[3]								
a) Firm Service (T-4)								
First 300 [2]	Mcf	@	$1.1900	+	$0.0000	=	$1.1900 per Mcf	(I)
Next 14,700 [2]	Mcf	@	0.6590	+	0.0000	=	0.6590 per Mcf	(I)
Over 15,000 [2]	Mcf	@	0.4300	+	0.0000	=	0.4300 per Mcf	(I)
b) Interruptible Service (T-3)								
First 15,000 [2]	Mcf	@	$0.5300	+	$0.0000	=	$0.5300 per Mcf	(I)
All Over 15,000	Mcf	@	0.3591	+	0.0000	=	0.3591 per Mcf	(I)

[1] Includes standby sales service under corresponding sales rates. GRI Rider may also apply. (T)

[2] All gas consumed by the customer (Sales and transportation; firm, high load factor, interruptible, and carriage) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

[3] Excludes standby sales service.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 11
Cancelling
Second Revised SHEET No. 11

WESTERN KENTUCKY GAS COMPANY

General Firm Sales Service
Rate G-1

1. **Applicable**

Entire Service Area of the Company.
(See list of towns – Sheet No. 3)

2. **Availability of Service**

Available for any use for individually metered service, other than auxiliary or standby service (except for hospitals or other uses of natural gas in facilities requiring emergency power, however, the rated input to such emergency power generators is not to exceed the rated input of all other gas burning equipment otherwise connected multiplied by a factor equal to 0.15) at locations where suitable service is available from the existing distribution system and an adequate supply of gas to reader service is assured by the supplier(s) of natural gas to the Company.

3. **Net Monthly Rate**

a) Base Charge
$ 9.00 per meter for residential service (I)
$24.00 per meter for non-residential service (I)
(T)

b) Distribution Charge

First[1]	300 Mcf	@	$1.2000 per 1,000 cubic feet	(I)
Next[1]	14,700 Mcf	@	0.6946 per 1,000 cubic feet	(I)
Over	15,000 Mcf	@	0.4299 per 1,000 cubic feet	(I)

c) Weather Normalization Adjustment (N)

d) Gas Cost Adjustment (GCA) Rider (T)

e) Margin Loss Recovery Rider (N)

[1] All gas consumed by the customer (Sales, Transportation, and Carriage; firm, high, load factor, interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

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ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 11
Cancelling
Second Revised SHEET No. 11

WESTERN KENTUCKY GAS COMPANY

General Firm Sales Service
Rate G-1

1. **Applicable**

Entire Service Area of the Company.
(See list of towns – Sheet No. 3)

2. **Availability of Service**

Available for any use for individually metered service, other than auxiliary or standby service (except for hospitals or other uses of natural gas in facilities requiring emergency power, however, the rated input to such emergency power generators is not to exceed the rated input of all other gas burning equipment otherwise connected multiplied by a factor equal to 0.15) at locations where suitable service is available from the existing distribution system and an adequate supply of gas to render service is assured by the supplier(s) of natural gas to the Company.

3. **Net Monthly Rate**

a) Base Charge
$ 7.50 per meter for residential service (
$20.00 per meter for non-residential service (
(

b) Distribution Charge

First[1]	300 Mcf	@	$1.1900 per 1,000 cubic feet	(
Next[1]	14,700 Mcf	@	0.6590 per 1,000 cubic feet	(
Over	15,000 Mcf	@	0.4300 per 1,000 cubic feet	(

c) Weather Normalization Adjustment, referenced on Sheet No. 26. (

d) Gas Cost Adjustment (GCA) Rider, referenced on Sheet No. 27. (

e) Margin Loss Recovery Rider, referenced on Sheet No. 291.. (

f) Demand Side Management Cost Recovery Mechanism, referenced on Sheet No. 30a. (

g) Gas Research Institute R&D Rider, referenced on Sheet No. 30d. (

[1] All gas consumed by the customer (Sales, Transportation, and Carriage; firm, high, load factor, interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 12
Cancelling
First Revised SHEET No. 12

WESTERN KENTUCKY GAS COMPANY

General Firm Sales Service
Rate G-1

4. **Net Monthly Bill**

The Net Monthly Bill shall be equal to the sum of the Base Charge, Distribution Charge, the Gas Cost Adjustment (GCA) Rider, and other riders applicable by class of service. (T)

5. **Minimum Monthly Bill**

The Base Charge plus any High Load Factor (HLF) demand charge, if applicable. (T,D)

6. **Service Period**

Open order. However, the Company may require a special written contract for large use or abnormal service requirements. This contract shall include provisions for load limitations and for curtailment or interruptions as necessary, at the discretion of the Company, to prevent the load adversely affecting firm service customers in the area.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 12
Cancelling
First Revised SHEET No. 12

WESTERN KENTUCKY GAS COMPANY

General Firm Sales Service
Rate G-1

4. **Net Monthly Bill**

The Net Monthly Bill shall be equal to the sum of the Base Charge, Distribution Charge, the Gas Cost Adjustment (GCA) Rider, and other riders applicable by class of service. (T)

5. **Minimum Monthly Bill**

The Base Charge plus any High Load Factor (HLF) demand charge, if applicable. (T,D)

6. **Service Period**

Open order. However, the Company may require a special written contract for large use or abnormal service requirements. This contract shall include provisions for load limitations and for curtailment or interruptions as necessary, at the discretion of the Company, to prevent the load adversely affecting firm service customers in the area.

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 13
Cancelling
Original SHEET No. 13
(First Substitute)

WESTERN KENTUCKY GAS COMPANY

General Firm Sales Service
Rate G-1

7. **Late Payment Charge**

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for services rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

8. **Premises Charge** (N)

New residential service connections on and after January 1, 2001 hereunder are subject to the Premises Charge described on Tariff Sheet No. 67.

9. **Rules and Regulations** (T)

Service furnished under this schedule is subject to the Company's Rules and Regulations and to applicable rate and rider schedules.

ISSUED: June 23, 1999

EFFECTIVE: July 24, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 13
Cancelling
Original SHEET No. 13
(First Substitute)

WESTERN KENTUCKY GAS COMPANY

General Firm Sales Service
Rate G-1

7. **Late Payment Charge**

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for services rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

8. **Rules and Regulations** (T)

Service furnished under this schedule is subject to the Company's Rules and Regulations and to applicable rate and rider schedules.

ISSUED: June 23, 1999

EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 15
Cancelling
First Revised SHEET No. 15

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

1. **Applicable**

Entire Service Area of the Company.
(See list of towns – Sheet No. 3)

2. **Availability of Service**

a) Available on an individually metered service basis to commercial and industrial customers for any use as approved by the Company on a strictly interruptible basis, subject to suitable service being available from the existing transmission and/or distribution facilities and when an adequate supply of gas is available to the Company under its purchase contracts with its pipeline supplier.

b) The supply of gas provided for herein shall be sold primarily on an interruptible basis, however, in certain cases and under certain conditions the contract may include High Priority service to be billed under "General Sales Service Rate G-1" limited to use and volume which, in the Company's judgement, requires and justifies such combination service.

c) The contract for service under this rate schedule shall include interruptible service or a combination of High Priority service and Interruptible service, however, the Company reserves the right to limit the volume of High Priority service available to any one customer.

3. **Delivery Volumes**

(T,N)

a) The volume of gas to be sold and purchases under this rate schedule shall be set forth in a written contract, specifying a maximum daily interruptible sales service volume and shall be subject to revision in accordance with the Company's approved curtailment plan.

ISSUED: June 23, 1999

EFFECTIVE: July 24, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 15
Cancelling
First Revised SHEET No. 15

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

1. **Applicable**

Entire Service Area of the Company.
(See list of towns – Sheet No. 3)

2. **Availability of Service**

a) Available on an individually metered service basis to commercial and industrial customers for any use as approved by the Company on a strictly interruptible basis, subject to suitable service being available from the existing transmission and/or distribution facilities and when an adequate supply of gas is available to the Company under its purchase contracts with its pipeline supplier.

b) The supply of gas provided for herein shall be sold primarily on an interruptible basis, however, in certain cases and under certain conditions the contract may include High Priority service to be billed under "General Sales Service Rate G-1" limited to use and volume which, in the Company's judgement, requires and justifies such combination service.

c) The contract for service under this rate schedule shall include interruptible service or a combination of High Priority service and Interruptible service, however, the Company reserves the right to limit the volume of High Priority service available to any one customer.

3. **Delivery Volumes**

(T,N)

a) The volume of gas to be sold and purchases under this rate schedule shall be set forth in a written contract, specifying a maximum daily interruptible sales service volume and shall be subject to revision in accordance with the Company's approved curtailment plan

ISSUED: June 23, 1999

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ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 16
Cancelling
First Revised SHEET No. 16

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

b) High Priority Service
The volume for High Priority service shall be established on a High Priority Daily Contract Demand basis which shall be the maximum quantity the Company is obligated to deliver and which the customer may receive in any one day, subject to other provisions of this rate schedule and the related contract.

c) Interruptible Service
The volume for Interruptible service shall be established on an Interruptible Daily Contract Demand basis which shall be the maximum quantity the Company is obligated to deliver and which the customer may receive subject to other provisions of this rate schedule and the related contract.

d) Revision of Delivery Volumes
The Daily Contract Demand for High Priority service and the Daily Contract Demand for Interruptible service shall be subject to revision as necessary so as to coincide with the customer's normal operating conditions and actual load with consideration given to any anticipated changes in customer's utilization, subject to the Company's contractual obligations with other customers or its suppliers, and subject to system capacity and availability of the gas if an increased volume is involved.

4. Net Monthly Rate

a) Base Charge: $250.00 per delivery point per month (I)
Minimum Charge: The Base Charge plus any Transportation Fee and EFM facilities charge

b) Distribution Charge: (T)

High Priority Service
The volume of gas used each day up to, but not exceeding the effective High Priority Daily Contract Demand shall be totaled for the month and billed at the "General Firm Sales Service Rate G-1".

ISSUED: June 23, 1999 EFFECTIVE: July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 16
Cancelling
First Revised SHEET No. 16

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

b) High Priority Service
The volume for High Priority service shall be established on a High Priority Daily Contract Demand basis which shall be the maximum quantity the Company is obligated to deliver and which the customer may receive in any one day, subject to other provisions of this rate schedule and the related contract.

c) Interruptible Service
The volume for Interruptible service shall be established on an Interruptible Daily Contract Demand basis which shall be the maximum quantity the Company is obligated to deliver and which the customer may receive subject to other provisions of this rate schedule and the related contract.

d) Revision of Delivery Volumes
The Daily Contract Demand for High Priority service and the Daily Contract Demand for Interruptible service shall be subject to revision as necessary so as to coincide with the customer's normal operating conditions and actual load with consideration given to any anticipated changes in customer's utilization, subject to the Company's contractual obligations with other customers or its suppliers, and subject to system capacity and availability of the gas if an increased volume is involved.

4. Net Monthly Rate

a) Base Charge: $220.00 per delivery point per month (I
Minimum Charge: The Base Charge plus any Transportation Fee and EFM facilities charge

b) Distribution Charge: (T

High Priority Service
The volume of gas used each day up to, but not exceeding the effective High Priority Daily Contract Demand shall be totaled for the month and billed at the "General Firm Sales Service Rate G-1".

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 17
Cancelling
First Revised SHEET No. 17

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

Interruptible Service

Gas used per month in excess of the High Priority Service shall be billed as follows:

First 15,000 Mcf	$0.5300 per 1,000 cubic feet	(I)
Over 15,000 Mcf	0.3301 per 1,000 cubic feet	(I)

c) Gas Cost Adjustment (GCA) Rider (N)

d) Margin Loss Recovery Rider (D)

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[1] All gas consumed by the customer (Sales, Transportation, and Carriage; firm, high, load factor, interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 17
Cancelling
First Revised SHEET No. 17

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

Interruptible Service

Gas used per month in excess of the High Priority Service shall be billed as follows:

First 15,000 Mcf	$0.5300 per 1,000 cubic feet	(
Over 15,000 Mcf	0.3591 per 1,000 cubic feet	(

c) Gas Cost Adjustment (GCA) Rider, referenced on Sheet No. 26. (

d) Margin Loss Recovery Rider, referenced on Sheet No. 29L. (

e) Demand Side Management Cost Recovery Mechanism, referenced on Sheet No. 30a. (

f) Gas Research Institute R&D Rider, referenced on Sheet No. 30d. (

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[1] All gas consumed by the customer (Sales, Transportation, and Carriage; firm, high, load factor, interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 18
Cancelling
Original SHEET No. 18

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

5. Standby or Auxiliary Equipment and Fuel (D) (T)

It shall be the responsibility of the customer to provide and maintain such stand-by, auxiliary equipment and fuel, as the customer may, in its discretion, require to protect its fuel requirements and best interest and to assure continuous operation during any period of interruption of gas deliveries.

(D)

6. Alternative Fuel Responsive Flex Provision (N)

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the otherwise applicable rate on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request.

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

ISSUED: June 23, 1999
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ISSUED BY: William J. Senter
Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 18
Cancelling
Original SHEET No. 18

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

5. Standby or Auxiliary Equipment and Fuel

It shall be the responsibility of the customer to provide and maintain such stand-by, auxiliary equipment and fuel, as the customer may, in its discretion, require to protect its fuel requirements and best interest and to assure continuous operation during any period of interruption of gas deliveries.

6. Alternative Fuel Responsive Flex Provision

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the otherwise applicable rate on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request.

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

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EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter
Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 19
Cancelling
Original SHEET No. 19

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

(D)
(T)

7. **Curtailment**

(C) All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission and for any causes due to force majeure (which includes acts of God, strikes, lockouts, civil commotion, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, etc.); and for any other necessary or expedient reason at the discretion of the Company.

8. **Penalty for Unauthorized Overruns** (N)

a) In the event a customer fails in part or in whole to comply with a Company Curtailment Order either as to time or volume of gas used or uses a greater quantity of gas than its allowed volume under terms of the Curtailment Order, the Company may, at its sole discretion, apply a penalty rate of up to $15.00 per Mcf.

b) In addition to other tariff penalty provisions, the customer shall be responsible for any penalty(s) assessed by the interstate pipeline(s) or suppliers resulting from the customer's failure to comply with terms of a Company Curtailment Order.

c) The payment of penalty charges shall not be considered as giving any customer the right to take unauthorized volumes of gas nor shall such penalty charges be considered as a substitute for any other remedy available to the Company.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 19
Cancelling
Original SHEET No. 19

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

7. **Curtailment** (D)
(T)

(C) All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission and for any causes due to force majeure (which includes acts of God, strikes, lockouts, civil commotion, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, etc.); and for any other necessary or expedient reason at the discretion of the Company.

8. **Penalty for Unauthorized Overruns** (N)

a) In the event a customer fails in part or in whole to comply with a Company Curtailment Order either as to time or volume of gas used or uses a greater quantity of gas than its allowed volume under terms of the Curtailment Order, the Company may, at its sole discretion, apply a penalty rate of up to $15.00 per Mcf.

b) In addition to other tariff penalty provisions, the customer shall be responsible for any penalty(s) assessed by the interstate pipeline(s) or suppliers resulting from the customer's failure to comply with terms of a Company Curtailment Order.

c) The payment of penalty charges shall not be considered as giving any customer the right to take unauthorized volumes of gas nor shall such penalty charges be considered as a substitute for any other remedy available to the Company.

ISSUED: June 23, 1999 **EFFECTIVE:** December15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 20
Cancelling
Original SHEET No. 20
(First Substitute)

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

9. **Special Provisions** (T)

a) A written contract with a minimum term of one year shall be required.

b) The Rules and Regulations and Orders of the Public Service Commission and of the Company and the Company's general terms and conditions applicable to industrial and commercial sales, shall apply to this rate schedule and all contracts thereunder.

c) No gas delivered under this rate schedule and applicable contract shall be available for resale.

10. **Late Payment Charge** (T)

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

ISSUED: June 23, 1999
EFFECTIVE: July 24, 1999

ISSUED BY: William J. Senter
Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 20
Cancelling
Original SHEET No. 20
(First Substitute)

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

9. **Special Provisions** (T

a) A written contract with a minimum term of one year shall be required.

b) The Rules and Regulations and Orders of the Public Service Commission and of the Company and the Company's general terms and conditions applicable to industrial and commercial sales, shall apply to this rate schedule and all contracts thereunder.

c) No gas delivered under this rate schedule and applicable contract shall be available for resale.

10. **Late Payment Charge** (T

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

ISSUED: June 23, 1999
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ISSUED BY: William J. Senter
Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 21
Cancelling
Second Revised SHEET No. 21

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

1. **Applicable**

Entire Service Area of the Company.
(See list of towns – Sheet No. 3)

2. **Availability of Service**

Available to any customer (with an expected demand of at least 36,500 Mcf per year) where usage is individually metered at locations where suitable service is available from the existing distribution system and an adequate supply of gas to render service is assured by the supplier(s) of natural gas to the Company. Except as provided in the service agreement, LVS service is not available in conjunction with any other tariffed gas service.

3. **Net Monthly Rate**

a) Base Charge:

LVS-1 Service	[illegible] 24.00 per Meter	(I)
LVS-2 Service	250.00 per Meter	(I)
Combined Service	250.00 per Meter	(I)

b) Distribution Charge for LVS-1 Service (T)

First[1]	300 Mcf	@	$1.2000 per Mcf	(I)
Next[1]	14,700 Mcf	@	0.6946 per Mcf	(I)
Over	15,000 Mcf	@	0.4299 per Mcf	(I)

c) Distribution Charge for LVS-2 Service (T)

First[1]	15,000 Mcf	@	$0.5300 per Mcf	(I)
Over	15,000 Mcf	@	0.3301 per Mcf	(I)

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[1] All gas consumed by the customer (Sales, Transportation, and Carriage; firm, high, load factor, interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 21
Cancelling
Second Revised SHEET No. 21

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

1. **Applicable**

Entire Service Area of the Company.
(See list of towns – Sheet No. 3)

2. **Availability of Service**

Available to any customer (with an expected demand of at least 36,500 Mcf per year) where usage is individually metered at locations where suitable service is available from the existing distribution system and an adequate supply of gas to render service is assured by the supplier(s) of natural gas to the Company. Except as provided in the service agreement, LVS service is not available in conjunction with any other tariffed gas service.

3. **Net Monthly Rate**

a) Base Charge:

LVS-1 Service	$ 20.00 per Meter	(I)
LVS-2 Service	220.00 per Meter	(I)
Combined Service	220.00 per Meter	(I)

b) Distribution Charge for LVS-1 Service (T)

First[1]	300 Mcf	@	$1.1900 per Mcf	(I)
Next[1]	14,700 Mcf	@	0.6590 per Mcf	(I)
Over	15,000 Mcf	@	0.4300 per Mcf	(I)

c) Distribution Charge for LVS-2 Service (T)

First[1]	15,000 Mcf	@	$0.5300 per Mcf	(I)
Over	15,000 Mcf	@	0.3591 per Mcf	(I)

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[1] All gas consumed by the customer (Sales, Transportation, and Carriage; firm, high, load factor, interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 22
Cancelling
First Revised SHEET No. 22

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales

Rates LVS-1 (High Priority), LVS-2 (Low Priority)

d) The Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

e) The Weighted Average Commodity Gas Cost is based on current purchase costs including all related variable delivery costs for the billing period for which the gas was delivered.

f) The True-Up Adjustment shall be customer account specific and shall include all prior period adjustments known at time of billing.

g) Notice of the Weighted Average Commodity Gas Cost and True-Up Adjustment will be filed with the Commission prior to billing.

h) Margin Loss Recovery Rider (N)

4. **Net Monthly Bill** (T)

The Net Monthly Bill shall be equal to the sum of the Base Charge, the High Load Factor demand charge, the Distribution Charge, the Non-Commodity Component, the Weighted Average Commodity Gas Cost and the True-Up Adjustment.

5. **Minimum Monthly Bill** (T,D)

The Base Charge and High Load Factor demand charge, if applicable.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 22
Cancelling
First Revised SHEET No. 22

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales

Rates LVS-1 (High Priority), LVS-2 (Low Priority)

d) The Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

e) The Weighted Average Commodity Gas Cost is based on current purchase costs including all related variable delivery costs for the billing period for which the gas was delivered.

f) The True-Up Adjustment shall be customer account specific and shall include all prior period adjustments known at time of billing.

g) Notice of the Weighted Average Commodity Gas Cost and True-Up Adjustment will be filed with the Commission prior to billing.

h) Margin Loss Recovery Rider, referenced on Sheet No. 29L. (I

4. **Net Monthly Bill** (

The Net Monthly Bill shall be equal to the sum of the Base Charge, the High Load Factor demand charge, the Distribution Charge, the Non-Commodity Component, the Weighted Average Commodity Gas Cost and the True-Up Adjustment.

5. **Minimum Monthly Bill** (T.

The Base Charge and High Load Factor demand charge, if applicable.

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ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 23
Cancelling
Original SHEET No. 23

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

(D)

6. **Standby or Auxiliary Equipment and Fuel**

It shall be the responsibility of the customer to provide and maintain such stand-by, auxiliary equipment and fuel, as the customer may, in its discretion, require to protect its fuel requirements and best interest and to assure continuous operation during any period of interruption of gas deliveries.

7. **Alternative Fuel Responsive Flex Provision (LVS-2 Service Only)** (T)

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the otherwise applicable distribution charge on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request.

Pursuant to this Section, the Company may flex the applicable Distribution Charge to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component and weighted average commodity gas cost of the customer's otherwise applicable rate. (T)

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 23
Cancelling
Original SHEET No. 23

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

(I

6. **Standby or Auxiliary Equipment and Fuel**

It shall be the responsibility of the customer to provide and maintain such stand-by, auxiliary equipment and fuel, as the customer may, in its discretion, require to protect its fuel requirements and best interest and to assure continuous operation during any period of interruption of gas deliveries.

7. **Alternative Fuel Responsive Flex Provision (LVS-2 Service Only)** (1

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the otherwise applicable distribution charge on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request.

Pursuant to this Section, the Company may flex the applicable Distribution Charge to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component and weighted average commodity gas cost of the customer's otherwise applicable rate. (T

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

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PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 24
Cancelling
Original SHEET No. 24

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

8. Curtailment (N)

All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission and for any causes due to force majeure (which includes acts of God, strikes, lockouts, civil commotion, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, etc.); and for any other necessary or expedient reason at the discretion of the Company.

9. Penalty for Unauthorized Overruns (N)

a) In the event a customer fails in part or in whole to comply with a Company Curtailment Order either as to time or volume of gas used or uses a greater quantity of gas than its allowed volume under terms of the Curtailment Order, the Company may, at its sole discretion, apply a penalty rate of up to $15.00 per Mcf.

b) In addition to other tariff penalty provisions, the customer shall be responsible for any penalty(s) assessed by the interstate pipeline(s) or suppliers resulting from the customer's failure to comply with terms of a Company Curtailment Order.

c) The payment of penalty charges shall not be considered as giving any customer the right to take unauthorized volumes of gas nor shall such penalty charges be considered as a substitute for any other remedy available to the Company.

10. Service Agreement

The Company will require a written contract for a minimum term of twelve months. This contract shall include provisions for load limitations and for curtailment or interruptions as necessary, at the discretion of the Company, to prevent the load adversely affecting service of equal or higher priority customers in the area. (D)

A customer with an unexpired contract for other services may subscribe to LVS service by contract amendment provided the contract, as amended, has a remaining term of at least twelve months.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 24
Cancelling
Original SHEET No. 24

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

8. Curtailment (

All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission and for any causes due to force majeure (which includes acts of God, strikes, lockouts, civil commotion, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, etc.); and for any other necessary or expedient reason at the discretion of the Company.

9. Penalty for Unauthorized Overruns (

a) In the event a customer fails in part or in whole to comply with a Company Curtailment Order either as to time or volume of gas used or uses a greater quantity of gas than its allowed volume under terms of the Curtailment Order, the Company may, at its sole discretion, apply a penalty rate of up to $15.00 per Mcf.

b) In addition to other tariff penalty provisions, the customer shall be responsible for any penalty(s) assessed by the interstate pipeline(s) or suppliers resulting from the customer's failure to comply with terms of a Company Curtailment Order.

c) The payment of penalty charges shall not be considered as giving any customer the right to take unauthorized volumes of gas nor shall such penalty charges be considered as a substitute for any other remedy available to the Company.

10. Service Agreement

The Company will require a written contract for a minimum term of twelve months. This contract shall include provisions for load limitations and for curtailment or interruptions as necessary, at the discretion of the Company, to prevent the load adversely affecting service of equal or higher priority customers in the area. (

A customer with an unexpired contract for other services may subscribe to LVS service by contract amendment provided the contract, as amended, has a remaining term of at least twelve months.

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J Senter Vice President Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 25
Cancelling
Original SHEET No. 25

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

The volume of gas to be sold and purchased under this rate schedule and the related contract shall be established on a daily, monthly and seasonal basis. The priority of contract volumes shall be subject to revision in accordance with the Company's approved curtailment plan.

The contract volumes (or service mix) shall be subject to revision by the Company as appropriate so as to coincide with the customer's normal operating conditions and actual load with consideration give to any reasonably anticipated changes in customer's utilization, subject to the Company's contractual obligations with other customers or its suppliers, and subject to system capacity and availability of the gas if an increased volume is involved.

11. Late Payment Charge (T)

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

12. Exit Fee (T)

When service under this schedule is discontinued, the customer is responsible for (or entitled to) an exit fee (or refund) equal to the lagging true-up adjustments related to the customer's service period.

13. Rules and Regulations (T)

Service furnished under this schedule and applicable contracts are subject to the Company's Rules and Regulations and to applicable rate and rider schedules.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 25
Cancelling
Original SHEET No. 25

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

The volume of gas to be sold and purchased under this rate schedule and the related contract shall be established on a daily, monthly and seasonal basis. The priority of contract volumes shall be subject to revision in accordance with the Company's approved curtailment plan.

The contract volumes (or service mix) shall be subject to revision by the Company as appropriate so as to coincide with the customer's normal operating conditions and actual load with consideration give to any reasonably anticipated changes in customer's utilization, subject to the Company's contractual obligations with other customers or its suppliers, and subject to system capacity and availability of the gas if an increased volume is involved.

11. Late Payment Charge (T)

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

12. Exit Fee (T)

When service under this schedule is discontinued, the customer is responsible for (or entitled to) an exit fee (or refund) equal to the lagging true-up adjustments related to the customer's service period.

13. Rules and Regulations (T)

Service furnished under this schedule and applicable contracts are subject to the Company's Rules and Regulations and to applicable rate and rider schedules.

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 26
Cancelling
Original SHEET No. 26

WESTERN KENTUCKY GAS COMPANY

Weather Normalization Adjustment Rider
WNA

(N)

1. Applicable

Applicable to Rate G-1 Sales Service, excluding industrial class only.

The distribution charge per Mcf for gas service as set forth in G-1 Sales Service shall be adjusted by an amount hereinunder described as the Weather Normalization Adjustment (WNA). The WNA shall be applicable to Rate G-1 Sales Service, excluding Industrial Sales Service.

The WNA shall apply to all residential, commercial and public authority bills based on meters read during the months of November through April. The WNA shall increase or decrease accordingly by month. The WNA will not be billed to reflect meters read during the months of May through October. Customer base loads and heating sensitivity factors will be determined by class and computed annually.

2. Computation of Weather Normalization Adjustment

The WNA shall be computed using the following formula:

$$WNA_i = R_i \frac{(HSF_i \quad (NDD - ADD)\ )}{(BL_i + \quad (HSF_i \text{ x } ADD)\ )}$$

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

NDD = normal billing cycle heating degree days

ADD = actual billing cycle heating degree days

BL_i = base load for the ith schedule or classification

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 26
Cancelling
Original SHEET No. 26

WESTERN KENTUCKY GAS COMPANY

Weather Normalization Adjustment Rider
WNA

(N

1. Applicable

Applicable to Rate G-1 Sales Service, excluding industrial class only.

The distribution charge per Mcf for gas service as set forth in G-1 Sales Service shall be adjusted by an amount hereinunder described as the Weather Normalization Adjustment (WNA). The WNA shall be applicable to Rate G-1 Sales Service, excluding Industrial Sales Service.

For a five year period commencing on November 1, 2000, the WNA shall apply to all residential, commercial and public authority bills based on meters read during the months of November through April. The WNA shall increase or decrease accordingly by month. The WNA will not be billed to reflect meters read during the months of May through October. Customer base loads and heating sensitivity factors will be determined by class and computed annually.

2. Computation of Weather Normalization Adjustment

The WNA shall be computed using the following formula:

$$WNA_i = R_i \frac{(HSF_i \quad (NDD - ADD)\ )}{(BL_i + \quad (HSF_i \text{ x } ADD)\ )}$$

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

NDD = normal billing cycle heating degree days

ADD = actual billing cycle heating degree days

BL_i = base load for the ith schedule or classification

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 27
Cancelling
First Revised SHEET No. 27

WESTERN KENTUCKY GAS COMPANY

Gas Cost Adjustment
Rider GCA

1. Applicable

Gas Tariffs in effect for the entire Service Area of the Company as designated in the particular tariff.

2. Gas Cost Adjustment (GCA)

The Company shall file a Monthly Report with the Commission which shall contain an updated Gas Cost Adjustment (GCA) at least thirty (30) days prior to the beginning of each month. The GCA shall become effective for meter readings on and after the first day of the month.

3. Determination of GCA

The monthly amount computed under each of the rate schedules to which this GCA is applicable shall be increased or decreased at a rate per Mcf calculated for each billing month in accordance with the following formula as applicable to each rate class:

GCA = EGC + CF + RF (T,D)

Where:

EGC – is the weighted average Expected Gas Cost per Mcf of gas supply which is reasonably expected to be experienced during the month the GCA will be applied for billings.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 27
Cancelling
First Revised SHEET No. 27

WESTERN KENTUCKY GAS COMPANY

Gas Cost Adjustment
Rider GCA

1. Applicable

Gas Tariffs in effect for the entire Service Area of the Company as designated in the particular tariff.

2. Gas Cost Adjustment (GCA)

The Company shall file a Quarterly Report with the Commission which shall contain an updated Gas Cost Adjustment (GCA) at least thirty (30) days prior to the beginning of each quarter. The quarterly GCA shall become effective in the months of February, May, August, and November. The GCA shall become effective for meter readings on and after the first day of the quarter. The Company may make out of time filings when warranted.

3. Determination of GCA

The amount computed under each of the rate schedules to which this GCA is applicable shall be increased or decreased at a rate per Mcf calculated for each billing quarter in accordance with the following formula as applicable to each rate class:

GCA = EGC + CF + RF

Where:

EGC – is the weighted average Expected Gas Cost per Mcf of gas supply which is reasonably expected to be experienced during the quarter the GCA will be applied for billings.

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 28
Cancelling
Second Revised SHEET No. 28

WESTERN KENTUCKY GAS COMPANY

Gas Cost Adjustment
Rider GCA

EGC is composed of the following:

1) Expected commodity costs of all current purchases at reasonably expected prices, including all related variable delivery costs and FERC authorized charges (i.e., take-or-pay, transition costs, etc.) billed to the Company on a commodity basis.

2) Expected non-commodity costs including pipeline demand charges, gas supplier reservation charges, and FERC authorized charges (i.e., take-or-pay, transition costs, etc.) billed to the Company on a non-commodity basis.

3) The cost of other gas sources for system supply (no-notice supply, Company storage, withdrawals, etc.).

Less

4) The cost of gas purchases expected to be injected into underground storage.

5) Projected recovery of non-commodity costs and Lost and Unaccounted for costs from transportation transactions.

6) Projected recovery of non-commodity and commodity costs from LVS-1 and LVS-2 transactions.

7) The cost of Company-use volumes.

8) Projected recovery of non-commodity costs from High Load Factor (HLF) demand charges.

(D)

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 28
Cancelling
Second Revised SHEET No. 28

WESTERN KENTUCKY GAS COMPANY

Gas Cost Adjustment
Rider GCA

EGC is composed of the following:

1) Expected commodity costs of all current purchases at reasonably expected prices, including all related variable delivery costs and FERC authorized charges (i.e., take-or-pay, transition costs, etc.) billed to the Company on a commodity basis.

2) Expected non-commodity costs including pipeline demand charges, gas supplier reservation charges, and FERC authorized charges (i.e., take-or-pay, transition costs, etc.) billed to the Company on a non-commodity basis.

3) The cost of other gas sources for system supply (no-notice supply, Company storage, withdrawals, etc.).

Less

4) The cost of gas purchases expected to be injected into underground storage.

5) Projected recovery of non-commodity costs and Lost and Unaccounted for costs from transportation transactions.

6) Projected recovery of non-commodity and commodity costs from LVS-1 and LVS-2 transactions.

7) The cost of Company-use volumes.

8) Projected recovery of non-commodity costs from High Load Factor (HLF) demand charges.

(D)

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

A change was not originally proposed to this page.

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 29
Cancelling
First Revised SHEET No. 29

WESTERN KENTUCKY GAS COMPANY

Gas Cost Adjustment
Rider GCA

CF - is the Correction Factor per Mcf which compensates for the difference between the expected gas cost and the actual gas cost for prior periods.

The Company shall file an updated Correction Factor (CF) in its April and October GCA filings, to become effective in May and November respectively. The April filing shall update the CF for the six months ended January while the October filing shall update the CF for the six months ended July.[1] (T

RF - is the sum of any Refund Factors filed in the current and three preceding quarterly filings. The current Refund Factor reflects refunds received from suppliers during the reporting period. The Refund Factor will be determined by dividing the refunds received plus estimated interest[2], by the annual sales used in the quarterly filing less transported volumes. After a refund factor has remained in effect for twelve months, the difference in the amount received and the amount refunded plus the accrued interest[2] will be rolled into the next refund calculation. The refund account will be operated independently of the CF and only added as a component to the GCA in order to obtain a net GCA. In the event of any large or unusual refunds, the Company may apply to the Commission for the right to depart from the refund procedure herein set forth. (T)

[1] The April GCA filing effective May 2000 shall update the CF for the seven months ended January 2000 to account for the change in methodology ordered in Case No. 99-070. (N)

[2] At a rate equal to the average of the "3-Month Commercial Paper Rates" for the immediately preceding 12-month period less ½ or 1% to cover the costs of refunding as stated in the KPSC Order from Case No. 7157-KK. These monthly rates are reported in both the Federal Reserve Bulletin and the Federal Reserve Statistical Release.

4. High Load Factor (HLF) Option

Customer with daily contract demands for firm service of 240 Mcf or greater may elect to contract for High Load Factor (HLF) service and will be applicable to G-1, LVS-1, and T-2/G-1 services. (T)

The HLF option provides for billing of the non-commodity costs in the EGC applicable only to firm service on the basis of daily contract demand rather than on a commodity basis.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995).

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Original SHEET No. 29L

WESTERN KENTUCKY GAS COMPANY

Margin Loss Recovery Rider
MLR

(N)

Intent

This Margin Loss Recovery Rider is intended to authorize the Company to recover 90% of distribution charge losses that result from (1) discounts pursuant to the Alternate Fuel Responsive Flex Provision, or, (2) special contracts approved by the Public Service Commission of Kentucky.

Calculation of the Margin Loss Recovery Factor

The Margin Loss Recovery Factor will be calculated in accordance with the following formula:

$$MLR = \frac{(NGPM - AGPM) \times .9}{S}$$

Where:

MLR is the Margin Loss Recovery Factor

NGPM is the normally applicable distribution charges

AGPM is the actual distribution charges under Flex Sales or Transportation transactions, or, as stated in the special contract

S is the expected sales volumes as used in the Correcting Factor of the Gas Cost Adjustment Rider

Filing with the Public Service Commission of Kentucky

The MLR shall be filed every March and September, to become effective in April and October, respectively. The March filing shall update the MLR for the six months ended December period while the September filing shall update the MLR for the six months ended June period.

ISSUED: June 23, 1999

EFFECTIVE: July 24, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Original SHEET No. 29L

WESTERN KENTUCKY GAS COMPANY

Margin Loss Recovery Rider
MLR

(N

1. Applicable

Applicable to tariff Sales Service Rates G-1, G-2, LVS-1 and LVS-2. This Margin Loss Recovery Rider is intended to authorize the Company to recover 50% of distribution charge losses that result from (1) discounts pursuant to the Alternate Fuel Responsive Flex Provision, (2) special contracts approved by the Public Service Commission of Kentucky, or (3) a customer's bypass of the Company's system.

2. Calculation of the Margin Loss Recovery Factor

The Margin Loss Recovery Factor will be calculated in accordance with the following formula:

$$MLR = \frac{(ML_f + ML_s + ML_b) \times .5}{S}$$

Where:

MLR is the Margin Loss Recovery Factor

ML_f is the sum of discounts pursuant to the Alternate Fuel Responsive Flex Provision, calculated by multiplying the discount below the customer's otherwise applicable distribution charge times the volumes delivered under the flex provision.

ML_s is the sum of discounts pursuant to special contracts implemented subsequent to Case 99-070, calculated by multiplying the discount below the customer's otherwise applicable distribution charge times the customer's volumes in the test year for Case 99-070 or the customer's current annual volumes (whichever is less).

ML_b is the sum of margin losses associated with customer bypass of the Company's system subsequent to Case 99-070, equaling the total margin attributable to the customer during the test year for Case 99-070.

S is the expected sales volumes as used in the Correcting Factor of the Gas Cost Adjustment Rider

Filing with the Public Service Commission of Kentucky

The MLR shall be filed every January and July, to become effective in February and August, respectively. The February filing shall update the MLR for the six months ended November period while the August filing shall update the MLR for the six months ended May period.

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ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Original SHEET No. 30A

WESTERN KENTUCKY GAS COMPANY

Demand-Side Management Cost Recovery Mechanism
DSM

(N)

1. Applicable

Applicable to Rate G-1 Sales Service, residential class only.

The monthly Distribution Charge under Residential Rate G-1 Sales Service, shall be increased or decreased annually beginning January 2000 by the DSM Cost Recovery Component (DSMRC) at a rate per Mcf in accordance with the following formula:

$$DSMRC = DCRC + DCRP + DBA$$

Where:

DCRC = DSM Cost Recovery-Current. The DCRC shall include all projected costs for the next twelve-month period. These costs shall be limited to expected payments to program implementation contractors over that period, as well as any costs incurred by or on behalf of the DSM collaborative process. These costs would be divided by the expected Mcf sales for the upcoming twelve-month period to determine the DCRC.

DCRP = DSM Cost Recovery-Pilot. The DCRP shall include all costs associated with the implementation of the DSM Pilot program. These costs include payments to implementation contractors, as well as costs incurred on behalf of the collaborative process, including consultants. These costs shall be amortized over a three-year period beginning January 2000 through December 2002. The costs to be amortized over the upcoming twelve-month period shall be divided by the expected Mcf sales for the upcoming twelve-month period to determine the DCRP.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Original SHEET No. 30A

WESTERN KENTUCKY GAS COMPANY

Demand-Side Management Cost Recovery Mechanism
DSM

(N)

1. Applicable

Applicable to Rate G-1 Sales Service, residential class only.

The Distribution Charge under Residential Rate G-1 Sales Service, shall be increased or decreased for three annual periods beginning January 2000 by the DSM Cost Recovery Component (DSMRC) at a rate per Mcf in accordance with the following formula:

$$DSMRC = DCRC + DBA$$

Where:

DCRC = DSM Cost Recovery-Current. The DCRC shall include all projected costs for the next twelve-month period. These costs shall be limited to expected payments to program implementation contractors over that period, as well as any costs incurred by or on behalf of the DSM collaborative process. These costs would be divided by the expected Mcf sales for the upcoming twelve-month period to determine the DCRC.

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Original SHEET No. 30B

WESTERN KENTUCKY GAS COMPANY

Demand-Side Management Cost Recovery Mechanism

DSM

(N)

DBA = DSM Balance Adjustment. The DBA shall 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.

The DBA for the upcoming twelve-month period shall be calculated as the sum of the balance adjustments for the DCRC, DCRP and DBA. For the DCRC, the balance adjustment shall be the difference between the amount billed in a twelve-month period from the application of the DCRC unit charge and the actual cost of the DSM Program during the same twelve-month period.

For the DCRP, the balance adjustment shall 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 DSM pilot program as amortized at no interest over three years.

For the DBA, the balance adjustment shall 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 twelve-month period. The balance adjustments plus interest shall be divided by the expected Mcf sales for the upcoming twelve-month period to determine the DBA.

The Company will file modifications to the DSMRC on an annual basis at least two months prior to the beginning of the effective upcoming twelve-month period for billing. This annual filing shall include detailed calculations of the DCRC, the DCRP, and the DBA, as well as data on the total cost of the DSM Program over the twelve-month period.

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Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Original SHEET No. 30B

WESTERN KENTUCKY GAS COMPANY

Demand-Side Management Cost Recovery Mechanism

DSM

(N)

DBA = DSM Balance Adjustment. The DBA shall be calculated on a calendar year basis and be used to reconcile the difference between the amount of revenues actually billed through the DCRC and previous applications of the DBA, and the revenues which should have been billed.

The DBA for the upcoming twelve-month period shall be calculated as the sum of the balance adjustments for the DCRC and DBA. For the DCRC, the balance adjustment shall be the difference between the amount billed in a twelve-month period from the application of the DCRC unit charge and the actual cost of the DSM Program during the same twelve-month period.

For the DBA, the balance adjustment shall 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 twelve-month period. The balance adjustments plus interest shall be divided by the expected Mcf sales for the upcoming twelve-month period to determine the DBA.

The Company will file modifications to the DSMRC on an annual basis at least two months prior to the beginning of the effective upcoming twelve-month period for billing. This annual filing shall include detailed calculations of the DCRC and the DBA, as well as data on the total cost of the DSM Program over the twelve-month period.

ISSUED: June 23, 1999

EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Original SHEET No. 30C

WESTERN KENTUCKY GAS COMPANY

Demand-Side Management Cost Recovery Mechanism
DSM

(N)

DSM Cost Recovery Component (DSMRC):

DSM Cost Recovery – Current:	$0.0155 per Mcf
DSM Cost Recovery – Pilot:	$0.0225 per Mcf
DSM Balance Adjustment:	$0.0000 per Mcf
DSMRC Residential Rate G-1	$0.0380 per Mcf

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ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Original SHEET No. 30C

WESTERN KENTUCKY GAS COMPANY

Demand-Side Management Cost Recovery Mechanism
DSM

(N)

DSM Cost Recovery Component (DSMRC):

DSM Cost Recovery – Current:	$0.0155 per Mcf
DSM Balance Adjustment:	$0.0000 per Mcf
DSMRC Residential Rate G-1	$0.0155 per Mcf

ISSUED: June 23, 1999

EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Original SHEET No. 30D

WESTERN KENTUCKY GAS COMPANY

Gas Research Institute R & D Rider

GRI R & D Unit Charge

(N)

Application:
This rider applies to the distribution charge applicable to all gas transported by the Company other than Rate T-3 and T-4 Carriage Service.

GRI R&D Unit Charge:
The intent of the Gas Research Institute R&D Unit Charge is to maintain the Company's level of contribution per Mcf as of December 31, 1998. The Unit Charge will be billed according to the transition schedule outlined in the pipelines' tariffs.

Waiver Provision:
The GRI R&D Unit Charge may be reduced or waived for one or more classifications of service or rate schedules at any time by the Company by filing notice with the Commission.

Remittance of Funds:
All funds collected and this rider will be remitted to Gas Research Institute on a monthly basis. The amounts so remitted shall be reported to the Commission annually.

Reports to the Commission:
A statement setting forth the manner in which the funds remitted have been invested in research and development will be filed with the Commission annually.

Termination of this Rider: Participation in the GRI R&D funding program is voluntary on the part of the Company. This rider may be terminated at any time by the Company by filing a notice of recision with the Commission.

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ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Original SHEET No. 30D

WESTERN KENTUCKY GAS COMPANY

Gas Research Institute R & D Rider

GRI R & D Unit Charge

(N)

Applicable:
This rider applies to the distribution charge applicable to all gas transported by the Company other than Rate T-3 and T-4 Carriage Service.

GRI R&D Unit Charge:
The intent of the Gas Research Institute R&D Unit Charge is to maintain the Company's level of contribution per Mcf as of December 31, 1998. The Unit Charge will be billed according to the transition schedule outlined in the pipelines' tariff.

	Rate Per Mcf
GRI R&D Unit Charge	$0.0004

Note 1: The GRI R&D Unit Charge is a weighted average of the rates under the pipelines' transition schedules and applicable annual volumes.

Waiver Provision:
The GRI R&D Unit Charge may be reduced or waived for one or more classifications of service or rate schedules at any time by the Company by filing notice with the Commission. Any such waiver shall not increase the GRI R&D Unit Charge to the remaining classifications of service or rate schedules without Commission approval.

Remittance of Funds:
All funds collected under this rider will be remitted to Gas Research Institute on a monthly basis. The amounts so remitted shall be reported to the Commission annually.

Reports to the Commission:
A statement setting forth the manner in which the funds remitted have been invested in research and development will be filed with the Commission annually.

Termination of this Rider:
Participation in the GRI R&D funding program is voluntary on the part of the Company. This rider may be terminated at any time by the Company by filing a notice of recision with the Commission.

ISSUED: June 23, 1999

EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised Sheet No. 34
Cancelling
Second Revised Sheet No. 34

WESTERN KENTUCKY GAS COMPANY

General Transportation Service
Rate T-2 (T)

1. Applicable

Entire service area of the Company to any customer receiving service under the General Sales Service (G-1) and/or Interruptible Sales Service (G-2).

2. Availability of Service (T)

Available to any customer with an expected consumption of at least 9,000 Mcf per year, on an individual service at the same premise, who has purchased its own supply of natural gas and require transportation by the Company to the customer's facilities subject to suitable service being available from existing facilities.

3. Net Monthly Rate

In addition to any and all charges assessed by other parties, there will be applied:

a) Transportation Administration Fee - $50.00 per customer per month (I)

b) Distribution Charge for High Priority Service (T)

First	300	Mcf	@	$ 1.2000	per	Mcf	(I)
Next	14,700	Mcf	@	0.6946	per	Mcf	(I)
Over	15,000	Mcf	@	0.4299	per	Mcf	(I)

c) Distribution Charge for Low Priority Service

First	15,000	Mcf	@	$ 0.5300	per	Mcf	(I)
Over	15,000	Mcf	@	0.3301	per	Mcf	(R)

d) Applicable Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

e) Electronic Flow Measurement ("EFM") facilities charge, if applicable (Sheet No. 51).

All gas consumed by the customer (Sales, transportation, and carriage; firm, high load factor, interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised Sheet No. 34
Cancelling
Second Revised Sheet No. 34

WESTERN KENTUCKY GAS COMPANY

General Transportation Service
Rate T-2 (T)

1. Applicable

Entire service area of the Company to any customer receiving service under the General Sales Service (G-1) and/or Interruptible Sales Service (G-2).

2. Availability of Service (T)

Available to any customer with an expected consumption of at least 9,000 Mcf per year, on an individual service at the same premise, who has purchased its own supply of natural gas and require transportation by the Company to the customer's facilities subject to suitable service being available from existing facilities.

3. Net Monthly Rate

In addition to any and all charges assessed by other parties, there will be applied:

a) Transportation Administration Fee - $50.00 per customer per month (I)

b) Distribution Charge for High Priority Service (T)

First	300	Mcf	@	$ 1.1900	per	Mcf	(I)
Next	14,700	Mcf	@	0.6590	per	Mcf	(I)
Over	15,000	Mcf	@	0.4300	per	Mcf	(I)

c) Distribution Charge for Low Priority Service

First	15,000	Mcf	@	$ 0.5300	per	Mcf	(I)
Over	15,000	Mcf	@	0.3591	per	Mcf	(R)

d) Applicable Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

e) Electronic Flow Measurement ("EFM") facilities charge, if applicable (Sheet No. 51).

All gas consumed by the customer (Sales, transportation, and carriage; firm, high load factor, interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

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ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised Sheet No. 35
Cancelling
Second Revised Sheet No. 35

WESTERN KENTUCKY GAS COMPANY

General Transportation Service (T)
Rate T-2

4. Net Monthly Bill

The Net Monthly Bill, for T-2 Service, shall be equal to the sum of the Transportation Administration Fee and the appropriate Transportation Charge (Distribution Charge plus Non-commodity component) applied to the customer's transported volumes and any applicable Electronic Flow Measurement ("EFM") facilities charges (see Subsection 7 "Special Provisions" of this tariff). The customer will also be billed for purchases and the applicable Base Charge and High Load Factor (HLF) demand charge under Rates G-1 and G-2. (T)

5. Nominated Volume

Definition: "Nominated Volume" or "Nomination" – The Level of daily volume in Mcf as requested by the customer to be transported and delivered by the Company. Such volume nominated by the Customer shall include an allowance for the Company's system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6. The volumes delivered by the Customer to the Company for redelivery to the Customer's facilities will be reduced to cover the related system Lost and Unaccounted gas quantities.

Such nomination request shall be made by the customer to the Company on a periodic basis prior to the nomination deadline of the respective interstate transporter. Such nomination may be adjusted prospectively from time to time during the billing period as may become necessary. However, the Company retains the right to limit the number of nomination adjustments during the billing period.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised Sheet No. 35
Cancelling
Second Revised Sheet No. 35

WESTERN KENTUCKY GAS COMPANY

General Transportation Service (T)
Rate T-2

4. Net Monthly Bill

The Net Monthly Bill, for T-2 Service, shall be equal to the sum of the Transportation Administration Fee and the appropriate Transportation Charge (Distribution Charge plus Non-commodity component) applied to the customer's transported volumes and any applicable Electronic Flow Measurement ("EFM") facilities charges (see Subsection 7 "Special Provisions" of this tariff). The customer will also be billed for purchases and the applicable Base Charge and High Load Factor (HLF) demand charge under Rates G-1 and G-2. (T)

5. Nominated Volume

Definition: "Nominated Volume" or "Nomination" – The Level of daily volume in Mcf as requested by the customer to be transported and delivered by the Company. Such volume nominated by the Customer shall include an allowance for the Company's system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6. The volumes delivered by the Customer to the Company for redelivery to the Customer's facilities will be reduced to cover the related system Lost and Unaccounted gas quantities.

Such nomination request shall be made by the customer to the Company on a periodic basis prior to the nomination deadline of the respective interstate transporter. Such nomination may be adjusted prospectively from time to time during the billing period as may become necessary. However, the Company retains the right to limit the number of nomination adjustments during the billing period.

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 36
Cancelling
Second Revised SHEET No. 36

WESTERN KENTUCKY GAS COMPANY

General Transportation Service
Rate T-2 (T)

b) It will be the responsibility of the customer to pay all costs for additional facilities and/or equipment which will be required as a result of receiving transportation under this Transportation Tariff Rate (additional facilities may be required to allow for changing from weekly or monthly meter readings to daily meter record for the billing period). Electronic flow measurement ("EFM") equipment is required to be installed, maintained, and operated by the Company to obtain transportation service. The customer is responsible for providing the electric and communications support services related to the EFM equipment. Customers required to install EFM may elect the optional monthly EFM facilities charges (Sheet No. 51). EFM equipment is not required for customers whose contractual requirements with the Company are less than 300 Mcf/day; however, such customers may, at their option, elect to install EFM equipment under the same provisions set forth above. (T)

8. **Terms and Conditions**

a) Specific details relating to volume, delivery point and similar matters shall be covered by a separate written contract or amendment with the customer.

b) Gas transported under this Transportation Tariff Rate is subject to the provisions of the Company's curtailment order.

c) The Company will not be obligated to deliver a total supply of gas to the customer in excess if the customer's maximum contracted volumes.

d) It shall be the customer's responsibility to make all necessary arrangements, including obtaining any regulatory approval required, to deliver gas transported under this Transportation Tariff Rate to the facilities of the Company.

e) The Company reserves the right to refuse to accept gas that does not meet the Company's quality specifications.

f) The Rules and Regulations and Orders of the Kentucky Public Service Commission and of the Company and the Company's General Terms and Conditions applicable to the Company's Sales Tariff Rates shall likewise apply to these Transportation Tariff Rates and all contracts and amendments thereunder.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 36
Cancelling
Second Revised SHEET No. 36

WESTERN KENTUCKY GAS COMPANY

General Transportation Service
Rate T-2 (T)

b) It will be the responsibility of the customer to pay all costs for additional facilities and/or equipment which will be required as a result of receiving transportation under this Transportation Tariff Rate (additional facilities may be required to allow for changing from weekly or monthly meter readings to daily meter record for the billing period). Electronic flow measurement ("EFM") equipment is required to be installed, maintained, and operated by the Company to obtain transportation service. The customer is responsible for providing the electric and communications support services related to the EFM equipment. Customers required to install EFM may elect the optional monthly EFM facilities charges (Sheet No. 51). EFM equipment is not required for customers whose contractual requirements with the Company are less than 300 Mcf/day; however, such customers may, at their option, elect to install EFM equipment under the same provisions set forth above. (T)

8. **Terms and Conditions**

a) Specific details relating to volume, delivery point and similar matters shall be covered by a separate written contract or amendment with the customer.

b) Gas transported under this Transportation Tariff Rate is subject to the provisions of the Company's curtailment order.

c) The Company will not be obligated to deliver a total supply of gas to the customer in excess if the customer's maximum contracted volumes.

d) It shall be the customer's responsibility to make all necessary arrangements, including obtaining any regulatory approval required, to deliver gas transported under this Transportation Tariff Rate to the facilities of the Company.

e) The Company reserves the right to refuse to accept gas that does not meet the Company's quality specifications.

f) The Rules and Regulations and Orders of the Kentucky Public Service Commission and of the Company and the Company's General Terms and Conditions applicable to the Company's Sales Tariff Rates shall likewise apply to these Transportation Tariff Rates and all contracts and amendments thereunder.

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised Sheet No. 37
Cancelling
First Revised Sheet No. 37

WESTERN KENTUCKY GAS COMPANY

General Transportation Service (T)
Rate T-2

9. **Alternative Fuel Responsive Flex Provision**

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the otherwise applicable Distribution Charge on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request. (T)

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised Sheet No. 37
Cancelling
First Revised Sheet No. 37

WESTERN KENTUCKY GAS COMPANY

General Transportation Service (T)
Rate T-2

9. **Alternative Fuel Responsive Flex Provision**

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the otherwise applicable Distribution Charge on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request. (T)

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

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PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Fourth Revised Sheet No. 38
Cancelling
Third Revised Sheet No. 38

WESTERN KENTUCKY GAS COMPANY

(D)

Reserved for Future Use

ISSUED: June 23, 1999

EFFECTIVE: July 24, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Fourth Revised Sheet No. 38
Cancelling
Third Revised Sheet No. 38

WESTERN KENTUCKY GAS COMPANY

(D)

Reserved for Future Use

ISSUED: June 23, 1999

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ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 40
Cancelling
Second Revised SHEET No. 40

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)
Rate T-3 (T)

1. **Applicable**

Entire service area of the Company to any customer for that portion of the customer's interruptible requirements not included under one of the Company's sales tariffs.

2. **Availability of Service**

a) Available to any customer with an expected demand of at least 9,000 Mcf per year, on an individual service at the same premise, who has purchased its own supply of natural gas and require interruptible carriage service by the Company to customer's facilities subject to suitable service being available from existing facilities.

b) The Company may decline to initiate service to a customer under this tariff or to allow a customer receiving service under this tariff to elect any other service provided by the Company, if in the Company's sole judgment, the performance of such service would be contrary to good operating practice or would have a detrimental impact on other customers serviced by the Company.

3. **Net Monthly Rate**

In addition to any and all charges assessed by other parties, there will be applied:

a) Base Charge - $250.00 per delivery point (I)
b) Transportation Administration Fee - 50.00 per customer per month (I)

c) Distribution Charge for Interruptible Service (T)

First 15,000 Mcf @ $0.5300 per Mcf
Over 15,000 Mcf @ 0.3301 per Mcf (I) (R)

d) Applicable Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

e) Electronic Flow Measurement ("EFM") facilities charge, if applicable (Sheet No. 51).

All gas consumed by the customer (Sales, transportation, and carriage; firm, high load factor, interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

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EFFECTIVE: July 24, 1999

ISSUED BY: William J. Senter
Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 40
Cancelling
Second Revised SHEET No. 40

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)
Rate T-3 (T)

1. **Applicable**

Entire service area of the Company to any customer for that portion of the customer's interruptible requirements not included under one of the Company's sales tariffs.

2. **Availability of Service**

a) Available to any customer with an expected demand of at least 9,000 Mcf per year, on an individual service at the same premise, who has purchased its own supply of natural gas and require interruptible carriage service by the Company to customer's facilities subject to suitable service being available from existing facilities.

b) The Company may decline to initiate service to a customer under this tariff or to allow a customer receiving service under this tariff to elect any other service provided by the Company, if in the Company's sole judgment, the performance of such service would be contrary to good operating practice or would have a detrimental impact on other customers serviced by the Company.

3. **Net Monthly Rate**

In addition to any and all charges assessed by other parties, there will be applied:

a) Base Charge - $220.00 per delivery point (I)
b) Transportation Administration Fee - 50.00 per customer per month (I)

c) Distribution Charge for Interruptible Service (T)

First 15,000 Mcf @ $0.5300 per Mcf
Over 15,000 Mcf @ 0.3591 per Mcf (I) (R)

d) Applicable Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

e) Electronic Flow Measurement ("EFM") facilities charge, if applicable (Sheet No. 51).

All gas consumed by the customer (Sales, transportation, and carriage; firm, high load factor, interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

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Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 41
Cancelling
Second Revised SHEET No. 41

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)

Rate T-3 (T)

4. **Net Monthly Bill**

The Net Monthly Bill shall be equal to the sum of the Base Charge, the Transportation Administration Fee, and applicable Distribution Charge and Non-Commodity Component, and any applicable Electronic Flow Measurement ("EFM") facilities charges (see Subsection 8 "Special Provisions" of this tariff.) (T)

5. **Nominated Volume**

Definition: "Nominated Volume" or "Nomination" – The level of daily volume in Mcf as requested by the customer to be transported and delivered by the Company. Such volume nominated by the Customer shall include an allowance for the Company's system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6. The volumes delivered by the Customer to the Company for redelivery to the Customer's facilities will be reduced to cover the related system Lost and Unaccounted gas quantities.

Such nomination request shall be made by the customer to the Company on a periodic basis prior to the nomination deadline of the respective interstate transporter. Such nomination may be adjusted prospectively from time to time during the billing period as may become necessary. However, the Company retains the right to limit the number of nomination adjustments during the billing period.

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Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 41
Cancelling
Second Revised SHEET No. 41

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T

Rate T-3 (T

4. **Net Monthly Bill**

The Net Monthly Bill shall be equal to the sum of the Base Charge, the Transportation Administration Fee, and applicable Distribution Charge and Non-Commodity Component, and any applicable Electronic Flow Measurement ("EFM") facilities charges (see Subsection 8 "Special Provisions" of this tariff.) (T

5. **Nominated Volume**

Definition: "Nominated Volume" or "Nomination" – The level of daily volume inMcf as requested by the customer to be transported and delivered by the Company. Such volume nominated by the Customer shall include an allowance for the Company's system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6. The volumes delivered by the Customer to the Company for redelivery to the Customer's facilities will be reduced to cover the related system Lost and Unaccounted gas quantities.

Such nomination request shall be made by the customer to the Company on a periodic basis prior to the nomination deadline of the respective interstate transporter. Such nomination may be adjusted prospectively from time to time during the billing period as may become necessary. However, the Company retains the right to limit the number of nomination adjustments during the billing period.

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Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 41A
Cancelling
First Revised SHEET No. 41A

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)
Rate T-3

6. **Imbalances**

The Company will calculate, on a monthly basis, the customer's Imbalance resulting from the differences that occur between the volume that the customer had delivered into the Company's facilities and the volume the Company delivered to the customer's facilities plus an allowance for system Lost and Unaccounted gas quantities.

$$\text{Imbalance} = [\ \text{Mcf}_{\text{Customer}}\ \text{X}\ (1 - \text{L\&U\%})\ ] - \text{Mcf}_{\text{Company}}$$

Where:

1. "$\text{Mcf}_{\text{Customer}}$" are the total volumes that the customer had delivered to the Company's facilities.
2. "$\text{Mcf}_{\text{Company}}$" are the volumes the Company delivered into customer's facilities, however, the Company will adjust the Imbalance, if at the Company's request, the customer did not take deliveries of the volumes the customer had delivered to the Company's facilities.
3. "L&U%" is the system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6.

The Imbalance volumes will be resolved by use of the following procedure:

a) If the Imbalance is negative and Imbalance volumes were approved by the Company, then the customer-will be billed for the Imbalance volumes at a rate equal to 110% of the Company's sales rate (G-2). However, if the Imbalance volumes were not approved by the Company, then the Imbalance volumes shall be deemed as an overrun and the Company may, at its sole discretion, apply a penalty rate of up to $15.00 per Mcf. The Company has no obligation to provide gas supply to a customer electing service under this tariff. (N,T)

If the Imbalance is positive, then the Company will purchase the Imbalance volumes in excess of "parked" volumes from the customer at the rates described in the following "Cash out" method in item (b).

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 41A
Cancelling
First Revised SHEET No. 41A

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T
Rate T-3

6. **Imbalances**

The Company will calculate, on a monthly basis, the customer's Imbalance resulting from the differences that occur between the volume that the customer had delivered into the Company's facilities and the volume the Company delivered to the customer's facilities plus an allowance for system Lost and Unaccounted gas quantities.

$$\text{Imbalance} = [\ \text{Mcf}_{\text{Customer}}\ \text{X}\ (1 - \text{L\&U\%})\ ] - \text{Mcf}_{\text{Company}}$$

Where:

1. "$\text{Mcf}_{\text{Customer}}$" are the total volumes that the customer had delivered to the Company's facilities.
2. "$\text{Mcf}_{\text{Company}}$" are the volumes the Company delivered into customer's facilities, however, the Company will adjust the Imbalance, if at the Company's request, the customer did not take deliveries of the volumes the customer had delivered to the Company's facilities.
3. "L&U%" is the system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6.

The Imbalance volumes will be resolved by use of the following procedure:

a) If the Imbalance is negative and Imbalance volumes were approved by the Company, then the customer-will be billed for the Imbalance volumes at a rate equal to 110% of the Company's sales rate (G-2). However, if the Imbalance volumes were not approved by the Company, then the Imbalance volumes shall be deemed as an overrun and the Company may, at its sole discretion, apply a penalty rate of up to $15.00 per Mcf. The Company has no obligation to provide gas supply to a customer electing service under this tariff. (N,T

If the Imbalance is positive, then the Company will purchase the Imbalance volumes in excess of "parked" volumes from the customer at the rates described in the following "Cash out" method in item (b).

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

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PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 41B
Cancelling
First Revised SHEET No. 41B

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service
Rate T-3
(T)

b) "Cash out" Method

Imbalance volumes		Cash-out Price
First [1] 5% of Mcf$_{Customer}$	@	100% of Index Price [2]
Next [1] 5% of Mcf$_{Customer}$	@	90% of Index Price [2]
Over [1] 10% of Mcf$_{Customer}$	@	80% of Index Price [2]

[1] Not to exceed the Imbalance volumes

[2] The index price will equal the effective "Cash out" index price in effect for the transporting pipeline or as filed with the Commission by the Company.

c) Customer will be reimbursed for all pipeline transportation commodity charges applying to cash out volumes. However, the reimbursement will not exceed pipeline transportation commodity charges the Company would have incurred to transport the "Cash Out" volumes.

d) In addition to other tariff penalty provisions, the customer shall be responsible for any penalty (s) assessed by the pipeline (s) resulting from the customer's failure to match volumes that the customer had delivered to the Company's facilities with volumes the Company delivered into customer's facilities.

e) Customer may, by written agreement with the Company, arrange to "park" positive imbalance volumes, up to 10% of "MCF$_{Company}$", on a monthly basis at .10/MCF per month. The parking service will be provided on a "best efforts" basis by the Company. Parked volumes will be deemed "first through the meter" delivered to the Customer in the month following delivery to the Company on the Customer's account.

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Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 41B
Cancelling
First Revised SHEET No. 41B

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service
Rate T-3
(T)

b) "Cash out" Method

Imbalance volumes		Cash-out Price
First [1] 5% of Mcf$_{Customer}$	@	100% of Index Price [2]
Next [1] 5% of Mcf$_{Customer}$	@	90% of Index Price [2]
Over [1] 10% of Mcf$_{Customer}$	@	80% of Index Price [2]

[1] Not to exceed the Imbalance volumes

[2] The index price will equal the effective "Cash out" index price in effect for the transporting pipeline or as filed with the Commission by the Company.

c) Customer will be reimbursed for all pipeline transportation commodity charges applying to cash out volumes. However, the reimbursement will not exceed pipeline transportation commodity charges the Company would have incurred to transport the "Cash Out" volumes.

d) In addition to other tariff penalty provisions, the customer shall be responsible for any penalty (s) assessed by the pipeline (s) resulting from the customer's failure to match volumes that the customer had delivered to the Company's facilities with volumes the Company delivered into customer's facilities.

e) Customer may, by written agreement with the Company, arrange to "park" positive imbalance volumes, up to 10% of "MCF$_{Company}$", on a monthly basis at .10/MCF per month. The parking service will be provided on a "best efforts" basis by the Company. Parked volumes will be deemed "first through the meter" delivered to the Customer in the month following delivery to the Company on the Customer's account.

ISSUED: June 23, 1999

EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Fifth Revised SHEET No. 42
Cancelling
Fourth Revised SHEET No. 42

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)
Rate T-3

7. **Curtailment**

a) The Company shall have the right at any time without liability to the customer to curtail or to discontinue the delivery of gas entirely to the customer for any period of time when such curtailment or discontinuance is necessary to protect the requirements of domestic and commercial customers; to avoid an increased maximum daily demand in the Company's gas purchases; to avoid excessive peak load and demands upon the gas transmission or distribution system; to relieve system capacity constraints; to comply with any restriction or curtailment of any governmental agency having jurisdiction over the Company or its supplier or to comply with any restriction or curtailment as may be imposed by the Company's supplier; to protect and insure the operation of the Company's underground storage system; for any causes due to force majeure (which includes acts of God; strikes, lockouts, civil commotion, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, etc.); and for any other necessary or expedient reason at the discretion of the Company.

b) All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission.

8. **Special Provisions**

It will be the responsibility of the customer to pay all costs for additional facilities and/or equipment which will be required as a result of receiving service under this Interruptible Carriage Service Rate T-3. Electronic flow measurement ("EFM") equipment is required to be installed, maintained, and operated by the Company to obtain transportation service. The customer is responsible for providing the electric and communications support services related to the EFM equipment. Customers required to install EFM may elect the optional monthly EFM facilities charge (Sheet No. 51). EFM equipment is not required for customers whose contractual requirements with the Company are less than 100 Mcf/day; however, such customers may, at their option, elect to install EFM equipment under the same provisions set forth above. (T)

No gas delivered under this rate schedule and applicable contract shall be available for resale to anyone other than an end-user for use as a motor vehicle fuel. (D)

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Fifth Revised SHEET No. 42
Cancelling
Fourth Revised SHEET No. 42

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)
Rate T-3

7. **Curtailment**

a) The Company shall have the right at any time without liability to the customer to curtail or to discontinue the delivery of gas entirely to the customer for any period of time when such curtailment or discontinuance is necessary to protect the requirements of domestic and commercial customers; to avoid an increased maximum daily demand in the Company's gas purchases; to avoid excessive peak load and demands upon the gas transmission or distribution system; to relieve system capacity constraints; to comply with any restriction or curtailment of any governmental agency having jurisdiction over the Company or its supplier or to comply with any restriction or curtailment as may be imposed by the Company's supplier; to protect and insure the operation of the Company's underground storage system; for any causes due to force majeure (which includes acts of God; strikes, lockouts, civil commotion, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, etc.); and for any other necessary or expedient reason at the discretion of the Company.

b) All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission.

8. **Special Provisions**

It will be the responsibility of the customer to pay all costs for additional facilities and/or equipment which will be required as a result of receiving service under this Interruptible Carriage Service Rate T-3. Electronic flow measurement ("EFM") equipment is required to be installed, maintained, and operated by the Company to obtain transportation service. The customer is responsible for providing the electric and communications support services related to the EFM equipment. Customers required to install EFM may elect the optional monthly EFM facilities charge (Sheet No. 51). EFM equipment is not required for customers whose contractual requirements with the Company are less than 100 Mcf/day; however, such customers may, at their option, elect to install EFM equipment under the same provisions set forth above. (T)

No gas delivered under this rate schedule and applicable contract shall be availablefor resale to anyone other than an end-user for use as a motor vehicle fuel. (D)

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 43
Cancelling
Second Revised SHEET No. 43

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service

Rate T-3

(T)

9. **Terms and Conditions**

a) Specific details relating to volume, delivery point and similar matters shall be covered by a separate written contract or amendment with the customer.

b) The Company will not be obligated to deliver a total supply of gas to the customer in excess of the customer's maximum daily carriage volumes. The Company has no obligation under this tariff to provide any sales gas to the customer.

c) It shall be the customer's responsibility to make all necessary arrangements, including obtaining any regulatory approval required, to deliver gas under this Interruptible Carriage Service Rate to the facilities of the Company.

d) The Company reserves the right to refuse to accept gas that does not meet the Company's quality specifications.

e) The Rules and Regulations and Orders of the Kentucky Public Service Commission and of the Company and the Company's General Terms and Conditions applicable to the Company's Sales Tariff Rates shall likewise apply to these Carriage Service Rates and all contracts and amendments thereunder.

f) In the event the customer loses its gas supply, it may be allowed a reasonable time in which to secure replacement volumes (up to the contract daily carriage quantity), subject to provisions of Section 5 of this tariff.

A "reasonable time" will be, except when precluded by operational constraints, matched to the make-up grace period by the respective interstate pipeline transporter.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 43
Cancelling
Second Revised SHEET No. 43

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service

Rate T-3

(T)

9. **Terms and Conditions**

a) Specific details relating to volume, delivery point and similar matters shall be covered by a separate written contract or amendment with the customer.

b) The Company will not be obligated to deliver a total supply of gas to the customer in excess of the customer's maximum daily carriage volumes. The Company has no obligation under this tariff to provide any sales gas to the customer.

c) It shall be the customer's responsibility to make all necessary arrangements, including obtaining any regulatory approval required, to deliver gas under this Interruptible Carriage Service Rate to the facilities of the Company.

d) The Company reserves the right to refuse to accept gas that does not meet the Company's quality specifications.

e) The Rules and Regulations and Orders of the Kentucky Public Service Commission and of the Company and the Company's General Terms and Conditions applicable to the Company's Sales Tariff Rates shall likewise apply to these Carriage Service Rates and all contracts and amendments thereunder.

f) In the event the customer loses its gas supply, it may be allowed a reasonable time in which to secure replacement volumes (up to the contract daily carriage quantity), subject to provisions of Section 5 of this tariff.

A "reasonable time" will be, except when precluded by operational constraints, matched to the make-up grace period by the respective interstate pipeline transporter.

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PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 44
Cancelling
First Revised SHEET No. 44

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service
Rate T-3 (T)

g) The customer will be solely responsible to correct, any imbalances it has caused on the applicable pipeline's system.

10. **Late Payment Charge**

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 44
Cancelling
First Revised SHEET No. 44

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service
Rate T-3 (T)

g) The customer will be solely responsible to correct, any imbalances it has caused on the applicable pipeline's system.

10. **Late Payment Charge**

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 45
Cancelling
Original Sheet No. 45

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)
Rate T-3

11. Alternative Fuel Responsive Flex Provisions

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the applicable Distribution Charge on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request. (T)

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

ISSUED: June 23, 1999

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Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 45
Cancelling
Original Sheet No. 45

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)
Rate T-3

11. Alternative Fuel Responsive Flex Provisions

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the applicable Distribution Charge on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request. (T)

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

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Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 46
Cancelling
First Revised SHEET No. 46

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service (T)
Rate T-4

1. **Applicable**

Entire Service Area of the Company to any customer for that portion of the customer's firm requirements not included under one of the Company's sales tariffs.

2. **Availability of Service**

a) Available to any customer with an expected demand of at least 9,000 Mcf per year, on an individual service at the same premise, who has purchased its own supply of natural gas and require firm carriage service by the Company to customer's facilities subject to suitable service being available from existing facilities.

b) The Company may decline to initiate service to a customer under this tariff or to allow a customer receiving service under this tariff to elect any other service provided by the Company, if in the Company's sole judgment, the performance of such service would be contrary to good operating practice or would have a detrimental impact on other customers serviced by the Company.

3. **Net Monthly Rate**

In addition to any and all charges assessed by other parties, there will be applied:

a) Base Charge - $250.00 per delivery point (I)

b) Transportation Administration Fee - 50.00 per customer per month (I)

c) Distribution Charge for Firm Service
First 300 Mcf @ $1.2000 per Mcf (T)
Next 14,700 Mcf @ 0.6946 per Mcf (I)
Over 15,000 Mcf @ 0.4299 per Mcf (I)

(I)

d) Applicable Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

e) Electronic Flow Measurement ("EFM") facilities charges, if applicable (Sheet No. 51).

All gas consumed by the customer (Sales, transportation, and carriage; firm, high load factor, interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

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Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 46
Cancelling
First Revised SHEET No. 46

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service (T)
Rate T-4

1. **Applicable**

Entire Service Area of the Company to any customer for that portion of the customer's firm requirements not included under one of the Company's sales tariffs.

2. Availability of Service

a) Available to any customer with an expected demand of at least 9,000 Mcf per year, on an individual service at the same premise, who has purchased its own supply of natural gas and require firm carriage service by the Company to customer's facilities subject to suitable service being available from existing facilities.

b) The Company may decline to initiate service to a customer under this tariff or to allow a customer receiving service under this tariff to elect any other service provided by the Company, if in the Company's sole judgment, the performance of such service would be contrary to good operating practice or would have a detrimental impact on other customers serviced by the Company.

3. Net Monthly Rate

In addition to any and all charges assessed by other parties, there will be applied:

a) Base Charge - $220.00 per delivery point (I)

b) Transportation Administration Fee - 50.00 per customer per month (I)

c) Distribution Charge for Firm Service
First 300 Mcf @ $1.1900 per Mcf (T)
Next 14,700 Mcf @ 0.6590 per Mcf (I)
Over 15,000 Mcf @ 0.4300 per Mcf (I)

(I)

d) Applicable Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

e) Electronic Flow Measurement ("EFM") facilities charges, if applicable (Sheet No. 51).

All gas consumed by the customer (Sales, transportation, and carriage; firm, high load factor, interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

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Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 47
Cancelling
Original SHEET No. 47

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service (T)
Rate T-4

4. **Net Monthly Bill**

The Net Monthly Bill shall be equal to the sum of the Base Charge, the Transportation Administration Fee, and applicable Distribution Charge and Non-Commodity Component, and any applicable Electronic Flow Measurement ("EFM") facilities charges (see subsection 8 "Special Provisions" of this tariff.) (T)

5. **Nominated Volume**

Definition: "Nominated Volume" or "Nomination" – The level of daily volume in Mcf as requested by the customer to be transported and delivered by the Company. Such volume nominated by the Customer shall include an allowance for the Company's system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6. The volumes delivered by the Customer to the Company for redelivery to the Customer's facilities will be reduced to cover the related system Lost and Unaccounted gas quantities.

Such nomination request shall be made by the customer to the Company on a periodic basis prior to the nomination deadline of the respective interstate transporter. Such nomination may be adjusted prospectively from time to time during the billing period as may become necessary. However, the Company retains the right to limit the number of nomination adjustments during the billing period.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 47
Cancelling
Original SHEET No. 47

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service (T)
Rate T-4

4. **Net Monthly Bill**

The Net Monthly Bill shall be equal to the sum of the Base Charge, the Transportation Administration Fee, and applicable Distribution Charge and Non-Commodity Component, and any applicable Electronic Flow Measurement ("EFM") facilities charges (see subsection 8 "Special Provisions" of this tariff.) (T)

5. **Nominated Volume**

Definition: "Nominated Volume" or "Nomination" – The level of daily volume inMcf as requested by the customer to be transported and delivered by the Company. Such volume nominated by the Customer shall include an allowance for the Company's system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6. The volumes delivered by the Customer to the Company for redelivery to the Customer's facilities will be reduced to cover the related system Lost and Unaccounted gas quantities.

Such nomination request shall be made by the customer to the Company on a periodic basis prior to the nomination deadline of the respective interstate transporter. Such nomination may be adjusted prospectively from time to time during the billing period as may become necessary. However, the Company retains the right to limit the number of nomination adjustments during the billing period.

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PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 47A
Cancelling
Original SHEET No. 47A

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4

(T)

6. Imbalances

The Company will calculate, on a monthly basis, the customer's Imbalance resulting from the differences that occur between the volume that the customer had delivered into the Company's facilities and the volume the Company delivered to the customer's facilities plus an allowance for system Lost and Unaccounted gas quantities.

$$\text{Imbalance} = [\,\text{Mcf}_{\text{Customer}} \text{ X } (1\text{-L\&U\%})\,] - \text{Mcf}_{\text{Company}}$$

Where:

1. "Mcf $_{\text{Customer}}$" are the total volumes that the customer had delivered to the Company's facilities.
2. "Mcf $_{\text{Company}}$" are the volumes the Company delivered into customer's facilities, however, the Company will adjust the Imbalance, if at the Company's request, the customer did not take deliveries of the volumes the customer had delivered to the Company's facilities.
3. "L&U%" is the system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6.

The Imbalance volumes will be resolved by use of the following procedure:

a) If the Imbalance is negative and Imbalance volumes were approved by the Company, then the customer will be billed for the Imbalance volumes at a rate equal to 110% of the Company's sales rate (G-1). However, if the Imbalance volumes were not approved by the Company, then the Imbalance volumes shall be deemed as an overrun and may be billed at $15.00 per Mcf. The Company has no obligation to provide gas supply to a customer electing service under this tariff.

If the Imbalance is positive, then the Company will purchase the Imbalance volumes in excess of "parked" volumes from the customer at the rates described in the following "Cash out" method in item (b).

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Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 47A
Cancelling
Original SHEET No. 47A

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4

(T)

6. Imbalances

The Company will calculate, on a monthly basis, the customer's Imbalance resulting from the differences that occur between the volume that the customer had delivered into the Company's facilities and the volume the Company delivered to the customer's facilities plus an allowance for system Lost and Unaccounted gas quantities.

$$\text{Imbalance} = [\,\text{Mcf}_{\text{Customer}} \text{ X } (1\text{-L\&U\%})\,] - \text{Mcf}_{\text{Company}}$$

Where:

1. "Mcf $_{\text{Customer}}$" are the total volumes that the customer had delivered to the Company's facilities.
2. "Mcf $_{\text{Company}}$" are the volumes the Company delivered into customer's facilities, however, the Company will adjust the Imbalance, if at the Company's request, the customer did not take deliveries of the volumes the customer had delivered to the Company's facilities.
3. "L&U%" is the system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6.

The Imbalance volumes will be resolved by use of the following procedure:

a) If the Imbalance is negative and Imbalance volumes were approved by the Company, then the customer will be billed for the Imbalance volumes at a rate equal to 110% of the Company's sales rate (G-1). However, if the Imbalance volumes were not approved by the Company, then the Imbalance volumes shall be deemed as an overrun and may be billed at $15.00 per Mcf. The Company has no obligation to provide gas supply to a customer electing service under this tariff.

If the Imbalance is positive, then the Company will purchase the Imbalance volumes in excess of "parked" volumes from the customer at the rates described in the following "Cash out" method in item (b).

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Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 47B
Cancelling
Original SHEET No. 47B

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4

(T)

b) "Cash out" Method

Imbalance volumes		Cash-out Price
First [1] 5% of Mcf $_{\text{Customer}}$	@	100% of Index Price [2]
Next [1] 5% of Mcf $_{\text{Customer}}$	@	90% of Index Price [2]
Over [1] 10% of Mcf $_{\text{Customer}}$	@	80% of Index Price [2]

[1] Not to exceed the Imbalance volumes

[2] The index price will equal the effective "Cash out" index price in effect for the transporting pipeline or as filed with the Commission by the Company.

c) Customer will be reimbursed for all pipeline transportation commodity charges applying to cash out volumes. However, the reimbursement will not exceed pipeline transportation commodity charges the Company would have incurred to transport the "Cash Out" volumes.

d) In addition to other tariff penalty provisions, the customer shall be responsible for any penalty(s) assessed by the pipeline(s) resulting from the customer's failure to match volumes that the customer had delivered to the Company's facilities with volumes the Company delivered into customer's facilities.

e) Customer may, by written agreement with the Company, arrange to "park" positive imbalance volumes, up to 10% of "MCF $_{\text{Company}}$ ", on a monthly basis at .10/MCF per month. The parking service will be provided on a "best efforts" basis by the Company. Parked volumes will be deemed "first through the meter" delivered to the Customer in the month following delivery to the Company on the Customer's account.

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 47B
Cancelling
Original SHEET No. 47B

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4

(T)

b) "Cash out" Method

Imbalance volumes		Cash-out Price
First [1] 5% of Mcf $_{\text{Customer}}$	@	100% of Index Price [2]
Next [1] 5% of Mcf $_{\text{Customer}}$	@	90% of Index Price [2]
Over [1] 10% of Mcf $_{\text{Customer}}$	@	80% of Index Price [2]

[1] Not to exceed the Imbalance volumes

[2] The index price will equal the effective "Cash out" index price in effect for the transporting pipeline or as filed with the Commission by the Company.

c) Customer will be reimbursed for all pipeline transportation commodity charges applying to cash out volumes. However, the reimbursement will not exceed pipeline transportation commodity charges the Company would have incurred to transport the "Cash Out" volumes.

d) In addition to other tariff penalty provisions, the customer shall be responsible for any penalty(s) assessed by the pipeline(s) resulting from the customer's failure to match volumes that the customer had delivered to the Company's facilities with volumes the Company delivered into customer's facilities.

e) Customer may, by written agreement with the Company, arrange to "park" positive imbalance volumes, up to 10% of "MCF $_{\text{Company}}$ ", on a monthly basis at .10/MCF per month. The parking service will be provided on a "best efforts" basis by the Company. Parked volumes will be deemed "first through the meter" delivered to the Customer in the month following delivery to the Company on the Customer's account.

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Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 47C
Cancelling
Original SHEET No. 47C

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4

(T)

7. **Curtailment**

All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission and for any causes due to force majeure (which includes acts of God; strikes, lockouts, civil commotion, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, etc.); and for any other necessary or expedient reason at the discretion of the Company.

8. **Special Provisions**

It will be the responsibility of the customer to pay all costs for additional facilities and/or equipment which will be required as a result of receiving service under this Firm Carriage Service Rate T-4. Electronic flow measurement ("EFM") equipment is required to be installed, maintained, and operated by the Company to obtain transportation service. The customer is responsible for providing the electric and communications support services related to the EFM equipment. Customers required to install EFM may elect the optional monthly EFM facilities charges (Sheet No. 51). EFM equipment is not required for customers whose contractual requirements with the Company are less than 100 Mcf/day; however, such customers may, at their option, elect to install EFM equipment under the same provisions set forth above. (T)

No gas delivered under this rate schedule and applicable contract shall be available for resale to anyone other than an end-user for use as a motor vehicle fuel. (D)

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 47C
Cancelling
Original SHEET No. 47C

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4

(T)

7. **Curtailment**

All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission and for any causes due to force majeure (which includes acts of God; strikes, lockouts, civil commotion, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, etc.); and for any other necessary or expedient reason at the discretion of the Company.

8. **Special Provisions**

It will be the responsibility of the customer to pay all costs for additional facilities and/or equipment which will be required as a result of receiving service under this Firm Carriage Service Rate T-4. Electronic flow measurement ("EFM") equipment is required to be installed, maintained, and operated by the Company to obtain transportation service. The customer is responsible for providing the electric and communications support services related to the EFM equipment. Customers required to install EFM may elect the optional monthly EFM facilities charges (Sheet No. 51). EFM equipment is not required for customers whose contractual requirements with the Company are less than 100 Mcf/day; however, such customers may, at their option, elect to install EFM equipment under the same provisions set forth above. (T)

No gas delivered under this rate schedule and applicable contract shall be available for resale to anyone other than an end-user for use as a motor vehicle fuel. (D)

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 47D
Cancelling
Original SHEET No. 47D

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service (T)
Rate T-4

9. **Terms and Conditions**

a) Specific details relating to volume, delivery point and similar matters shall be covered by a separate written contract or amendment with the customer.

b) The Company will not be obligated to deliver a total supply of gas to the customer in excess of the customer's maximum daily carriage volumes. The Company has no obligation under this tariff to provide any sales gas to the customer.

c) It shall be the customer's responsibility to make all necessary arrangements, including obtaining any regulatory approval required, to deliver gas under this Firm Carriage Service Rate to the facilities of the Company. (T)

d) The Company reserves the right to refuse to accept gas that does not meet the Company's quality specifications.

e) The Rules and Regulations and Orders of the Kentucky Public Service Commission and of the Company and the Company's General Terms and Conditions applicable to the Company's Sales Tariff Rates shall likewise apply to these Carriage Service Rates and all contracts and amendments thereunder.

f) In the event the customer loses its gas supply, it may be allowed a reasonable time in which to secure replacement volumes (up to the contract daily carriage quantity), subject to provisions of Section 5 of this tariff.

A "reasonable time" will be, except when precluded by operational constraints, matched to the make-up grace period by the respective interstate pipeline transporter.

g) The customer will be solely responsible to correct, or cause to be corrected, any imbalances it has caused on the applicable pipeline's system.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 47D
Cancelling
Original SHEET No. 47D

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service (T)
Rate T-4

9. **Terms and Conditions**

a) Specific details relating to volume, delivery point and similar matters shall be covered by a separate written contract or amendment with the customer.

b) The Company will not be obligated to deliver a total supply of gas to the customer in excess of the customer's maximum daily carriage volumes. The Company has no obligation under this tariff to provide any sales gas to the customer.

c) It shall be the customer's responsibility to make all necessary arrangements, including obtaining any regulatory approval required, to deliver gas under this Firm Carriage Service Rate to the facilities of the Company. (T)

d) The Company reserves the right to refuse to accept gas that does not meet the Company's quality specifications.

e) The Rules and Regulations and Orders of the Kentucky Public Service Commission and of the Company and the Company's General Terms and Conditions applicable to the Company's Sales Tariff Rates shall likewise apply to these Carriage Service Rates and all contracts and amendments thereunder.

f) In the event the customer loses its gas supply, it may be allowed a reasonable time in which to secure replacement volumes (up to the contract daily carriage quantity), subject to provisions of Section 5 of this tariff.

A "reasonable time" will be, except when precluded by operational constraints, matched to the make-up grace period by the respective interstate pipeline transporter.

g) The customer will be solely responsible to correct, or cause to be corrected, any imbalances it has caused on the applicable pipeline's system.

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PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 48
Cancelling
Original SHEET No. 48

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4 (T)

10. Late Payment Charge

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for *rendered services*. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

11. Alternative Fuel Responsive Flex Provision

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the applicable Distribution Charge on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request. (T)

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

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Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 48
Cancelling
Original SHEET No. 48

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4 (T)

10. Late Payment Charge

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

11. Alternative Fuel Responsive Flex Provision

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the applicable Distribution Charge on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request. (T)

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

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Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised Sheet No. 49
Cancelling
Orginal Sheet No. 49

WESTERN KENTUCKY GAS COMPANY

Alternate Receipt Point Service
Rate T-5

(N)

1. **Applicable**

Entire service area of the Company to any customer, subject to limitations noted below, for that portion of the customer's transportation (Rate T-2) or carriage service (Rate T-3 or Rate T-4) requirements.

2. **Availability of Service**

a) Available, subject to restrictions noted below, to any customer utilizing transportation or carriage services, on an individual service at the same premise, who has purchased its own supply of natural gas and requests delivery to the Company at a receipt point other than the Company's interconnection with the pipeline, or supplier immediately upstream of customer's premises.
b) The alternate receipt point through which service is requested must be physically accessible via the Company's existing pipeline system upstream of the delivery point to the customer's facilities.
c) The Company, in its sole judgment, shall determine the portions of its system to which access may be granted to a specific Alternate Receipt Point.
d) Access to certain alternate receipt points may be limited or restricted altogether by the Company, in its sole judgment.
e) Availability of service is contingent upon the Company's sole determination that such service is available through existing facilities.
f) The Company may decline to initiate service to a customer under this tariff, if in the Company's sole judgment, the performance of such service would be contrary to good operating practice or would have a detrimental impact on other customers serviced by the Company.

3. **Net Monthly Rate**

In addition to any and all charges assessed by other parties, and in addition to the charges applicable to Customer associated with their transportation (Rate T-2) or carriage service (Rate T-3 or Rate T-4) requirements, the following supplemental distribution charge will be applied to all volumes received and transported from the Alternate Receipt Point:

a) Distribution Charge @ $0.10 per Mcf

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised Sheet No. 49
Cancelling
Orginal Sheet No. 49

WESTERN KENTUCKY GAS COMPANY

Alternate Receipt Point Service
Rate T-5

(N)

1. Applicable
Entire service area of the Company to any customer, subject to limitations noted below, for that portion of the customer's Rate T-2 transportation or carriage service (Rate T-3 or Rate T-4) requirements.

2. Availability of Service
a) Available, subject to restrictions noted below, to any customer utilizing transportation or carriage services, on an individual service at the same premise, who has purchased its own supply of natural gas and requests delivery to the Company at a receipt point other than the Company's interconnection with the pipeline, or supplier immediately upstream of customer's premises, or the receipt point designated as the primary receipt point in such customer's contract with the Company.
b) The alternate receipt point through which service is requested must be physically accessible via the Company's existing pipeline system upstream of the delivery point to the customer's facilities.
c) The Company shall determine the portions of its system to which access may be granted to a specific Alternate Receipt Point.
d) Access to certain alternate receipt points may be limited or restricted altogether by the Company.
e) Availability of service is contingent upon the Company's determination that such service is available through existing facilities.
f) The Company may decline to initiate service to a customer under this tariff, if in the Company's judgment, the performance of such service would be contrary to good operating practice or would have a detrimental impact on other customers serviced by the Company.

3. Net Monthly Rate
In addition to any and all charges assessed by other parties, and in addition to the charges applicable to Customer associated with their Rate T-2 transportation or Rate T-4 carriage service requirements, the following supplemental administrative charge will be applied during months in which volumes are received and transported from the Alternate Receipt Point:

a) Administrative Charge @ $50.00 per month

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PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised Sheet No. 50
Cancelling
Original Sheet No. 50

WESTERN KENTUCKY GAS COMPANY

Alternate Receipt Point Service
Rate T-5 (N)

4. **Imbalances**

a) Volumes delivered by the Company under the Alternate Receipt Point service may be subjected to imbalance restrictions additional to those specified in the transportation (Rate T-2) or carriage (Rate T-3 or Rate T-4) tariffs.
b) Banking or Parking allowances for volumes delivered under the Alternate Receipt Point service may be limited or restricted altogether, at the Company's sole judgment.

5. **Terms and Conditions**

a) Volumes under the Alternate Receipt Point service are received for redelivery by the Company on a strictly interruptible basis.
b) The Company is not responsible for any costs incurred by the customer in its arrangement for gas supply or capacity to the Alternate Receipt Point.
c) Specific details relating to volume, receipt point(s) and similar matters shall be covered by a separate written contract or amendment with the customer.
d) Other than provisions referenced herein, or as more specifically set forth in the contract or amendment with the customer, all provisions of the customer's transportation (Rate T-2) or carriage (Rate T-3 or Rate T-4) tariffs shall apply.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised Sheet No. 50
Cancelling
Original Sheet No. 50

WESTERN KENTUCKY GAS COMPANY

Alternate Receipt Point Service
Rate T-5 (N)

The administrative fee is waived if, during the month, the Alternate Receipt Point represents the only point of receipt utilized by the customer.

4. **Imbalances**
a) Volumes delivered by the Company under the Alternate Receipt Point service may be subjected to imbalance restrictions additional to those specified in the transportation (Rate T-2) or carriage (Rate T-3 or Rate T-4) tariffs.
b) Banking or Parking allowances for volumes delivered under the Alternate Receipt Point service may be limited or restricted altogether, at the Company's judgment.

5. **Terms and Conditions**
a) Volumes under the Alternate Receipt Point service are received for redelivery by the Company on a strictly interruptible basis.
b) The Company is not responsible for any costs incurred by the customer in its arrangement for gas supply or capacity to the Alternate Receipt Point.
c) Specific details relating to volume, receipt point(s) and similar matters shall be covered by a separate written contract or amendment with the customer.
d) Other than provisions referenced herein, or as more specifically set forth in the contract or amendment with the customer, all provisions of the customer's transportation (Rate T-2) or carriage (Rate T-3 or Rate T-4) tariffs shall apply.

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 51
Cancelling
First Revised SHEET No. 51

WESTERN KENTUCKY GAS COMPANY

Special Charges

Service	After Hours	Regular	
Meter Set*	$35.00	$28.00	(N)
Turn-on*	25.00	20.00	(N,I)
Read	14.00	12.00	(N)
Reconnect Delinquent Service	40.00	34.00	(N,I)
Seasonal Charge	73.00	65.00	(N)
Special Meter Reading Charge	N/A	No Charge	
Meter Test Charge	N/A	20.00	
Returned Check Charge	N/A	23.00	(I)
Late Payment Charge (Rate G-1 only)		5%	(N)
Premises Charge for new residential service connections**			
- Requiring main extension		13.05 per mo.	(N)
- Not requiring main extension		11.25 per mo.	
Optional Facilities Charge for Electronic Flow Measurement ("EFM") equipment			
- Class 1 EFM equipment (less than $7,500, including installation costs)		105.00 per mo.	
- Class 2 EFM equipment (more than $7,500, including installation costs)		245.00 per mo.	(N)

* Waived for qualified low income applicants ("LIHEAP participants")
** Waived for qualified low income applicants ("LIHEAP participants") and HUD-certified low income new housing (N)

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 51
Cancelling
First Revised SHEET No. 51

WESTERN KENTUCKY GAS COMPANY

Special Charges

Service	After Hours	Regular	
Meter Set*	$35.00	$28.00	(N)
Turn-on*	25.00	20.00	(N,I
Read	14.00	12.00	(N)
Reconnect Delinquent Service	40.00	34.00	(N,I
Seasonal Charge	73.00	65.00	(N)
Special Meter Reading Charge	N/A	No Charge	
Meter Test Charge	N/A	20.00	
Returned Check Charge	N/A	23.00	(I)
Late Payment Charge (Rate G-1 only)		5%	(N)
Optional Facilities Charge for Electronic Flow Measurement ("EFM") equipment			
- Class 1 EFM equipment (less than $7,500, including installation costs)		105.00 per mo.	
- Class 2 EFM equipment (more than $7,500, including installation costs)		245.00 per mo.	(N)

* Waived for qualified low income applicants ("LIHEAP participants")

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 62
Cancelling
Original SHEET No. 62

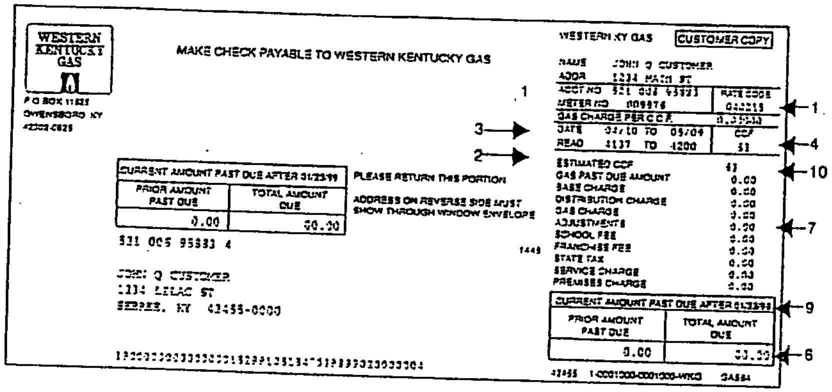
WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(C)

4. **Billings**

a) The following is an example of the monthly bills sent to the Company's residential customers:



WESTERN KENTUCKY GAS
P O BOX 11825
OWENSBORO KY
42302-0825

MAKE CHECK PAYABLE TO WESTERN KENTUCKY GAS

CURRENT AMOUNT PAST DUE AFTER 01/23/99	
PRIOR AMOUNT PAST DUE	TOTAL AMOUNT DUE
0.00	00.00

PLEASE RETURN THIS PORTION

ADDRESS ON REVERSE SIDE MUST SHOW THROUGH WINDOW ENVELOPE

321 005 95333 4

JOHN Q CUSTOMER
1234 LILAC ST
SERRES, KY 42455-0000

WESTERN KY GAS CUSTOMER COPY

NAME JOHN Q CUSTOMER
ADDR 1234 MAIN ST
ACCT NO 321 005 95333 RATE CODE G42215
METER NO 009976
GAS CHARGE PER C C F
DATE 04/10 TO 05/09 CCF
READ 4137 TO 4200 53

ESTIMATED CCF 43
GAS PAST DUE AMOUNT 0.00
BASE CHARGE 0.00
DISTRIBUTION CHARGE 0.00
GAS CHARGE 0.00
ADJUSTMENTS 0.00
SCHOOL FEE 0.00
FRANCHISE FEE 0.00
STATE TAX 0.00
SERVICE CHARGE 0.00
PREMISES CHARGE 0.00

CURRENT AMOUNT PAST DUE AFTER 01/23/99	
PRIOR AMOUNT PAST DUE	TOTAL AMOUNT DUE
0.00	00.00

1. Class of Service (Please see Sheet 7).
2. Present and last preceding meter reading.
3. Date of present reading.
4. Number of units consumed.
5. Meter constant if any – not applicable to Residential service.
6. Net amount for service rendered.
7. Any adjustments.
8. Gross amount of bill – not applicable to Residential service.
9. Date after which a penalty may apply.
10. Indicates an estimated or calculated bill.

NOTE: LARGE VOLUME COMMERCIAL AND INDUSTRIAL BILLING WILL DISPLAY THE ABOVE INFORMATION, BUT MAY BE PRESENTED IN A DIFFERENT FORMAT.

ISSUED: June 23, 1999

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ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 62
Cancelling
Original SHEET No. 62

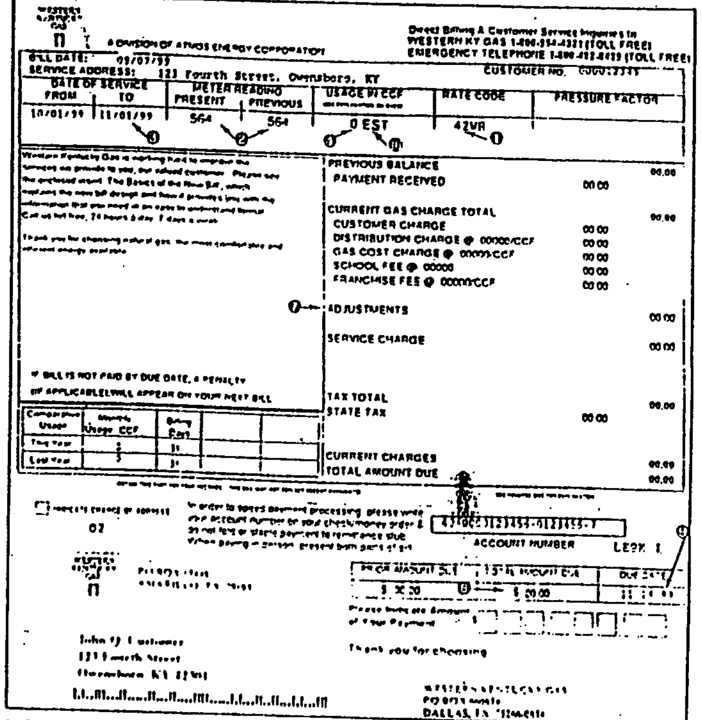
WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(C)

4. **Billings**

a) The following is an example of the monthly bills sent to the Company's residential customers:



A DIVISION OF ATMOS ENERGY CORPORATION

Direct Billing & Customer Service Inquiries to
WESTERN KY GAS 1-800-354-4321 (TOLL FREE)
EMERGENCY TELEPHONE 1-800-482-8439 (TOLL FREE)

BILL DATE: 09/07/99
SERVICE ADDRESS: 123 Fourth Street, Owensboro, KY
CUSTOMER NO.

DATE OF SERVICE		METER READING		USAGE IN CCF	RATE CODE	PRESSURE FACTOR
FROM	TO	PRESENT	PREVIOUS			
10/01/99	11/01/99	564	564	0 EST	42VR	

PREVIOUS BALANCE		00.00
PAYMENT RECEIVED	00.00	
CURRENT GAS CHARGE TOTAL		00.00
CUSTOMER CHARGE	00.00	
DISTRIBUTION CHARGE @ 00000/CCF	00.00	
GAS COST CHARGE @ 00000/CCF	00.00	
SCHOOL FEE @ 00000	00.00	
FRANCHISE FEE @ 00000/CCF	00.00	
ADJUSTMENTS		00.00
SERVICE CHARGE		00.00
TAX TOTAL		00.00
STATE TAX	00.00	
CURRENT CHARGES		00.00
TOTAL AMOUNT DUE		00.00

IF BILL IS NOT PAID BY DUE DATE, A PENALTY (IF APPLICABLE) WILL APPEAR ON YOUR NEXT BILL

02

ACCOUNT NUMBER

Thank you for choosing

DALLAS, TX

1 Class of Service (Please See Sheet No. 7)
2 Present and Last Preceding Meter Reading
3 Date of Present Reading
4 Number of Units Consumed
5 Meter Constant If Any - Not Applicable to Residential Service
6 Net Amount for Service Rendered
7 Any Adjustments
8 Gross Amount of Bill - Not Applicable to Residential Service
9 Date After Which a Penalty May Apply
10 Indicates an Estimated or Calculated Bill

NOTE Large Volume Commercial and Industrial Billing Will Display the Above Information, But May be Presented in a Different Format

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Vice President – Rates & Regulatory Affairs

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 65
Cancelling
Original Sheet No. 65

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

e) The Company will issue to every customer from whom a deposit is collected a receipt of deposit. The receipt will show the name of the customer, location of the service or customer, account number, date, and amount of deposit. If the deposit amount changes, the Company will issue a new receipt of deposit to the customer.

f) Except for Winter Hardship Reconnections (as provided by Section 12 of these Rules and Regulations) customer service may be refused or discontinued if payment of requested deposit is not made.

g) Interest will accrue on all deposits at a rate prescribed by law, beginning on the date of deposit. Interest accrued will be refunded to the customer or credited to the customer's bill on an annual basis, except that the Company will not be required to refund or credit interest on deposits if the customer's bill is delinquent on the anniversary of the deposit date. If interest is paid or credited to the customer's bill prior to twelve (12) months from the date of deposits, the payment or credit shall be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill with any remainder refunded to the customer.

When a deposit is required from a customer it will be held for twelve (12) months, or until service is discontinued, unless one of the following has occurred: (a) service has been terminated for non-payment of services or (b) the customer has been late on two (2) or more payments in the last twelve (12) months.

6. **Special Charges**

The Company may make special nonrecurring charges, approved by the Commission, to recover customer-specific costs incurred to benefit specific customers. Listed below are the special charges included in the Company's tariff and a short description of the related service performed or action taken by the Company. See the Special Charges, Sheet No. 51 for the amount of the charge.

a) Meter Set. A meter set charge may be assessed for a new service or re-set, or temporary service. (N)

b) Turn On. A turn on charge may be assessed for connecting service which has been terminated or idle at a given premises for reasons other than nonpayment of bills or violation of the Company or Commission regulations. (T)

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 65
Cancelling
Original Sheet No. 65

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

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f) Except for Winter Hardship Reconnections (as provided by Section 12 of these Rules and Regulations) customer service may be refused or discontinued if payment of requested deposit is not made.

g) Interest will accrue on all deposits at a rate prescribed by law, beginning on the date of deposit. Interest accrued will be refunded to the customer or credited to the customer's bill on an annual basis, except that the Company will not be required to refund or credit interest on deposits if the customer's bill is delinquent on the anniversary of the deposit date. If interest is paid or credited to the customer's bill prior to twelve (12) months from the date of deposits, the payment or credit shall be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill with any remainder refunded to the customer.

When a deposit is required from a customer it will be held for twelve (12) months, or until service is discontinued, unless one of the following has occurred: (a) service has been terminated for non-payment of services or (b) the customer has been late on two (2) or more payments in the last twelve (12) months.

6. **Special Charges**

The Company may make special nonrecurring charges, approved by the Commission, to recover customer-specific costs incurred to benefit specific customers. Listed below are the special charges included in the Company's tariff and a short description of the related service performed or action taken by the Company. See the Special Charges, Sheet No. 51 for the amount of the charge.

a) Meter Set. A meter set charge may be assessed for a new service or re-set, or temporary service. (N)

b) Turn On. A turn on charge may be assessed for connecting service which has been terminated or idle at a given premises for reasons other than nonpayment of bills or violation of the Company or Commission regulations. (T)

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PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 66
Cancelling
Original SHEET No. 66

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

c) Read. A read charge may be assessed for the establishment of new service where only a meter read is required. (N)

d) Reconnect Delinquent Service. A reconnect delinquent service charge may be assessed to reconnect a service which has been terminated for nonpayment of bills or violation of the Company or Commission regulations. Customers qualifying for service reconnection under Section 12 of these Rules and Regulations shall be exempt from reconnect charges. (T)

e) Seasonal Charge. A seasonal charge may be assessed when the customer's service has been disconnected at his request and at any time subsequently within (12) months is reconnected at the same or any other premises. (N)

f) After Hours Charge. An additional charge shall be applied to any special service activity, including reconnects for delinquent service, initiated at the customer's request outside normal business hours such as at night, on weekends or holidays. The Company shall advise the customer of the applicable after hours charge upon initiation of the service request and offer the customer the alternative to perform the requested activity during normal business hours, including reconnects for delinquent service, as a means to avoid the after hours charge. (N)

g) Special Meter Reading Charge. This charge may be assessed when a customer requests that a meter be reread and the second reading shows that the original reading was correct. No charge shall be assessed if the original reading was incorrect. This charge may also be assessed when a customer who reads his own meter fails to read the meter for three (3) consecutive months, and it is necessary for a Company representative to make a trip to read the meter.

(No such charge may be assessed until the amount of the charge is approved or otherwise accepted by the Commission).

h) Meter Resetting Charge. A charge may be assessed for resetting a meter if the meter has been removed at the customer's request.

i) Meter Test Charge. This charge may be assessed if a customer requests the meter be tested pursuant to Section 13 and 807 KAR 5:006, section 18, and the tests show the meter is not more than two (2) percent fast. No charge shall be made if the test shows the meter is more than two (2) percent fast.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 66
Cancelling
Original SHEET No. 66

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

c) Read. A read charge may be assessed for the establishment of new service where only a meter read is required. (

d) Reconnect Delinquent Service. A reconnect delinquent service charge may be assessed to reconnect a service which has been terminated for nonpayment of bills or violation of the Company or Commission regulations. Customers qualifying for service reconnection under Section 12 of these Rules and Regulations shall be exempt from reconnect charges. (

e) Seasonal Charge. A seasonal charge may be assessed when the customer's service has been disconnected at his request and at any time subsequently within (12) months is reconnected at the same or any other premises. (

f) After Hours Charge. An additional charge shall be applied to any special service activity, including reconnects for delinquent service, initiated at the customer's request outside normal business hours such as at night, on weekends or holidays. The Company shall advise the customer of the applicable after hours charge upon initiation of the service request and offer the customer the alternative to perform the requested activity during normal business hours, including reconnects for delinquent service, as a means to avoid the after hours charge. (

g) Special Meter Reading Charge. This charge may be assessed when a customer requests that a meter be reread and the second reading shows that the original reading was correct. No charge shall be assessed if the original reading was incorrect. This charge may also be assessed when a customer who reads his own meter fails to read the meter for three (3) consecutive months, and it is necessary for a Company representative to make a trip to read the meter.

(No such charge may be assessed until the amount of the charge is approved or otherwise accepted by the Commission).

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ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 67
Cancelling
Original SHEET No. 67

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

j) Returned Check Charge. A returned check charge may be assessed if a check accepted for payment of a Company bill is not honored by the customer's financial institution.

k) Late Payment Charge. A late payment charge may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received will first be applied to the bill for services rendered. Additional penalty charges will not be assessed on unpaid penalty charges.

l) 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: (N)

1) Separate charges shall be computed and applied for those service connections requiring main extension and for those connections not requiring main extension.

2) The charges are applicable to all new residential service connections, commencing with connections made on and after January 1, 2001.

3) The charge shall be payable for 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.

4) Premises Charges shall not be applicable to HUD-certified low-income new housing or to LIHEAP-qualified customers at any service address.

5) The Company shall update the amounts of the charges annually and, upon Commission approval, apply 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 in the ensuing year.

6) 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.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
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WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

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7. Customer Complaints to the Company

Upon complaint to the Company by a customer at the Company's office, by telephone, or in writing, the Company will make a prompt and complete investigation and advise the complainant of its findings. If a written complaint or a complaint made in person at the Company's office is not resolved, the Company will provide written notice to the complainant of his right to file a complaint with the Commission, and will provide him with the address and telephone number of the Commission. If a telephone complaint is not resolved, the Company will provide at least oral notice to the complainant of his right to file a complaint with the Commission and the address and telephone number of the Commission.

8. Bill Adjustments

a) If upon periodic test, request test, or complaint test, a meter in service is found to be more than two (2) percent fast, additional tests shall be made to determine the average error of the meter. The test will be made in accordance with Commission regulations applicable to the type of meter involved.

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Rules and Regulations

(C,T)

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ISSUED: June 23, 1999 EFFECTIVE: July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Settlement eliminated this
proposed page.

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 78
Cancelling
Original SHEET No. 78

WESTERN KENTUCKY GAS COMPANY

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e) The customer's piping extending from the outlet of the meter shall be installed and maintained by the customer at his expense.

f) The customer shall notify the Company promptly of any leaks in the transmission line or equipment, also, of any hazards or damages to same.

g) Customers may be required to send in monthly meter readings to the Company on suitable forms provided by the Company.

19. Owners Consent

In case the customer is not the owner of the premises where service is to be provided, it will be the customer's responsibility to obtain from the property owner or owners the necessary consent to install and maintain in or on said premises all such piping and other equipment as are required or necessary for supplying gas service to the customer whether the piping and equipment be the property of the customer or the Company.

The Company will not require a prospective customer to obtain easements or rights-of-way on property not owned by the prospective customer as a condition for providing service. The cost of obtaining easements or rights-of-way will be included in the total per foot cost of an extension, and will be apportioned according to Section 28 in these Rules and Regulations.

20. Customer's Equipment and Installation

a) The customer shall furnish, install and maintain at his expense the necessary customer's service line extending from the Company's service connection at the curb or property line to the building or place of utilization of the gas.

b) The installation of the customer's service line shall be made in accordance with the requirement of the constituted authorities and the Company's specifications covering locations, installation, kind and size of pipe, type of pipe coating or wrapping, and method of connecting the joints of pipe. The location shall be the point of easiest access to the Company from its facilities and the Company shall be consulted and its approval obtained before the installation is made.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 78
Cancelling
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WESTERN KENTUCKY GAS COMPANY

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ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 82
Cancelling
Original SHEET No. 82

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

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27. **Point of Delivery of Gas**

The point of delivery of gas supplied by the Company shall be at the point where the gas passes from the pipes of the Company's service connection in to the customer's service line or pipe or at the outlet of the meter, whichever is nearest the delivery main of the Company.

28. **Distribution Main Extensions**

a) The Company will extend an existing distribution main up to one hundred (100) feet for each single customer provided the following criteria is met:

1) The existing main is of sufficient capacity to properly supply the additional customer(s);

2) Provided that the customer(s) contracts to use gas on a continuous basis for one (1) year or more; and,

3) Provided 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.

b) Whenever an extension exceeds one hundred (100) feet per customer, the Company will enter into an agreement with the customer(s) or subscriber(s). The agreement will provide for the extension on a cost per foot basis with the additional amount to be deposited with the Company by the customer(s) or subscriber(s). The agreement will contain provisions for a proportionate and equitable refund in the event other customers are connected to the extension within a ten (10) year period. Refunds shall be made only after the customer(s) has used gas service for a minimum continuous period of one (1) year. The Company reserves the right to determine the length of the extension, to specify the pipe size and location of the extension, and to construct the extension in accordance with its standard practices. Title to all extensions covered by agreements shall be and remain in the Company and in no case shall the amount of any refunds exceed the original deposit. Any further or lateral extension shall be treated as a new and separate extension.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 82
Cancelling
Original SHEET No. 82

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(T)

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ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

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PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 85
Cancelling
First Revised SHEET No. 85

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

33. Curtailment Order

In cases of impairment of gas supply or distribution system capacity, or partial or total interruptions and when it appears that the Company is, or will be, unable to supply the requirements of all of its customers in any system or segment thereof, the Company shall curtail gas service to its customers in the manner set forth below. (T)

a) Definitions:

Residential – Service to customers for residential purposes including housing complexes and apartments.

Commercial – Service to customers engaged primarily in the sale of goods or services including institutions and local and federal agencies for uses other than those involving manufacturing.

Industrial – Service to customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product, including the generation of electric power for sale.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 85
Cancelling
First Revised SHEET No. 85

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

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ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

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PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 86
Cancelling
First Revised SHEET No. 86

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(C)

b) Priorities of Curtailment:

Sales Service

The Company may curtail or discontinue sales service in whole or in part on a daily, monthly or seasonal basis in any purchase zone in accordance with the following priorities, starting with Priority 8 and proceeding in descending numerical order.

High Priority

Priority 1. Residential and services essential to the public health where no alternate fuel exists (Rate G-1)

Priority 2. Small commercials less than 50 Mcf per day (Rate G-1).

Priority 3. Large commercials over 50 Mcf per day not included under lower priorities (Rates G-1, LVS-1)

Priority 4. Industrials served under Rate G-1 or LVS-1.

Low Priority

Priority 5. Customers served under Rates G-2 or LVS-2 other than boilers included in Priority 6.

Priority 6. Boiler loads shall be curtailed in the following order (Rates G-2 or LVS-2).

A – Boilers over 3,000 Mcf per day.
B – Boilers between 1,500 Mcf and 3,000 Mcf per day.
C – Boilers between 300 Mcf and 1,500 Mcf per day.

Priority 7. Imbalance sales service under Rate T-3 and Rate T-4.

Priority 8. Flex sales transactions.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 86
Cancelling
First Revised SHEET No. 86

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(C)

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PROPOSED TARIFF

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 87
Cancelling
First Revised SHEET No. 87

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(T)

c) Penalty for Unauthorized Overruns

In the event a customer fails in part or in whole to comply with a Company Curtailment Order either as to time or volume of gas used or uses a greater quantity of gas than its allowed volume under terms of the Curtailment Order, the Company may, at its sole discretion, apply a penalty rate of up to $15.00 per Mcf.

In addition to other tariff penalty provisions, the customer shall be responsible for any penalty(s) assessed by the interstate pipeline(s) or suppliers resulting from the customer's failure to comply with terms of a Company Curtailment Order.

The payment of penalty charges shall not be considered as giving any customer the right to take unauthorized volumes of gas, nor shall such penalty charges be considered as a substitute for any other remedy available to the Company.

d) Discontinuance of Service

The Company shall have the right, after reasonable notice to discontinue the gas supply of any customer that fails to comply with a valid curtailment order.

ISSUED: June 23, 1999 **EFFECTIVE:** July 24, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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SETTLEMENT TARIFF

FOR ENTIRE SERVICE AREA
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Second Revised SHEET No. 87
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First Revised SHEET No. 87

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

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ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

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)

ORDER

On June 23, 1999, Western Kentucky Gas Company ("Western"), a division of Atmos Energy Corporation, filed an application for a rate adjustment. On December 3, 1999, all parties to this case -- Western; the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention; and WBI Southern, Inc. -- filed a Joint Stipulation and Settlement ("Settlement"). The Commission entered an Order on December 6, 1999, requiring all parties to submit direct testimony on the reasonableness of the Settlement.

After having considered the record in this case, reviewing the Settlement, and being otherwise sufficiently advised, the Commission finds that:

1. All parties were given an opportunity to file evidence to support the reasonableness of the Settlement.

2. All parties filed evidence in support of the reasonableness of the Settlement on December 9, 1999.

3. The record in this matter is sufficient for the Commission to make its decision.

4. The hearing scheduled in this case for December 14, 1999 at 9:00 a.m. should be cancelled and the case submitted to the Commission for a decision on the record.

IT IS THEREFORE ORDERED that the hearing scheduled for December 14, 1999, at 9:00 a.m. is cancelled and the case is hereby submitted to the Commission for a decision on the record.

Done at Frankfort, Kentucky, this 10th day of December, 1999.

By the Commission

ATTEST:

Executive Director

Murry

BEFORE THE KENTUCKY
PUBLIC SERVICE COMMISSION

WESTERN KENTUCKY GAS COMPANY
AN UNINCORPORATED DIVISION OF
ATMOS ENERGY CORPORATION

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

December 1999

BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

PREPARED REBUTTAL 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. Are you the same Donald A. Murry who has testified previously in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. I want to comment on Carl G. K. Weaver's testimony on behalf of the Attorney General's Office.

Q. What issues do you have with Dr. Weaver's testimony?

A. There are three broad areas that I would like to address. Each of these are important mechanical problems with the analysis described in his testimony. First, Dr. Weaver uses data that encompass an overly broad time period. This arbitrary selection of a time period lowers his results. Second, he chooses to include return on equity (ROE) estimates that are less than the current return on Baa rated utility bonds. These low returns are unreasonable and serve no purpose other than to bias his calculations downward. In turn, this serves to lower his ROE recommendation in this case. Third, Dr. Weaver uses an inappropriate method to calculate his Capital Asset Pricing Model (CAPM), which lowers his estimate. The financial literature advises against the method he used.

Q. You stated that Dr. Weaver's data encompass an overly broad time period. Why is this important?

A. As part of his Discounted Cash Flow (DCF) analysis, he used a ten-year time period to represent his historical growth rate. The ten-year period includes the influence of many economic factors that have little relevance in assessing current and future risks of Western Kentucky and the gas distribution sector. Data ten-years old will not influence current investors and when used without discretion, produce misleading results.

Q. Does the use of historical data about dividends per share (DPS), earnings per share (EPS), and book value per share (BVS) have any use in the DCF calculation of ROE?

A. Yes, they do. A more prudent empirical analysis would examine DPS, EPS, and BVS data from a more recent period, such as the past five years. Even then there is a question of appropriateness because rates are being set for the future, and today's investors are primarily interested in the future returns during the time they will hold the securities. Dr. Weaver's choice of the ten-year data serve to lower the historical growth rate in the DCF.

Q. What is the effect of Dr. Weaver's use of ten-year data upon his DCF estimate of the ROE for Western Kentucky?

A. It serves to produce a downward bias in the DCF.

Q. How does the use of the ten-year data lower the growth rate of Dr. Weaver's DCF analysis?

A. I have revised his Schedule 20 using *Value Line*'s five-year historical data in my Schedule DAM-R1. As one can see, the five-year data present a different financial picture than do the ten-year data. As Schedule DAM-R1 shows, the EPS growth for the Selected Companies increase from 4.8% to 7.6%. Likewise, Atmos' EPS growth increased from 4.5% to 9.5%. There is a five hundred basis point difference. I have revised Dr. Weaver's Schedule 23 by including the five-year historical growth rates in the DCF calculation which I have illustrated in Schedule DAM-R2. It is easy to see how dramatically different the results produced are when one uses more current and more relevant data in Dr. Weaver's analysis.

Q. Earlier you stated that Dr. Weaver included ROE estimates in his analysis that were lower than the Moody's Baa Utility Bond Yields. How did you come to that conclusion?

A. In Schedule 18 of his Direct Testimony, Dr. Weaver reports a Baa bond yield of 8.14%.

Q. Should Dr. Weaver have excluded all ROE estimates less than 8.14% from his analysis?

A. Yes. But he should have excluded even more than those. When rational investors have the choice between two investments with the same returns, yet different risks, they will choose the investment with less risk. In this case, investors typically would choose to purchase Baa utility bonds with their relatively guaranteed yield. In contrast, the stock returns have the possibility of not materializing.

Q. What would a prudent analyst do to adjust for the differences in risk?

A. The financial literature indicates that the return on equity is typically between three hundred to five hundred basis points higher than the yield of utility bonds. Consequently, Dr. Weaver should have excluded any ROE estimate from his judgement that falls below that range. In order to be conservative, I adjusted Dr. Weaver's DCF to exclude all DCF estimates that were less than 150 basis points higher than the Baa Utility Bond yields. In other words, I eliminated those ROE estimates less than 9.64%.

Q. What effect does the exclusion of ROE estimates that are less than 9.64% have on Dr. Weaver's DCF analysis?

A. As I demonstrate in Schedule DAM-R2, the revisions of Weaver's Schedule 23 serve to remove the downward empirical bias of their inclusion. Upon close inspection, one will note that it removes most of the ten-year historical DCF estimates from the analysis. Likewise, the DCF estimates using DPS growth rates disappear entirely from consideration. When adjusted, the DCF serves to produce more credible estimates.

Q. What range of ROE estimates does the corrected DCF produce?

A. When corrected, the DCF produces a range of 9.76% to 11.39% for the Selected Comparable Companies and a range of 14.23% to 14.37% for Atmos. These ranges meet or exceed the return estimates from my Direct Testimony.

Q. Does Dr. Weaver's CAPM analysis correct for the analytical mistakes he made in his DCF analysis?

A. No, it does not. In fact, Dr. Weaver repeats many of the mistakes of his DCF in his CAPM analysis.

Q. What mistakes does he make in his CAPM?

A. There are three broad analytical errors that produce downward biases in Dr. Weaver's CAPM estimates. First, he uses short-term T-Bill yields for his risk-free in his CAPM analysis. The financial literature cautions against their use. Second, Dr. Weaver applies a geometric mean as his market return when the financial literature clearly prescribes the arithmetic mean in the CAPM. Third, he includes ROE estimates in his CAPM analysis that are less than the current yields on Baa Utility bonds.

Q. Why should Dr. Weaver have excluded short-term T-Bill yields as his risk-free rate in his CAPM analysis?

A. T-Bill yields are notoriously unstable. Their variance is greater than longer term Treasury bonds. In addition, the planning horizon for equity investments more closely matches the planning horizon of longer maturity bonds. As such, the overall risk of holding either gets captured in the risk-free rate of these instruments. T-Bills do not possess the necessary premia of expected inflation and other market uncertainties which are similar to the equity investment in Treasury bonds.

Q. You stated that Dr. Weaver used a geometric mean in his analysis rather than an arithmetic mean. Why is the use of a geometric mean inappropriate for the market return in the CAPM?

A. The geometric mean measures realized returns rather than expected returns. The arithmetic mean assesses expected returns by including adjustments that account for the uncertainty associated with the equity investment. By using the geometric mean for his market return, Dr. Weaver understates the expected ROE with a biased estimate. Dr. Weaver's market return was 15.2% when it should have been 18.15%. This error lowered the estimate from his CAPM methodology.

Q. How can you be certain that Dr. Weaver used a geometric mean calculation in his CAPM analysis?

A. The data indicates that he did, and he confirmed that he used a geometric mean calculation in his response to Western Kentucky's Data Request Number 3. The question asked was the following:

> Refer to Schedules 24 and 25 of Dr. Weaver's Direct Testimony. Is the market return using the Value Line data that Dr. Weaver uses calculated using a geometric average or an arithmetic average? If the Market Return is a geometric average, please cite sources from referred journals that prescribe the use of a geometric average when calculating a market return.

Dr. Weaver's response was the following:

> A geometric mean was used to determine a one-year growth rate from the August 27 Appreciation Potential which was 65%.
>
> The calculation was: $[(1.65)^{1/4} - 1]$ = annual rate.
>
> This assumes that price appreciation growth occurs at a compound rate which is a correct assumption when considering growth over a period a years. A good discussion of this can be found in an investment management text book by Henry Latane and Donald L. Tuddle. This book dates from the late 1960's or early 1970. I no longer have it in my possession. Ibbotsen[sic] at one time discussed the proper use of a geometric mean to determine a growth rate versus an arithmetic mean to determine a descriptor of a population of data in the SBBI Handbook.

Although, Dr. Weaver is correct that Ibbotson's SBBI Handbook discusses the use of a geometric mean in a CAPM analysis, this source unequivocally states that it is incorrect to do so. Ibbotson states as follows:

> For use as the expected equity risk premium in the CAPM, the *arithmetic or simple difference* of the *arithmetic means* of stock market returns and riskless rates if the relevant number. This is because the CAPM is an additive model where the cost of capital is the sum of its parts. Therefore, the CAPM expected equity risk premium must be derived by arithmetic, *not geometric*, subtraction.

Please see Schedule DAM-R3.

Q. Does Dr. Weaver repeat the analytical mistake of his DCF by including ROE estimates that are less than the Baa Utility Bond yields?

A. Yes, he does. I compensate for his oversight by excluding those ROE estimates that exceed the Baa Utility bond yield of 8.14% by 150 basis points. I demonstrate the results in Schedules DAM-R4 and DAM-R5.

Q. Were there any other corrections to Dr. Weaver's CAPM analysis?

A. Yes. In estimating his total market return, he examined only capital appreciation. He ignored dividend returns completely.

Q. What do the revised schedules show regarding the proper calculation of the CAPM ROE?

A. Schedule DAM-R4, the revision of Dr. Weaver's Schedule 24, shows that the CAPM for the Selected Comparable Companies produces a ROE of 11.82%. This is one hundred basis points higher than Dr. Weaver's estimate, which has a low bias. Again, the corrected CAPM closely resembles, and confirms, the results of my analysis presented in my Direct Testimony.

Q. When you apply these corrections to Dr. Weaver's CAPM analysis for Atmos, what are the results?

A. The effects are dramatic. Dr. Weaver's biased estimate produced a ROE of 9.09%. When done correctly, the result is 11.99%. This ROE is actually higher than the one my analysis produces. Schedule DAM-R5, the revision of Dr. Weaver's Schedule 25, demonstrates these results.

Q. Can you summarize your rebuttal testimony?

A. The summary of the corrections to Dr. Weaver's calculations are shown in Schedule DAM-R6. Dr. Weaver applies irrelevant data and analytically deficient methods in both his DCF and CAPM calculations. When the obvious, biased data and methods are corrected, his results are equal to or higher than the results of my calculations presented in my Direct Testimony.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Schedule DAM-R1

Exhibit____
Carl G. K. Weaver
Schedule 20 **REVISED**

Western Kentucky Gas Company
Five-Year Historical Growth Rates

Company Name	Value Line EPS	Value Line DPS	Value Line BVS
Energen	7.5%	4.0%	9.5%
Laclede	5.5%	1.5%	3.5%
New Jersey Res.	9.5%	1.0%	2.5%
Piedmont	8.0%	6.0%	6.5%
Average	7.6%	3.1%	5.5%
Atmos	9.5%	4.0%	4.0%

Source: Value Line September 24, 1999; Annual Rates, past 5 years

Schedule DAM-R2

Exhibit ____
Carl G. K. Weaver
Schedule 23 **REVISED**

Western Kentucky Gas Company
Selected Comparable Companies
Discounted Cash Flow Analysis

Source for Estimated Growth	Growth Rates	Dividend Yield	Growth Adjusted Dividend Yield	DCF Estimated Cost of Equity	Adjusted Greater than 1.5% Moody's Baa
Forecasted Growth Rates for Selected Companies					
I/B/E/S	5.60%	4.53%	4.78%	10.38%	10.38%
VL-EPS	6.90%	4.53%	4.84%	11.74%	11.74%
VL-DPS	3.40%	4.53%	4.68%	8.08%	
VL-BVS	6.50%	4.53%	4.82%	11.32%	11.32%
Average:				10.38%	11.15%
Forecasted Growth Rates for Atmos					
I/B/E/S	8.10%	4.45%	4.81%	12.91%	12.91%
VL-EPS	11.50%	4.45%	4.96%	16.46%	16.46%
VL-DPS	4.50%	4.45%	4.65%	9.15%	
VL-BVS	8.50%	4.45%	4.83%	13.33%	13.33%
Average:				12.96%	14.23%
10 Year Historical Growth Rates for Selected Companies					
EPS	4.80%	4.53%	4.75%	9.55%	
DPS	4.10%	4.53%	4.72%	8.82%	
BVS	5.00%	4.53%	4.76%	9.76%	9.76%
Average:				9.37%	9.76%
10 Year Historical Growth Rates for Atmos					
EPS	4.50%	4.45%	4.65%	9.15%	
DPS	4.00%	4.45%	4.63%	8.63%	
BVS	4.50%	4.45%	4.65%	9.15%	
Average:				8.98%	Undefined
5 Year Historical Growth Rates for Selected Companies					
EPS	7.63%	4.53%	4.88%	12.50%	12.50%
DPS	3.13%	4.53%	4.67%	7.80%	
BVS	5.50%	4.53%	4.78%	10.28%	10.28%
Average:				10.19%	11.39%
5 Year Historical Growth Rates for Atmos					
EPS	9.50%	4.45%	4.87%	14.37%	14.37%
DPS	4.00%	4.45%	4.63%	8.63%	
BVS	4.00%	4.45%	4.63%	8.63%	
Average:				10.54%	14.37%

Source: Weaver Schedule 23

Schedule DAM-R4

Exhibit___
Carl G. K. Weaver
Schedule 24 **REVISED**

Western Kentucky Gas Company
Selected Companies
Capital Asset Pricing Model Analysis

Sources			Risk Free Rate	Beta	Market Return	CAPM Estimated Cost of Equity	Adjusted Greater than 1.5% Moody's Baa
Rf	*Beta*	*Km*					
Long-Term Current	S&P	S&P 500	6.44%	0.46	16.10%	10.88%	10.88%
Long-Term Current	Value Line	S&P 500	6.44%	0.61	16.10%	12.33%	12.33%
Long-Term Current	S&P	Value Line	6.44%	0.46	18.15%	11.83%	11.83%
Long-Term Current	Value Line	Value Line	6.44%	0.61	18.15%	13.58%	13.58%
Long-Term Forecast	S&P	S&P 500	5.75%	0.46	16.10%	10.51%	10.51%
Long-Term Forecast	Value Line	S&P 500	5.75%	0.61	16.10%	12.06%	12.06%
Long-Term Forecast	S&P	Value Line	5.75%	0.46	18.15%	11.45%	11.45%
Long-Term Forecast	Value Line	Value Line	5.75%	0.61	18.15%	13.31%	13.31%
Long-Term Projected	S&P	S&P 500	5.40%	0.46	16.10%	10.32%	10.32%
Long-Term Projected	Value Line	S&P 500	5.40%	0.61	16.10%	11.93%	11.93%
Long-Term Projected	S&P	Value Line	5.40%	0.46	18.15%	11.27%	11.27%
Long-Term Projected	Value Line	Value Line	5.40%	0.61	18.15%	13.18%	13.18%
Short-Term Current	S&P	S&P 500	4.97%	0.46	16.10%	10.09%	10.09%
Short-Term Current	Value Line	S&P 500	4.97%	0.61	16.10%	11.76%	11.76%
Short-Term Current	S&P	Value Line	4.97%	0.46	18.15%	11.03%	11.03%
Short-Term Current	Value Line	Value Line	4.97%	0.61	18.15%	13.01%	13.01%
Short-Term Forecast	S&P	S&P 500	4.80%	0.46	16.10%	10.00%	10.00%
Short-Term Forecast	Value Line	S&P 500	4.80%	0.61	16.10%	11.69%	11.69%
Short-Term Forecast	S&P	Value Line	4.80%	0.46	18.15%	10.94%	10.94%
Short-Term Forecast	Value Line	Value Line	4.80%	0.61	18.15%	12.94%	12.94%
Short-Term Projected	S&P	S&P 500	4.50%	0.46	16.10%	9.84%	9.84%
Short-Term Projected	Value Line	S&P 500	4.50%	0.61	16.10%	11.58%	11.58%
Short-Term Projected	S&P	Value Line	4.50%	0.46	18.15%	10.78%	10.78%
Short-Term Projected	Value Line	Value Line	4.50%	0.61	18.15%	12.83%	12.83%
Average of CAPM Analysis						11.82%	11.82%
Standard Deviation						1.03%	1.03%

Source: Weaver Schedule 24

Schedule DAM-R5

Exhibit ____
Carl G. K. Weaver
Schedule 25 **REVISED**

Western Kentucky Gas Company
Atmos
Capital Asset Pricing Model Analysis

	Sources		Risk Free Rate	Beta	Market Return	CAPM Estimated Cost of Equity	Adjusted Greater than 1.5% Moody's Baa
Rf	*Beta*	*Km*					
Long-Term Current	S&P	S&P 500	6.44%	0.18	16.10%	8.18%	
Long-Term Current	Value Line	S&P 500	6.44%	0.55	16.10%	11.75%	11.75%
Long-Term Current	S&P	Value Line	6.44%	0.18	18.15%	8.55%	
Long-Term Current	Value Line	Value Line	6.44%	0.55	18.15%	12.88%	12.88%
Long-Term Forecast	S&P	S&P 500	5.75%	0.18	16.10%	7.61%	
Long-Term Forecast	Value Line	S&P 500	5.75%	0.55	16.10%	11.44%	11.44%
Long-Term Forecast	S&P	Value Line	5.75%	0.18	18.15%	7.98%	
Long-Term Forecast	Value Line	Value Line	5.75%	0.55	18.15%	12.57%	12.57%
Long-Term Projected	S&P	S&P 500	5.40%	0.18	16.10%	7.33%	
Long-Term Projected	Value Line	S&P 500	5.40%	0.55	16.10%	11.29%	11.29%
Long-Term Projected	S&P	Value Line	5.40%	0.18	18.15%	7.70%	
Long-Term Projected	Value Line	Value Line	5.40%	0.55	18.15%	12.41%	12.41%
Short-Term Current	S&P	S&P 500	4.97%	0.18	16.10%	6.97%	
Short-Term Current	Value Line	S&P 500	4.97%	0.55	16.10%	11.09%	11.09%
Short-Term Current	S&P	Value Line	4.97%	0.18	18.15%	7.34%	
Short-Term Current	Value Line	Value Line	4.97%	0.55	18.15%	12.22%	12.22%
Short-Term Forecast	S&P	S&P 500	4.80%	0.18	16.10%	6.83%	
Short-Term Forecast	Value Line	S&P 500	4.80%	0.55	16.10%	11.02%	11.02%
Short-Term Forecast	S&P	Value Line	4.80%	0.18	18.15%	7.20%	
Short-Term Forecast	Value Line	Value Line	4.80%	0.55	18.15%	12.14%	12.14%
Short-Term Projected	S&P	S&P 500	4.50%	0.18	16.10%	6.59%	
Short-Term Projected	Value Line	S&P 500	4.50%	0.55	16.10%	10.88%	10.88%
Short-Term Projected	S&P	Value Line	4.50%	0.18	18.15%	6.96%	
Short-Term Projected	Value Line	Value Line	4.50%	0.55	18.15%	12.01%	12.01%
Average of CAPM Analysis						9.96%	11.99%
Standard Deviation						2.10%	0.63%

Source: Weaver Schedule 25

Schedule DAM-R6

Western Kentucky Gas Company

Comparison of Weaver's Common Stock Return on Equity Estimates

	Weaver		Adjusted	
	Selected Companies	Atmos	Selected Companies	Atmos
DCF-Forecasted Growth	10.38%	12.96%	11.15%	14.23%
DCF-Historical Growth (10 Year)	9.37%	8.98%	9.76%	Undefined
DCF-Historical Growth (5 Year)			11.39%	14.37%
CAPM	10.85%	9.09%	11.82%	11.99%
Bond-Yield-Risk-Premium	12.90%		12.90%	

Sources:
Direct Testimony of Carl G. K. Weaver, p.31, lines 20-25
Schedules DAM-R1, DAM-R2, DAM-R4, DAM-R5

Buchanan

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

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

REBUTTAL TESTIMONY OF REBECCA M. BUCHANAN

Q. Please state your name and business address.

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

Q. Did you submit pre-filed direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I have reviewed the prepared direct testimony, workpapers and data request responses of Mr. Lafayette K. Morgan on behalf of the Attorney General (AG). I will comment on certain adjustments and recommendations proposed by Mr. Morgan.

Rate Base

Plant in Service

Q. What concerns do you have about Mr. Morgan's findings and recommendations regarding the Company's rate base?

A. The main area of concern is Mr. Morgan's adjustment to test year plant in service - a reduction of ($6,360,678) from what was originally filed by Western. I have reviewed Mr. Morgan's direct testimony, schedules, workpapers and data request response. I am concerned because I was unable to trace certain plant in service calculations from his detail workpapers to his summary workpapers. It appears that $3,000,000 in Western plant additions are missing from Mr. Morgan's final plant in service recommendation.

The workpapers in question are provided by Mr. Morgan in his response to the KPSC data request to the AG, set 1, item 11a. Additionally, Western requested that Mr. Morgan provide all workpapers and supporting documentation not previously provided (Western DR to the AG, set 1, item 16). Mr. Morgan responded that there were no other workpapers.

Without additional information explaining how Mr. Morgan's detail plant calculations tie to his final plant in service amount, Western does not have confidence in Mr. Morgan's recommendation. Using Mr. Morgan's detail workpapers, I have calculated that his plant in service recommendation is understated by at least $3 million, assuming acceptance of his major adjustments and underlying supporting data.

Q. Does Western have confidence in Mr. Morgan's underlying supporting data?

A. No. In calculating his proposed level of plant in service, Mr. Morgan admittedly failed to utilize or overlooked certain detail supporting workpapers, corrections and revisions provided to him in Western's data request responses. As a result, Mr. Morgan's proposed level of plant in service is understated by roughly $500,000 (this is on top of the $3 million discussed above).

Q. Did Western make available to the AG all the detail information necessary to calculate an adjusted level of test year of plant in service?

A. Yes. The AG was provided with a copy of the original filing as well as a copy of each Western data request response, supporting workpapers and diskettes. On page three of his direct testimony, Mr. Morgan states that he reviewed these documents.

Q. Did Mr. Morgan's responses to Western's DR's indicate that he overlooked pertinent information provided to him by Western?

A. Yes. In Western's data request to the AG, set 1-6(a), Mr. Morgan was asked why he did not use the updated capital budget that Western submitted in response to

KPSC DR 4-2 (formerly KPSC DR 3-58) as the baseline capital budget for his adjustments. Mr. Morgan's response was that "the detailed information was not available to calculate the plant in service balance . . .." A copy of Western's DR 1-6 along with the AG's response is provided as Attachment RMB-1.

Q. Western did in fact provide the detailed information to calculate the plant in service balance. Please tell where this was made available to Mr. Morgan.

A. In our response to KPSC DR 4-2 (formerly DR 3-58, dated September 20, 1999) Western included a diskette which contained the detail excel spreadsheets needed to recalculate the test year plant in service. Because this information was provided in excel format, Mr. Morgan had available the detail information that should have allowed him to make accurate adjustments with relative flexibility, speed and ease. (As a side note, the fact that the KPSC's data request asked Western to adjust its capital budget to show a 94% completion rate should not have hindered Mr. Morgan's ability to use the excel spreadsheet for his own calculations. The capital budget was provided both before and after the application of the 94 % completion rate.) It appears from his response that Mr. Morgan did not utilize this valuable resource when preparing his plant in service workpapers and schedules.

Q. Are there other instances where Mr. Morgan did not utilize the detail information provided to him by Western?

A. Yes. Western's DR 1-6(b) (see Attachment RMB-1) asks "What is the basis for Mr. Morgan's adjustment to "0" of all System Maintenance – Retirements and System Improvements – Public Works Maintenance Reimbursements, given, for example, Western's response to KPSC DR 2-21b and KPSC DR 3-43c?" Mr. Morgan responded that "Since there were no account numbers assigned" to these line items, "the amounts in those accounts were spread over the other accounts in each category . . . on a pro rated basis."

Q. Why does Mr. Morgan's response to Western's DR 1-6(b) cause concern?

A. Mr. Morgan's statement that "there were no account numbers assigned" to Retirements and Public Works Maintenance Reimbursements causes great concern because Western discussed and provided a schedule of the account assignments in the following DR responses: KPSC DR 2-21a, KPSC DR 3-42, and KPSC DR 3-43a&b. Western is concerned that Mr. Morgan overlooked this important piece of information even though it was provided on multiple occasions.

Q. Did Mr. Morgan improperly apply overhead to the capital budget item "Forfeitures" despite the fact that Western pointed out this mistake in its own filing?

A. In the process of preparing data request responses, Western discovered that it had made an error in applying overhead and inflation to the line item "Forfeitures" within the capital budget and plant in service workpapers. This error was immediately disclosed and discussed at length in the following DR responses: KPSC DR 2-21b, KPSC DR 3-43c, and KPSC DR 4-2 (formerly DR 3-58a&d). In his response to Western's DR 1-6(c), Mr. Morgan admits that due to oversight, he duplicated the error on his workpapers.

Q. Did Mr. Morgan apply an incorrect factor to the Division 02 Shared Services plant, resulting in an underallocation of plant in service to Western Kentucky Gas?

A. Western has established that the residual factor for allocating Division 02 Shared Services plant is 16.657%. This factor is shown in numerous instances in Western's filed schedules, supporting workpapers (especially "wp factors" found in Volume 10, tab 15 of the original filing), diskettes and responses to data requests (especially KPSC DR 1-36b and KPSC DR 1-42). Mr. Morgan, however, applied an allocation factor of 16%, which caused his test year plant in service allocation to Western to be understated.

Q. Have you approximated what the plant in service amount would be had Mr. Morgan made his adjustments using the correct information provided by Western?

A. Yes. I have calculated that Mr. Morgan's plant in service recommendation is understated by $3.5 million. If Mr. Morgan had utilized all the information provided to him by Western, his adjusted plant in service amount would have been approximately $246.1 million versus the $242.6 million shown on his schedule LKM-2 (direct testimony, Morgan).

Q. What is the effect on Depreciation and Rate Base?

A. As a result of his plant in service being understated, Mr. Morgan's calculation of accumulated depreciation and depreciation expense are understated by approximately $200,000. The net affect is that Mr. Morgan's recommended level of Rate Base is understated by $3.3 million. This figure assumes agreement with Mr. Morgan's stated adjustments to plant in service - a 92% completion rate on direct capital projects, a 39.5% overhead rate, and elimination of the incremental increase in structures and improvements, as indicated in his direct testimony.

Q. Does Western agree with Mr. Morgan's adjustments for the 92% completion rate on direct capital projects, a 39.5% overhead rate, and elimination of the incremental increase in structures and improvements?

A. No. Reversing these adjustments would bring Western's adjusted plant in service amount to approximately $248.1 million (that is, an additional $2 million), and Rate Base to over $129 million. Western's position on these adjustments is discussed in the rebuttal testimony of Mr. David H. Doggette.

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

A. Yes.

WESTERN KENTUCKY GAS COMPANY
DOCKET NO. 99-070
ATTORNEY GENERAL'S RESPONSE TO
WESTERN KENTUCKY GAS CO. DATA REQUESTS
SET I

6. With respect to the rate base adjustments:

   a. Why did Mr. Morgan not use the updated capital budget submitted in response to KPSC DR 4-2 (formerly KPSC DR 3-58) as the baseline capital budget for his adjustments?

   b. What is the basis for Mr. Morgan's adjustment to "0" of all System Maintenance - Retirements and System Improvements - Public Works Reimbursements, given, for example, Western's response to KPSC DR 2-21b and KPSC DR 3-43c?

   c. Why was an overhead factor applied to the projected forfeitures, given Western's response to KPSC DR 2-21 and KPSC DR 3-43?

   d. Why did Mr. Morgan use a ratio of 16% for Div 02 Shared Services Plant Allocations, when he consistently used 16.75% in all of his other calculations?

   e. Aside from the issues referenced in a. through d. above, is Mr. Morgan aware of any unspecified adjustments that would further reduce rate base by $300,000?

<u>Response</u>

a. The detailed information was not available to calculate the plant in service balance based upon the 92 percent ratio instead of the 94 percent ratio.

b. Since there were no account numbers assigned to System Maintenance-Retirements and System Improvements-Public Works Reimbursements, the amounts in those accounts were spread over the other accounts in each category (System Improvements or System Maintenance) that had projected capital expenditures associated with them during the forecast period on a pro rated basis.

WESTERN KENTUCKY GAS COMPANY
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SET I

Response 6 (cont'd.)

c. At time of testing the spreadsheet, the attempt was to follow the Company's method as closely as possible to ensure that similar amounts would result. Due to an oversight, the Company's error was not changed.

d. At the time of preparing the spreadsheet, the workpapers in Volume 10, Tab 15 of the Company's filing was followed. In order to ensure similar amounts resulted from the calculation, the 16 percent was used as indicated on the workpapers. Due to an oversight, the 16 percent was not changed.

e. No.

Responsible Witness: Lafayette K. Morgan, Jr.

Doggette

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY OF DAVID H. DOGGETTE

Q. Please identify yourself.

A. My name is David H. Doggette. My business address is 2401 New Hartford Road, Owensboro, Kentucky, 42303. I am employed by Western Kentucky Gas (Western) as Vice President of Technical Services.

Q. Did you provide pre-filed testimony in this proceeding?

A. Yes.

Q. Have you reviewed testimony filed by others on behalf of the Attorney General?

A. Yes.

Q. Which testimony do you wish to address?

I will address the testimony given by Mr. Lafayette K. Morgan of Exeter Associates, Inc. filed on behalf of the Office of Rate Intervention of the Attorney General.

Q. What specific concerns regarding Mr. Morgan's testimony do you wish to address?

A. I will discuss the following issues:

1) Clarification of "System Improvement and Maintenance" as opposed to Mr. Morgan's "Structures and Improvements", and

the projected increase in System Improvements & Maintenance capital expenditures,

2) The forecasted overhead costs attributable to capital expenditures, and
3) Mr. Morgan's proposal to apply a 92% factor to the forecasted capital budgets.

I. STRUCTURES AND IMPROVEMENTS

Q. What is the concern regarding the clarification of "System Improvements and Maintenance as opposed to Mr. Morgan's use of "Structures and Improvements"?

A. Mr. Morgan uses the terminology "Structures and Improvements" throughout his testimony and Data Request responses. Usually the term "Structures and Improvements" relates to general plant assets such as buildings, offices, and ancillary facilities and assets. However, the category of assets he is adjusting includes the piping, valves and stations used to operate Western's gas systems.

The testimony and forecasted budgeting that Mr. Morgan refers to relates to capital projects undertaken to increase Plant In Service that will maintain the integrity of our piping systems, provide for increased capacity to accommodate growth in demand from our piping systems, and to relocate facilities that are in conflict with Public Works projects undertaken by the Transportation Cabinet of the Commonwealth of Kentucky or by the city or county governments in the areas that Western serves. Projects of these types are necessary to provide service continuity and reliability, to meet the needs of the public, and to ensure public safety.

It is not clear in Mr. Morgan's testimony as to whether he was mistaken about the types of projects contemplated in these budget areas, or as to whether his use of "Structures and Improvements" is simply as mistake in terminology. It is also unclear as to whether Mr. Morgan's interpretation had a bearing on his decision to exclude funding for these projects that are in the interest of public safety and progress throughout the Commonwealth and communities that are served by Western.

Q. Do you have other concerns regarding this subject?

A. Yes. Mr. Morgan has proposed the disallowance of all funds represented by the 36.25% increment related to specific System Improvement and Maintenance projects in the forecasted budgets. He states in his testimony, Page 6 – Line 8 and following, that Western did not offer any additional justification for these forecasted amounts. Also, in his response to Question 1 c) of the Kentucky Public Service Commission Data Request Set 1 to the Attorney General, Mr. Morgan reiterates that Western had not provided "any data" to support the forecasted System Improvement and Maintenance increase.

In fact, a detailed analysis was provided in my response to the Attorney General's Supplemental Data Request, Question 5, Schedule 1. This schedule, attached as Attachment DHD-R2 , shows the specific projects in FY 1999 that were beyond the normal course of system maintenance and repairs. This amount was adjusted for overheads to determine the direct cost of these capital projects. That was compared to the projected FY 2000 specific projects. The forecasted budget for FY 2000 included an increase of only $705,216 while the detailed analysis of specific projects for FY 2000 resulted in a total of $793,742. Therefore, a shortfall in the forecasted budget is predicted.

Q. Please summarize your position on this issue.

A. The forecasted System Maintenance and Improvement capital requirements are essential to maintain Western's system reliability and safe operations. FY 1999 was an unusual year in which there were very few specific projects required in the areas of System Improvements and Maintenance, especially in the area of relocation projects to accommodate roadway and drainage public works. The level of projects indicated for FY2000 are normal. There is no reason to believe that the low level of capital construction experienced in FY 1999 will be repeated during the forecast period. Sufficient detail was submitted and made available for Mr. Morgan's review, and supports the full allowance of the proposed capital funds in the forecasted budgets.

II. FORECASTED OVERHEADS INCLUDED IN THE CAPITAL BUDGETS

Q. What concerns do you have regarding Mr. Morgan's proposal to reduce the overhead amounts attributable to the forecasted capital budgets?

A. Mr. Morgan's approach to determining the amount of overheads, 39.5%, seems arbitrary in light of the nature of these costs. Simply taking an average of historical percentages overlooks the fact that these costs are relatively fixed. Mr. Morgan acknowledges that these costs are "fixed and less avoidable than direct capital expenditures" in his response to Western's first Data Request to the Attorney General, Item 10a,b & c.

A major component of overhead costs are due to labor. To achieve the reduction that Mr. Morgan suggests Western would have to significantly lower payroll rates and/or reduce the number of personnel. The other alternative would be to include the excess amount as additional Operating & Maintenance expenses. Such an addition was not included by Ms. Adams in developing Western's O&M budget forecasts.

While Western has made strides in reducing overhead costs, they have not been reduced by an amount proportionate to the reduction of forecasted capital construction costs. Mr. Morgan states in his response to Data Request Item 10d that "overheads as a percentage of direct construction expenditures will decrease as construction expenditures increase". The opposite must is also be true; that is, as direct expenditures decrease overheads as a percentage of those expenditures will increase.

Mr. Morgan states in the Data Request response that he believes holding the FY 1999 overheads constant to be reasonable. If the FY 1999 overheads are applied to the direct construction costs proposed for FY 2000, the overhead amount is 46.5% which is significantly more than the 39.5% he proposes in his testimony.

In his testimony Mr. Morgan does not reveal how he calculated the 39.5% figure, but it appears that he used overheads as a percentage of the total capital spending (which already includes the overheads). The forecasted budgets were developed by applying overheads to the direct construction costs. By first subtracting the overheads out of the totals and then recalculating an average, the resulting average overhead for the past four years is about 58%. The 50% rate proposed by Western is reasonable compared to this.

Simply stated, a fixed overhead amount as a part of a large budget is a smaller percentage when compared to the same dollar amount as a part of a smaller budget. It becomes a larger percentage of the total budget. Sufficient information and detail was submitted and made available for Mr. Morgan which supports Western proposed overhead rate of 50%.

III. FORECASTED CAPITAL BUDGETS

Q. Mr. Morgan has used a figure of 92% in Data Requests and in testimony attempting to relate a projection of actual capital expenditures to the amounts forecasted in the capital budgets. Please address this issue.

A. Western's filing was developed based on the use of forecasted capital budgets. These forecasted budgets were based on the fact that FY 1999 had an unusually low level of activity in expenditures for System Improvements and Maintenance and that other facets of our capital expenditures were reflective of routine, normal business requirements. Adjustments were made, as set forth in my testimony beginning at Page 9, Line 24 to develop capital budget forecasts to meet expected requirements.

The 92% in Mr. Morgan's testimony is used to impute a relationship of historical budgets and expenditures to the development of forecasted budgets. To follow that logic, the forecasted budgets should have been built based on the historical trends of past budgets and spending. By doing a linear trending forward of Western's historical budgets, the implied capital budget for FY 2000 would be approximately $15.5 million dollars. The forecasted budgets proposed by Western are less than 2/3 of this amount. Please see Chart DHD-R1.

Even compared to an average of past capital expenditures Western's forecasted budgets are only about 7/8 of the historical amounts.

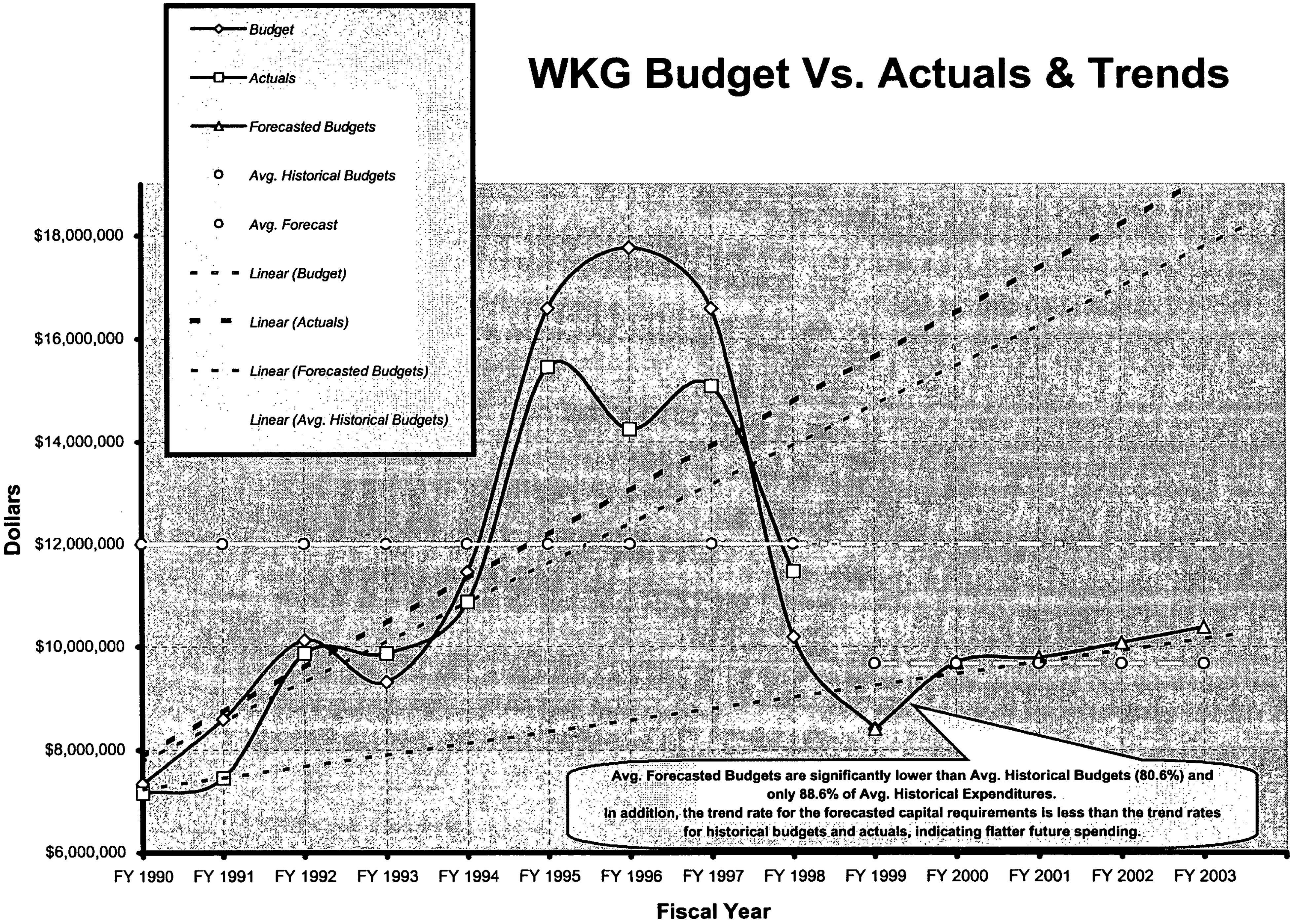
Mr. Morgan has actually demonstrated that Western has had a need for 92% of the funds budgeted in the past, or on average $11 million. Western has proposed forecasted budgets that are only 88.6% of the average historical spending. All of the forecasted capital budgets are less than $11 million, therefore Western's forecasts should be considered valid as originally submitted.

Ms. Buchanan has calculated that Mr. Morgan's adjustment for the three issues discussed above understates Western's Rate Base by $2 million. For further discussion of plant in service and rate base adjustments, please refer to the rebuttal testimony of Rebecca M. Buchanan.

Q. Does this conclude your rebuttal testimony?

A. Yes.

WKG Budget Vs. Actuals & Trends



Avg. Forecasted Budgets are significantly lower than Avg. Historical Budgets (80.6%) and only 88.6% of Avg. Historical Expenditures.
In addition, the trend rate for the forecasted capital requirements is less than the trend rates for historical budgets and actuals, indicating flatter future spending.

David H. Doggette

KPSC Case 99-070

Chart DHD-R1

Attachment DHD-R2

FY1999 vs. FY2000 System Maintenance & System Improvements **AG SDR- 5, Schedule 1**

FY 1999

Numbers Include Overheads

Specific Projects		
700' 2" Main Replacement-Owensboro	$	2,800
Replace 2" Field Lines	$	5,962
700' HP Trans Line Replacement	$	9,476
AM/FM Map Conversion	$	100,000
Customer EFM-Statewide	$	98,000
-Less Reimbursement	$	(26,400)
Liberty Sta. 6" Valve Replacement-Madisonville	$	5,959
Hwy 121 Relocation-Mayfield	$	61,374
-Less Reimbursement	$	(31,765)
4" T Line Replacement-Mayfield	$	49,468
Uprate Commerce Park-Hopkinsville	$	17,000
Skyline Drive Relocation-Hopkinsville	$	118,505
Main Relocation N. Race St.-Glasgow	$	52,848
-Less Reimbursement	$	(20,850)
2" Replacement, Skyline Dr.-Hopkinsville	$	5,391
Install Reg. Stations, Commerce Park-Hopkinsville	$	131,000
Reg. Station Replacement-Elkton	$	23,500
Relocate 1100' of 2" Plastic Pipe	$	12,749
	$	615,017

FY 2000

Numbers Do Not Include Overheads

		Specific Projects
$	13,500	State Hwy Relocation
$	34,116	Town Border #3 Relocation
$	16,667	Commerce Park Upgrade
$	25,500	Shelbyville Cast Iron Replacement
$	12,482	Moreland Tie-back Pressure Improvement
$	19,500	Danville Sreamland Improvement
$	12,400	Campbellsville ByPass
$	232,620	Line 133 Upgrade
$	18,000	Lancaster Purchase Station
$	5,000	Mt. Eden Purchase Station
$	2,000	Lebanon TBS Fencing
$	10,000	Lancaster Ground Bed Relocation
$	46,750	Rumsey (Calhoun) Bridge Relocation
$	44,483	Hwy 231 Relocation
$	(13,997)	-Less Reimbursement
$	13,000	Replace Habit Odorant System
$	70,000	Hwy 41 Relocation
$	55,272	Hwy 91 Relocation
$	12,000	Ground Bed Replacement-Sharp Avenue
$	16,530	Blandville Road-Paducah
$	7,500	Husband Rd. Ground Bed Replacement
$	22,000	EFM for customers
$	57,200	EFM for customers
$	21,119	Odorize 12"-Midwest
$	20,000	Uprate Hickory lines for load
$	54,000	Optimize gathering lines
$	100,002	Map conversion project
$	17,770	Bon Harbor Rectifier Bed
$	31,030	Relocate Habit Dehydrator
$	50,260	Hoffman #1 Well Workover
$	21,933	10" & 12" Leakage
$	25,000	Richards #1 Well Workover
$	25,000	McGregor #1 Well Workover
$	1,098,637	Estimated Direct Costs

Adjust for 1999 Overheads and Compare to FY 2000 Projection

Cost of FY 1999 Project	$	615,017
-Less 50.425% Overheads	$	310,122
Direct Costs	$	304,895

$	1,098,637	Estimated Direct Costs
$	304,895	-Less Comparable Projects From FY 1999
$	793,742	
$	705,216	***Amount Forecasted in FY 2000 Budget Projection***
$	88,526	**Amount NOT Included in FY 2000 Forecast**

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

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

REBUTTAL TESTIMONY OF DONALD P. BURMAN

Q. Please identify yourself.

A. My name is Donald P. Burman. I am the Assistant Controller of Atmos Energy Corporation, 5430 LBJ Freeway, Dallas, Texas 75240.

Q. Did you pre-file testimony in this proceeding?

A. Yes.

Q. Have you reviewed the testimony filed by Mr. Morgan on behalf of the Attorney General?

A. Yes.

Q. What concerns, if any, do you have about his recommendations?

A. My primary concerns relate to his adjustment related to pensions and his adjustment to merger related expenses, because of the amount of his adjustments and the ratemaking precedent which would be set.

Q. Please discuss your concerns regarding his adjustment for pension expense.

A. Mr. Morgan is recommending, on page sixteen of his testimony, that an adjustment be made to operations and maintenance expense to reflect a negative pension expense of $2,272,501. If this adjustment is made, it will mean that this amount of cash will flow back from the company to the ratepayers in the form of reduced rates. Mr. Morgan is correct when he states that, on page fourteen, "the pension expense credit of $853,000 does not mean that funds are flowing out the pension plan trust fund". However, he does not go on to say that any negative pension expense will cause the funds to flow out of the company. This cash outflow would in effect amount to a shareholder-funded refund to ratepayers. The only way to prevent this erosion on the cash flows of the company is to set the pension expense at zero.

The impractical, if not illogical, effects his recommendation would have on company cash flows is emphasized by his response to WKG DR 1-14, which I have attached as Attachment DPB-1. In WKG DR 1-14, Mr. Morgan declares, in response to item a., that Western's pension proposal would result in a "windfall" even though there is no cash generated. He also fails to give a straight answer to the simple question asked in item b. With respect to item c. he is presented with the logical extreme of his recommendation. That is, what if the annual net periodic pension credit exceeded the level of total annual O&M expense incurred by Western in a year? Would he deny the company, for all future years rates set in this case are in effect, all the cash required to pay for its annual O&M costs because of a large current net pension credit? Assuming all other things constant, what if Western's pension credit went positive in subsequent years? Would Western be justified to file a whole new rate case just to reset its rates as a result of the volatility evidenced in returns on pensions plan assets? Evidently, based upon his response to item c., the answer is yes.

A company cannot operate without cash, yet Mr. Morgan would deny the company any cash flow from operations to the extent its negative net pension credit is a greater amount, even if that meant denying the company all of its cash requirements. Setting rates based so heavily on actuarially calculated pension plan returns during a period of rising stock prices is impractical and argues for a logical solution which would stabilize the volatile effects of accounting for pension plan asset performance on customer rates. That solution is the one made by Western – to set all expense at zero.

Q. Do you have any other comments regarding Mr. Morgan's pension expense adjustment?

A. I strongly disagree with Mr. Morgan's adjustment for the net pension credit; however, if such an adjustment is held to be appropriate for ratemaking, because of the volatility of actuarially calculated net periodic pension costs from year to year, that adjustment should be a conservative one which does not over-react to a single year occurrence, and should never be greater than the most recent actuarial estimate.

Q. What concerns do you have regarding Mr. Morgan's recommendations to disallow all of Western's share of the cost associated with the United Cities merger?

A. My concern is twofold. First, while he acknowledges the benefits of the merger, he would deny the company any ability to recover the costs related to achieving these benefits. This is evidenced in his response to WKG DR 1-12, which is attached as Attachment DPB-2. Second, while he discusses his adjustment as a component of the reserve taken by Western, in fact, he removes the entire cost of the merger not just an allocation of the reserve. Such a disallowance is unwarranted and, if sustained by the Commission, would discourage Western and Atmos from any participating in any future mergers, regardless of the benefits of that merger.

Q. To appropriately recognize the benefits of this merger and encourage future business decisions designed to achieve similar results, what language would you recommend the Commission include in its final order in this proceeding?

A. I would recommend the following language:

> "In approving this rate increase, the Commission considered the Company's investment in merger and integration costs and approved the inclusion of those costs in allowable rate base and cost of service."

Inclusion of this language would send the appropriate signal to utilities and investors that mergers which produce significant savings for customers, as Western has demonstrated in its Supplemental Response to KPSC DR 1-6, are beneficial and should be recognized for the benefits they produce.

Q. Does this conclude your testimony?

A. Yes.

WESTERN KENTUCKY GAS COMPANY
DOCKET NO. 99-070
ATTORNEY GENERAL'S RESPONSE TO
WESTERN KENTUCKY GAS CO. DATA REQUESTS
SET I

14. With respect to the pension expense adjustment:

a. Is Western's pension credit a source of cash Western can apply to its daily operations in providing service to its customers?

b. If Western's annual net periodic pension cost becomes positive does Mr. Morgan believe that Western is or is not obligated to contribute cash to the pension plan?

c. If Western's annual net periodic pension cost were a $27 million credit due to the performance of plan assets, would Mr. Morgan recommend that no annual operating expenses be recognized in the setting of Western's rates?

Response

a. No. However, if rates are based upon a level of pension expense that is higher than the actual expense, the Company will receive a windfall.

b. Yes.

c. The recommended level of operating expenses would be on the SFAS 87 pension expense amount.

Responsible Witness: Lafayette K. Morgan, Jr.

WESTERN KENTUCKY GAS COMPANY
DOCKET NO. 99-070
ATTORNEY GENERAL'S RESPONSE TO
WESTERN KENTUCKY GAS CO. DATA REQUESTS
SET I

12. Western's response to Supplemental Response to KPSC DR 1-6 includes the net effects of the United Cities merger with Atmos.

    a. With respect to the adjustment for merger and integration expenses, does Mr. Morgan deny that Western's ratepayers will benefit from this merger?

    b. Does Mr. Morgan agree that Western's allocation of Shared Services expenses declined from about 22% prior to the merger to about 18% after the merger?

    c. Given Western's return during the test year, what is the savings the shareholders "enjoy" if the Company does not earn a reasonable return?

<u>Response</u>

a. No.

b. Yes.

c. The benefits are not limited to one period. Atmos Management has acknowledged that there are long term benefits to be achieved from the merger.

Responsible Witness: Lafayette K. Morgan, Jr.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF)

RATE APPLICATION BY) Case No. 99-070

WESTERN KENTUCKY GAS COMPANY)

REBUTTAL TESTIMONY OF BETTY L. ADAMS

Q. Please identify yourself.

A. My name is Betty L. Adams, my business address is Western Kentucky Gas Company, 2401 New Hartford Road, Owensboro, Kentucky, 42301. I am employed by Western Kentucky Gas Company, a division of Atmos Energy Corporation ("Atmos") as Vice President and Controller.

Q. Did you pre-file direct testimony in this proceeding?

A. Yes.

Q. Have you reviewed the testimony filed by Mr. Lafayette Morgan on behalf of the Attorney General?

A. Yes.

Q. Do you have any concerns about his recommendations?

A. Yes. My primary concerns relate to those to those items with the greatest financial impact.

Q. What concern do you have regarding Mr. Morgan's adjustment to Western's uncollectible expense?

A. Mr. Morgan has made an adjustment to uncollectible expense in the amount of ($234,223) as shown on his schedule LKM-9.

Mr. Morgan takes exception to the increase in uncollectible expense we applied in the forecast year over the partially forecasted (six months actual + six months budget) FY1999 base year. His recommended decrease in the forecast year is the $234,223 increased Western's uncollectible expense above the base year. He supports this adjustment based upon the average of uncollectible expense to revenues of 0.40 percent for the five year period ending Fiscal Year 1998 (FY1998).

My concern is that the percentage of uncollectible expense for Western has trended upward lately and Mr. Morgan has not acknowledged this trend. For example, the FY1997 percentage was 0.50, for FY 1998 it was 0.68, and for FY1999 it was 1.3. If the percentage for the most recently completed year at the time our filing was made (FY1998) was used for our forecast year; the projected expense would be $653,407. This is verified in our response to AG DR 1–211 b&c. This amount is very close to the total $618,580 of uncollectible expense we projected for the forecast year. Mr. Morgan's adjustment reduces our forecast year uncollectible expense to only $384,357.

Q. What is your concern regarding Mr. Morgan's adjustment for Western's lawsuit settlement costs?

A. The adjustment of ($189,789) disallowing the amortization of a lawsuit settlement cost is shown on his schedule LKM-10. His adjustment is for the current period of a five-year amortization of the settlement of a lawsuit arising out of our normal operations. His stated rationale is that these costs relate to a prior period and have not been authorized by the Commission for amortization or deferral.

Q. What is wrong with his reasoning?

A. First of all, the expenses themselves fall within the annual retention (deductible) of $1 million that our insurance policies cover. If we carried a lower retention, the annual premiums would be much higher. In his response to WKG DR 1-13, Mr. Morgan acknowledges that premiums may vary with the deductible. In essence, they are discretionary substitutes; yet, he is not recommending disallowance of our premiums. Both premiums and the deductible payment he would disallow are recoverable expenses. Mr. Morgan acknowledges this fact in his data request response. I am attaching WKG DR 1-13 as Attachment BLA-1.

Secondly, the amortization of this dollar amount into the forecast year is appropriate because such an expenditure, if incurred, would normally be amortized over several years. In other words, we are only following normal accounting practices in our amortization.

Thirdly, we are unaware of any specific requirement that any such amortization must be pre-approved by the Commission.

Q. What is your concern regarding Mr. Morgan's reduction of labor costs?

A. Mr. Morgan adjusted the payroll expense in the amount of ($586,455) by reducing the total number of employees budgeted by 24. This is shown in his schedule LKM-15. Mr. Morgan has recommended a reduction in our labor expense based upon our employee level as of September 1999, because this employee level was below that which we projected for the forecast year.

In response to AG DR 2-26, we submitted the following number of employees by month:

Employees by Month	
October	269
November	269
December	269
January	267
February	267
March	262
April	265
May	261
June	260
July	260
August	259
September	258

Although our employee complement is 282, most of the positions remained unfilled due to our low earnings as a result of the warmer weather and its effect upon our earnings. In March when our employee level dropped to 262, we hired 3 new employees to fill vacancies. In May our level of employees decreased due to some employees leaving the company, retiring or as a result of going onto long term disability. Even though our current employee level at the end of September was 258 (which is the level to which his reduction was made), we have since hired one new employee and have advertised the vacant engineering position. Our hiring of the employees in May demonstrates that we do intend to fill vacancies. Obviously, we cannot defer the hiring of vacancies indefinitely, but to the extent we can manage our way through under warmer than normal weather and poor earnings, this is an appropriate business decision. Mr. Gruber discussed this situation in his response to AG DR 1-237 and KPSC DR 2-60.

Our employee budget for the forecast year was 282 employees. This budget assumed normal operating conditions including normal winter weather and adequate earnings. With the year 2000 so close upon us, obviously it will be difficult to add 24 full time employees all at once. Consequently. a minimum level of employees of 267, not 282 (nor 258), would be most likely accurate, based upon the constraints we now face in filling the vacant positions.

Lastly, I would point out, that if Mr. Morgan's recommended reduction is adopted; at a minimum, the average payroll amount per employee should be adjusted by removing the officer's salaries before calculating the average payroll amount. Otherwise, the average payroll base is skewed. This also affects payroll taxes. The effect of this correction to Mr. Morgan's methodology would decrease his recommended reduction from ($586,455) to ($344,251) as shown on Attachment BLA-2.

Q. Does this conclude your rebuttal testimony?

A. Yes.

WESTERN KENTUCKY GAS COMPANY
DOCKET NO. 99-070
ATTORNEY GENERAL'S RESPONSE TO
WESTERN KENTUCKY GAS CO. DATA REQUESTS
SET I

13. With respect to Mr. Morgan's lawsuit settlement adjustment:

a. Does Mr. Morgan agree that annual liability insurance premiums may vary with the annual retention (the deductible)?

b. Does Mr. Morgan agree that liability insurance premiums are a recoverable expense?

Response

a. Yes.

b. Yes.

Responsible Witness: Lafayette K. Morgan, Jr.

Western Kentucky Gas Company
Case #99-070

Attachment BLA-2

Correction to Morgan's Labor Methodology

	FY2000	
	WKG Proposal	AG Proposal (1)
Start	11,718,375	
Less O/T	239,188	
Less S/B	178,447	
Known & Measurable change for empl from vacant to filled	11,156	
	11,311,896	
Less Officers (8)	743,986	
New base	10,567,910	11,718,375
	274	282
	38,569	41,555
Employees added	9	9
	347,121	373,995
	69.775%	69.775%
9 Employee Adj	242,204	260,955
9 Employee Adj - WKG	242,204	
9 Employee Adj - AG	(260,955)	(260,955)
15 Positions	(325,500)	(325,500)
Net Adj	(344,251)	(586,455)

(1) Information in this column taken from LKM-15

Petersen

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF)
RATE APPLICATION BY) Case No. 99-0070
WESTERN KENTUCKY GAS COMPANY)

REBUTTAL 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. Did you file pre-filed, direct testimony in this proceeding?

A. Yes.

Q. Have you reviewed the testimony related to the Company's class cost of service study filed by Mr. Galligan and Dr. Estomin on behalf of the Attorney General?

A. Yes.

Q. What concerns, if any, do you have about their recommendations?

A. Both Mr. Galligan and Dr. Estomin discussed one aspect of the Company's class cost of service study, the allocation of the cost of distribution mains among classes of customers. They criticized the company's proposed allocation, Mr. Galligan from a theoretical perspective and Dr. Estomin from a statistical perspective. Mr. Galligan then modified the Company's class cost of service study to incorporate his recommended allocation of the cost of distribution mains. Mr. Galligan's recommended allocation is based on a flawed analysis of cost causation.

Q. How do the Company's and Mr. Galligan's analysis of cost causation and allocation of the cost of mains differ?

A. The Company allocates costs among classes of customers using data that is available by class. Thus, allocations are based on the number of customers served, the amount of commodity delivered, or the daily demands placed on the system by each class. Costs that are primarily related to the number of customers, such as the cost of meters, are allocated on that basis. Costs that are primarily related to the amount of gas delivered or to peak demands placed on the system are allocated on those bases. Distribution mains are designed to connect all customers to the system and to provide for delivery of peak demands to those customers. Mains that meet these requirements will, of course, deliver gas to customers at off peak times. The cost of distribution mains is therefore related to both the number of customers and peak demands. In compliance with the Commission's order in the Company's Case No. 9556, the cost of mains is divided between customers and demand categories using a zero intercept or regression analysis. This method is intended to classify mains costs that vary with the size of the pipe, primarily the cost of the pipe, as demand costs and those costs that do not vary with the size of the pipe, primarily installation costs, as customer costs. The result in this case was that 77 percent of the cost of mains was allocated on peak demand and 23 percent was allocated on number of customers.

Mr. Galligan's allocation is based on a flawed analysis of cost causation. He argues that since the Company would not extend mains to serve a customer who would use no gas, none of the cost of mains is customer related. He allocates 50 percent of mains costs on annual usage and 50 percent on peak demands. Based on Mr. Galligan's reasoning one would conclude that the cost of a meter at a customer's premises would not be a customer related cost since the Company would not set a meter for a customer who would not use gas. In fact, Mr. Galligan's reasoning leads to the conclusion that no utility costs are customer related. However, generally accepted methodologies for fully distributed class cost of service studies recognize that the level of some costs, such as meters and a portion of mains costs, are related to the number of customers served.

Mr. Galligan attempts to support his argument by selectively quoting from Professor Bonbright's discussion of problems associated with treating secondary or low voltage electric distributions system costs as customer costs. He fails to mention that these remarks were part of Professor Bonbright's discussion of these costs being strictly unallocable. Professor

Bonbright's concern is that a weak correlation between the area of an electric distribution system and the number of customers on that system make an allocation based on the number of customers imperfect. Since an allocation based on demand or volumetric basis is inappropriate, he is left with a strictly unallocable cost. Of course, distribution mains costs must be allocated on a practical basis in a fully distributed class cost of service study as they were in the Company's study. Professor Bonbright's remarks do not support Mr. Galligan's recommended allocations.

Dr. Estomin tries to support Mr. Galligan's recommendations through his statistical critique of the regression analysis used by the Company to divide mains costs between those that vary with the diameter of the pipe installed and those that do not vary with pipe size. He concludes that no statistical evidence exists to support using anything but a zero value for the mains costs that do not vary with pipe size. This result is contrary to common experience in installing mains as is clearly described on lines 10 through 17 of Mr. Galligan's testimony. Much of the cost of installing distribution mains is not affected by the diameter of the pipe installed. An analysis, such as Dr. Estomin's, that implies otherwise should not be relied on.

Q. Based on your review of Mr. Galligan's and Dr. Estomin's testimony have you changed your opinion about any conclusions or recommendations in your pre-filed direct testimony?

A. No.

Q. Does this conclude your testimony?

A. Yes

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF)

RATE APPLICATION BY) **Case No. 99-070**

WESTERN KENTUCKY GAS COMPANY)

REBUTTAL TESTIMONY OF GARY L. SMITH

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. Did you file direct testimony in the Company's Application in this Case?

A. Yes, I did, at volume 2 of 10, Tab 11 of the Application.

Q. What were the primary aspects of the Company's Application for which you were the sponsor?

A. My major areas of responsibility were the Company's volume/revenue forecasts for the Test Year and the design of the Company's proposed rate structures.

Q. Have you reviewed the testimony of the parties that intervened in this proceeding - the Office of the Attorney General and WBI Southern, Inc.?

A. Yes I have.

Q. Among the four witnesses testifying for the Office of the Attorney General, who reviewed subjects directly pertaining to your areas of responsibility in the Company's application?

A. Mr. Lafayette K. Morgan reviewed the Company's forecasted test year budget, including the revenue budget I sponsored, and Mr. Richard A. Galligan reviewed the

Company's proposed rate design. The other witnesses did not directly address subjects in the Company's Application that I sponsored.

Q. Did Mr. Morgan recommend any adjustments to the Company's revenue budget for the forecasted test year?

A. No, Mr. Morgan did not propose any adjustments to the Company's revenue budget in his prepared direct testimony (reference Schedule LKM-1, Page 1 of 2). In Mr. Morgan's response to the Commission's Data Request to the Attorney General, Item 9, he stated that he reviewed "the data contained in the Company's filing as well as its responses to data requests" and "based on recent sales trends and forecasted sales level, Western's sales level was not considered unreasonable."

Q. Did Mr. Galligan recommend any changes in the Company's proposed rate design?

A. Yes, Mr. Galligan stated opinions differing from that of the Company - most significantly, in regard to the distribution of the rate increase to individual customer classes and in regard to the portion of the increases to be reflected in the monthly customer charge versus the distribution charge.

Q. Please explain the recommendation of Mr. Galligan regarding the distribution of the rate increase to individual customer classes, and problems that would be created by his recommendation.

A. Mr. Galligan, on page 22, line 16, through page 23, line 18 of his testimony recommends a "proportional increase in class revenue responsibilities". Mr. Galligan quantifies his recommendation on Table 3, on page 23 of his testimony, calculating the distribution of increase to customer 'classes' utilized in the Company's cost-of-service study. In this Table, however, Mr. Galligan fails to factor in the inability of the Company to increase transportation charges to customers under special contract filed with, and approved by the Commission. These special contract customers, as a group, constitute 57% of the Company's total Test Year industrial sales and transportation deliveries.

In the Commission's Administrative Case 297 (applicable portions submitted in the Company's response to Attorney General DR #2, Item 24), the Commission references the importance of "equity" in rate design - defined as rate structures that "enable the utility to earn a capital-attracting rate of return". The Company has exhibited in its Application and Data Request responses that its current rate structures have produced certain undesirable results, namely the inability to sustain financial integrity without seeking rate increases every three to five years. In regard to individual customer classes, we have noted the competitive environment in which Western competes. Industrial rates have contributed to the necessity of discounting tariff rates to retain certain bypass vulnerable accounts. Residential class rates produce inadequate returns on the extension of service to new customers. These are significant factors that have led to the Company's experience of successively declining revenues since the last rate case. Implementing a "proportionate" increase to each class merely continues this plight for the Company.

Thus, the realignment of class revenue responsibilities, as proposed by the Company, is essential to the effectiveness of Western's rate structures supporting the opportunity to sustain reasonable returns going forward.

Q. What was Mr. Galligan's recommendation regarding the amount of increase to be reflected in the monthly base charge versus the distribution charge?

A. On pages 28-29 of his testimony, Mr. Galligan recommends maintaining the Company's residential monthly customer charge at its present level of $5.10 per month. His recommendation is based on an analysis he prepared concerning what he terms as the "avoided cost amount", consisting solely of the O&M expense component of Western's calculated 'customer' costs in its class cost-of-service study.

Q. What concerns, if any, do you have about his recommendation to maintain the monthly customer charge at its present level?

A. The Company disagrees with Mr. Galligan's conclusions and recommendations on this matter. For one reason, although the parties appear to agree that embedded class cost-of-service studies represent only one element of consideration in the design of rate structures, Mr. Galligan's exclusion of costs, such as Depreciation & Amortization, Property & Other Taxes, Income Taxes and Return, from the 'customer' costs is without basis. Including such costs would reflect a 'customer' cost per month of $9.57.

Also, as mentioned earlier in this rebuttal testimony, other factors, such as the effectiveness and 'equity' of rate design must be considered in combination with results of embedded class cost-of-service studies. The re-balancing of fixed and variable components of Western's rates, as proposed in the Company's Application, is essential to the effectiveness of rate structures supporting the opportunity to sustain reasonable returns going forward.

Q. How does Mr. Galligan's recommendation to maintain the monthly customer charge at its present level impair the Company's opportunity to sustain reasonable returns?

A. As demonstrated in Western's Application and Data Request responses, weather normalized residential and commercial sales demand is declining. This phenomenon is not unique to Western. As referenced in the Company's response to KPSC DR#2, Item 50(b), the Gas Research Institute is in the process of evaluating this national trend of declining usage patterns. The extent to which Western's margin is produced via a per Mcf 'distribution' charge, the Company will clearly be vulnerable financially to this continued trend. Mr. Galligan's recommendation to apply the full increase to the volumetric distribution charge would unnecessarily compound this problem.

Western, in its proposed rate design, considered both the indicated 'customer' costs calculated in its cost-of-service study, as well as the ongoing effectiveness of the fixed and variable balance of rate components. Despite our recognition of the declining volumetric trends, Western proposed that a portion of its increase be borne in the per Mcf distribution charge. The Company proposed this rate design as an incremental correction to rebalancing of fixed and variable rate components.

Q. Are there any other recommendations by Mr. Galligan regarding the Company's proposed rate design which cause concerns?

A. Yes. Mr. Galligan also recommends that the Commission reject Western's Margin Loss Recovery Rider and the Premises Charge.

Q. Please describe further Mr. Galligan's recommendation to reject the Margin Loss Recovery and the consequences of such an action on the Company.

A. The Company, in its Application and Data Request responses, identified the competitive pressures in its industrial market and the consequences upon Western historically, absent a Margin Loss Recovery mechanism.

Mr. Galligan refers to the Company's response to Attorney General DR #1, Item 112, in which Western calculated to 'margin loss' recoverable through this mechanism under various customer volume and discount scenarios. The Company calculated the 'margin losses' in the referenced DR response according to methods utilized by the Atmos division United Cities Gas Company, which possesses a margin loss rider in several jurisdictions. Recognizing Mr. Galligan's observations, the Company would consider altering its proposed Margin Loss Recovery tariff to provide further assurance that the recovery will be limited to actual annual margin losses attributable to the customer subject to the discount or flex, compared to the revenue relied upon from that customer in the Company's Test Year. While recognizing the merits of the Margin Loss Recovery rider exhibited by the Company in its Application and DR responses, the Company would also entertain a sharing ratio different than the 90:10 ratio included in the Application.

Q. Please provide additional details regarding Mr. Galligan's recommendation to reject the Company's proposed Premises Charge and the consequences this recommended action would have on Western's performance.

A. Although Mr. Galligan recommends rejection of the Premises Charge, he suggests that this problem would be related to the Commission's customer extension rules, that as a practical matter, would affect all gas distribution utilities in Kentucky. He further suggests a possible "proceeding addressing the generic customer extension rules".

Mr. Galligan fails to recognize in his testimony that, although Kentucky distribution utilities may face similar extension costs due to the Commission's customer extension rules, the margins generated by these utilities for the average residential consumer varies widely.

In his response to the Company's Data Request, Item 20, Mr. Galligan acknowledges that revenues, as well as costs, are "part of a rational investment analysis".

Q. What was the scope of the testimony filed by WBI Southern, Inc?

A. WBI Southern's filed testimony was limited to Western's proposed Rate T-5 Alternate Receipt Point service.

Q. What, if any, changes to the Company's proposed Rate T-5 service were recommended by WBI Southern?

A. WBI Southern supported the Company's proposal to allow alternate receipt points for transportation customers, and they concurred that a lower priority of service is appropriate for alternate points. WBI Southern, however, objected to Western's proposed $0.10 per Mcf incremental charge for customer volumes transported from alternate receipt points.

Q. Does the Company have concerns regarding the opinions and recommendations of WBI Southern?

A. WBI Southern's objection to the proposed $0.10 per Mcf fee appears to be based on their plans to activate a new interconnection with Western, and their opinion that this fee would have a detrimental impact on the marketability of that supply to end-users under Rate T-5 service. The Company, in its development of this new tariff, did not intend such a consequence. Western proposed the Rate T-5 tariff to establish a framework under which transportation and carriage customers could be afforded access to these new interconnects or other alternative supply receipt points into Western's system. The additional fee was proposed in recognition of the additional administrative complexities faced by Western to provide this service - including nomination/balancing complexities, system monitoring requirements and accounting/contractual matters relating to these transactions.

Recognizing that the administrative factors are similar, conceptually, to those recovered through Western's Transportation Administrative Fee, the Company would consider alternate pricing structures for Rate T-5 service - perhaps a monthly administrative fee as opposed to the volumetric fee proposed in the Application.

Q. Are there any other significant concerns regarding comments filed by intervenors pertaining directly to areas of Western's Application for which you were responsible?

A. No, there are no other significant recommendations warranting comment in this rebuttal testimony.

Q. Does this conclude your rebuttal testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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PUBLIC SERVICE
COMMISSION

In the Matter of:

The Application of Western)
Kentucky Gas Company) Case No. 99-070
for an Adjustment of Rates)

WESTERN'S DATA REQUEST TO THE ATTORNEY GENERAL

Western Kentucky Gas Company, by counsel, submits the following data requests to the Attorney General pursuant to the Commission's procedural orders:

Questions of Carl G. K. Weaver

1. Please provide the syllabi from Dr. Weaver's last two years of teaching at James Madison University.

2. Please provide the list of textbooks that Dr. Weaver used in the last five years of teaching finance.

3. Refer to Schedules 24 and 25 of Dr. Weaver's Direct Testimony. Is the market return using the Value Line data that Dr. Weaver uses calculated using a geometric average or an arithmetic average? If the Market Return is a geometric average, please cite sources from refereed journals that prescribe the use of a geometric average when calculating a market

return.

4. Please refer to Schedules 24 and 25 of Dr. Weaver's Direct Testimony. Please provide the workpapers and source documents used to calculate the Standard & Poor's Market Return.

5. Refer to page 10, lines 13-17 of Dr, Weaver's Direct Testimony. He states:

> "...I next examined the market service area that is reported by Value Line for the fifteen remaining companies. I eliminated AGL Resources, Peoples Energy Corporation, and Washington Gas Light because the service area for these companies are concentrated in Atlanta, Chicago, and Washington, D.C. - all urban areas, far different from the service area of Western Kentucky."

a. Is it Dr. Weaver's opinion that a gas distribution company which has its service area concentrated in St. Louis, MO. is comparable to Western Kentucky? Please explain.

b. Did Dr. Weaver choose to include Laclede Gas because its service area was not concentrated in Atlanta, Chicago, or Washington, D.C. ?

c. Did Dr. Weaver choose to include New Jersey Resources because its service territory is concentrated in Monmouth and Ocean Counties, New Jersey ?

d. In Dr. Weaver's opinion, which company has the larger geographic service territory, AGL Resources or New Jersey Resources ?

Questions for Lafayette Morgan

6. With respect to the rate base adjustments:

a. Why did Mr. Morgan not use the updated capital budget submitted in response to KPSC DR 4-2 (formerly KPSC DR 3-58) as the baseline capital budget for his adjustments?

b. What is the basis for Mr. Morgan's adjustment to "0" of all System Maintenance - Retirements and System Improvements - Public Works Reimbursements, given, for example, Western's response to KPSC DR 2-21b and KPSC DR 3-43c?

c. Why was an overhead factor applied to the projected forfeitures, given Western's response to KPSC DR2-21 and KPSC DR 3-43?

d. Why did Mr. Morgan use a ratio of 16% for Div 02 Shared Services Plant Allocations, when he consistently used 16.75% in all of his other calculations?

e. Aside from the issues referenced in a. through d. above, is Mr. Morgan aware of any unspecified adjustments that would further reduce rate base by $300,000?

7. Please provide support for the use of the 92% adjustment factor applied to Western's capital budget.

8. Based upon the information in the table below:

Fiscal Year	**Capital Budget**	**Actual Spending**	**Percent Spent**
1990	$ 7,339,009	$ 7,155,701	97.5
1991	$ 8,594,319	$ 7,454,806	86.7
1992	$ 10,129,578	$ 9,870,231	97.4
1993	$ 9,323,533	$ 9,864,309	105.8
1994	$ 11,453,427	$ 10,872,491	94.9
1995	$ 16,592,171	$ 15,458,057	93.2
1996	$ 17,770,373	$ 14,254,212	80.2
1997	$ 16,595,360	$ 15,085,222	90.9
1998	$ 10,194,434	$ 11,459,605	112.4
	$ 107,992,204	$ 101,474,634	
1990-1998 Average Percentage Spent			95.5

a. Does Mr. Morgan agree that the average annual percentage of capital spent versus budget from 1990 to 1998 (that is, an average of the annual percentages) is 95.5%7

b. Does Mr.Motion agree that the years 1995, 1996 and 1997 represent both the highest level of annual direct capital budgets and direct capital expenditures, between S14 and $18 million, incurred by Western between 1990-19987

c. Does Mr. Morgan agree that the range of actual and budgeted expenditures between 1990-1998, excluding 1995-1997, is between $7 and $12 million?

d. Does Mr. Morgan agree that the percentage of actual annual capital expenditures versus annual capital budget is lowest in the years 1995, 1996 and 1997, with the exception of 1991?

e. Does Mr. Morgan agree that when the years 1995, 1996 and 1997 are removed from the calculation of the average annual percentage of actual annual capital expenditures versus annual capital budget (an average of the annual percentages), the result is an average of 99.1%?

f. Does Mr. Morgan agree that direct capital budgets for Western from 1999 to 2001 are between $7 million and $12 million, and not between $14 million and $18 million?

g. Based upon the responses to the a through f above, is it not more likely that Western's percentage of actual annual capital expenditures to budget would more likely approximate 99.1% than 92%?

9. Does Ms. Morgan disagree that Western's average annual capital budget from 1999-2003 is approximately 88.6% of the average annual capital budget for 1990-19987

10. With respect to the adjustment made to overheads:

a. In general, is it likely that the addition of one typically sized capital project in a given year is likely to significantly increase Western's overhead costs?

b. In general, is it likely that the deletion of one typically sized capital project in a given year is likely to significantly decrease Western's overhead costs?

c. Does Mr. Morgan generally agree that the nature of overhead costs, including executive, engineering, supervisory and clerical costs, is that they are more fixed components of costs and, therefore, are generally less avoidable than the capital projects to which they are applied?

d. If the answer to c. above is yes, given the more fixed nature of overhead costs, why is it not reasonable that the percentage of overheads to direct costs would increase as direct costs decline?

e. If the answer to c. above is no, please explain.

f. Does Mr. Morgan agree that Western's capital overheads ranged from $4.1 million to $5.6 million from 1996 to 1998, but are forecasted by Western to range from $2.9 million to $3.5 million during 1999 to 20037

g. Does Mr. Morgan agree that Western is projecting a decline in its capital overheads from 1996-1998 to 1999-2003?

11. With respect to the "structures and improvements" adjustment:

a. To what types of projects does Mr. Morgan intend to apply: buildings and offices, or remedial work applicable to piping systems providing for public safety and reliable service?

b. If the answer to a. above includes remedial work applicable to piping systems, how does he rationalize this with Western's response to AG DR 2-5?

c. Did Mr. Morgan intend to eliminate the incremental increase in spending above 1999 levels on all specific projects associated with remedial work on piping systems providing for public safety and reliable service?

d. Western's average annual expenditure in system maintenance and improvements in its 1990-1998 was $4,011,505. If related spending in 1999 was reduced to $2,926,403 due to a planned one-time reduction in such expenditures due to the transition to new systems, including the Oracle financial project, is it not reasonable that Western would plan to increase its spending on such projects in subsequent years after the transition?

12. Western's response to Supplemental Response to KPSC DR 1-6 includes the net effects of the United Cities merger with Atmos.

a. With respect to the adjustment for merger and integration expenses, does Mr.

Morgan deny that Western's ratepayers will benefit from this merger?

b. Does Mr. Morgan agree that Western's allocation of Shared Services expenses declined from about 22% prior to the merger to about 18% after the merger?

c. Given Western's return during the test year, what is the savings the shareholders "enjoy" if the Company does not earn a reasonable return?

13. With respect to Mr. Morgan's lawsuit settlement adjustment:

a. Does Mr. Morgan agree that annual liability insurance premiums may vary with the annual retention (the deductible)?

b. Does Mr. Morgan agree that liability insurance premiums are a recoverable expense?

14. With respect to the pension expense adjustment:

a. Is Western's pension credit a source of cash Western can apply to its daily operations in providing service to its customers?

b. If Western's annual net periodic pension cost becomes positive does Mr. Morgan believe that Western is or is not obligated to contribute cash to the pension plan?

c. If Western's annual net periodic pension cost were a $27 million credit due to the performance of plan assets, would Mr. Morgan recommend that no annual operating expenses be recognized in the setting of Western's rates?

15. On schedule LKM-17, did Mr. Morgan intend to apply depreciation expense at 100% ignoring Western's standard practice of capitalizing 4.55% of depreciation?

16. Provide all workpapers and supporting documents not previously provided.

Questions of Richard Galligan:

17. Reference pages 8-9 of Mr. Galligan's testimony and his reference to excerpts

from Bonbright's Principles of Public Utility Rates, pages 347-348. Does that reference provide specific opinions on how to allocate "distribution costs"? If, yes, provide the excerpts regarding those comments.

18. Please provide the workpapers associated with Mr. Galligan's cost of service study summarized in RAG-1.

19. Reference pages 25-26 lines 26-2 of Galligan's testimony. Does Mr. Galligan suggest that a sharing ratio other than 90%:10% would more effectively provide an incentive to the Company to maximize its flexible rates? Explain.

20. Reference page 27, lines 5-10. Does Mr. Galligan agree that in addition to costs associated with facilities required by the Commission's customer extension rules the return on the investment or margin generated by the extension would also impact the economics of the extension?

Questions for Steven Estomin:

21. Provide copies of testimony filed by Mr. Estomin in rate proceedings for the last two years.

22. Provide workpapers and source documents utilized in the preparation of exhibit SLE-1.

Submitted By:

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Certification:

I certify that a copy of this request was served on the Attorney General, 1025 Capital Center Drive, Frankfort, Ky 40601 and J. Mel Camenish, Jr. 201 E. Main St. #1000 Lexington, KY 40507-1380, this the 8th day of November, 1999.

John N. Hughes
John N. Hughes

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
OCT 18 1999
PUBLIC SERVICE COMMISSION

In the Matter of:)
THE APPLICATION OF WESTERN) Case No. 99-070
KENTUCKY GAS COMPANY)
FOR AN ADJUSTMENT OF RATES)

NOTICE OF FILING AND CERTIFICATE OF SERVICE

The Attorney General submits his prepared direct testimony.

Counsel certifies that an original and ten copies of the direct testimony were served and filed by hand delivery to Helen C. Helton, Executive Director, Public Service Commission, 730 Schenkel Lane, Frankfort, KY 40601; further, it was served (per counsel for Western's request) by overnight delivery to William J. Senter, Western Kentucky Gas, 2401 New Hartford Road, Owensboro, KY 42303 1312, and Mark R. Hutchinson, 115 East Second Street, Owensboro, KY 42303, personal exchange to John N. Hughes, 124 West Todd Street, Frankfort, KY 40601, and by mailing a copy, first class postage prepaid to 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 18th day of October, 1999.

Respectfully submitted,

A.B. CHANDLER III
ATTORNEY GENERAL

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COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

WESTERN KENTUCKY) Case No. 99-070
GAS COMPANY)

DIRECT TESTIMONY

OF

LAFAYETTE K. MORGAN

ON BEHALF OF THE

OFFICE OF RATE INTERVENTION OF THE ATTORNEY GENERAL

FOR THE COMMONWEALTH OF KENTUCKY

OCTOBER 1999

EXETER
Associates, Inc.
12510 Prosperity Drive
Suite 350
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BEFORE THE

COMMONWEALTH OF KENTUCKY

PUBLIC SERVICE COMMISSION

WESTERN KENTUCKY)
GAS COMPANY)
Case No. 99-070

Direct Testimony of Lafayette K. Morgan, Jr.

Introduction and Summary

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Lafayette K. Morgan, Jr. I am a Senior Regulatory Analyst with Exeter Associates, Inc. Our offices are located at 12510 Prosperity Drive, Silver Spring, Maryland 20904. Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND QUALIFICATIONS.

A. I received a Master of Business Administration degree from The George Washington University. The major area of concentration for this degree was Finance. I received a Bachelor of Business Administration degree with concentration in Accounting from North Carolina Central University. I am also a Certified Public Accountant licensed in the State of North Carolina.

Q. WOULD YOU PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE?

A. From May 1984 until June 1990, I was employed by the North Carolina Utilities Commission (NCUC) - Public Staff in Raleigh, North Carolina. I was responsible for analyzing testimony, exhibits, and other data presented by parties before the NCUC. I had the additional responsibility of performing the examinations of books and records of utilities involved in rate proceedings and summarizing the results into testimony and exhibits for presentation before the NCUC. I was also involved in numerous special projects, including participating in compliance and prudence audits of a major utility and conducting research on several issues affecting natural gas and electric utilities.

From June 1990 until July 1993, I was employed by Potomac Electric Power Company (Pepco) in Washington, D.C. At Pepco, I was involved in the preparation of the cost of service, rate base and ratemaking adjustments supporting the company's requests for revenue increases in the State of Maryland and the District of Columbia. In addition, I was responsible for preparing Pepco's lead-lag study. I also conducted research on several issues affecting the electric utility industry for presentation to management.

In July 1993, I accepted my current position with Exeter Associates, Inc. Since then, I have been involved in the analysis of the operations of public utilities, with particular emphasis on utility rate regulation. I have also been involved in the review and analysis of utility rate filings, focusing primarily on revenue requirements determination. This work has involved natural gas, water, electric and telephone companies.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON UTILITY RATES?

A. Yes. I have previously presented testimony and affidavits on numerous occasions before the NCUC, the Pennsylvania Public Utility Commission, the Virginia Corporation Commission, the Louisiana Public Service Commission, the Georgia Public Service Commission, the Maine Public Utilities Commission, the Kentucky Public Service Commission and the Federal Energy Regulatory Commission (FERC).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Exeter Associates has been retained by the Office of Attorney General (AG) to review the reasonableness of the level of revenues which Western Kentucky Gas Company (WKG or the Company) is proposing to charge its customers. In this testimony, I present my findings on behalf of the AG regarding certain adjustments to WKG's test year rate base and net operating income at present rates. In addition, I also present a summary of the AG's findings regarding the current levels of WKG's earnings and determine the necessary change in its revenues that is required to produce a overall rate of return on rate base of 8.94 percent. This return is based on the recommendation of AG witness Weaver.

Q. IN CONNECTION WITH THIS CASE, HAVE YOU PERFORMED AN EXAMINATION AND REVIEW OF THE COMPANY'S TESTIMONY AND EXHIBITS?

A. Yes. I have reviewed WKG's testimony and exhibits, its rate filing, as well as its responses to the AG's and other parties' data requests.

Q. WOULD YOU PLEASE SUMMARIZE WHAT IS PRESENTED ON THE ATTACHED SCHEDULES?

A. Yes. I have prepared a set of schedules which present my findings and recommendations regarding the Company's rate base and cost of service. Schedule LKM-1 summarizes my overall findings regarding cost of service. Schedule LKM-2 presents a summary of rate base and my adjustments thereto. Schedule LKM-3 summarizes my adjustments to WKG's net income. Schedule LKM-4 presents a reconciliation of the combined current income taxes. The remaining schedules show the derivation of each of my adjustments to rate base and net operating income.

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. WKG has proposed to increase its rates to reflect a 9.97 percent overall return on rate base. This increase reflects a 12.25 percent return on equity and is based upon the forecasted test year ending December 31, 2000. As shown on Schedule LKM-1, I have determined the appropriate increase in WKG's revenues to be $7,417,710. This represents a reduction of $6,709,956 to the Company's requested revenue increase of $14,127,666. On a percentage basis, the AG proposed revenue requirement represents a 6.2 percent increase to current rates in comparison with the Company's 11.7 percent increase in rates.

Q. WHAT TIME PERIOD DID YOU USE IN YOUR ANALYSIS OF THE COMPANY'S OPERATING RESULTS?

A. The Company's filing included a partially projected based period ending September 30, 1999 and a fully forecasted test period ending December 31, 2000. I have based my analysis of the Company's operating results on the forecasted test year ending December 31, 2000. This is the same period used by the Company to determine its requested rate increase in its rate filing, direct testimonies and exhibits.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of this testimony addresses the individual adjustments which I am proposing and is presented in the order identified in the table of contents to this testimony. For each issue, I will document and explain why it was necessary to make the adjustment.

Rate Base

Plant in Service

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU ARE RECOMMENDING TO PLANT IN SERVICE.

A. WKG's plant in service for the forecasted test year is based upon its capital budget ?for? the year 2000. That budget was developed using the budget for the 1999 fiscal year as a baseline. Future expenditures were then projected by applying a 3 percent inflation rate, an overhead rate of 50 percent of direct expenditures and a 36.25 percent structures and improvement factor. I have made several changes to the level of plant in service for the forecasted period. First, I have adjusted the level of plant in the 1999 fiscal year budget since that budget serves as the starting period for the forecasted test year plant in service. According to documents received from the Company, historically the cost of its completed plant is 92 percent of the budgeted level. Therefore, I have adjusted the budgeted plant, which serves as the baseline for the forecasted plant, to reflect the 92 percent completion ratio. This adjustment is necessary to avoid overstating the forecasted level of plant.

The second change I have made to plant in service for the forecasted period is to reflect a 39.5 percent overhead factor. As indicated earlier, WKG applied a overhead allocation factor of 50 percent of direct construction costs in deriving the forecasted test year plant in service. In data reviewed in response to a data request submitted by the AG, it was determined that historically the overhead level has averaged 39.5 percent of direct construction costs. Consequently, I have reflected the 39.5 percent factor in my determination of the forecasted period plant in service. The 39.5 percent factor was used because it represents a normalized level of overhead costs as compared to the Company's 50 percent factor which is based upon only one year's activity. The use of only one year's activity is of concern because, in any one year, the level of costs could be unusually high or low. Thus, a several year average provides a better measure of costs.

The third change made to the level of plant in service for the forecasted test year involves the inclusion of a structures and improvement factor of 36.25 percent. In determining the level of plant in service for the forecasted period, the Company included structures and improvement based upon the 1999 fiscal year budget. WKG also included an additional level of structures and improvement based upon 36.25 percent of the direct structures and improvement expenditures in the 1999 fiscal year budget. During the AG's investigation in this proceeding, an attempt was made to determine the reason for the additional costs associated with structures and improvement. The data provided by WKG did not offer any additional justification for the additional plant. As a result, I have removed these costs from the forecasted level of plant in service.

On Schedule LKM-5, I present the adjustment which captures all the changes I am recommending to the level of plant in service. This adjustment reduces rate base by $6,360,678.

<u>Accumulated Depreciation</u>

Q. WHAT ADJUSTMENT HAVE YOU MADE TO ACCUMULATED DEPRECIATION?

A. As a result of the changes I am recommending to plant in service, the level of depreciation expense will change due to the use of plant in service balances that differ from that which was used by WKG. The adjustment I am recommending on Schedule LKM-17 increases rate base by $310,369.

Accumulated Deferred Income Taxes

Q. HAVE YOU MADE AN ADJUSTMENT TO ACCUMULATE DEFERRED INCOME TAXES (ADIT) TO REFLECT CHANGES TO THE LEVEL OF PLANT IN SERVICE AND DEPRECIATION?

A. No, I have not. However, I acknowledge that the adjustment to plant in service and depreciation expense may affect the level of ADIT. At the time of preparing my testimony, I did not have the data that would have allowed me to make the necessary adjustment. If the data are provided by the Company, I will make the necessary adjustment.

Allowance for Cash Working Capital

Q. WHAT ADJUSTMENT HAVE YOU MADE TO THE ALLOWANCE FOR CASH WORKING CAPITAL?

A. The Company's presentation of cash working capital is based upon the formula approach of one-eighth of Operations and Maintenance (O&M) expenses. Under this approach, O&M expenses serve as the base on which the allowance for cash working capital is calculated. Thus, the O&M expenses which serve as the cash working capital base should not contain expenses found to be improper for inclusion in the cost of service, or expenses removed to reflect a normalized level of costs. Such items are excluded because, for ratemaking purposes, cash working capital should represent the funds a utility needs to have on hand to fund the day-to-day utility operations. Consequently, it would be improper to reflect in the working capital base those O&M expenses that have been deemed unnecessary in deriving the cost of service. I have made adjustments to the cash working base to remove such expenses prior to applying the cash working capital factor. On Schedule LKM-6, I present this adjustment which reduces rate base by $399,197.

Prepayments and Material and Supplies

Q. WHAT ADJUSTMENT HAVE YOU MADE TO PREPAYMENTS?

A. In the development of rate base, the Company has included the 13-month average balance of prepaid expenses. Also, as a component of material and supplies, WKG included the average balance of merchandise. The concept of including prepayments in rate base is a normal ratemaking practice that is usually accepted by most commissions. However, the adjustment I am proposing to prepayments is composed of two components. First, as a result of data requests submitted by the AG, the Company has noted instances where there were errors in the filing. These errors involved the balances associated with the CIS project, the Oracle data base maintenance, Alliance Gas and Ten Alliance Gas. I have recalculated the average prepayments balance based upon the information provided by the Company.

The second component of my adjustment involved the removal of costs that are improper for inclusion in prepayments. In that respect, I have removed the costs associated with the credit facility fee paid to Nationsbank of Texas. According to the Company, these costs were included as a component of the short-term debt cost in its cost of capital calculation. Since these costs are recovered as part of the cost of capital, it is improper to include them in rate base. Including these costs in rate base would allow the Company to overrecover them.

With respect to the level of merchandise included in material and supplies, I am recommending the removal of those costs because merchandise held in material and supplies is usually associated with non-utility activities. If WKG produces information that shows that these items are for utility operations, I will withdraw my adjustment. On Schedule LKM-7, I present this adjustment to rate base which is a reduction of $114,620.

Operating Income

Rate Case Expense

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO RATE CASE EXPENSE.

A. In WKG's filing, it included a level of rate case expenses based upon a three-year amortization of rate case expense. The Company's recent history indicates that the frequency of rate cases averages approximately one every four years. Therefore, on Schedule LKM-8, I am recommending an adjustment that amortizes rate case expenses over a four-year period. This adjustment reduces operating expenses by $27,500.

Uncollectible Expense

Q. COULD YOU EXPLAIN YOUR ADJUSTMENT TO UNCOLLECTIBLE EXPENSE?

A. Yes. In determining the level of uncollectibles for the forecast period, WKG compared the uncollectible expense level in the base year budget with the actual level of uncollectibles for fiscal year 1998. Because the level of uncollectibles was higher during fiscal year 1998, the Company assumed that uncollectibles would be higher than it had budgeted, and made an adjustment to increase uncollectibles. The Company did not provide any specific reason for its assumption of higher uncollectible, neither could it provide any accounts receivable aging analysis for the period to support the assumption of an increase in uncollectible expense.

I have made an adjustment to uncollectible expense because I do not believe the Company has properly supported its claim for increased expenses. Moreover, uncollectible expense is the type of cost that has a tendency to fluctuate from year to year. Hence, it is not reasonable to project that cost based upon only one year's activity. The adjustment I am recommending to uncollectible expense is based upon the average uncollectible ratio of .40 percent for the last five years. This is the same ratio used by

WKG in its calculation of the gross revenue conversion factor. The use of this ratio results in a reduction to uncollectibles expense of $234,223, and this adjustment is summarized on Schedule LKM-9.

Lawsuit Settlement Costs

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO LAWSUIT SETTLEMENT COSTS.

A. WKG included in its forecasted test year O&M expenses a five-year amortization of a lawsuit settlement. The lawsuit was the result of a natural gas incident involving the Company in Danville, Kentucky. The amortization of these costs began in October 1998 and the amount included in the forecasted test year is $189,789.

On Schedule LKM-10, I am recommending an adjustment that removes the entire amortization amount from the revenue requirement. This adjustment is necessary because these costs are related to a prior period and not current test year costs. Recovery of these costs would constitute retroactive ratemaking. Also, WKG has not demonstrated why it is appropriate for ratepayers to pay these costs. Additional information on the lawsuit was sought, but was not provided. Without additional information, it is difficult to assess whether these costs should be in the cost of service. Furthermore, the Commission has not authorized the deferral and amortization of these costs. Therefore, these costs should not be recovered.

Merger-Related Costs

Q. WHAT ADJUSTMENT HAVE YOU MADE TO MERGER-RELATED COSTS?

A. In WKG's operations and maintenance costs, it has included $306,000 associated with merger of Atmos Energy Corporation and United Cities Gas Company. The merger of the two companies was announced in July 1996. As a result of the merger, merger and integration costs were incurred as well as separation and other costs. In its 1997 Annual Report to Shareholders, the Company stated:

> There are substantial longer term benefits to our customers and our shareholders from the merger of the two companies, which the company expects to result in cost savings over the next 10 years totaling about $375 million. The company believes a significant amount of the costs to achieve these benefits will be recovered through rates and future operating efficiencies of the combined operations, and therefore, the company recorded the costs of the merger with and integration of United Cities as regulatory assets. However, the company established a general reserve of approximately $20 million ($12.6 million after-tax) to account for a portion of the costs that may be shared by our shareholders for their portion of the benefits.

The adjustment I am proposing is associated with the $20 million costs that the Company indicated that its shareholders may absorb. There are several reasons why I believe it is appropriate for shareholders to absorb these costs. First, the Company has recognized that it may be appropriate for shareholders to absorb these costs because of the expected benefits of the merger. Second, since the merger of the two companies, WKG's rates have remained unchanged. Therefore, any cost savings that the company has enjoyed went directly to shareholders. Third, these costs are outside the test period. There has been no orders from this Commission that authorized the Company to defer these costs for future recovery. Therefore, the recovery of these costs would amount to a retroactive recovery of prior period costs. On Schedule LKM-11, I present this adjustment which reduces operations and maintenance expenses by $306,000.

<u>Shared Services Unit Costs</u>

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE SHARED SERVICES UNIT COSTS.

A. The Shared Services Unit (Shared Services) established by the Company serves as organization within Atmos that perform functions and tasks that benefit more than one of the business units. Costs are either allocated to the business unit, if those costs are related to activities that benefit more than one business unit, or the costs are directly charged to the business unit that is associated with the activity that caused the costs. As a result, in the operating expenses of each business unit such as WKG, there is a level of costs associated with charges from Shared Services.

During my review of the Shared Services' costs included in the forecasted test period, there were certain costs that, in my view, should not be included in the cost of service in this proceeding. The first category of costs are associated with lobbying activities. The Governmental Services Department within Shared Services is charged with two broad areas of activities: (1) Legislative Research, Administration and Issue Coordination, and (2) Lobbying and Political Campaigns. Under traditional ratemaking practices lobbying costs are not included in expenses for ratemaking purposes. As a result, I have removed the costs associated with lobbying. In deriving the amount associated lobbying, I have first removed the direct costs related to lobbyists that were included in the Governmental Services budget. The other component of the lobbying expenses amounts to 50 percent of the Governmental Services department's non-lobbying costs. These costs include other costs associated with the operation of the department such as supplies, travel, etc. I have removed 50 percent of these costs as a measure of other costs associated with lobbying activities. Since the department serves two broad areas, I have assumed a 50/50 division of the costs.

The other costs I am removing from O&M expenses is associated with the Information Technology department. Data reviewed during this proceeding suggests that the Company has included costs of temporary labor associated with the mainframe support during the implementation of the IT strategy. According to the Company, the IT strategy is related to the Oracle/Orbit conversion and should be complete before the forecast period. Thus, these costs should not be included as a component of the forecasted test year. Therefore, I am recommending an adjustment to remove these costs.

On Schedule LKM-12, I present an adjustment that summarizes the two categories of costs that I have discussed. This adjustment results in a $127,563 decrease in operations and maintenance expenses.

PSC Assessments

Q. WHY HAVE YOU MADE AN ADJUSTMENT TO PSC FEES?

A. I have made an adjustment to remove costs associated with out-of-period costs that were included in the cost of service. In WKG's filing, it attempted to reflect the expected decease in its PSC assessments. However, in the Company's calculation of the decrease it excluded the costs associated with the 1997 assessments paid in 1999 and the assessments to be expensed during October through December of 1999. Since both of these amounts are associated with periods other than the forecasted test year, I have removed them from the PSC assessments for the forecasted test period. I have made this adjustment because it is important when setting rates that the cost of service reflects only an annual level of costs. On Schedule LKM-13, I present this adjustment which decreases the cost of service by $51,161.

Pensions Expense

Q. PLEASE EXPLAIN THE ADJUSTMENT TO PENSIONS EXPENSE.

A. For financial reporting purposes, WKG records pensions expense based upon Financial Accounting Standards Board Statement No. 87 (FASB 87). Under FASB 87, the level of pension expense recorded during a given period is measured so that the costs are recognized during the period when the obligation is incurred by the employee service. The FASB 87 costs that are recognized during the accounting period are determined through an actuarial study that considers several factors including age, benefits and the assets of the pension plan. Based upon FASB 87, WKG's budget for the forecasted test year included a pension expense credit of $853,000. Stated differently, WKG's budgeted pension expense was a negative $853,000. The pension expense is a credit because the pension plan is in an overfunded position due to a reduction in the number of eligible employees and the performance of the pension plan assets.

The Company has proposed an adjustment to remove the negative pension expense, and thereby reflect a pension expense of $0 (zero) for the forecasted test year. According to the Company, the adjustment was made so that it will not flow back cash to ratepayers since it does not receive any cash from the pension plan. The Company states that it will set pension expense to $0 for the period rates from this proceeding are in effect regardless of the amount WKG records on its book for pension expense.

Q. DOES REFLECTING THE $853,000 CREDIT PENSION EXPENSE RESULT IN A FLOW BACK OF FUNDS HELD IN THE PENSION PLAN TRUST?

A. No. The pension expense credit of $853,000 does not mean that funds are flowing out the pension plan trust fund. The credit of $853,000 reflects the current pension expense under the accrual basis and is not a transfer of funds from the trust fund. As I indicated earlier, under FASB 87, pension expense is calculated under the accrual basis to reflect pension costs as incurred. However, the credit expense is the current level of pension expense under FASB 87 rules.

Q. IS THERE AN INCONSISTENCY IN THE COMPANY'S APPLICATION OF FASB 87?

A. Yes, there is an inconsistency in the Company's position. In response to AG Data Request 2-11, WKG stated:

> The company follows FAS 87 for pension accounting purposes and recognizes pension costs on an accrual basis, such that financial statements match costs with the period in which employee service is rendered. Similarly, for

> ratemaking purposes, the Company follows the accrual method to the extent that pension expense is positive, thus funding today's pension costs from today's rates.

Essentially, the Company is being arbitrary in its selection of its choice of accounting methods. While for ratemaking purposes the Company may choose which method of accounting for pensions it prefers, it must apply that method on a consistent basis and not be allowed to switch back and forth based upon the revenue impact.

Q. IS THERE A REASON TO SINGLE OUT THE PENSION EXPENSE CREDIT FOR A DIFFERENT ACCOUNTING METHOD?

A. No. The reasons for the pension expense overfunding is the performance of the pension plan assets and a change in the eligible number of employees. There are also other factors that affect pension expense. In fact, in the response to AG Data Request 2-11, WKG states the following:

> Other pension cost elements include: the discount interest cost associated with payment of future benefits, actual return on plan assets, gains and losses associated with changes in projected benefit obligation or plan assets resulting from experience different than projected, service cost for today's employees, amortization of unrecognized prior service cost, and transition obligations at the date of implementation of FAS 87.

Regardless of whether the pension expense is a debt or credit, the Company's pension expense is still subject to all cost factors that the Company has listed. Therefore, to treat a credit expense differently is without merit.

To further illustrate the point, assume the Company's budget reflected an $853,000 (positive) pension expense. Under the position stated by WKG, it would reflect pension expense for ratemaking purposes under SFAS 87. However, any of the cost factors it listed could change and cause pension expense to decrease or increase. As can be seen, the cost factors are relevant not only when costs are negative.

Q. HOW HAVE YOU QUANTIFIED YOUR PENSION EXPENSE ADJUSTMENT?

A. During my review, I requested support for the pension expense amount included in the Company's budget, and the Company provided the 1999 actuarial estimate. I have used the 1999 actuarial estimate because it is the most recent estimate of pensions costs. I have therefore made an adjustment to reflect pension expense based upon FASB 87. This adjustment is presented on Schedule LKM-14 and it reduces operations and maintenance expense by $2,272,501.

Payroll Expenses

Q. WHAT ADJUSTMENT HAVE YOU MADE TO PAYROLL EXPENSES?

A. The Company has indicated that the cost of service has been adjusted to reflect a full complement of employees. The Company states that it plans to hire additional employees to increase its employee level from the base period level of 267 employees to the authorized level of 282 employees. I am proposing an adjustment to reflect the base year actual level of 258 employees.

Q. WHY HAVE YOU REFLECTED THE BASE YEAR LEVEL OF EMPLOYEES?

A. There are three reasons why I believe that it is inappropriate to reflect a full complement of employees. First, historically the Company has maintained a level of employees that is less than a full complement. In fact, this phenomenon is not unique to WKG. Because of employee attrition and other factors, almost no company can maintain a full complement of employees year round. Therefore, it would be inappropriate to build into rates a level of costs that is not attained.

Second, the Company has not hired these employees nor does it have a firm plan for hiring these employees. Consequently, these costs are not known and certain.

Finally, the actual level of employees has decreased during the base period to 258 employees. This suggests that the level of employees included in the cost of service is already higher than that which will exist during the rate effective period.

Because of these reasons, I am presenting an adjustment on Schedule LKM-15 to reduce payroll expense by $586,455.

Q. IF THE LEVEL OF EMPLOYEES THAT YOU ARE INCLUDING IN PAYROLL REFLECTS LESS THAN FULL COMPLEMENT, HAVE YOU REMOVED THE COST OF CONTRACTOR LABOR THAT MAY DO THE WORK RELATED TO THE VACANT POSITIONS?

A. No. I have not removed any contractor labor costs that are included in the test year. In so doing, I have recognized that there are times when the work load may require the use of temporary employees.

Benefits Expense

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO BENEFITS EXPENSE.

A. The Company's filing includes benefits expense for the additional employees needed to meet a full complement. In addition, the Company includes benefits expense to reflect 23 percent of payroll costs. I have made an adjustment to remove the benefits associated with the additional employees, consistent with my adjustment to payroll expense. Since the employees are not included in the cost of service, it is proper to remove the associated costs. In addition, I have revised the postretirement benefits component to reflect the most recent costs associated with those benefits. On Schedule LKM-16, I present this adjustment which increases operations and maintenance expense by $550,458.

Depreciation Expense

Q. WHY HAVE YOU ADJUSTED DEPRECIATION EXPENSE?

A. The level of depreciation expense included in the cost of service by WKG was based upon its level of plant in service. Since I have adjusted the level of plant in service, it is necessary to make the corresponding adjustment to depreciation expense. On Schedule LKM-17, I present this adjustment which reduces depreciation expense by $310,369.

Payroll Taxes

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO PAYROLL TAXES?

A. As a result of the adjustment I am recommending to payroll expense, I am recommending an adjustment to payroll taxes to reflect the decrease in the level of payroll. On Schedule LKM-18, I present this adjustment which reduces payroll taxes by $74,956.

Interest Synchronization

Q. PLEASE SUMMARIZE YOUR ADJUSTMENT TO PROVIDE FOR A SYNCHRONIZED INTEREST DEDUCTION.

A. As presented on Schedule LKM-19, I have applied the weight cost of debt as recommended by witness Weaver to my recommended level of rate base. This results in a reduction in synchronized interest deductions of $287,926 and a corresponding increase in income taxes of $116,214.

Demand Side Management Program

Q. DO YOU HAVE ANY COMMENTS WITH RESPECT TO WKG'S REQUEST FOR A DEMAND SIDE MANAGEMENT (DSM) SURCHARGE?

A. The Company has requested to implement a DSM surcharge to recover DSM costs from its customers. The Company has broken the DSM costs to be recovered into two components -- past DSM costs arising out of the last rate case, and prospective costs to be incurred if the DSM expenditures proposed in this proceeding are approved. I have been advised by counsel that the Attorney General's Office has taken the position that the past DSM costs are not eligible for recovery and should not be allowed as part of any DSM surcharge arising out of this proceeding. With respect to the prospective charge, the Attorney General's Office reserves the right to address this issue later in brief.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE

COMMONWEALTH OF KENTUCKY

PUBLIC SERVICE COMMISSION

WESTERN KENTUCKY	)	Case No. 99-070
GAS COMPANY	)	

EXHIBITS ACCOMPANYING THE DIRECT TESTIMONY OF LAFAYETTE K. MORGAN, JR.

ON BEHALF OF THE

OFFICE OF ATTORNEY GENERAL

OCTOBER 1999

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

WESTERN KENTUCKY) CASE NO. 99-070
GAS COMPANY)

Affidavit of

LAFAYETTE K. MORGAN

I, Lafayette K. Morgan hereby certify that the statements contained in the foregoing testimony are true and correct to the best of my knowledge, information, and belief.

Lafayette Morgan L.
Lafayette K. Morgan

STATE OF MARYLAND)
COUNTY OF ~~MONTGOMERY~~ Prince Georges) SS
)

Subscribed and sworn to before me, this 15th day of October 1999.

P. J. Gardner
Notary Public

P. J. GARDNER
Notary Public, State of Maryland
County of Prince George
My Commission Expires July 16, 2000

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

WESTERN KENTUCKY GAS COMPANY	))	Case No. 99-070

EXHIBITS ACCOMPANYING THE
DIRECT TESTIMONY
OF
LAFAYETTE K. MORGAN

ON BEHALF OF THE

OFFICE OF RATE INTERVENTION OF THE ATTORNEY GENERAL

FOR THE COMMONWEALTH OF KENTUCKY

OCTOBER 1999

EXETER
Associates, Inc.
12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

Case No. 99-070
Schedule LKM-1
Page 1 of 2

WESTERN KENTUCKY GAS COMPANY

Summary of Operating Income
For the Test Year Ending December 31, 2000

	Amount Per Company	AG Adjustments	Amount After Adjustments	Proposed Rate Increase	After Proposed Rate Increase
Operating Revenues	$120,503,329	$0	$120,503,329	$7,417,710	$127,921,039
Operating & Maintenance Expenses:					
Purchased Gas Costs	$77,522,158	$0	$77,522,158	$0	$77,522,158
Other O&M Expenses	26,583,262	(3,193,573)	23,389,689	41,087	23,430,776
Depreciation Expense	10,054,907	(310,369)	9,744,538	0	9,744,538
Taxes Other Than Income	1,952,000	(126,117)	1,825,883	0	1,825,883
State & Federal Income Taxes	(239,551)	1,581,397	1,341,846	2,977,389	4,319,235
Total Operating Expenses	$115,872,776	($2,048,662)	$113,824,114	$3,018,476	$116,842,590
Net Operating Income	$4,630,553	$2,048,662	$6,679,215	$4,399,234	$11,078,449
Rate Base	$130,484,159		$123,920,033		$123,920,033
Rate of Return	3.55%		5.39%		8.940%

WESTERN KENTUCKY GAS COMPANY

Determination of Revenue Increase
For the Test Year Ending December 31, 2000

		Amount	Source
AG Recommended Rate Base		$123,920,033	Schedule LKM-2, Page 2
Required Rate of Return		8.94%	
Net Operating Income Required		$11,078,451	
Net Operating Income at Present Rates		6,679,215	Schedule LKM-1, Page 1
Income Deficiency		$4,399,236	
Revenue Multiplier		1.686136	
Revenue Increase Required		$7,417,710	
Proposed Revenue Increase		$7,417,710	
Uncollectibles	0.4000%	29,671	
Subtotal		$7,388,039	
PSC Fees	0.15390%	11,416	
Subtotal		$7,376,623	
State Income Tax	8.25%	608,571	
Subtotal		$6,768,052	
Federal Income Tax at	35.00%	2,368,818	
Net Income Increase Required		$4,399,234	

Case No. 99-070
Schedule LKM-2
Page 1 of 2

WESTERN KENTUCKY GAS COMPANY

Summary of Rate Base
For the Test Year Ending December 31, 2000

	Amount Per Company	AG Adjustments	Amount After Adjustments
Plant in Service	$248,939,511	($6,360,678)	$242,578,833
Accumulated Depreciation and Amortization	(111,910,842)	310,369	(111,600,473)
Net Plant in Service	$137,028,669	($6,050,309)	$130,978,360
Working Capital Requirement			
Cash Working Capital	$3,322,908	($114,620)	$3,208,288
Other Working Capital Allowance	8,782,404	(399,197)	8,383,207
Total Working Capital Allowance	$12,105,312	($513,817)	$11,591,495
Customer Advances For Construction	($6,120,429)	$0	($6,120,429)
Accumulated Deferred Income Taxes & Investment Tax Credits	(12,529,393)	0	(12,529,393)
Total Rate Base	$130,484,159	($6,564,126)	$123,920,033

WESTERN KENTUCKY GAS COMPANY

Summary of Rate Base Adjustments
For the Test Year Ending December 31, 2000

	Amount
Rate Base per Company Filing	$130,484,159
<u>AG Adjustments:</u>	
Adjustment to Materials & Supplies and Prepayments	($114,620)
Adjustment to Allowance for Cash Working Capital	(399,197)
Adjustment to Plant In Service	(6,360,678)
Adjustment to Accumulated Depreciation	310,369
Total AG Adjustments	($6,449,506)
AG Adjusted Rate Base	$124,034,653

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Schedule LKM-3
Page 1 of 2

WESTERN KENTUCKY GAS COMPANY

Summary of Adjustments to Net Income
For the Test Year Ending December 31, 2000

	Amount
Net Income per Company	$4,630,553
AG Adjustments:	
Adjustment to Remove Merger & Integration Expenses	$182,491
Adjustment to Remove Amortization of Lawsuit Settlement	113,185
Adjustment to Uncollectible Accounts Expense	139,685
Adjustment to Pension Expense	1,355,263
Adjustment to PSC Assessment Fees	30,511
Adjustment to Rate Case Expense	16,400
Adjustment to Shared Services Expense	76,075
Adjustment to Payroll Expense	349,747
Adjustment to Employee Benefits	(328,279)
Adjustment to Depreciation Expense	185,096
Adjustment to Payroll Taxes	44,702
Interest Synchronization	(116,214)
Total AG Adjustments	$2,048,662
Total Adjusted Income per AG	$6,679,215

Case No. 99-070
Schedule LKM-3
Page 2 of 2

WESTERN KENTUCKY GAS COMPANY

Summary of Adjustments to Net Income
For the Test Year Ending December 31, 2000

	Operating Revenues	Purchased Gas	Other O&M Expenses	Depreciation Expense	Taxes Other Than Income	State & Federal Income Taxes	Net Operating Income
Amount per Company	$120,503,329	$77,522,158	$26,583,262	$10,054,907	$1,952,000	($239,551)	$4,630,553
AG Adjustments:							
Adjustment to Remove Merger & Integration Expenses	$0	$0	($306,000)	$0	$0	$123,509	$182,491
Adjustment to Remove Amortization of Lawsuit Settlement	0	0	(189,789)	0	0	76,604	113,185
Adjustment to Uncollectible Accounts Expense	0	0	(234,223)	0	0	94,538	139,685
Adjustment to Pension Expense	0	0	(2,272,501)	0	0	917,238	1,355,263
Adjustment to PSC Assessment Fees	0	0	0	0	(51,161)	20,650	30,511
Adjustment to Rate Case Expense	0	0	(27,500)	0	0	11,100	16,400
Adjustment to Shared Services Expense	0	0	(127,563)	0	0	51,488	76,075
Adjustment to Payroll Expense	0	0	(586,455)	0	0	236,708	349,747
Adjustment to Employee Benefits	0	0	550,458	0	0	(222,179)	(328,279)
Adjustment to Depreciation Expense	0	0	0	(310,369)	0	125,273	185,096
Adjustment to Payroll Taxes	0	0	0	0	(74,956)	30,254	44,702
Interest Synchronization	0	0	0	0	0	116,214	(116,214)
Total AG Adjustments	$0	$0	($3,193,573)	($310,369)	($126,117)	$1,581,397	$2,048,662
Total Adjusted Income per AG	$120,503,329	$77,522,158	$23,389,689	$9,744,538	$1,825,883	$1,341,846	$6,679,215

Case No. 99-070
Schedule LKM-7

WESTERN KENTUCKY GAS COMPANY

Adjustment to Materials & Supplies and Prepayments
For the Test Year Ending December 31, 2000

	Amount	
Prepayments:		
Total Western Kentucky 13 - Month Average Prepayments Reflecting Correction to CIS & Oracle Data Base Maintenance and Removal of NationsBank Credit Facility Fee	$357,807	1/
Total Western Kentucky 13 - Month Average Prepayments per Company	460,653	2/
Adjustment to Prepayments	(102,846)	
Adjustment to Remove Merchandise Included in Rate Base	(11,774)	3/
Adjustment to Rate Base	($114,620)	

Notes:
1/ Calculated based on response to AG Data Request.
2/ Company Filing Schedule B-4.1, Sheet 2 of 2.
3/ Company Filing, WP B-4.1, Page 2 of 2.

Case No. 99-070
Schedule LKM-8

WESTERN KENTUCKY GAS COMPANY

Adjustment to Rate Case Expense
For the Test Year Ending December 31, 2000

	Amount	
Total Projected Rate Case Expense	$330,000	1/
Amortization Period (Years)	4	
Rate Case Expense per AG	$82,500	
Rate Case Expense per Company	110,000	2/
Adjustment to O&M Expense	($27,500)	

Notes:
1/ Company Filing, Schedule F-6, Page 1.
2/ Company Filing, Schedule D-2.2, Sheet 2 of 2.

Case No. 99-070
Schedule LKM-9

WESTERN KENTUCKY GAS COMPANY

Adjustment to Uncollectible Accounts Expense
For the Test Year Ending December 31, 2000

	Amount	
Adjusted Jurisdictional Revenues Subject to Uncollectibles	$96,089,208	1/
5-Year Average Uncollectible Percentage	0.40%	2/
Uncollectible Expense per AG	384,357	
Forecasted Test Year Uncollectible Accounts Expense	618,580	3/
Adjustment to Uncollectible Accounts Expense	(234,223)	

Notes:
1/ Company Filing, Schedule D-1, Sheet 1 of 4.
2/ Company Filing, Schedule H, Sheet 1.
3/ Company Filing Schedule C-2.1, Sheet 9 of 10, Account 904.

Case No. 99-070
Schedule LKM-10

WESTERN KENTUCKY GAS COMPANY

Adjustment to Remove Amortization of Lawsuit Settlement For the Test Year Ending December 31, 2000

	Amount	
Amortization of Lawsuit Settlement Costs Included in Forecasted Test Year	$189,789	1/
Adjustment to O&M Expense	($189,789)	

Notes:
1/ Response to AG Data Request No. 2-17.

Case No. 99-070
Schedule LKM-11

WESTERN KENTUCKY GAS COMPANY

Adjustment to Remove Merger & Integration Expenses
For the Test Year Ending December 31, 2000

	Amount	
Amortization of Merger & Integration Costs Included in Forecasted Test Year	$306,000	1/
Adjustment to O&M Expense	($306,000)	

Notes:
1/ Response to AG Data Request No. 1-165.

Case No. 99-070
Schedule LKM-12

WESTERN KENTUCKY GAS COMPANY

Adjustment to Shared Services Expense
For the Test Year Ending December 31, 2000

	Amount 1/	WKG Allocation Factor 2/	Amount
Temporary Contractors for Implementation of IT Strategy	$374,000	17.70%	$66,198
Lobbying costs in Governmental Services	252,000	15.70%	39,564
50% of Govt. Affairs Non-Lobbying Expenses	138,861	15.70%	21,801
Western Kentucky Portion of Costs			$127,563
Adjustment to O&M Expense			($127,563)

Notes:
1/ Response to KPSC Data Request 1-83.
2/ Company Filing, FR10(9)(u), Schedule 2, Page 2.

Case No. 99-070
Schedule LKM-13

WESTERN KENTUCKY GAS COMPANY

Adjustment to PSC Assessment Fees
For the Test Year Ending December 31, 2000

	Amount 1/
1997 Expense Amount	$30,325
Amount to be Expensed during Oct. Nov. & Dec. 1999	20,836
Total Out of Period Amounts	51,161
Adjustment to Taxes Other Than Income	($51,161)

Notes:
1/ Response to KPSC Data Request 1-74.

Case No. 99-070
Schedule LKM-5

WESTERN KENTUCKY GAS COMPANY

Adjustment to Plant in Service
For the Test Year Ending December 31, 2000

	Amount	
Average Plant In Service Per AG	$242,578,833	1/
Average Plant In Service Per Company	248,939,511	2/
Adjustment to Plant In Service	($6,360,678)	

Notes:
1/ Calculated from data provided by Company.
2/ Company Filing Schedule B-1, Sheet 2 of 2.

Case No. 99-070
Schedule LKM-6

WESTERN KENTUCKY GAS COMPANY

Adjustment to Allowance for Cash Working Capital
For the Test Year Ending December 31, 2000

	Amount	
Total O&M Expenses per Company Filing	$26,583,262	1/
Expenses Separately Adjusted:		
Pensions Expense	($2,272,501)	2/
Merger & Integration Costs	(306,000)	2/
Uncollectible Expense	(234,223)	2/
Lawsuit Amortization	(189,789)	2/
Shared Services	(127,563)	2/
Rate Case Expense	(27,500)	2/
Payroll Expense	(586,455)	2/
Adjustment to Employee Benefits	550,458	2/
O&M Expenses subject to Working Capital Factor	$23,389,689	
Working Capital Factor	12.50%	
Working Capital Allowance Per AG	$2,923,711	
Working Capital Allowance Per Co.	3,322,908	1/
Adjustment to Working Capital Allowance	($399,197)	

Notes:
1/ Company Filing, Schedule B-4.2, Sheet 2 of 2.
2/ Schedule LKM -3, Page 2.

Case No. 99-070
Schedule LKM-4

WESTERN KENTUCKY GAS COMPANY

Reconciliation of Combined Income Taxes
For the Test Year Ending December 31, 2000

Description		Test Year Per Company 1/	AG Adjustments	Test Year at Present Rates	Proposed Increase	After Proposed Increase
CALCULATION OF COMBINED INCOME TAX						
Net Operating Income Before Income Taxes		$4,391,002	$3,630,059	$8,021,061	$7,376,623	$15,397,684
Interest Expense		(4,984,495)	287,926	(4,696,569)	0	(4,696,569)
Combined Taxable Income		($593,493)	$3,917,985	$3,324,492	$7,376,623	$10,701,115
Composite Income Tax Rate at	40.36251%	($239,534)	$1,581,397	$1,341,848	$2,977,390	$4,319,239
Net Combined Income Tax		($239,534)	$1,581,397	$1,341,848	$2,977,390	$4,319,239
Total Combined Income Taxes (Schedule LKM-1, Page 1)		(239,551)	1,581,397	1,341,846	2,977,389	4,319,235
Unreconciled		$17	$0	$2	$1	$4

Case No. 99-070
Schedule LKM-14

WESTERN KENTUCKY GAS COMPANY

Adjustment to Pension Expense
For the Test Year Ending December 31, 2000

	Amount	1/
Budgeted Pension Expense for the Forecasted Period	($853,000)	
Forecasted Test Year Pension Expense Per Company	0	
Adjustment to Reverse Company Adjustment	($853,000)	
Updated Pension Costs	($3,255,918)	2/
O&M Ratio	69.80%	3/
Updated Pension Expense to Be Charged top O&M	($2,272,501)	
Reversal of Company Adjustment	853,000	
Additional Adjustment to Reflect Updated Pension Expense	($1,419,501)	
Adjustment to O&M Expense	($2,272,501)	

Notes:
1/ Direct Testimony of Western Kentucky Witness Burman.
2/ Calculated Based on data supplied in response to AG Data Request No. 1-197.
3/ Company Filing, Schedule G-2.

Case No. 99-070
Schedule LKM-15

WESTERN KENTUCKY GAS COMPANY

Adjustment to Payroll Expense
For the Test Year Ending December 31, 2000

	Amount	
Adjustment to Remove Cost Associated with 15 Vacant Positions as Adjusted by Company	($325,500)	1/
<u>Adjustment to Reflect the Base Year Level of Employees</u>		
Revised Forecast Year Payroll Labor Costs	$11,718,375	2/
Number of Employees	282	
Average Payroll Cost Per Employee	$41,555	
Reduction of Employees During the Base Year	9	
Total Payroll Related to the 9 Employees	$373,995	
O&M Ratio	69.775%	
Adjustment to O&M Expense Related to The 9 Employees	($260,955)	
Total Adjustment to Payroll Expense	($586,455)	

Notes:
1/ Response to AG Data Request No. 1-173.
2/ Company Filing, Schedule G-2.

Case No. 99-070
Schedule LKM-16

WESTERN KENTUCKY GAS COMPANY

Adjustment to Employee Benefits
For the Test Year Ending December 31, 2000

	Amount	1/
Workers Comp.	$150,000	
Basic Life	57,886	
Medical & Dental	1,170,288	
Disability Ins	58,999	
ESOP Match	445,277	
ESOP Other	19,350	
Subject to Payroll Level	$1,901,800	
Postretirement Benefits Other Than Pensions	1,583,200	2/
Total Employee Benefits	$3,485,000	
O&M Ratio	69.774%	
O&M Benefits Expense	$2,431,624	
Benefits Expense Per Company	1,881,166	3/
Adjustment to Benefits Expense	$550,458	

Case No. 99-070
Schedule LKM-17

WESTERN KENTUCKY GAS COMPANY

Adjustment to Depreciation Expense
For the Test Year Ending December 31, 2000

	Plant in Service Per AG	Plant in Service Per WKG	Adjustment	Depreciation Rate	Adjustment to Depreciation Expense
Storage Plant					
Rights of Way	$4,682	$4,682	$0	0.92%	$0
Compression Stat Equip	121,265	121,774	(509)	1.93%	(10)
Meas. & Reg Equip	23,138	23,138	0	1.93%	0
Other Structures	144,554	144,554	0	1.93%	0
Well Construction	2,196,476	2,172,800	23,676	2.71%	642
Well Equip	535,976	579,991	(44,015)	2.71%	(1,193)
Leaseholds	178,530	178,530	0	0.30%	0
Storage Rights	54,614	54,614	0	1.83%	0
Field Lines	235,436	261,841	(26,405)	1.35%	(356)
Tributary Lines	222,764	228,934	(6,170)	1.35%	(83)
Compression Stat. Equip	470,685	470,685	0	1.51%	0
Meas. & Reg Equip	288,851	288,851	0	2.06%	0
Purification Equip	239,930	239,930	0	1.30%	0
Subtotal	$4,716,901	$4,770,324	($53,423)		($1,001)
Transmission Plant					
Rights of Way	$403,419	$403,419	$0	0.89%	$0
Structures &Improvements.	14,797	32,921	(18,124)	1.39%	(252)
Other Structures	69,172	69,172	0	1.39%	0
Mains	19,363,672	19,441,293	(77,621)	1.27%	(986)
Meas. & Reg Equip	2,961,525	2,995,622	(34,097)	2.28%	(777)
Subtotal	$22,812,585	$22,942,427	($129,842)		($2,015)
Distribution Plant					
Right Of Way	$44,872	$44,872	$0	1.68%	$0
Structure & Improvements T.B	106,376	106,376	0	1.95%	0
Improvements	7,518	7,518	0	1.95%	0
Land Rights	46,591	46,591	0	1.95%	0
Mains	73,059,579	75,047,099	(1,987,520)	2.39%	(47,502)
Meas.& Reg. Sta.Equip. Gen.	2,123,884	2,363,549	(239,665)	2.49%	(5,968)
Meas.& Reg. Sta.Equip. TB	1,815,076	1,917,181	(102,105)	2.57%	(2,624)
Services	45,146,574	45,854,769	(708,195)	6.86%	(48,582)
Meters	18,176,022	19,396,585	(1,220,563)	3.35%	(40,889)
V&P Gauges	109,524	109,524	0	3.35%	0
Meters Installations	14,303,236	14,560,567	(257,331)	3.06%	(7,874)
Regulator Services	3,430,387	3,733,713	(303,326)	2.85%	(8,645)
Regulators Relief	581,749	481,545	100,204	2.85%	2,856
House Reg. Installations	163,937	166,402	(2,465)	3.37%	(83)
Ind. Meas. & reg. Sta Equip.	3,156,244	3,211,613	(55,369)	2.73%	(1,512)
Subtotal	$162,271,568	$167,047,904	($4,776,336)		($160,823)
General Plant					
Structures & Improvement	$316,621	$316,621	$0	2.12%	$0
Improvements	64,111	64,111	0	2.12%	0
Air Conditioning Equipment	9,771	9,771	0	2.12%	0
Improvement to leased Premises	2,375,392	2,504,775	(129,383)	5.00%	(6,469)
Office Furniture & equipment	2,474,399	2,550,590	(76,191)	7.05%	(5,371)
General Office Equip	15,072	16,898	(1,826)	0.00%	0
Office Machines	383,054	405,141	(22,087)	7.05%	(1,557)
Transportation Equip	6,037,718	6,054,009	(16,291)	8.92%	(1,453)
Trailers	165,970	165,970	0	8.92%	0
Tool& Work Equipment	3,074,366	3,082,589	(8,223)	3.28%	(270)
Dichers	831,023	853,615	(22,592)	2.79%	(630)
Backhoes	706,023	706,023	0	2.79%	0
Welders	92,413	92,413	0	2.79%	0
Communications equip. - phones	1,231,414	1,293,379	(61,965)	5.21%	(3,228)
Communications equip. - fixed radios	32,278	28,653	3,625	5.21%	189
Communications equip. - mobile	58,023	68,220	(10,197)	5.21%	(531)
Communications equip. - telemetering phones	114,695	114,695	0	5.21%	0
Misc. equip	141,044	153,632	(12,588)	10.94%	(1,377)
Other tangible property	9,866	11,061	(1,195)	0.00%	0
Other tangible property - CPU	175,274	196,508	(21,234)	0.00%	0
Other tangible property-MF Hardw	592,179	607,494	(15,315)	1.19%	(182)
Other tangible property-PC Hardw	3,476,604	3,551,824	(75,220)	18.51%	(13,923)
Other tangible property- PC Softw	491,929	546,060	(54,131)	15.85%	(8,580)
Other tangible property-appl. Softw	19,453,317	20,278,490	(825,173)	12.50%	(103,147)
Other tangible property- System Softw	448,223	502,523	(54,300)	0.00%	0
Server Hardware	695,971	695,971	0	14.29%	0
Server Software	228,311	228,311	0	14.29%	0
Network Cost	332,234	332,234	0	14.29%	0
Start up Cost	5,696,831	5,696,831	0	8.33%	0
Subtotal					($146,531)
Total					($310,369)

Case No. 99-070
Schedule LKM-18

WESTERN KENTUCKY GAS COMPANY

Adjustment to Payroll Taxes
For the Test Year Ending December 31, 2000

	Amount 1/
Reduction in SUTA due to decrease in Employees	(\$552)
Reduction in FUTA due to decrease in Employees	(\$1,288)
Average Labor Cost per Employee	\$41,555
Reduction in Employee Level	23
Reduction in Payroll Level	(\$955,765)
FICA Rate	7.65%
Reduction in FICA due to decrease in Employees	(\$73,116)
Adjustment to Payroll Taxes	(\$74,956)

Notes:
1/ Calculated from data provided in Response to AG Data Request 1-206.

Case No. 99-070
Schedule LKM-19

WESTERN KENTUCKY GAS COMPANY

Interest Synchronization Adjustment
For the Test Year Ending December 31, 2000

	Amount
AG Rate Base	$123,920,033
Weighted Cost of Debt	3.79%
Adjusted Interest Deduction	4,696,569
Interest Deduction Per Company	4,984,495
Adjustment to Synchronize Interest Expense	(287,926)
Combined Income Tax Rate	40.3625%
Adjustment to Income Taxes	$116,214

LAFAYETTE K. MORGAN, JR.

Mr. Morgan is a Senior Regulatory Analyst with Exeter Associates, Inc. At Exeter, Mr. Morgan has been involved in the analysis of the operations of public utilities with particular emphasis on rate regulation. He has reviewed and analyzed utility rate filings, focusing primarily on revenue requirements determination. This work included natural gas, water, electric, and telephone utilities.

Education and Qualifications:

B.B.A. (Accounting) - North Carolina Central University, Durham, North Carolina, 1983

M.B.A. (Finance) - The George Washington University, Washington, District of Columbia, 1993

C.P.A. - Licensed in the State of North Carolina

Previous Employment:

1990 to 1993 -	Senior Financial Analyst, Potomac Electric Power Company, Washington, D.C.
1984 to 1990 -	Staff Accountant, North Carolina Utilities Commission - Public Staff, Raleigh, N.C.

Previous Professional Experience:

As a Staff Accountant with the North Carolina Utilities Commission - Public Staff, Mr. Morgan was responsible for analyzing testimony, exhibits, and other data presented by parties before the Commission. In addition, he performed examinations of the books and records of utilities involved in rate proceedings and summarized the results into testimony and exhibits for presentation before the Commission. Mr. Morgan also participated in several policy proceedings involving regulated utilities.

As a Senior Financial Analyst with Potomac Electric Power Company, Mr. Morgan prepared cost of service, rate base, and ratemaking adjustments supporting the Company's request for revenue increases in its retail jurisdictions. He also prepared the lead-lag study which supported the Company's cash working capital claim.

Expert Testimony

of Lafayette K. Morgan, Jr.

Kings Grant Water Company (North Carolina Utilities Commission Docket No. W-250, Sub 5), 1984. Presented testimony on rate base, cost of service and revenue and expense adjustments on behalf of the North Carolina Utilities Commission - Public Staff.

W.D. & J.T. Billingsley (North Carolina Utilities Commission Docket No. W-632, Sub 1), 1985. Presented testimony on rate base, cost of service and revenue and expense adjustments on behalf of the North Carolina Utilities Commission Public Staff.

Northwood Water Company (North Carolina Utilities Commission Docket No. W-690, Sub 1), 1985. Presented testimony on rate base, cost of service and revenue and expense adjustments on behalf of the North Carolina Utilities Commission - Public Staff.

Emerald Village Water System (North Carolina Utilities Commission Docket No. W-184, Sub 3), 1985. Presented testimony on rate base, cost of service and revenue and expense adjustments on behalf of the North Carolina Utilities Commission - Public Staff.

General Telephone Company of the South (North Carolina Utilities Commission Docket No. P-19, Sub 207), July 1986. Presented testimony on the level of cash working capital allowance on behalf of the North Carolina Utilities Commission - Public Staff.

Heins Telephone Company (North Carolina Utilities Commission Docket No. P-26, Sub 93), November 1986. Presented testimony on rate base, cost of service and revenue and expense adjustments on behalf of the North Carolina Utilities Commission - Public Staff.

Carolina Power and Light Company (North Carolina Utilities Commission Docket No. E-2, Sub 537), March 1988. Presented testimony on rate base, cost of service and revenue and expense adjustments on behalf of the North Carolina Utilities Commission - Public Staff.

Public Service Company of North Carolina, Inc. (North Carolina Utilities Commission Docket No. G-5, Sub 246), August 1989. Presented testimony on rate base, cash working capital allowance, cost of service and revenues and expense adjustments on behalf of the North Carolina Utilities Commission - Public Staff.

Conestoga Telephone and Telegraph Company (Pennsylvania Public Utility Commission Docket No. I-00920015), September 1993. Presented testimony on cost of service on behalf of the Pennsylvania Office of Consumer Advocate.

Louisiana Power and Light Company (Louisiana Public Service Commission Docket No.

U-20925), February 1995. Presented testimony on rate base and working capital issues on behalf of the Louisiana Public Service Commission Staff.

South Central Bell Telephone Company-Louisiana (Louisiana Public Service Commission Docket No. U-17949, Subdocket E), June 1995. Presented testimony on rate base and working capital issues on behalf of the Louisiana Public Service Commission Staff.

Apollo Gas Company (Pennsylvania Public Utility Commission, Docket No. R-00953378), August 1995. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Carnegie Natural Gas Company (Pennsylvania Public Utility Commission, Docket No. R-00953379), August 1995. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Tennessee Gas Pipeline Company (Federal Energy Regulatory Commission, Docket No. RP95-112), September 1995. Presented testimony rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Virginia-American Water Company (Virginia State Corporation Commission Case No. PUE-950003), March 1996. Presented testimony on rate base and cost of service issues on behalf of the City of Alexandria.

GTE North Inc. Interconnection Arbitration (Pennsylvania Public Utility Commission, Docket No. A-310125F0002), September 1996. Presented testimony on the determination of the appropriate resale discount on behalf of the Pennsylvania Office of Consumer Advocate.

United Cities Gas Company (Georgia Public Service Commission, Docket No. 6691-U), October 1996. Presented testimony on rate base and cost of service issues on behalf of the Office of Governor, Consumer Utility Counsel Division.

GTE North Inc. (Pennsylvania Public Utility Commission, Docket No. R-00963666 and R-00963666C001), February 1997. Presented testimony on the determination of the appropriate resale discount on behalf of the Pennsylvania Office of Consumer Advocate.

Consumers Maine Water Company (Maine Public Utilities Commission, Docket No. 96-739), May 1997. Presented testimony on rate base, cost of service and rate of return issues on behalf of the Maine Public Advocate Office.

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission, Docket No. R-00973944), July 1997. Presented testimony on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Pennsylvania-American Water Company - Wastewater Operations (Pennsylvania Public Utility Commission, Docket No. R-00973973), July 1997. Presented testimony on rate base, cost of service, depreciation and rate design issues on behalf of the Pennsylvania Office of Consumer Advocate.

Jackson Purchase Electric Cooperative Corporation (Kentucky Public Service Commission, Case No. 97-224), December 1997. Presented testimony on rate base and cost of service issues on behalf of the Kentucky Office of Attorney General.

Henderson Union Electric Cooperative Corporation (Kentucky Public Service Commission, Case No. 97-220), January 1998. Presented testimony on the return of patronage capital on behalf of the Kentucky Office of Attorney General.

Green River Electric Corporation (Kentucky Public Service Commission, Case No. 97-219), January 1998. Presented testimony on the return of patronage capital on behalf of the Kentucky Office of Attorney General.

Other Projects:

Texas Gas Transmission Corporation (Federal Energy Regulatory Commission, Docket No. RP93-106), Technical analysis and participation in settlement negotiations on cost of service, invested capital and revenue deficiency on behalf of the Indiana Office of Utility Consumer Counselor.

Natural Gas Pipeline Company of America (Federal Energy Regulatory Commission, Docket No. RP93-36), Technical analysis and participation in settlement negotiations on cost of service, invested capital and revenue deficiency on behalf of the Indiana Office of Utility Consumer Counselor.

Texas Gas Transmission Company (Federal Energy Regulatory Commission, Docket No. RP94-423), Technical analysis and participation in settlement negotiations on cost of service, invested capital and revenue deficiency on behalf of the Indiana Office of Utility Consumer Counselor.

Lafourche Telephone Company (Louisiana Public Service Commission, Docket No. U-21181), Analysis and investigation of earnings and appropriate rate of return on behalf of the Louisiana Public Service Commission Staff.

Natural Gas Pipeline Company of America (Federal Energy Regulatory Commission, Docket No. RP95-326), Technical analysis and participation in settlement negotiations on cost of service, invested capital and revenue deficiency on behalf of the Indiana Office of Utility Consumer Counselor.

Pymatuning Independent Telephone Company (Pennsylvania Public Utility Commission, Docket No. R-00953502), Technical analysis and development of settlement position in the Company's rate case on behalf of the Pennsylvania Office of Consumer Advocate.

Illinois Bell Telephone Company (Illinois Commerce Commission, Docket No. 96-0172), Technical analysis of the Company's annual rate filing pursuant to its Price Cap Plan on behalf of Citizens Utility Board.

Illinois Bell Telephone Company (Illinois Commerce Commission, Docket No. 97-0157), Technical analysis of the Company's annual rate filing pursuant to its Price Cap Plan on behalf of Citizens Utility Board.

TDS Telecom (Pennsylvania Public Utility Commission, Docket Nos. R-00973892 and R-00973893), Technical analysis regarding rate base, cost of service, rate design and rate of return and assistance in settlement negotiations in the Company's rate case and alternative regulatory filing on behalf of the Pennsylvania Office of Consumer Advocate.

Appalachian Power Company (Virginia State Corporation Commission, Case No. PUE 960301), Technical analysis regarding rate base and cost of service and assistance in settlement negotiations in the Company's rate case and alternative regulatory filing on behalf of the Office of Attorney General.

Central Maine Power Company (Maine Public Utilities Commission, Docket No. 97-580), Technical analysis regarding attrition issues in the Company's Transmission and Distribution unbundling proceeding on behalf of the Maine Public Utilities Commission Staff.

Illinois Bell Telephone Company (Illinois Commerce Commission, Docket No. 98-0259), Technical Analysis of the Company's annual rate filing pursuant to its Price Cap Plan on behalf of Citizens Utility Board.

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

WESTERN KENTUCKY GAS COMPANY	))	Case No. 99-070

DIRECT TESTIMONY

OF

RICHARD A. GALLIGAN

ON BEHALF OF THE

OFFICE OF RATE INTERVENTION OF THE ATTORNEY GENERAL

FOR THE COMMONWEALTH OF KENTUCKY

OCTOBER 1999

EXETER
Associates, Inc.
12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

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COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

WESTERN KENTUCKY) Case No. 99-070
GAS COMPANY)

DIRECT TESTIMONY OF RICHARD A. GALLIGAN

I. Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard A. Galligan. I am a principal President with Exeter Associates, Inc., a firm of consulting economists specializing in utility economics. My business address is 12510 Prosperity Drive, Suite 350, Silver Spring, Maryland, 20904.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have two degrees from the University of Wisconsin, including a Master's degree in economics and, in addition, I completed two years of graduate study at the University of Minnesota, where I fulfilled all of the course work requirements for the Ph.D. degree.

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A. I have taught economics at the University of Minnesota, the University of Wisconsin, Mankato State University, and Webster College. In these positions, I taught a wide range of courses covering all aspects of economics.

In January 1975, I joined the staff of the Minnesota Public Service Commission at the commencement of that commission's responsibility over gas and electric utility operations in the State of Minnesota. From 1976 to 1984, I was an economic consultant specializing in public utility rate regulation of gas, electric and telephone utilities.

From 1984 until 1987, I was Director of Utilities Division at the Iowa State Commerce Commission and Executive Director of the Texas Public Utility Commission. At Iowa, my responsibilities included the management and administration of all Utilities Division activities regarding the regulation of gas, electric and telephone utilities operating in the State of Iowa under Iowa State Commerce Commission jurisdiction. At the Texas Public Utility Commission, I was responsible for the management and day-to-day administration of that Commission's regulatory activities regarding all aspects of its jurisdictional responsibilities. I also served briefly as General Manager of Rates & Regulatory Affairs at Gas Company of New Mexico before assuming my present position at Exeter Associates, Inc. in October 1987.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON UTILITY RATES?

A. Yes. I have previously presented testimony on more than 60 occasions before the Federal Energy Regulatory Commission ("FERC") and the public utility commissions of Alabama, California, Connecticut, Delaware, the District of Columbia, Florida, Georgia, Idaho, Illinois, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Missouri, Montana, Nevada, New Hampshire, New Jersey, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, and Utah.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Office of Attorney General, Office for Rate Intervention ("Attorney General").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. On June 23, 1999, Western Kentucky Gas Company, Inc. ("Western" or "Company") filed its perfected Application to the Commission for a rate adjustment. Western's proposed rates would result in test year customer class total gas margin increases of

$13,633,184 annually. The Company proposes to achieve its $13.6 million margin increase by increasing its customers' rates as follows:

	Revenue Increase	Percentage Increase
Residential	$ 9,221,264	38.2%
Firm Commercial	3,330,022	33.0
Firm Industrial	205,277	21.1
Interr. & Carriage	699,398	16.8
Large Interr. & Carriage	177,224	4.9
Total Margin Increase	$13,633,185	31.7%

Western arrived at this proposed revenue spread, in part, by adjusting each class' revenues so as to produce a class rate of return at proposed rates that moves each toward the overall rate of return based on the Company's proposed class cost of service study.

Exeter Associates, Inc. was retained by the Attorney General to review the cost of service study and rate design proposals reflected in Western's application. My testimony presents my findings, conclusions and recommendations concerning the Company's cost of service study and rate design proposals.

Q. WHAT CONCLUSIONS HAVE YOU REACHED AS A RESULT OF YOUR REVIEW AND ANALYSIS?

A. Based on the results of my review and analysis, I have reached the following conclusions:

- Western's class cost of service study misallocates major categories of the costs of providing service, and the results of that study cannot be relied upon as an accurate indication of class cost responsibilities;
- Average embedded class cost of service studies should be used as guides in the determination of class revenue responsibilities and class rates;
- Reasonable class cost of service produces do not support the Company's proposed rates in this proceeding;
- An across-the-board spread of any Commission-approved rate increase is reasonable;

- Western should provide evidence that its Interruptible Service offering is a different service, in fact, from its firm service and that its Interruptible Service provides system benefits; and
- The proposed premises charge should be rejected.
- The proposed automatic flow-through between rate cases through a surcharge mechanism of discounts to flexibly priced customers should be rejected.
- The proposed increase in the monthly customer charge, or base charge, from $5.10 to $9.00 is unreasonable and should be rejected.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Following this introductory section, my testimony is divided into three additional sections. In the first additional section, I detail the reasons that support a finding that the Company's recommended class cost of service study produces an unreliable indication of the costs of serving the various customer classes. The second additional section addresses class revenue requirement determinations. The final section of my testimony addresses Western's proposed rate design.

II. Cost Allocation

Q. PLEASE BRIEFLY DESCRIBE THE COST OF SERVICE STUDY SUBMITTED BY WESTERN IN THESE PROCEEDINGS.

A. The Company submitted an allocated average embedded class cost-of-service study. Sometimes an average embedded allocated cost of service study is referred to as a fully distributed cost study. The performance of such a study requires that every cost included in the total cost of service be ascribed, somehow, to the customers who allegedly, or to the best ability of the cost practitioner performing the study to determine, have "caused" the Company to incur such costs. Customers cause the Company to incur costs by demanding the services for which the Company incurs costs.

Western first functionalized its costs of service into categories including storage, transmission and distribution. Fixed costs are then classified as being related to customer, throughput, or demand. Variable costs are generally classified as throughput related. Generally, customer related costs were allocated in a manner related to number of customer; throughput related costs were allocated on throughput volumes; transmission plant was allocated on peak and average demands; and distribution demand related costs were allocated on peak demands. Of Western's $124 million total rate base, the Company proposes that $60 million is customer related; $56 million is demand related; and $6 million of its total plant cost is related to volumes of gas deliveries; and 2 million can be directly assigned. The allocation of fixed or capacity related costs is the most controversial aspect of performing an allocated cost of service study.

Q. HOW DID WESTERN ALLOCATE ITS DISTRIBUTION MAINS PLANT INVESTMENT?

A. Western allocated its distribution mains plant investment on the basis of the number of customers in each class and class maximum design day demands. Mains investment, at in excess of $43 million, represents the largest single category of costs on Western's system, as is generally the case for local gas distribution companies (LDCs). If Western's proposed allocation of total mains cost is to be consistent with the principle of cost causation, then Western's total mains cost would necessarily have to be caused entirely by the fact that customers exist, and by those customer demands for gas only under design day weather conditions.

Q. HOW DID WESTERN ESTIMATE THE AMOUNT OF DISTRIBUTION MAINS INVESTMENT THAT IT BELIEVES IS CAUSED BY THE MERE EXISTENCE OF A CUSTOMER?

A. Western used the so-called "zero-intercept" method to make its determination of what it believes is a customer component of distribution mains investment. This method regresses pipe size, and the average cost per foot of each given pipe size. The cost per foot of each pipe size utilized is the average cost of the nominal pipe investment cost incurred each year over decades and decades of system operations. Based on this relationship, a calculated value of the cost per foot of a hypothetical zero-inch pipe is determined. This calculated value is then multiplied by the actual linear footage of distribution pipe on Western's system. The resulting calculated investment is assumed to be the cost of stringing zero-inch pipe to all the customers on the system and presumably represents the customer cost, since no volumes of gas can actually be delivered through a zero-inch pipe. Western then reasons that the rest of the excess of actual distribution mains investment cost is related to the cost of the real, positive diameter pipe on the Western system, which was installed, not just to connect customers, but to actually deliver gas under the customers most demanding requirements -- design day demands. The entire excess of actual mains cost over the zero-intercept cost presumably represents peak demand related costs in Western's view. Specifically, based on the zero-intercept method, Western alleges that 23 percent of its distribution mains investment was incurred for no other purpose than to connect customers (i.e., extend its system so it goes to and past each customer location), thus making them "customer" costs. Western classifies the remaining 77 percent of distribution costs as demand related, and proposes to allocate demand related distribution costs entirely on the basis of class design day demands.

Q. IS IT REASONABLE TO BELIEVE THAT A GAS DISTRIBUTION COMPANY WOULD INCUR DISTRIBUTION MAINS INVESTMENT COSTS SIMPLY FOR THE PURPOSE OF CONNECTING CUSTOMERS?

A. No, and especially no for a gas distribution company. Gas distribution companies, including Western, are under no obligation to extend or enhance their existing systems to be able to attach prospective customers who would burn no gas. Mains extension requirements included in 807 KAR 5:022, Section 9 limit the standard distribution mains extension allowance to 100 feet for a new customer. Western's tariff at Section 28, Sheet No. 82, requires that the 100 foot extension allowance is dependent on the potential consumption and revenue being of such an amount and permanence so as to warrant the capital expenditures involved to make the investment economically feasible. Feasibility relates to sufficient customer demand for gas deliveries such that the average per unit cost of delivered gas can compete with alternate energy sources. A deposit, over and above the costs of the footage allowance can be required when an extension would exceed the footage allowance and be economically infeasible. A gas utility has no obligation to incur distribution mains investment costs, and would certainly find it uneconomic to extend its system in accord with the theoretical basis of the zero-intercept method.

Q. WHEN A PORTION OF DISTRIBUTION MAINS INVESTMENT COST IS ALLOCATED ON THE BASIS OF THE NUMBER OF CUSTOMERS, HOW DOES A COST MISALLOCATION RESULT?

A. The costs associated with investment in mains is misallocated due to Western's introduction into its COS study of the minimum system concept, in this case a zero-inch system, upstream of services investment and back into the allocation of mains investment. Mains costs are not incurred simply to connect customers and thus, dependent on the number of customers served from them, but for the loads placed upon them. This is made clear in the following example: Along one city block are located 10 Residential customers with a coincident peak demand of one Mcf each. The main running down the street would have to be capable of delivering 10 Mcf at peak. On another city block is only a small plastics factory that exhibits a maximum demand of 10 Mcf. The main for that one customer has to be sized to deliver 10 Mcf when the plastics factory demand peaks. It is clear that the mains investment is driven by the loads placed upon it -- not by the number of customers served from it. Finally, imagine that the plastics factory is torn down to make room for five large residences, each of which exhibits a demand at time of coincident peak of 2 Mcf. Again, the main which is sized to deliver 10 Mcf is adequate. One customer, 5 customers or 10 customers does not determine the amount of mains investment; rather, mains investment is a function of the loads to be served. A local distribution utility company is in the business of distributing gas, and is not in the business of incurring costs to connect customers who use no gas.

Q. DOES ANY RECOGNIZED AUTHORITY AGREE WITH YOUR CONCLUSION THAT IT IS IMPROPER TO ALLOCATE A PORTION OF THE MAINS DISTRIBUTION SYSTEM ON THE BASIS OF BEING CUSTOMER RELATED?

A. Yes. While Western here attempts to derive the costs of zero-inch system, Professor Bonbright, at pages 347 and 348 of his Principles of Public Utility Rates, utilizing an example from the electric industry, states:

> "But the really controversial aspect of customer-cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitely

> earmarked as incurred for the benefit of specific customers but also a substantial fraction of the annual maintenance and capital costs of the secondary (low voltage) distribution system -- a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. This minimum capacity is sometimes determined by the smallest sizes of conductors deemed adequate to maintain voltage and to keep from falling of their own weight. In any case, the annual costs of this phantom, minimum-sized distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section.
>
> Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they, therefore, vary indirectly with the number of customers.
>
> What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. for it makes no allowance for the density factor (customers per linear mile or per square mile). Indeed, if the Company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatsoever in the costs of a minimum-sized distribution system.
>
> While, for the reason just suggested, the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to me clearly indefensible, its exclusion from the demand-related costs stands on much firmer ground."

Professor Bonbright clearly agrees that distribution costs, except for those costs that can be definitely earmarked to benefit specific customers, are not properly classified as customer costs.

Q. ARE THERE OTHER REASONS FOR NOT RELYING ON WESTERN'S COST OF SERVICE STUDY THAT RELATE TO ITS UTILIZATION OF THE ZERO-INTERCEPT METHOD APPLICATION?

A. Yes, my associate, Dr. Steven Estomin has reviewed Western's application of the zero-intercept method to its distribution system. Based on his discussion of the Company's particular application of the zero-intercept methodology to Western's system, I believe the zero-intercept application in this case renders the Company's cost of service study results invalid. For the reasons discussed in my testimony and in Dr. Estomin's testimony, Western's misallocation of 23 percent of its distribution mains investment cost on the basis of number of customers destroys any basis for reliance on that study's results.

Q. WILL WESTERN EXTEND ITS SERVICE SIMPLY BECAUSE A CUSTOMER EXISTS?

A. No. Even under the 100 foot extension rule, Western will not, as a matter of policy, extend service to a gas cooking only customer without requiring a deposit for the main extension because the potential *consumption* is not consistent with warranting the capital expenditure to make the investment economically feasible. Clearly, the mere existence of a potential customer will not cause Western to incur any cost of extending its mains simply for the sake of hooking up a customer that would use no gas.

Q. IS IT REASONABLE TO ALLOCATE A PORTION OF THE MAINS INVESTMENT COST ON THE BASIS OF NUMBER OF CUSTOMERS?

A. No. As just discussed, Western will not extend its mains or incur any mains extension costs merely to hook up a customer who would use no gas. Western will extend its mains only to serve a customer's gas requirements, and Western's policy is that, in practice, a customer's request for heat load is essential for satisfying the "economic feasibility" test included in its tariff. It is the customer's load, not the mere existence of a customer that triggers Western's obligation to serve. The allocation of mains investment costs on the basis of customer load requirements is, therefore, in accord with the principle of cost causation. The allocation of mains costs on the basis of number of customers violates the principle of cost causation. Western's allocation of 23 percent of its mains investment costs on the basis of the number of customers violates the principle of cost causation and destroys any basis for reliance on Western's cost study results.

Q. WHY DO GAS DISTRIBUTION COMPANIES INCUR DISTRIBUTION MAINS INVESTMENT COSTS?

A. The basic reason, of course, why LDC's, including Western, invest monies in their distribution systems is to meet the annual demands for gas by end-use customers. This is the *raison d'etre* for the existence of the LDC in the first place. Without sufficient annual gas usage over which to amortize the annual costs of providing service, there would be no gas distribution system. Additionally, as I will describe later, a small amount of the total cost of distribution service is related to installing a system with enough throughput capacity to meet peak demands as well as annual demands.[1]

Q. WHY IS IT PROPER TO ALLOCATE DISTRIBUTION MAINS INVESTMENT ON THE BASIS OF ANNUAL AS WELL AS PEAK DEMANDS?

A. The allocation of distribution mains investment costs on the basis of both annual and peak demands is in accord with the principle of allocating costs on the basis of cost causality. Natural gas is of little or no value to an end user if that gas cannot be delivered to the location of the gas burning equipment. Western's distribution system imparts locational value to the natural gas delivered across that system by allowing for the movement of that gas from its acquisition source to each customer's location. Western's distribution system exists, and related costs are incurred, to deliver gas to its customers whenever, over the course of each year, its customers demand gas. In other words, Western's system was built and costs were incurred to deliver gas both at the time of peak system demand and generally throughout the year. Because costs are incurred to deliver gas generally throughout the year, and additional costs are incurred to meet peak demands, Western's delivery costs must be allocated on the basis of both annual and peak demands if those costs are to be allocated in accord with the principle of cost causality. It is improper and a violation of the principle of cost causality to pretend that Western

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[1] Because class average demands bear the same relationship as class annual demands, an allocation of a portion of a utility's costs on the basis of average demand or annual requirements is identical.

incurred 23 percent of its distribution mains investment cost to string pipe to customers who would use no gas. And it is improper to reason that the extra costs of meeting peak demands supports an allocation of total demand related costs of the basis of peak usage requirements.

Q. PLEASE EXPLAIN YOUR STATEMENT THAT COSTS ARE INCURRED TO MOVE BOTH ANNUAL AND PEAK VOLUMES ACROSS WESTERN'S SYSTEM.

A. Western's customers are projected to move approximately 50,014,309 Mcf across Western's system during the cost of service study test period. This equates to an average demand of about 137,000 Mcf each day. The Company's estimated non-curtailable peak day demand is 287,219 Mcf. Western's actual peak demands are 436,589 Mcf. Western could not have met its customers' annual gas demands with a system capability any smaller than 137,000 Mcf. In other words, if there were no variance in the daily demands on Western's system, the capacity of that system would have to be designed to accommodate the daily movement of 137,000 Mcf just to meet non-curtailable the annual demands. To meet peak demands, Western's system capacity must be larger than 137,000 Mcf. Thus, some costs are related to the movement of average demand on the Western system, and some costs are related to the movement of gas when demands are above the average demand.

Rational investment decision analysis requires the consideration of annual volumes delivered across a natural gas distribution company's system. A gas distribution system would not exist if all demand related costs were the responsibility of peak demands. A viable gas market is dependent upon the ability to amortize delivery costs over a sufficient volume of service so as to result in a unit cost that can be recovered from the price at which gas can be sold and still compete with other energy sources. Western's customer extension policy is entirely consistent with this view. It does not follow that simply because a system is sized to meet not only average demand but peak demand, as well, that those peak demands are totally responsible for all distribution demand related costs. The association of costs with annual as well as peak demands, and the ability to allocate and recover costs from annual and peak demands for gas is absolutely essential to the economic feasibility of a gas delivery system.

Q. HOW DO THE COSTS OF PROVIDING FOR THE MOVEMENT OF PEAK DEMANDS COMPARE TO THE COSTS OF PROVIDING FOR THE MOVEMENT OF LESSER DEMANDS?

A. Many of the costs associated with the distribution delivery system do not depend upon pipe sizes. These costs would include surveying, excavation, hauling, pipe bed preparation, unloading and stringing of pipe, municipal inspection, backfill, and pavement and sidewalk replacement. Since a portion of total costs does not vary with pipe size, or are fixed costs, total costs do not increase at a one-to-one ratio with increases in maximum demands. The additional costs associated with meeting elevated demands is generally limited to the cost of the pipe itself. Pipe costs typically comprise only a small percentage of total mains installation cost.

Moreover, throughput capability increases not at a one-to-one ratio with the size of the pipe, but at a rate equal to the square of the pipe's diameter. Doubling the diameter of a pipe, for example, increases its capacity by four times the original capacity. Thus, the additional costs of providing additional capacity are lower than the average costs of providing capacity. This means that the costs associated with providing capacity for the movement of average demands are greater on a unit basis than are the costs associated with providing capacity for additional demands. Western's distribution system exists to deliver annual system requirements. There are costs that are uniquely associated with meeting peak demands, and as such peak demands should bear some cost responsibility. But the additional costs incurred to meet peak demands tend to be small.

Q. ARE GAS FLOWS DURING THE DESIGN PEAK SO IMPORTANT THAT WESTERN'S TOTAL DISTRIBUTION SYSTEM COSTS ARE DIRECTLY RELATED TO, AND CAUSED BY, DESIGN DAY DEMAND REQUIREMENTS?

A. No. Peak demands do not cause all of Western's demand related mains cost, and it is wrong therefore to allocate total demand related costs on the basis of peak demands, as Western proposes. Only the marginal costs incurred to meet peak distribution demands above other demands are directly related to peak requirements. The Western gas distribution system simply would not exist if the only demand for gas was the demand associated with design day weather conditions, or peak demands each year. The Western distribution system exists because the total annual demand for gas is sufficient to warrant its existence. It is an extreme and erroneous view that the total demand costs associated with Western's distribution network are caused by demands at the design peak day. The allocation of all distribution system demand related costs on the basis of peak demands would misallocate substantial costs. Because Western's system exists to deliver annual gas requirements, but some additional costs are related to the delivery of gas during periods of elevated demand, it is appropriate to allocate distribution mains on both annual and peak demands.

Q. PLEASE JUXTAPOSE YOUR VIEWS ON HOW DISTRIBUTION SYSTEM DEMAND RELATED COSTS SHOULD BE ALLOCATED WITH WESTERN'S VIEWS.

A Western allocates total distribution system demand related costs on the basis of peak demands. Western must believe that all costs classified as *demand related* are costs related to facilities installed to meet peak usage requirements if it allocation of distribution mains investment costs is to comport with the principle of cost causality. This is wrong. I have shown that there are incremental costs, small though they may be, associated with building a gas distribution system with sufficient capacity to meet peak demands, which are higher than average demands. Western erroneously applies this incremental peak cost circumstance to its total demand classified distribution mains costs. Ironically, the upshot of Western's allocation proposal is that no distribution system costs are allocated on the basis of customer requirements throughout the year, which is the basic service that Western provides and the very reason Western exists in the first place. Clearly, Western's cost allocation scheme, which in fact, allocates no costs on the primary service (average annual delivery of gas) that Western provides, and without which the Western distribution system would not exist, violates the principle of allocating costs in accord with cost causality. On the other hand, an allocation of distribution system costs on the basis of average demands and on the basis of peak demands certainly comports with the principle that costs should be allocated to the service units that cause the costs.

Q. HOW CAN DISTRIBUTION MAIN INVESTMENT COSTS BE PROPERLY ALLOCATED?

A. Clearly, the additional costs of providing capacity in order to meet peak demands, as opposed to lesser demands, should be allocated on a peak demand basis. This would be a relatively small amount because the marginal capacity costs are small, as discussed earlier. The distribution system costs that are incurred to deliver annual volumes under other than peak conditions, should be allocated on annual volumes. I have prepared a Western class cost of service study that allocates fully 50 percent of Western's distribution mains cost on peak demand, and 50 percent on annual usage. Because the marginal costs of capacity are small, this allocation of 50 percent of the cost of mains on the basis of peak demands and 50 percent on the basis of average demands represents a conservative recognition of annual volumes in the allocation of Western's distribution mains cost.

Q. HAVE YOU PERFORMED A CLASS COST OF SERVICE STUDY ON THE WESTERN SYSTEM?

A. Yes. Exhibit __RAG-1 is a copy of the cost of service study I have performed on the Western system. By allocating 50 percent of mains investment costs on the basis of average demand in this study, I have recognized the critical fact that Western's existence as a viable business entity relies upon, and thus, its distribution mains investment costs are caused by, end-user annual gas requirements. I have also recognized that some additional costs are incurred to install pipe that can flow peak demand requirements in excess of average requirements by allocating 50 percent of mains investment costs on the basis of peak demands. These changes to the Company's cost study correct significant misallocations of major cost components of Western's total cost of service.

III. Class Revenue Requirements

Q. HOW DO THE RATES OF RETURN FOR EACH CLASS COMPARE UNDER THE COMPANY'S STUDY AND YOUR REVISED STUDY?

A. The rates of return for each class at Western proposed and the Attorney General proposed studies compare as follows:

Table 1

Western Natural Gas Company, Inc.
Class Rates of Return
12 Months Ended December 31, 1998

Customer Class	Rate of Return Company Proposed Study	Rate of Return of Attorney General Study
Residential	7.06%	8.23%
Commercial	6.22	6.29
Industrial	14.17	12.39
Interruptible Carriage	18.85	15.61
Large Int./Carriage	9.61	5.40
Total Company	7.93%	7.93%

The results generally show that when costs are allocated on the basis of service units that cause the costs, smaller residential and general service customers pay rates that more than cover their allocated share of costs. Larger customer rates fall somewhat or substantially below their share of the allocated costs of service. This result is not surprising when one observes the non-gas margins provided by end-users in the customer classes.

Q. MR. GALLIGAN, HOW DO WESTERN'S CURRENT RATES IN THIS PROCEEDING COMPARE FOR END-USERS IN THE SEVERAL CUSTOMER CLASSES?

A. The table below shows the non-gas cost margins for the customer classes at present rates.

Table 2

Western Natural Gas Company, Inc.
Class Margins

Class	Non-Gas Margin (Mcf)
Residential	$1.82
Commercial	1.42
Industrial	.72
Interruptible/Carriage	.56
Large Int./Carriage	.26

The margins vary widely, ranging from 26 cents per Mcf for Large Interruptible and Carriage customers to $1.82 per Mcf for residential customers. Rates above marginal cost are necessary to provide the Company with the opportunity to recover its fixed costs including a reasonable return on its investment. There has been no showing that the high margins paid by Western's smaller customers are subsidized by larger customer rates or are so inadequately low as to require an above average increase in rates, even though Western's testimony is replete with such allegations.

Q. PLEASE EXPLAIN HOW WESTERN DEVISED ITS APPORTIONMENT OF PROPOSED GAS BASE RATE REVENUE CHANGE TO CLASSES OF SERVICE.

A. Western utilized its proposed average embedded class cost of service study results as a guide in arriving at it proposed allocation of its requested rate increase among customer classes and its proposed customer charges. Observing the calculated class rates of return as reported in that study (and Table 1 on page 17 of my testimony), the Company proposes rates that increase smaller residential and commercial customers by percentage amounts that exceed the 6.8 percent average increase, along with less than average percentage increases for its larger customers. Western's revenue increase proposal is not consistent with study results when costs are properly allocated and is not consistent with the class margin disparities shown on Table 2.

Q. ARE THE RESULTS OF ANY ONE CLASS COST OF SERVICE STUDY SO PRECISE AS TO WARRANT EXCLUSIVE USAGE OF THEIR RESULTS IN THE DETERMINATION OF CLASS REVENUE RESPONSIBILITIES?

A. No. No average embedded class cost of service study produces singularly unique class cost of service results that are so precise as to warrant total reliance on those results in the determination of class revenue requirements. I earlier testified that Western believes that no distribution mains plant investment is related to throughput. This compares to Western finding that $40.1 million of total plant costs are demand related, the lion's share being essentially fixed costs. In the very first sentence of the section addressing demand costs in the Fully Distributed Costs chapter of Professor Bonbright's Principles of Public Utility Rates, the author states: "We now come to that category of costs, the treatment of which has made a nightmare of utility cost analysis."[10] [Bonbright, 350, footnote omitted] The allocation of fixed costs, which are an extremely large portion of a local gas distribution company's total costs, do not vary with any service component in the short run and are very difficult to allocate on a cost-causal basis. Total reliance on the results of any one average cost of service study, out of many such studies that can be performed, implies a precision that is not possible to produce given the large number of studies that could be utilized and the huge amount of costs to which judgment, albeit reasoned, must apply.

Q. HOW SHOULD THE RESULTS OF AVERAGE EMBEDDED CLASS COST OF SERVICE STUDIES BE USED FOR THE PURPOSE OF DETERMINING CLASS REVENUE REQUIREMENTS IN THESE PROCEEDINGS?

A. Class cost of service studies are useful as a guide to determining class revenue responsibilities. Using fully distributed costs as a guide to determining class revenue requirements is supported by the imprecision in class cost of service studies related to:

- the necessity of *somehow* allocating all costs of service, including costs which do not vary with the amount of service provided throughout the test period;
- the large amount of fixed costs which *must* be allocated in a fully distributed cost study, even though the fixed costs, by definition and operation, do not vary with service provided during the test year;
- the allocation of many O&M costs on the basis of how plant costs are allocated, the plant costs themselves being fixed;
- the practical limitation of using three or four functionalization categories which apply to all costs of service;
- the judgment which must be applied to the allocation of fixed costs which do not vary with test year service units; and
- the myriad choices available to the cost practitioner for the allocation of fixed costs of service.

The imprecise results attendant to the performance of a fully distributed cost study simply does not support the slavish determination of class revenue responsibilities solely on the basis of any particular study variant.

Professor Bonbright reminds the reader in his text of the skepticism to be afforded the results of a fully distributed cost study at numerous places in his treatise of the subject.

> Even those experts who make and defend these apportioned total costs in rate cases before public service commissions or courts seldom, if ever, offer them as final measures of reasonable rates and rate relationships. Instead, they concede that rates which deviate substantially from the cost apportionments may be justified by a variety of noncost considerations.
>
> ... But there remains the question what, if any, significance should be attached to these fully distributed costs even as guides, or even as points of departure for rate determination, in view of the admitted fact that they fail to mark the dividing line between compensatory charges for particular classes or quantities of service. And to this question, the customary answers are woefully inadequate. The reply most frequently offered is that cost of service is only one of several factors to be

> considered in rate structure determination. But this assertion, while quite valid, is also quite beside the point. For the question at issue concerns the doubtful meaning and significance of apportioned total costs and not the weight to be given to a clearly defined specific cost as a basis of rate making.
>
> ... But, what, then is the meaning of total-cost apportionments which admittedly do not reflect differential or incremental costs and which therefore fail to make the dividing line between compensatory and noncompensatory charges for different types of service? The only plausible answer, in my view at least, is that these apportionments should be designed to reflect *relative* differential or incremental or marginal costs, not absolute costs.[2]
>
> ... Fully apportioned costs, then, should reflect cost relationships, not absolute costs. But beyond saying that the relationships should be among incremental or marginal costs, one cannot generalize as to their precise nature, since in this respect the analyses are not uniform.
>
> ... The particular cost relationship apparently sought for by most cost analysts is one that would measure those rate relationships which could be called "completely nondiscriminatory." These hypothetical, cost-related rates could then be used as points of departure from which to derive actual rates which would incorporate desirable types and degrees of discrimination while avoiding discrimination that could be deemed "unjust" or "undue."
>
> ... This chapter began by raising the question what, if any, significance should be attached to fully distributed cost apportionments as points of departure for public utility rate making. As a provisional answer, it suggested that the significance must lie in whatever claim can be made for the apportioned costs as indices, not of absolute costs but of relative differential or incremental or marginal costs.
>
> ... In my opinion, these merits are so dubious that they fully justify the skepticism with which utility cost analysis has been received by public utility companies and public service commissions. The basic deficiency of this analysis lies in its failure to distinguish between actual cost finding and mere cost apportionment -- between those costs that can be imputed to specific classes or units of service by differential cost analysis and those other costs that should be deemed unallocable from the standpoint of cost determination even if they are somehow apportioned as a provisional step in rate determination. This failure seems to be critical.
>
> Among the more specific deficiencies of the typical fully distributed cost analysis of the public utility type, three seem to me especially serious. In the first place, the capacity costs or demand-related costs are usually derived from book values of plant and equipment that reflect sunk costs in dollars of original investment, not costs that can be said to vary,

> except in a very indirect way, with present and future increases in plant capacity.
>
> ... In the second place, the cost analyst, faced with the necessity of apportioning all of his costs among three or four arbitrarily selected functional-cost categories, faces dilemmas such as that noted in the section of this chapter on customer costs.
>
> ... And in the third place, most analysts, unwilling to follow the implications of joint-cost and by-product cost analysis in their treatment of demand-related costs, accept some compromise formula of apportionment, such as one which imputes capacity costs in proportion to noncoincidental maximum class demand.
>
> [Bonbright, Professor James C., Principles of Public Utility Rates, Columbia University Press, New York, 1961, footnotes omitted.]

Fully distributed cost of service study results are clearly more properly used as guides in the ratemaking process than as precise, unique indicators of rates.

Q. HOW SHOULD THE REVENUE INCREASE AUTHORIZED BY THE COMMISSION IN THIS PROCEEDING BE SPREAD AMONG THE SEVERAL CUSTOMER CLASSES?

A. I believe the Commission should reject Western's proposed revenue increase spread and the results of Western's fully allocated cost study as a guide to determining class revenue requirements. This study, with its failure to allocate any distribution fixed costs on the delivery of annual gas requirements, the primary reason Western exists in the first place, renders the Company study results an unreliable indicator of class costs of service. I recommend, instead, that the Commission utilize the cost study I have performed, which recognizes the reasonableness of allocating a portion of fixed distribution mains cost on average demands, or annual deliveries, the primary service that Western provides, and allocates a portion of distribution mains costs on peak demands.

Even though the study I have performed is a more reasonable and accurate cost study, it, as any fully distributed cost study, should be used as a guide to the setting of rates. In that vein, I believe that a proportional increase in class revenue responsibilities for any rate increase ordered in this case would be reasonable. The following table shows the resulting class revenue responsibilities when each class is responsible for a proportionate share of the full rate increase requested by Western. Should the Commission authorize a lesser rate increase, class revenue increases should be scaled accordingly.

Table 3

Western Kentucky Gas Company
Class Margins Based on a
Proportional Rate Increase at Western
Proposed Total Costs of Service

Class	Margins at Present Rates[1]	Proposed Increase	Percent Increase
Residential	$24,126,628	$7,652,717	31.2%
Firm Commercial	10,085,014	3,198,862	31.2
Firm Industrial	972,788	308,558	31.2
Inter. & Carriage	4,174,173	1,324,005	31.2
Large Inter. & Carriage	3,622,571	1,149,042	31.2
Total	$42,981,174	$13,633,184	31.2%

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[1] Source: Response to KPSC Request No. 2, Item 71.

IV. Rate Design

Q. DOES WESTERN OFFER INTERRUPTIBLE SERVICE?

A. Yes. Western provides relatively small amounts of interruptible sales service and substantial amounts of interruptible transportation service that accounts for approximately one-half of Western's annual throughput.

Q. IS THERE A NOTICEABLE, PRACTICAL DIFFERENCE IN THE DELIVERY SERVICE RECEIVED BY AN INTERRUPTIBLE CUSTOMER COMPARED TO THE SERVICE RECEIVED BY A FIRM CUSTOMER?

A. No, there is not a noticeable, practical difference in service provided to an interruptible customer compared to a firm customer. When asked about interruptions on its system, Western responded that over the past ten years it had interruptions that were limited to a local area on its system and affected only several customers for parts of a day. [AG Data Request No. 11, Item 34] Western's Engineering and Operations personnel have addressed this area pressure problem, and up-rated the system operating pressures. There have been no low pressure-caused interruptions since 1995. [AG Data Request 2, Item 23] Moreover, Western's design day capacity is reported at 287,219 Mcf for its non-curtailable load. Its peak design day demands including curtailable load is 436,589 Mcf. While Western experienced design day or cooler conditions seven times between the period January 1990 to April 1998 on the area served by Texas Gas and three times during the same period for the area served by Tennessee Gas, there have been no interruptions at all on these peak days. If the transportation customers get their gas delivered to Western's citygates, it is apparent that the capacity on Western's system is sufficient to deliver the volumes of gas that Western is required to deliver. Therefore, the value of an interruption to Western or any difference in cost of providing firm or interruptible delivery service is not apparent. Moreover, there used to be some value to a utility in being able to use gas purchased by the utility and otherwise flowing to an interruptible customer during times of interruption. However, under the new, competitive gas acquisition market, with large customers generally buying their own gas supplies and gas supplies being available in a daily gas market, the value of interruption for this reason is again not apparent.

The more basic question than simply proposing to reduce the price difference only for its large high load factor customers is whether differences in firm and interruptible delivery services exist, and whether cost differences warrant the continuation of a separately tariffed interruptible service offering. Western should be required to file rebuttal testimony which sets forth any real differences in firm and interruptible delivery service provided on its system, any cost of service differences that may warrant lower interruptible rates, and any value of interruptible service offerings to the Company and to its firm customers.

Q. PLEASE EXPLAIN WESTERN'S PROPOSED LOST MARGIN RECOVERY RATE PROPOSAL.

A. Western is proposing to implement a rate change mechanism that would automatically increase rates for non-discounted sales customers between rate cases to provide revenues to Western to restore 90 percent of new discounts below normally applicable distribution charges. Rates wold automatically be adjusted twice each year under the Company's proposal.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission reject Westerns' Margin Loss Recovery Rider. Many things happen between rate cases to increase and decrease revenues and costs. It is piecemeal ratemaking to automatically adjust rates between rate cases for select cost or revenue changes. Western's proposed Rider drastically reduces the Company's incentives to maximize its flexible rates by automatically restoring 90 percent of additional discounts compared to current rate treatment. Moreover, the Company's proposed adjustment procedures are irrational, lead to counterintuitive results and are unfair to sales customers who would be subject to the Lost Margin Rider surcharges. In a data request, AG Data Request No. 1, Item 112, Western was asked to calculate lost margins for an industrial customer whose deliveries would change from 100,000 Mcf at a 15-cent margin to 200,000 Mcf at a discounted 10-cent margin. Actual margin from this customer would increase from $15,000 (100,000 Mcf x 15-cent margin rate) to $20,000 (200,000 Mcf x 10-cent margin rate). But Western, while actually receiving increased margin contribution from this customer, would increase its Lost Margin Rider surcharge and assess its sales customers an additional $10,000 revenue responsibility under its calculation procedures. This is illogical, and certainly unfair to sales customers whose rates would increase. Western's proposed Lost Margin Rider should be rejected.

Q. PLEASE EXPLAIN WESTERN'S PREMISES CHARGE PROPOSAL.

A. Western proposes to charge new customers requiring a mains and service extension $13.05 per month for 15 years. This charge, because it is continually applicable to new customers for 15 years and applicable to new customers each succeeding year, would produce the following rate increases between rate cases:

Year 1	$113,496
Year 2	340,056
Year 3	576,636
Year 4	794,706
Year 5	1,021,776
.	.
.	.
.	.

The rationale for this newly proposed Premises Charge is that new residential customer attachment costs exceed embedded costs. The charge could be updated annually under the Company's proposal.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission reject the proposed Premises Charge. If there is a problem under the Commission's customer extension rules, that problem would, as a practical matter, generically affect all gas distribution utilities to which the rules apply. This suggests that a proceeding addressing the generic customer extension rules is a more appropriate forum to address customer extensions than individual rate cases for select utilities.

Moreover, there are many solutions to address the concern Western identifies with regard to the cost of customer extensions, and each of the potential solutions has its own advantages and disadvantages. For example, Western's automatic, vintaged Premises Charge proposal results in various customers paying different rates depending on when they contact Western for service, and individuals in the housing market will not know what additional utility rates they will be subject to, if any at all, if they purchase various houses for sale in the community. Other possible methods addressing customer extensions would include assessing developers rather than end-use customers for part of the cost of extensions; changing the mains footage allowance; changing the service allowance and various combinations of these and other possible options.

Since customer extensions are included in the Commission's rules that generically apply to all utilities subject to Commission jurisdiction, a generic rules proceeding is a more appropriate forum for considering the impacts of any changes to the rules on all parties affected by those rules.

Q. WHAT IS WESTERN'S RESIDENTIAL CUSTOMER BASE CHARGE PROPOSAL?

A. Western is proposing to increase the fixed base charge to residential customers from its current $5.10 amount to a proposed $9.00 per month amount. This proposal would increase residential base revenues from $9,465,253 based on the number of customers included in the Company's cost of service study to $16,703,388, or by 76 percent. Almost 80 percent of the rate increase for residential customers is generated by this non-usage sensitive billing element under the Company's proposal. This Western proposal relies, in part, on its total embedded class cost of service study results.

Q. IS THIS PROPOSED 76 PERCENT INCREASE IN THE RESIDENTIAL CUSTOMER BASE RATE ELEMENT REASONABLE?

A. No, it is not reasonable. Western's average cost of service study shows the following indicated customer costs:

Customer Cost	Firm Residential
O&M Expense	$ 8,383,524
Depreciation & Amortization	2,513,209
Property & Other Taxes	702,041
Income Taxes	1,814,361
Return	4,347,011
Total	17,760,146
Number of Customers	154,661
Customer Cost Per Customer Per Month	$9.57

I propose that the residential customer charge, or base charge, remain at its current tariff rate of $5.10 per customer per month. Any increase authorized by the Commission in this proceeding should be placed on the usage rate component. The table above shows that costs that can be avoided if a residential customer were to leave Western's system based on the Company's cost of service study do not exceed $8,333,524. Avoided costs are those costs Western would save if a customer left the system. The avoided cost amount includes variable O&M costs associated with a customer's remaining on the Western system. Since the only way to avoid a customer charge is to leave the Western system, setting the customer charge above avoided costs does not provide a meaningful economic price signal to Western's end-use customers. Since the current $5.10 customer charge already exceeds the $4.52 avoided costs, I recommend that it remain at its current level.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, at this time.

Exhibit__RAG-1

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
RATE OF RETURN AT PRESENT RATES
TWELVE MONTHS ENDED SEPTEMBER 30, 1998

Line No.	Cost Item	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large Int. & Carr.
		(a)	(b)	(c)	(d)	(e)	(f)
1	Total Operating Margins	44,842,983	24,208,630	10,071,538	1,234,217	3,880,223	5,448,375
2							
3	O & M Expense	23,121,835	13,019,693	5,765,974	447,291	1,232,167	2,656,709
4							
5	Deprec. & Amortization	6,486,839	3,117,681	1,484,459	176,974	507,583	1,200,144
6							
7	Property & Other Taxes	1,908,720	917,290	438,898	53,314	149,093	350,127
8							
9	Interest	4,754,687	2,438,450	1,143,065	116,930	322,474	733,767
10							
11	Pre-Tax Expenses	36,272,081	19,493,114	8,832,396	794,509	2,211,316	4,940,746
12							
13	Taxable Income	8,570,902	4,715,516	1,239,142	439,708	1,668,907	507,629
14							
15	Income Taxes	3,459,430	1,903,300	500,149	177,477	673,612	204,892
16							
17	Return	9,866,159	5,250,666	1,882,058	379,161	1,317,769	1,036,504
18							
19	Rate Base	124,468,624	63,833,971	29,923,254	3,061,015	8,441,759	19,208,626
20							
21	Rate Of Return	7.93%	8.23%	6.29%	12.39%	15.61%	5.40%

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

WESTERN KENTUCKY)
GAS COMPANY)

CASE NO. 99-070

Affidavit of

Richard A. Galligan

I, Richard A. Galligan, hereby certify that the statements contained in the foregoing testimony are true and correct to the best of my knowledge, information, and belief.

Richard A. Galligan

Richard A. Galligan

STATE OF MARYLAND)
COUNTY OF Prince George ~~MONTGOMER~~Y) SS

Subscribed and sworn to before me, this 15th day of October 1999.

P. J. GARDNER
Notary Public, State of Maryland
County of Prince George
My Commission Expires July 16, 2000

P. J. Gardner

Notary Public

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

WESTERN KENTUCKY GAS COMPANY	))	Case No. 99-070

EXHIBIT ACCOMPANYING THE
DIRECT TESTIMONY
OF
RICHARD A. GALLIGAN

ON BEHALF OF THE

OFFICE OF RATE INTERVENTION OF THE ATTORNEY GENERAL

FOR THE COMMONWEALTH OF KENTUCKY

OCTOBER 1999

EXETER
Associates, Inc.
12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

RICHARD A. GALLIGAN

Mr. Galligan is a principal in Exeter Associates, Inc. He is an economist specializing in public utility regulation. Areas of expertise include rate structure, cost of service, and revenue requirements. Mr. Galligan has assisted numerous clients with their acquisitions of natural gas.

Mr. Galligan has given expert testimony on approximately 90 occasions before more than a 25 federal and state regulatory authorities. He has testified in electric, gas, and telephone proceedings on matters which include rate base, revenues, expenses, average and marginal cost studies, integrated resource planning, cost structure, and rate design. He has also prepared reports for state regulatory authorities dealing with matters of rate design, cost of service, and regulatory standards. Mr. Galligan has assisted the Defense Fuel Supply Center, the U.S. Army, and other Department of Defense installations in the competitive procurement of natural gas.

Education:

B.S. (with senior honors) - University of Wisconsin, 1965.

M.S. (Economics) - University of Wisconsin, 1966.

Ph.D. (Economics) - University of Minnesota, 1968; completed all course work.

Previous Employment:

March 1987- Sept. 1987	General Manager, Rates and Regulatory Affairs, Gas Company of New Mexico.
1985-1987 -	Executive Director, Texas Public Utility Commission.
1984-1985 -	Utilities Division Director, Iowa State Commerce Commission.
1981-1984 -	Principal and part owner, Exeter Associates, Inc., consulting economists.
1976-1980 -	Economist at J.W. Wilson & Associates, Inc., consulting economists.
1975-1976 -	Senior Rate Analyst, Minnesota Public Utilities Commission.
1968-1975 -	Assistant Professor of Economics, Mankato State University.

Professional Work:

At Gas Company of New Mexico, Mr. Galligan managed and directed the activities of the Gas Rate Department.

At the Texas Public Utility Commission, Mr. Galligan was directly responsible for technical matters regarding all aspects of utility regulation as well as the management and administration of the Commission's regulatory activities.

At the Iowa State Commerce Commission, Mr. Galligan directed the technical efforts of over 50 Utilities Division personnel regarding all aspects of utility regulatory analysis. Full administrative responsibility for the Division's activities and personnel were the direct responsibility of Mr. Galligan.

At Exeter Associates, Mr. Galligan was directly responsible for technical, economic analysis of electric, gas, and telephone regulatory matters, including cost of service, cost allocation, rate design and related matters. Mr. Galligan also handled all aspects of client relations, supervised office support staff, and served as treasurer and vice-president of Exeter.

At J.W. Wilson & Associates, Mr. Galligan had the primary responsibility for directing and developing the firm's work in the area of utility revenue requirements. Other major responsibilities included the performance of marginal and average cost studies, cost-of-service allocations, and development of cost-based utility rate structures for electric, gas, and telephone utilities.

Mr. Galligan began his work at the Minnesota Public Utilities Commission at the time state regulation of electric and gas utilities commenced. While at the Commission, Mr. Galligan had principal responsibility for the development of staff-proposed utility rate design. Cost-of-service analysis and rate structure issues were areas in which Mr. Galligan had lead staff responsibility.

At Mankato State University (MSU), Mr. Galligan taught a wide range of graduate and undergraduate courses, including Economics of the Public Sector, International Trade, and Economic Principles. Major emphasis focused on the microeconomic aspects, including pricing of goods in the public sector. Mr. Galligan achieved tenure status in his third year at MSU, and served as president of the Faculty Senate.

Publications and Reports:

"Rate Design Objectives and Realities," Public Utilities Fortnightly, 1976.

Paper presented before the Accounting & Financial Division of the Electric Council of England.

Paper presented before the Public Affairs Institute of Mankato State University.

Seminar on income tax and depreciation issues in regulatory proceedings before the New Hampshire Public Utilities Commission staff.

Director of costing and rate design study under a grant from the National Regulatory Research Institute.

"An Overview of the Components of Economic Regulation: Revenue Requirements, Revenue Contribution by Class of Service, Rate Structure Design," presented at the Second National Association of Regulatory Utility Commissions, Introductory Regional Training Program, St. Louis, March 1986.

"Public Utility Costing & Pricing Principles," presented at NARUC Regional Training Program, Denver, September 1987.

"Final Report - Task Group on Natural Gas Procurement," for the Defense Acquisition Board, Department of Defense, 1989, co-author.

"Natural Gas Supply Options for the DOE/SAN Labs," for the U.S. Department of Energy, 1989.

"Evaluation of Natural Gas Supply Options for Energy Technology Engineering Center," for the U.S. Department of Energy, 1989.

"A Survey of State Regulation of Non-Utility Generation," for the Maryland Department of Natural Resources, 1988.

"Report to the Commission and Recommendations Regarding Proposed PURPA Standards Included in Federal Energy Policy Act of 1992," for the Delaware Public Service Commission, 1993.

Audits:

Audit of Department of Natural Resources Environmental Surcharge for the Maryland Department of Natural Resources, 1983.

Management and Performance Audit of Gas Purchasing Practices and Policies of Columbia Gas of Ohio, for the Ohio Public Utilities Commission, 1988.

Management and Performance Audit of Gas Purchasing Practices and Policies of The River Gas Company, for the Ohio Public Utilities Commission, 1989.

Management and Performance Audit of Gas Purchasing Practices and Policies of Columbia Gas of Ohio, for the Ohio Public Utilities Commission, 1990.

Management and Performance Audit of Gas Purchasing Practices and Policies of Cincinnati Gas and Electric Company, for the Ohio Public Utilities Commission, 1991.

Management and Performance Audit of Gas Purchasing Practices and Policies of Columbia Gas of Ohio, for the Ohio Public Utilities Commission, 1992.

Management and Performance Audit of Gas Purchasing Practices and Policies of Ohio Gas Company, for the Ohio Public Utilities Commission, 1993.

Management and Performance Audit of Gas Purchasing Practices and Policies of National Gas and Oil Corporation, for the Ohio Public Utilities Commission, 1994.

Management and Performance Audit of Gas Purchasing Practices and Policies of Eastern Natural Gas Company and Pike Natural Gas Company, for the Ohio Public Utilities Commission, 1995.

Management and Performance Audit of Gas Purchasing Practices and Policies of Dayton Power and Light Company, for the Ohio Public Utilities Commission, 1996.

Management and Performance Audit of Gas Purchasing Practices and Policies of West Ohio Gas Company, for the Ohio Public Utilities Commission, 1996.

Management and Performance Audit of Gas Purchasing Practices and Policies of East Ohio Gas Company, for the Ohio Public Utilities Commission, 1998.

Management and Performance Audit of Gas Purchasing Practices and Policies of Columbia Gas of Ohio, for the Ohio Public Utilities Commission, 1998.

Expert Testimony

Presented by Richard A. Galligan

Telephone Rate Cases

Before the Alabama Public Service Commission

Expert witness in Docket 17743; South Central Bell Telephone Company.

Before the California Public Utilities Commission

Expert witness in Application No. 55723; Pacific Telephone and Telegraph Company.

Before the Connecticut Public Utilities Commission

Expert witness in Docket No. 760719; Southern New England Telephone Company.

Before the Maryland Public Service Commission

Expert witness in Case No. 6936; Atlantic Telephone Company, Inc.

Before the Minnesota Public Utilities Commission

Expert witness in Docket No. PSC-77-31-BS and Department No. PSC-P 421/C076-1053; Northwestern Bell Telephone Company.

Before the Missouri Public Service Commission

Expert witness in Docket No. 18565; Southwestern Bell Telephone Company.

Before the North Carolina Public Utilities Commission

Expert witness in Docket No. P-55, Sub 754; Southern Bell Telephone and Telegraph Company.

Before the Pennsylvania Public Utility Commission

Expert witness in Docket No. R-822109; General Telephone Company of Pennsylvania.

Before the South Carolina Public Service Commission

Expert witness in Docket No. 79-305-C; Southern Bell Telephone & Telegraph Company.

Expert witness in Docket No. 82-294-C; Southern Bell Telephone & Telegraph Company.

Electric and Gas Utility Rate Cases

Before the Connecticut Public Utilities Commission

Technical support for the Commission's Staff in Docket Nos. 760604, 760605, gas and electric general rate proceedings; and Docket No. 750204, generic rate design proceeding; Connecticut Light and Power Company; and Hartford Electric Light Company.

Before the Delaware Public Service Commission

Expert witness in Docket No. 923, Phase II; Delmarva Power & Light Company.

Expert witness in Docket No. 80-9; Delmarva Power & Light Company.

Expert witness in Docket No. 40; Delmarva Power & Light Company.

Before the District of Columbia Public Service Commission

Expert witness in Docket No. 680; Potomac Electric Power Company.

Before the Florida Public Service Commission

Expert witness in Docket No. 820150-EU; Gulf Power Company.

Before the Georgia Public Service Commission

Expert witness in Docket No. 4267-U; Atlanta Gas Light Company.

Expert witness in Docket No. 4177-U; Atlanta Gas Light Company.

Expert witness in Docket No. 4451-U; Atlanta Gas Light Company.

Expert witness in Docket No. 5259-U; Atlanta Gas Light Company.

Expert witness in Docket No. 5116-U; Atlanta Gas Light Company.

Expert witness in Docket No. 5650-U; Atlanta Gas Light Company.

Expert witness in Docket No. 5318-U; United Cities Gas Company.

Expert witness in Docket No. 5651-U; United Cities Gas Company.

Before the Idaho Public Utilities Commission

Expert witness in Case No. U-1006-185; Idaho Power Company.

Expert witness in Case No. U-1006-179; Idaho Power Company.

Before the Illinois Commerce Commission

Expert witness in Case No. 82-0026; Commonwealth Edison Company.

Expert witness in Case No. 83-0537; Commonwealth Edison Company.

Expert witness in Case No. 87-0427; Commonwealth Edison Company.

Before the Indiana Utility Regulatory Commission

Expert witness in Cause No. 39723; Northern Indiana Public Service Company.

Expert witness in Cause No. 37394-GCA41; Indiana Gas Company.

Expert witness in Cause Nos. 37394-GCA50-51 and 37399-GCA50-51, Indiana Gas Company and Department of Public Utilities of the City of Indianapolis.

Before the Kansas Corporation Commission

Expert witness in Docket No. 158,499-U; Kansas Power and Light Company.

Before the Louisiana Public Service Commission

Expert witness in Docket No. U-19997; Trans Louisiana Gas Company and Louisiana Intrastate Gas Corporation.

Before the Maryland Public Service Commission

Expert witness in Case Nos. 8500 (g,h,i) and 8229; Baltimore Gas & Electric Company.

Expert witness in Case No. 8241, Phase II; Baltimore Gas & Electric Company.

Expert witness in Case No. 8707, Phase II; Chesapeake Utilities Corporation.

Before the Michigan Public Service Commission

Expert witness in Case No. U-5365; Michigan Consolidated Gas Company.

Before the Minnesota Public Utilities Commission

Expert witness in Docket No. ER 2-1; Northern States Power Company.

Expert witness in Docket No. ER 1-1; Interstate Power Company.

Expert witness in Docket No. GR 1-1; Interstate Power Company.

Expert witness in Docket No. U-75-103; Anoka Electric Power Cooperative.

Expert witness in Docket No. E015/ER-76-408; Minnesota Power & Light Company.

Expert witness in Docket No. E002/GR-77-611; Northern States Power Company.

Expert witness in Docket No. E-862/M-78-753; Northern States Power Company.

Before the Montana Public Service Commission

Expert witness in Docket No. 6441; Montana Dakota Utilities.

Expert witness in Docket No. 6454; Montana Power Company.

Expert witness in Docket No. D97.7.91; PacifiCorp.

Before the Nevada Public Service Commission

Expert witness in Docket No. 87-1227; Sierra Pacific Power Company.

Expert witness in Docket No. 88-763; Southwest Gas Corporation.

Expert witness in Docket Nos. 90-1109/90-1110; Southwest Gas Corporation.

Expert witness in Docket No. 91-7080; Sierra Pacific Power Company.

Expert witness in Docket No. 92-1030; Sierra Pacific Power Company.

Expert witness in Docket No. 92-1032; Southwest Gas Corporation.

Before the New Hampshire Public Utilities Commission

Expert witness in Docket No. DR-75-20; Public Service Company of New Hampshire.

Before the New Jersey Board of Public Utilities

Expert witness in Docket No. GR-9030335J; New Jersey Natural Gas Company.

Before the Ohio Public Utilities Commission

Expert witness in Case No. 80-1129-EL-AIR; Ohio Edison Company.

Expert witness in Case No. 82-517-EL-AIR; Dayton Power and Light Company.

Expert witness in Case No. 97-219-GA-GCR; East Ohio Gas Company.

Before the Pennsylvania Public Utility Commission

Expert witness in Docket No. R-822133; Equitable Gas Company.

Expert witness in Docket No. R-880961; The Peoples Natural Gas Company.

Expert witness in Docket No. R-901607; The Peoples Natural Gas Company.

Expert witness in Docket No. R-901670; National Fuel Gas Distribution Corporation.

Expert witness in Docket No. R-911912; National Fuel Gas Distribution Corporation.

Expert witness in Docket No. R-953299; National Fuel Gas Distribution Corporation.

Expert witness in Docket No. R-00912164; Equitable Gas Company.

Expert witness in Docket No. R-00953297; UGI Utilities, Inc. Gas Division.

Before the Rhode Island Public Utilities Commission

Expert witness in Docket No. 1258; Providence Gas Company.

Expert witness in Docket No. 1294; Valley Gas Company.

Before the South Carolina Public Service Commission

Expert witness in Docket No. 79-300-E; Duke Power Company.

Expert witness in Docket No. 80-378-E; Duke Power Company.

Expert witness in Docket No. 88-203-G; Piedmont Natural Gas Company.

Before the South Dakota Public Utilities Commission

Expert witness in Docket No. F-3126; Montana Dakota Utilities Company.

Expert witness in Docket No. F-3188; Northern States Power Company.

Before the Board of Directors of the Tennessee Valley Authority

Expert witness in TVA Compliance Hearings on PURPA Section III Ratemaking Standards.

Before the Texas Public Utility Commission

Expert witness in Docket No. 5200; Texas Electric Service Company.

Before the Railroad Commission of Texas

Expert witness in Docket No. GUD 8664; Lone Star Gas Company.

Expert witness in Docket No. GUD 8878; Southern Union Gas Company.

Before the Utah Public Service Commission

Expert witness in Docket No. 89-057-15; Mountain Fuel Supply Company.

Expert witness in Docket Nos. 91-057-11 and 91-057-17; Mountain Fuel Supply Company.

Before the Vermont Public Service Board

Expert witness in Docket No. 6016; Vermont Gas Systems, Inc.

Before the Virginia State Corporation Commission

Expert witness in Case No. PUE920037; Commonwealth Gas Services, Inc.

Expert witness in Case No. PUE970455; Commonwealth Gas Services, Inc.

Before the Federal Energy Regulatory Commission

Expert witness in Docket No. RP87-7-020; Transcontinental Gas Pipe Line Corporation.

Expert witness in Docket No. RP90-104-000 et al.; Texas Gas Transmission Corporation.

Expert witness in Docket No. RP91-119; Texas Eastern Transmission Corporation.

Expert witness in Docket No. CP89-1582-000; National Fuel Gas Supply Corporation.

Expert witness in Docket No. RP88-221-000 et al.; CNG Transmission Corporation.

Expert witness in Docket No. RP93-151-000, et al.; Tennessee Gas Pipeline Company.

Expert witness in Docket No. RP91-203, et al.; Tennessee Gas Pipeline Company.

Expert witness in Docket No. RP94-343-000; Noram Gas Transmission Company.

Expert witness in Docket No. RP95-112; Tennessee Gas Pipeline Company.

Expert witness in Docket No. RP95-185; Northern Natural Gas Company.

Expert witness in Docket No. RP95-203; Northern Natural Gas Company.

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

WESTERN KENTUCKY) CASE NO. 99-070
GAS COMPANY)

DIRECT TESTIMONY

OF

STEVEN L. ESTOMIN, Ph.D.

ON BEHALF OF THE

OFFICE OF RATE INTERVENTION OF THE ATTORNEY GENERAL

FOR THE COMMONWEALTH OF KENTUCKY

OCTOBER 1999

EXETER
Associates, Inc.
12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

WESTERN KENTUCKY) CASE NO. 99-070
GAS COMPANY)

DIRECT TESTIMONY OF STEVEN L. ESTOMIN

I. Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven L. Estomin. My business address is 12510 Prosperity Drive, Suite 350, Silver Spring, Maryland, 20904. Exeter is an economics consulting firm specializing in public utility regulation.

Q. WHAT IS YOUR POSITION WITH EXETER ASSOCIATES, INC.?

A. I am a vice president and principal in the firm and my title is Senior Economist. My responsibilities include conducting and presenting economic and econometric analyses and providing other professional services predominantly related to regulated industries.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND BACKGROUND.

A. I received a Bachelor of Arts degree with a major in economics in 1975, a Master of Arts degree in economics in 1978, and a Ph.D. in economics in 1986, all from the University of Maryland. My areas of specialization in graduate school were industrial organization, econometrics, and environmental economics.

I joined Exeter Associates, Inc. in 1981 as an economist and have been involved with economic analysis related to regulated industry since that time. A detailed statement of my qualifications is included as an appendix to this testimony.

Q. HAVE YOU TESTIFIED AS AN EXPERT WITNESS IN OTHER REGULATORY PROCEEDINGS?

A. Yes. I have testified before the utility commissions in Maine, Maryland, Vermont, New Mexico, New Jersey, Illinois, Rhode Island, Kentucky, and the District of Columbia on issues related to load forecasting, weather normalization, production planning, statistical analysis and other issues. I have also testified in U.S. District Court and before the Federal Energy Regulatory Commission on issues related to statistical estimation.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I was requested by the Attorney General Office of Rate Intervention to assess the Company's application of the zero-intercept approach to functionalizing distribution system costs.

Q. IS YOUR TESTIMONY ACCOMPANIED BY EXHIBITS?

A. Yes. Exhibit___SLE-1, a six-page exhibit, is attached which provides the regression results used to develop the tables contained in my testimony and the data relied upon to run the regressions..

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. The findings of my review and analysis are:

- The Company relies on a weighted least square regression approach in its zero-intercept analysis fundamentally using the square root of the number of feet of each pipe size category as the weights.
- Use of the square root of the number of feet results in an estimated zero-intercept that is approximately nine times higher than the estimate obtained using the number of feet of mains as the weights.
- Use of the number of feet rather than the square root of the number of feet in the weighted regression is consistent with NARUC guidelines and results in a slightly better R-square statistic, which is a measure of goodness-of-fit.
- The estimated constant term, i.e., the zero intercept, is not statistically different from zero, regardless of whether feet or the square root of feet is used as a weight.

- use of ordinary least squares, absent any weighting, results in a negative intercept, which is also not statistically different from zero.

II. Review and Analysis

Q. PLEASE DESCRIBE THE ZERO-INTERCEPT METHOD OF FUNCTIONALIZING DISTRIBUTION SYSTEM COSTS.

A. The zero-intercept method is one of two approaches used to classify distribution system costs between a hypothesized customer-related component and a demand-related component of distribution mains investment cost. The other approach is referred to as the minimum system approach.

The zero-intercept method entails estimating a regression equation that has average costs per unit of distribution system (e.g., average cost per foot of distribution main) as the dependent variable and uses a size measure of the distribution component (e.g., diameter of pipe) as the independent, or causal, variable. Separate observations are made up of various size categories. Where warranted, other salient characteristics are used to delineate observations, for example, 3-inch pipe may be broken down into separate categories for plastic and steel. The regression equation is structured as:

$$Y_i = a + bX_i + e_i$$

where:

Y_i = average cost per unit of distribution system for category i;

a = constant term;

b = slope parameter;

X_i = the size dimension of category i; and

e_i = the randomly distributed error term associated with category i.

The estimated constant term (a) is the intercept along the vertical axis and can be interpreted as the per-unit cost of a zero-size distribution main, i.e., a distribution main with no carrying capacity.

Q. HAVE YOU REVIEWED THE COMPANY'S EXHIBIT RELATED TO THE REGRESSION EQUATION USED IN ITS ZERO-INTERCEPT ANALYSIS?

A. Yes, I have. The analysis is shown on page 7 of 9 under Tab 3 of Volume 9 of the Company's filing requirements. The exhibit was prepared by Mr. Peterson.

Q. IS THE APPROACH THAT YOU DESCRIBED ABOVE USED BY MR. PETERSON?

A. Yes, but the equation discussed above functionally relies on the square root of the number of feet of mains as weights rather than the number of square feet.

Q. WHAT ARE THE IMPLICATIONS OF USING THE SQUARE ROOT OF THE NUMBER OF FEET OF MAINS IN EACH CATEGORY COMPARED TO USING THE NUMBER OF FEET OF MAINS AS THE WEIGHTS?

A. Reliance on the square root of the number of feet as a weight rather than the number of feet substantially affects the results of the equation.

Q. IS THE USE OF A SQUARE ROOT TERM FOR WEIGHTS COMMONLY USED IN WEIGHTED LEAST SQUARES REGRESSION?

A. The square root of a data series such as the number of feet of mains is often used where weighted least squares is relied upon to correct for heteroscedasticity, a statistical problem that sometimes emerges with the use of OLS.[1]

Q. YOU NOTED THAT THE USE OF FEET AS A WEIGHT, RATHER THAN THE SQUARE ROOT OF FEET, RESULTS IN SUBSTANTIALLY DIFFERENT REGRESSION OUTPUT. PLEASE EXPLAIN.

---

[1] Heteroscedasticity results when the variance of the error terms is not constant.

A. I replicated the weighted least squares regression results obtained by Mr. Peterson and then reran the regression using feet as the weights rather than the square root of feet. A summary comparison is shown in the table below.

Comparison of Regression Results Using
Alternative Weighting Schemes
(t - Statistics in parentheses)

	Weight: sq. root of feet[1]	Weight: number of feet[2]	Weight: none[3]
Constant	0.891 (1.51)	0.097 (0.36)	-2.152 (-0.66)
Size Parameter	1.166 (5.70)	1.522 (12.84)	1.601 (3.26)
R-Square	0.955	0.996	0.603
Adjusted R-Square	0.949	0.995	0.540
F-Statistic	32.442	164.978	10.635

1. Exhibit__SLE-1, page 1 of 6.
2. Exhibit__SLE-1, page 2 of 6.
3. Exhibit__SLE-1, page 3 of 6.

As shown in the table, the Company's weighting scheme results in an estimate of the constant term (the zero-intercept) of 0.89 compared to 0.10 where feet are used as weights. Additionally, use of feet as weights results in slightly higher R-square and adjusted R-square statistics, which are measures of goodness of fit.

Q. DO YOU VIEW THESE DIFFERENCES IN THE REGRESSION RESULTS AS A PROBLEM?

A. Yes. Fundamentally, the selection of the weights used in the weighted regression substantially alters the results. The zero-intercept obtained using the square root of feet as the weighting is approximately nine times as high as the zero-intercept estimated using the number of feet as the weight. Consequently, we see that the results are highly sensitive to a judgmental assessment of an appropriate weighting scheme.

Q. IS THE WEIGHTING SCHEME USING THE SQUARE ROOT OF FEET SUGGESTED BY THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS (NARUC)?

A. No. The NARUC *Electric Utility Cost Allocation Manual* (January 1992), in discussing use of the zero-intercept method as applied to electric distribution systems, indicates at page 92 that the number of poles (not the square root of the number of poles) should be used for Account 364 (Poles, Tower, and Fixtures); for Account 365 (Overhead Conductors and Devices), NARUC indicates that number of feet (not the square root of the number of feet) should be used as a weight (page 92). The same is true for Accounts 366, 367, and 368 (pages 93 and 94).

Q. BASED ON THE NARUC DOCUMENT AND THE GOODNESS-OF-FIT MEASURES SHOWN IN THE SUMMARY COMPARISON TABLE, IS THE USE OF THE SQUARE ROOT OF THE NUMBER OF FEET AS A WEIGHTING SCHEME APPROPRIATE?

A. Both the NARUC document as well as the comparison of results suggest that, were one to rely on a weighting scheme, the number of feet rather than the square root of the number of feet would be a superior choice.

Q. ARE YOU RECOMMENDING THAT THE NUMBER OF FEET BE USED TO WEIGHT THE REGRESSION?

A. No. Despite NARUC's suggestions regarding weighting, I can see little advantage, and a significant disadvantage, to using weighted least squares for the purpose of estimating the zero-intercept to define the cost of the minimum system.

Q. PLEASE EXPLAIN.

A. The zero-intercept method is used to quantify, through regression analysis, the cost of the minimum system. The major disadvantage of using the weighted least squares approach can be seen by example. If we hypothesize a second gas company with the same system as Western Kentucky Gas Company in terms of net cost and length of pipe in each size category, we would expect the cost of the minimum system for Western Kentucky and the second company to be the same. If the second company then doubles the length of 2-inch pipe with the same average cost per foot as the original length of 2-inch pipe, the use of a weighted regression will cause a different zero-intercept to be estimated for that company; an unweighted regression, in contrast, will not result in any changes to the estimated zero-intercept. There appears to be no compelling explanation as to why the minimum system costs on a per foot basis should change as a result of this difference between the two companies (i.e., Western Kentucky and the hypothetical). A comparison of the regression results is shown in the following table.

Comparison of Weighted Least Squares Results
for Western Kentucky and a Hypothetical Company
with Twice the Length of 2-inch Main

	Weight: Square Root of Feet		Weight: Feet	
	Western Kentucky[1]	Hypothetical[2]	Western Kentucky[3]	Hypothetical[4]
Constant	0.891	0.821	0.097	0.079
Slope Parameter	1.166	1.180	1.522	1.526
R-Square	0.955	0.969	0.996	0.999
Adjusted R-Square	0.949	0.965	0.995	0.999
F-Statistic	32.442	36.299	164.978	177.068

1. Exhibit___SLE-1, p. 1 of 6; data from p. 6 of 6.
2. Exhibit___SLE-1, p. 4 of 6; data from p. 6 of 6.
3. Exhibit___SLE-1, p. 2 of 6; data from p. 6 of 6.
4. Exhibit___SLE-1, p. 5 of 6; data from p. 6 of 6.

Using the square root of feet as a weight, the estimated zero-intercept is shown to decline by approximately 8 percent when the amount of 2-inch main is doubled. With feet used as a weight, the zero-intercept declines by approximately 19 percent. Were no weights used, there would be no change in the regression equation results.

Q. DO THE GOODNESS-OF-FIT MEASURES SHOWN ON THE SUMMARY COMPARISON TABLE ON PAGE 5 OF YOUR TESTIMONY SUGGEST RELIANCE ON A WEIGHTED OLS APPROACH?

A. The goodness-of-fit measures (R-Square and adjusted R-Square) are substantially lower for the unweighted regression than for either of the two weighted regressions. Low R-Square measures, however, are not surprising given the nature of the cost data. Specifically, the cost information is accounting data booked over a long period of time. Further, the purpose to which the results are to be put logically calls for an unweighted rather than weighted approach, NARUC's recommendations not withstanding. In particular, each of the data points imparts cost information of equivalent value from a statistical vantage point. The cost information associated with pipes representing a relatively small portion of the system, therefore, should not be given less weight than the other data observations if a zero intercept method is relied upon.

Q. ARE YOU SUGGESTING RELIANCE ON THIS METHOD?

A. My colleague, Mr. Richard Galligan, addresses this issue in his testimony submitted in this proceeding. I would note that Mr. Galligan addresses this issue from a theoretical perspective rather than a statistical/computational perspective. In each of the regression variations presented herein, none of the estimated intercept parameters is statistically different from zero, including the Company's proposed zero-intercept. Consequently, the statistical evidence is entirely consistent with Mr. Galligan's theoretical position, and no strong statistical evidence exists to imply reliance on anything other than a zero value for the customer-related cost component of distribution mains.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

WESTERN KENTUCKY) CASE NO. 99-070
GAS COMPANY)

Affidavit of

STEVEN L. ESTOMIN

I, Steven L. Estomin, hereby certify that the statements contained in the foregoing testimony are true and correct to the best of my knowledge, information, and belief.

Steven Estomin
STEVEN L. ESTOMIN

STATE OF MARYLAND)
) SS
COUNTY OF ~~MONTGOMERY~~ Prince Georges)

Subscribed and sworn to before me, this 15th day of October 1999.

P. J. GARDNER
Notary Public, State of Maryland
County of Prince George
My Commission Expires July 16, 2000

P. Gardner
Notary Public

APPENDIX

QUALIFICATIONS OF STEVEN L. ESTOMIN, Ph.D.

STEVEN L. ESTOMIN

Dr. Estomin is a principal in Exeter Associates, Inc. He is a senior economist whose academic training and professional experience are in the areas of microeconomic applications, industry analysis, econometric modeling and environmental economics. At Exeter, Dr. Estomin specializes in utility load forecasting, computer modeling, financial analysis, utility contract negotiation, issues of competition, antitrust, and damage estimation.

Dr. Estomin has testified on issues related to load forecasting, statistical analysis, economic damage analysis, class cost-of-service and rate design. He has prepared numerous electric load forecasts and has directed projects for state and federal regulatory agencies. Dr. Estomin has prepared reports on load forecasting, energy conservation, alternative power supply procurement, bulk power supply planning, and damage estimations for federal and state agencies and for private firms. He has also provided technical support to federal agencies in utility contract negotiations and in the development of requests for proposals for competitive power supply procurement.

Education:

B.A. (Economics) - University of Maryland, 1975.

M.A. (Economics) - University of Maryland, 1978.

Ph.D. (Economics) - University of Maryland, 1986.

Previous Employment:

1980-1981 -	Faculty Research Assistant, Bureau of Business and Economic Research, University of Maryland, College Park, Maryland.
1976-1980 -	Research/Teaching Assistant, and Instructor, University of Maryland, Department of Economics, College Park, Maryland.
1976-1978 -	Economist, U.S. Department of Labor, Bureau of International Labor Affairs, Office of Trade Adjustment Assistance, Washington, D.C.

Professional Work:

At the Bureau of Business and Economic Research, Dr. Estomin supervised the development of an environmental pollution forecasting model which he linked to a county level regional economic model. This task included developing submodels for industrial/commercial activity, municipal wastes generation, and transportation and energy-related emissions. Several reports and estimations using the model were provided to the Bureau of Land Management (U.S. Department of the Interior) and were used to develop analyses of future development of the outer-continental shelf.

As a Graduate Teaching Assistant for the Department of Economics at the University of Maryland, Dr. Estomin was initially engaged in aiding senior faculty members in a variety of teaching-related tasks and later autonomously taught micro and macroeconomic theory courses. As an Instructor for the University, he taught upper-level courses in the economics of poverty and discrimination and the economics of American industry. As a Graduate Research Assistant, Dr. Estomin conducted extensive research in pollution abatement cost modeling.

At the U.S. Department of Labor, Dr. Estomin collected firm-specific data covering sales, inventory, employment, and production and used these data together with industry production, employment, and import data to analyze causes of employment reductions. Companies analyzed by Dr. Estomin include American Motors Corporation, Bethlehem Steel, and numerous smaller firms.

Major Publications and Reports:

"Nevada Test Site Utility Options Study," prepared for the U.S. Department of Energy, June 1999.

"Spallation Neutron Source Electrical Facilities Study," prepared for the U.S. Department of Energy, April 1999.

"Forecasted Electric Power Demands for the Delmarva Power and Light Company," prepared for the Power Plant Research Program, Maryland Department of Natural Resources, December 1998 (with Andrés Escalante).

"Assessment of DOD Electric Power Supply Options, Strategies, and Costs under Retail Open Access," prepared for the U.S. Department of Defense, Office of the Deputy Under Secretary of Defense, February 1998.

"The Engineering and Economic Feasibility of Using Poultry Litter as a Fuel to Generate Electric Power at Maryland's Eastern Correctional Institute," prepared for the Maryland Environmental Service, February 1998 (with Gary Walters).

"Power Supply and Cogeneration Options for the Eastern Correctional Institute," prepared for the Maryland Environmental Service," April 1997 (with Thomas King, P.E.)

"Cooperative Integrated Resource Plan for U.S. Department of Energy Installations Having Power Allocations from the Western Area Power Administration," prepared for the U.S. Department of Energy, June 1997.

"Cooperative Integrated Resource Plan for U.S. Navy Installations Having Power Allocations from the Western Area Power Administration," prepared for the U.S. Navy, SOUTHWESTNAVFACENGDIV, June 1997.

"Cooperative Integrated Resource Plan for U.S. Air Force Installations Having Power Allocations from the Western Area Power Administration," prepared for HQ AFCESA/CESE (Tyndall Air Force Base, Florida), June 1997.

"Analysis of Service Reliability -- Duquesne Light Company," prepared for the Pennsylvania Office of Consumer Advocate, June 1997.

"Estimated Power Supply Costs for the Accelerator Production of Tritium Project," prepared for the U.S. Department of Energy, Office of Project and Fixed Asset Management, October 1996.

"Customized Energy Conservation and Demand-Side Management Agreements between U.S. Air Force Bases and Utility Service Suppliers," prepared for HQ AFCESA/CESE (Tyndall Air Force Base, Florida), January 1996 (with Richard I. Chais).

"Evaluating and Implementing Privatization of Utility Distribution Systems at U.S. Air Force Bases," prepared for HQ AFCESA/CESE (Tyndall Air Force Base, Florida), December 1995 (with Richard I. Chais).

"Power Supply Options Study for Vandenberg Air Force Base," prepared for HQ AFCESA/CESE (Tyndall Air Force Base), December 1995 (with Richard Zumwalt, P.E.).

"U.S. Department of Energy Savannah River Site Power System Privatization Study," prepared for the U.S. Department of Energy, February 1995 (with Richard Zumwalt).

"Technical Report: Special Study of the MacDill Cogeneration Project," prepared for the Department of the Air Force, Headquarters Air Combat Command, May 1994.

"The Feasibility of Centralized Purchase of Electric Utility Service," prepared for the Department of the Air Force, March 1994.

"Long Range Energy Requirements for Charleston Air Force Base," (two volumes), prepared for the Department of the Air Force, July 1994.

"Long Range Energy Requirements for Wright-Patterson Air Force Base," (three volumes) prepared for the Department of the Air Force, Headquarters Air Force Logistics Command, April 1993.

"Forecasted Electric Power Demands for the Potomac Electric Power Company," (two volumes), prepared for the Power Plant Research Division, Maryland Department of Natural Resources, March 1992 (with John E. Beach).

"Optimal Allocation of Western Area Power Administration (Billings Area) Federal Preference Power Among Ellsworth, Minot, and Offutt Air Force Bases," prepared for the U.S. Air Force, November 1991.

"Impacts of Missile Site Deactivation on Electric Power Costs," *Environmental Impact Statement -- Deactivation of the Minuteman II Missile Wing at Ellsworth Air Force Base, South Dakota*, prepared for the Department of the Air Force, Headquarters Strategic Air Command, October 1991.

"Forecasted Electric Power Demands for the Baltimore Gas and Electric Company," (two volumes), prepared for the Power Plant and Environmental Review Division, Maryland Department of Natural Resources, May 1991 (with John E. Beach).

"Forecasted Electric Power Demands for the Delmarva Power and Light Company," (two volumes), prepared for the Power Plant and Environmental Review Division, Maryland Department of Natural Resources, September 1990 (with John E. Beach).

"Year 2000 Power Supply Reliability Assessment: SERC and SPP Regions," prepared for the U.S. Air Force, August 1990 (with Dennis Goins).

"Market and Regulatory Effects of the Elimination of the Manufacturing Restriction on the Regional Bell Operating Companies," prepared for the Telecommunications Committee of the National Association of State Utility Consumer Advocates (NASUCA), November 1989.

"Alternative Electric Power Supply Sources for Onizuka Air Force Base, California," prepared for the U.S. Air Force, June 1989.

"Vandenberg Air Force Base Power Supply Study," prepared for the U.S. Air Force, March 1989.

"Forecasted Electric Power Demands for the Potomac Electric Power Company," (two volumes), prepared for the Power Plant Research Program, Maryland Department of Natural Resources, July 1988 (with Walter Asmuth, III).

"Economic Damage Estimation -- Pittcon Industries, Inc.," Exeter Associates, Inc., prepared for Pittcon Industries, Inc., February 1988 (with Marvin H. Kahn).

"Report and Recommendations of the U.S. Air Force on Adjustments to the Mather AFB Surcharge," prepared for the U.S. Air Force for submission to the Board of Directors of the Sacramento Municipal Utility District, August 1987.

"Preliminary Assessment of Options Available to the U.S. Air Force to Reduce Electric Power and Energy Costs to the Northern California Air Force Bases," Exeter Associates, Inc., prepared for the U.S. Air Force, March 1987.

"An Analysis of the Optimal Allocation of Available Western Area Power Administration Preference Power Among the Northern California Air Force Bases," Exeter Associates, Inc., prepared for the U.S. Air Force, March 1987.

"A Survey of Methods Used to Estimate Conservation Potential," Exeter Associates, Inc., prepared for the Power Plant Research Program, Maryland State Department of Natural Resources, February 1987.

"End-Use Forecasting," presentation at the Power Plant Research Program Load Forecasting Workshop, Annapolis, Maryland, January 1987 (published in proceedings volume).

"Survey and Analysis of End-Use Modeling Practices," Exeter Associates, Inc., prepared for the Power Plant Research Program, Maryland State Department of Natural Resources, October 1986.

"Economic Damage Estimation -- Yacht Buyers Group," Exeter Associates, Inc., prepared for Yacht Buyers Group, Inc., August 1986 (with Marvin H. Kahn).

"Updated Load Forecast of Energy and Peak Demand for the Allegheny Power System," Exeter Associates, Inc., prepared for the Power Plant Research Program, Maryland State Department of Natural Resources, June 1986 (with Matthew I. Kahal).

The Determinants of Profitability and Premiums in Conglomerate Mergers, Ph.D. dissertation, University of Maryland, 1986.

"Updated Load Forecast of Energy and Peak Demand on the Delmarva Peninsula," Exeter Associates, Inc., prepared for the Power Plant Siting Program, Maryland State Department of Natural Resources, February 1986 (with Matthew I. Kahal).

"Estimated Value of Experimental Breeder Reactor II Generation to the Idaho National Engineering Laboratory -- 1985 Through 1986," Exeter Associates, Inc., prepared for the Idaho National Engineering Laboratory, U.S. Department of Energy, January 1986.

"An Economic Estimation of Electric Power Demands for the Baltimore Gas and Electric Company," (two volumes), Exeter Associates, Inc., prepared for the Power Plant Siting Program, Maryland State Department of Natural Resources, April 1985 (with Matthew I. Kahal).

"An Assessment of the State-of-the-Art of Gas Utility Load Forecasting," (with Thomas Bacon, Jr. and Matthew I. Kahal) published in the *Proceedings of the Fourth NARUC Biennial Regulatory Information Conference*, 1984.

"Projected Electric Power Demands for the Potomac Electric Power Company," (three volumes), Exeter Associates, Inc., prepared for the Power Plant Siting Program, Maryland State Department of Natural Resources, March 1984 (with Matthew I. Kahal).

"Economic and Demographic Forecasts for the PEPCO Service Area," Exeter Associates, Inc., prepared for the Power Plant Siting Program, Maryland State Department of Natural Resources, September 1982.

"The Behavior of Regulatory Agencies," published in *Attacking Regulatory Problems: An Agenda for Research in the 1980's*. (Allen Furgeson, ed.), Ballinger Publishers, Cambridge, Massachusetts, 1981 (with Wes Magat).

"Report on the Environmental Impacts from Outer-Continental Shelf Development in the Baltimore Canyon," Bureau of Business and Economic Research, University of Maryland, prepared for the Bureau of Land Management, U.S. Department of the Interior, September 1980 (with Virginia McConnell).

"The Environmental Systems Model," Bureau of Business and Economic Research, University of Maryland, June 1980 (with Virginia McConnell).

"Economic-Environmental Models of Regional Development -- The U.S. Experience," Department of Economics Working Paper 80-15, University of Maryland, November 1979 (with John H. Cumberland and Alan Krupnick).

Expert Testimony Presented:

Before the Kentucky Public Service Commission in Case No. 99-176, Delta Natural Gas Company, Inc., 1999, for the Office of Rate Intervention of the Attorney General. Testified on functionalization of distribution system costs.

Before the Maine Public Utilities Commission in Docket No. 97-580, Central Maine Power Company, 1998, for the MPUC Staff. Testified on generation-related administrative and general expenses.

Before the Maine Public Utilities Commission in Docket No. 96-116, Bangor Hydro Electric Company, 1997, for the MPUC Staff. Testified on load forecasting issues.

Before the New Mexico Public Service Commission, El Paso Electric Company, 1996, for the U.S. Air Force. Testified on rate design issues.

Before the State of Rhode Island and Providence Plantation Public Utilities Commission in Docket No. 2290, Narragansett Electric Company, 1995, for the Division of Public Utilities and Carriers. Testified on load forecasting issues.

Before the Illinois Commerce Commission in Docket No. 94-0065, Commonwealth Edison Company, June 1994, for the U.S. Department of Energy. Testified on load forecasting.

Before the Federal Energy Regulatory Commission in Docket No. RP91-203, et al., Tennessee Gas Pipeline Company, May 1994, for the Tennessee Rate Design Customer Group. Testified on issues related to econometric analysis.

Before the Public Service Commission of the District of Columbia in Formal Case No. 926, Chesapeake and Potomac Telephone Company, September 1993, for the Office of People's Counsel. Testified on issues related to finance and statistical analysis.

Before the Public Service Commission of the District of Columbia in Formal Case No. 814, Phase III, Chesapeake and Potomac Telephone Company, October 1992, for the Office of People's Counsel. Testified on issues related to competition in the telecommunications industry.

Before the Maine Public Utilities Commission in Docket No. 92-101, Maine Public Service Company, September 1992, for the Commission Staff. Testified on load forecasting.

Before the Maryland Public Service Commission in Case No. 8413, Potomac Electric Power Company, March 1992, for the Maryland Power Plant Research Division. Testified on load forecasting.

Before the State of New Jersey Board of Regulatory Commissioners in Docket No. GF91081393J, New Jersey Natural Gas Company, March 1992, for the Division of Rate Counsel. Testified on weather normalization.

Before the State of Rhode Island and Providence Plantations Public Utilities Commission in Docket 2019, Narragansett Electric Company, November 1991, for the Division of Public Utilities and Carriers. Testified on load forecasting.

Before the Maine Public Utilities Commission in Docket No. 91-010, Bangor Hydro-Electric Company, June 1991, for the Maine Public Advocate. Testified on load forecasting.

Before the Maryland Public Service Commission in Case No. 8241, Phase II, Baltimore Gas and Electric Company, May 1991, for the Maryland Power Plant and Environmental Review Division. Testified on load forecasting.

Before the State of Rhode Island and Providence Plantations Public Utilities Commission in Docket 1976, Narragansett Electric Company, October 1990, for the Revision of Public Utilities and Carriers. Testified on load forecasting.

Before the Maryland Public Service Commission in Case No. 8201, Delmarva Power and Light Company, October 1990, for the Maryland Power Plant and Environmental Review Division. Testified on load forecasting.

Before the Maine Public Utilities Commission in Docket No. 90-076, Central Maine Power Company, September 1990, for the Maine Public Advocate. Testified on load forecasting.

Before the Public Service Commission of the District of Columbia in Formal Case No. 890, District of Columbia Natural Gas, February 1990, for the Office of People's Counsel of the District of Columbia. Testified on load forecasting.

Before the Maryland Public Service Commission in Case No. 8102, Southern Maryland Cooperative, July 1988, for the Maryland Power Plant Research Program. Testified on load forecasting.

Before the Maryland Public Service Commission in Case No. 8063 Phase II, Potomac Electric Power Company, July 1988, for the Maryland Power Plant Research Program. Testified on load forecasting.

Before the U.S. District Court for the Eastern District of Pennsylvania in Civil Action No. 87-0805, March 1988, for Pittcon Industries, Inc. Testified on economic damages.

Before the Sacramento Municipal Utility District Board, September 1987, for the U.S. Air Force. Testified on the applicability and appropriate calculation of a special surcharge.

Before the Sacramento Municipal Utility District Board, September 1987, for the U.S. Air Force. Testified on cost estimation and cost allocation.

Before the Sacramento Municipal Utility District Board, February 1987, for the U.S. Air Force. Testified on rate design and cogeneration.

Before the Vermont Public Service Board in Docket No. 4661, Green Mountain Power Corporation, November 1982, for the Vermont Department of Public Service. Testified on production planning, fuel costs, and maintenance scheduling for nuclear plant on behalf of the Vermont Public Service Board.

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

WESTERN KENTUCKY)
) CASE NO. 99-070
GAS COMPANY)

EXHIBIT ACCOMPANYING THE DIRECT TESTIMONY OF STEVEN L. ESTOMIN, Ph.D.

ON BEHALF OF THE

OFFICE OF RATE INTERVENTION OF THE ATTORNEY GENERAL

FOR THE COMMONWEALTH OF KENTUCKY

OCTOBER 1999

EXETER
Associates, Inc.
12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

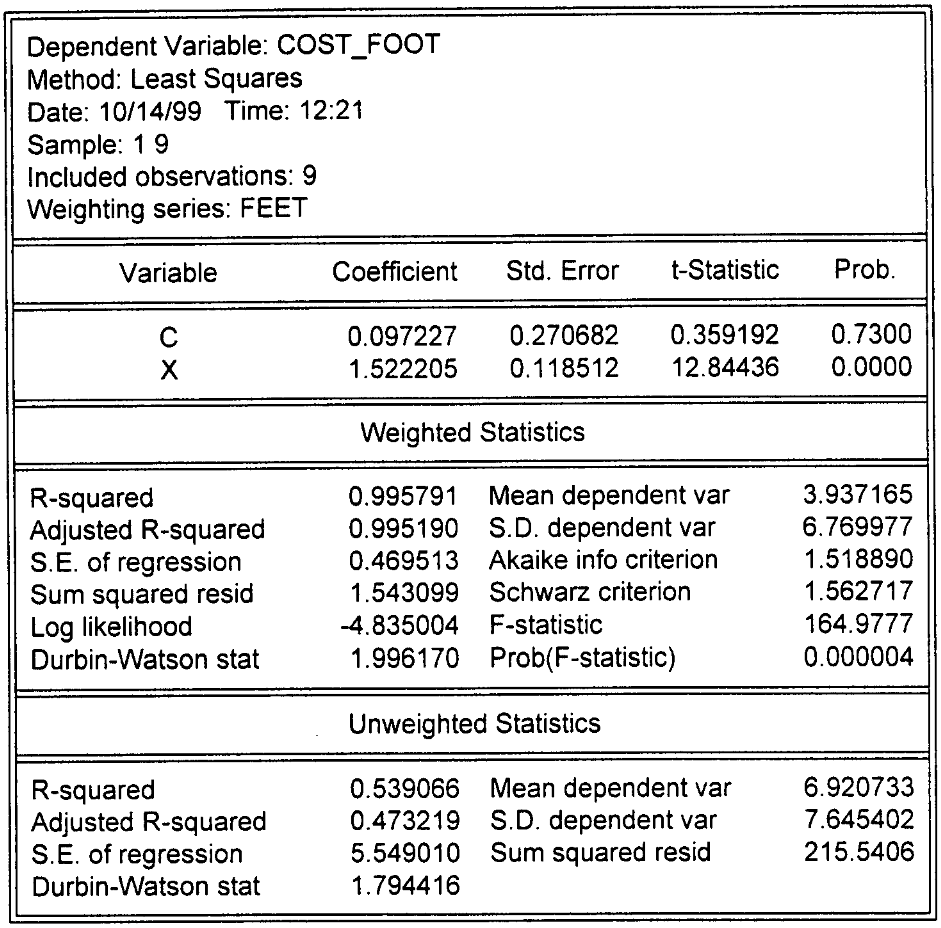
Case No. 99-070
Exhibit___(SLE-1)

Replication of Company's Results

```
Dependent Variable: COST_FOOT
Method: Least Squares
Date: 10/14/99   Time: 12:20
Sample: 1 9
Included observations: 9
Weighting series: FEET_SQ

        Variable       Coefficient   Std. Error   t-Statistic   Prob.

           C            0.891487     0.590138     1.510643     0.1746
           X            1.165806     0.204679     5.695780     0.0007

                          Weighted Statistics

R-squared                0.955541   Mean dependent var      4.299710
Adjusted R-squared       0.949190   S.D. dependent var      5.005757
S.E. of regression       1.128355   Akaike info criterion   3.272529
Sum squared resid        8.912294   Schwarz criterion       3.316356
Log likelihood          -12.72638   F-statistic             32.44191
Durbin-Watson stat       2.403221   Prob(F-statistic)       0.000739

                         Unweighted Statistics

R-squared                0.552066   Mean dependent var      6.920733
Adjusted R-squared       0.488075   S.D. dependent var      7.645402
S.E. of regression       5.470204   Sum squared resid       209.4619
Durbin-Watson stat       1.915943
```

Case No. 99-070
Exhibit___(SLE-1)
Page 2 of 6

Regression Weighted by Feet of Mains



```
Dependent Variable: COST_FOOT
Method: Least Squares
Date: 10/14/99   Time: 12:21
Sample: 1 9
Included observations: 9
Weighting series: FEET

        Variable        Coefficient   Std. Error   t-Statistic    Prob.

            C           0.097227     0.270682     0.359192     0.7300
            X           1.522205     0.118512     12.84436     0.0000

                            Weighted Statistics

R-squared               0.995791   Mean dependent var       3.937165
Adjusted R-squared      0.995190   S.D. dependent var       6.769977
S.E. of regression      0.469513   Akaike info criterion    1.518890
Sum squared resid       1.543099   Schwarz criterion        1.562717
Log likelihood         -4.835004   F-statistic              164.9777
Durbin-Watson stat      1.996170   Prob(F-statistic)        0.000004

                           Unweighted Statistics

R-squared               0.539066   Mean dependent var       6.920733
Adjusted R-squared      0.473219   S.D. dependent var       7.645402
S.E. of regression      5.549010   Sum squared resid        215.5406
Durbin-Watson stat      1.794416
```

Unweighted Regression Results

```
Dependent Variable: COST_FOOT
Method: Least Squares
Date: 10/14/99   Time: 12:19
Sample: 1 9
Included observations: 9

       Variable          Coefficient    Std. Error    t-Statistic    Prob.

          C               -2.152326      3.269131     -0.658379     0.5313
          X                1.601128      0.490984      3.261061     0.0138

R-squared                  0.603051   Mean dependent var          6.920733
Adjusted R-squared         0.546344   S.D. dependent var          7.645402
S.E. of regression         5.149481   Akaike info criterion       6.308799
Sum squared resid          185.6201   Schwarz criterion           6.352627
Log likelihood            -26.38960   F-statistic                 10.63452
Durbin-Watson stat         2.069452   Prob(F-statistic)           0.013844
```

Regression Results with the Number of Feet of 2-inch Mains Doubled; Weighted with the Square Root of Feet of Mains

```
Dependent Variable: COST_FOOT
Method: Least Squares
Date: 10/15/99   Time: 10:22
Sample: 1 9
Included observations: 9
Weighting series: FEET_2SQRT

       Variable      Coefficient   Std. Error   t-Statistic    Prob.

          C           0.820698     0.502884     1.631982      0.1467
          X           1.179847     0.195829     6.024887      0.0005

                        Weighted Statistics

R-squared              0.968977   Mean dependent var     4.130200
Adjusted R-squared     0.964545   S.D. dependent var     5.143765
S.E. of regression     0.968539   Akaike info criterion  2.967073
Sum squared resid      6.566470   Schwarz criterion      3.010901
Log likelihood        -11.35183   F-statistic            36.29927
Durbin-Watson stat     2.427820   Prob(F-statistic)      0.000529

                       Unweighted Statistics

R-squared              0.554698   Mean dependent var     6.920733
Adjusted R-squared     0.491084   S.D. dependent var     7.645402
S.E. of regression     5.454104   Sum squared resid      208.2307
Durbin-Watson stat     1.924127
```

Regression Results with the Number of Feet of 2-inch Mains Doubled; Weighted by Feet of Mains

```
Dependent Variable: COST_FOOT
Method: Least Squares
Date: 10/15/99   Time: 10:24
Sample: 1 9
Included observations: 9
Weighting series: FEET_2DBL

        Variable        Coefficient    Std. Error    t-Statistic    Prob.

           C            0.079154       0.238693      0.331613       0.7499
           X            1.526484       0.114716      13.30669       0.0000

                            Weighted Statistics

R-squared               0.998737    Mean dependent var      3.615110
Adjusted R-squared      0.998556    S.D. dependent var      7.443445
S.E. of regression      0.282834    Akaike info criterion   0.505220
Sum squared resid       0.559967    Schwarz criterion       0.549048
Log likelihood         -0.273490    F-statistic             177.0679
Durbin-Watson stat      2.012431    Prob(F-statistic)       0.000003

                           Unweighted Statistics

R-squared               0.538792    Mean dependent var      6.920733
Adjusted R-squared      0.472905    S.D. dependent var      7.645402
S.E. of regression      5.550663    Sum squared resid       215.6690
Durbin-Watson stat      1.792659
```

Input Data

obs	COST_FOOT	X	FEET	FEET_SQ	FEET_2DBL	FEET_2SQRT
1	2.209500	1.000000	784916.0	885.9549	784916.0	885.9549
2	3.128900	2.000000	10528812	3244.813	21057624	4588.859
3	1.970900	3.000000	431511.0	656.8950	431511.0	656.8950
4	6.416700	4.000000	3373749.	1836.777	3373749.	1836.777
5	1.063300	5.000000	6015.000	77.55643	6015.000	77.55643
6	6.866400	6.000000	661535.0	813.3480	661535.0	813.3480
7	8.061300	8.000000	96603.00	310.8102	96603.00	310.8102
8	6.402900	10.00000	12265.00	110.7475	12265.00	110.7475
9	26.16670	12.00000	6.000000	2.449490	6.000000	2.449490

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

In the Matter of	)	
Rate Application by	)	Case No. 99-070
Western Kentucky Gas Company	)	

Testimony of Carl G. K. Weaver
Appearing on behalf of the Office of
The Attorney General for the Commonwealth of Kentucky
Utility and Rate Intervention Division

October 18, 1999

BEFORE THE
PUBLIC SERVICE COMMISSION
COMMONWEALTH OF KENTUCKY

Testimony of
Carl G. K. Weaver
in the Matter of:

Rate Application by
Western Kentucky Gas Company, Inc.

Case No. 99-070

Q. Please state your name, address and occupation.

A. My name is Carl Weaver. My address is 4713 Wengers Mill Road, Linville, Virginia 22834. I am an emeritus professor of finance at James Madison University. In addition, I am a visiting professor at Washington and Lee University for this Fall Semester, 1999.

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

A. The purpose of my testimony is to present the results of a study of the cost of equity capital for Western Kentucky Gas Company, Inc. (WKGC). I will also examine the effect on the risks to equity that results from the adoption of the projected test year.

Q. Have you provided a description of your qualifications to perform these tasks?

A. Yes. It is included as Appendix I of this testimony.

Q. Have you prepared an exhibit to support your testimony?

A. Yes. It was prepared by me, and it is included as a part of this testimony.

Q. Dr. Weaver, before you begin your analysis of the cost of equity, would you please explain the concept of the cost of capital and the methods you used to determine the cost of equity.

A. The concepts of the cost of capital; risk, as it relates to the capital market; and the methods for determining the cost of equity are discussed in Appendix II of this testimony.

Q. What economic principles are mandated for determining the cost of capital for regulated utilities?

A. The economic principles for determining the cost of capital for regulated utilities have been set forth in the Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923), and F.P.C. v. Hope Natural Gas Co., 302 U.S. 591 (1944), Supreme Court decisions. The Court, in the Bluefield case stated:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

In the Hope case the Court stated:

> . . . It is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock . . . . By that standard, the return to the equity owner should be commensurate with the return on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

These principles have been confirmed in Permian Basin Area Rate Cases, 390 U.S. 747 (1968) and Federal Power Comm. v. Memphis Light Gas & Water Division, 411 U.S. 458 (1973).

Q. Dr. Weaver, how do you interpret these economic principles?

A. From a financial perspective, these U.S. Supreme Court decisions set forth three interrelated criteria that a regulatory determined rate of return should meet. First, the return should be comparable to the return that is earned by other companies that have similar risk. Second, the return should enable the regulated utility to obtain funds from the capital market at a cost commensurate with its risk. Third, the return should be sufficient to preserve the financial integrity of the company.

Q. How do your findings assure compliance with your interpretation of those economic principals?

A. I have selected methods for determining the cost of equity that rely on the "opportunity cost principal" and data from the capital market for Atmos Energy Corporation (Atmos), the owner of WKGC, and for companies similar to Atmos. WKGC is a division of Atmos. The reliance on the opportunity cost principal assures compliance with my interpretation of the requirements of Bluefield and Hope.

Q. Would WKGC have the same risk as Atmos since it is a division of Atmos?

A. No it would not. A forecasted test-year is being used to determine the rates for WKGC in this proceeding. The use of a forecasted test-year reduces the equity risk associated with the earnings of the WKGC division.

Q. How does the use of a forecasted test-year reduce the equity risk?

A. A forecasted test-year reduces equity risk in several ways. Some of the risk reduction benefits include:

- WKGC is using a test year that incorporates all foreseeable changes in the rate base, operating income, and the cost of capital.
- The foreasted test-year assumes a reduction in risk because it uses less leverage.
- The forecast period extends over a time horizon that is long enough to permit the new rates to go into effect near the beginning of the test-year and this will permit the majority of the change in the rate base, operating income and cost of capital to be factored into rates.
- WKGC will be able to file an application for a change in rates in anticipation of a decline in the rate of return before it occurs.
- WKGC will have more stable interest coverage ratios and a smaller variance of coverage.
- WKGC's earnings to Atmos will be more predictable and, since WKGC is one of Atmos' five major gas distribution company divisions, this will reduce the risk of Atmos.

Q. What is the opportunity cost principal?

A. The opportunity cost principal is based on the fact that, in the capital market, investors have numerous alternatives in which to invest. It recognizes that investors either directly or indirectly consider the prospective risk and return opportunities that are available from each investment alternative. Investors, after comparing their alternative investment opportunities, will choose those investments which are expected to have the highest level of expected return for a given level of potential risk.

Q. How will the use of a forecasted test-year affect the opportunity cost principal?

A. If Atmos risk is reduced because of WKGC's use of a forecasted test-year, the company could be in a lower risk class with respect to its required return. Consequently, its required rate of return at its lower level of risk will also be lower.

Q. How does the opportunity cost principle work to assure that the cost of equity meets the comparable earnings mandate that you described earlier?

A. The first Bluefield and Hope mandate requires that the regulated company's return be comparable to the return earned by other companies that have similar risk. In the capital market, investors continuously compare the expected returns and risks of investment alternatives to make their purchase and sell decisions. The purchase and sell decisions affect the supply and demand for securities, which, in turn, causes stock prices to rise or fall. As a result, stock prices reflect the return and risk expectations of a single investment opportunity relative to all other investment opportunities that exist in the capital market. Comparability of earnings automatically occurs from the use of cost of equity determination models that are implemented with stock price data.

Q. How does the use of the opportunity cost principal assure compliance with the financial integrity principal?

If a firm's return was so low that it could not pay its expenses when due, it would be more risky, and investors would not purchase that company's stock. Its stock price would fall, with all other factors remaining the same, causing its cost of capital to be considerably higher than the cost of capital for other firms. In regulation, the increased cost of capital would result in a higher return and higher rates. This would increase revenues and improve the regulated company's financial integrity. Once again, the use of stock price data from both the individual company and a group companies in a cost of equity determination model assures that financial integrity will be maintained.

Q. Please explain the relationship of the opportunity cost principal with the capital attraction mandate.

A. In the capital market, each firm is in competition with other firms to obtain capital at the lowest cost. Since the cost of equity rate is determined from the price that investors have been shown to be willing to pay for a security, it reflects the capital market's cost rate for attracting capital.

Q. You stated you used stock market data for Atmos and for companies that are similar to Atmos. How many companies did you use in your analysis?

A. I used data from four companies. These companies were Energen Corporation, Laclede Gas Company, New Jersey Resources Corp., and Piedmont Natural Gas Company. The use of capital market price data from Atmos and from the four companies causes the results to be in compliance with the Bluefield and Hope mandates that the return (1) be comparable to the return earned by other firms with similar risk, (2) preserve the firm's financial integrity, and (3) enable it to attract capital.

Q. Dr. Weaver, what cost of equity determination methods did you use in this analysis?

A. I used the discounted cash flow (DCF) technique, the Capital Asset Pricing Model (CAPM), and the bond-yield-plus-risk-premium approach (bond-risk-premium). These methods are discussed in Appendix II to this testimony.

Q. What capital market data does the DCF method use to conform to the opportunity cost principle?

A. The DCF method incorporates stock prices by requiring the dividend yield as one of the two components of the model. The dividend yield is determined from stock price data taken from the capital market. It is calculated as the expected dividend amount divided by the stock price.

Q. What capital market data does the CAPM require?

A. All of the data used by the CAPM comes from the capital market. The model's measurement starts with the risk-free interest rate that is observed in the capital market. The interest rate on government bonds or bills is usually used as a proxy for this risk-free rate. An equity risk-premium is added to the risk-free rate. This premium is determined as the average risk premium charged by equity securities in the capital market. This average premium is then adjusted to reflect the risk-premium of the company being evaluated. This is done by multiplying the market risk premium by Beta. The specific company's equity risk-premium, when added to the risk-free rate, indicates the cost of equity.

Q. Please explain how the bond-risk-premium method complies with the opportunity cost principal.

A. The bond-risk-premium method estimates the cost of equity by adding an equity risk premium to an interest rate. The interest rate is directly observed in the capital market. I measure the risk premium by subtracting the equity returns earned by the companies from long-term Treasury bonds. This provides a risk premium that can be added to current and forecasted long-term Treasury bond rates. The cost of equity provided by this method, since it uses the actual risk premiums measured in the capital market, complies with the opportunity cost principal.

Q. What steps did you take in your cost of equity analysis?

A. I first selected similar companies to use for the analysis. Next, I examined economic data to gain information about the current levels of capital market costs. I then implemented the DCF, CAPM, and the bond-risk-premium models to obtain information about the cost of equity. I also examined the effect of using a forecasted test-year on risk before I made my final determination about the cost of equity for WKGC. When I made the final determination for WKGC, I took its lower risk from use of a forecasted test year into consideration.

Q. Please describe how you selected the four companies that you used in this analysis.

A. I examined the risk measures for the companies and compared the risk of these companies to the risk of Atmos. The measures that were used to select similar companies were the common equity ratio, net sales to total assets, total asset size, the rate of increase in total assets in 1998, and total liabilities to total assets. I then examined other data to obtain additional information about the risks of Atmos and the four companies. The other data that I examined were the capital structure ratios, cash flow ratios, Standard and Poor's risk assessment measures, and Value Line assessment measures.

Selection of Companies and Risk Analysis

Q. Dr. Weaver, what steps did you use to select the companies you used for this analysis?

A. The data that I used to meet the selection criteria for the companies is shown in Schedules 1 - 4 of my Exhibit and summarized on Schedule 5. I started with the twenty four investor owned gas distribution companies that are listed in Value Line. I reduced the number of companies in four general steps.

1st- I used Atmos' 1996-98 average of the common equity ratio of 52.9% and selected all companies that had a common equity ratio within +/- 7.5% of Atmos. There were sixteen companies other than Atmos that had common equity ratios in this range. Schedule 1 in the exhibit provides the common equity ratio data. I eliminated Keyspan which was formed in May 1998 by a merger of Brooklyn Union and Long Island Lighting. It is a combination electric and gas company.

2d- I next examined the market service area that is reported by Value Line for the fifteen remaining companies. I eliminated AGL Resources, Peoples Energy Corporation and Washington Gas Light because the service area for these companies are concentrated in Atlanta, Chicago and Washington, D.C. -- all urban areas, far different from the service area of Western Kentucky.

3d- I examined the sales to total assets for the twelve companies that remained. This ratio reports the dollars of sales per dollar invested in assets. The inverse of this ratio, assets to sales, is sometimes used as a measure of operating leverage because generally, the more assets a company uses to produce sales, the more fixed costs it has. Companies that have similar sales to fixed costs could be expected to have similar operating leverage. Atmos has a sales to total assets ratio of 82% which can be interpreted as sales of $0.82 per $1.00 of assets. I eliminated Northwest Natural Gas Company whose sales to total assets ratio was 30% and South Jersey Industries, Inc. that had a ratio of 55%.

4th Last, I examined the size of the remaining ten companies as measured by the dollar value of the total assets. These are reported on Schedule 3. Atmos, in 1998, had total assets in the amount of $1,141,390. I selected all companies whose total assets were between $750,000 and $1,250,000. These bands caused Providence, Cascade, CTG, NICOR, and Connecticut Energy to be eliminated. In addition, NUI was eliminated because it had negative total asset growth between 1997 and 1998.

Four companies remained. These were: Energen, Laclede, New Jersey Resources, and Piedmont. I examined the total liabilities to total assets for these companies and they were in a range between 62% and 67% -- close to Atmos' ratio of 68%.

Q. Please summarize the selection measures for the four companies.

A. Schedule 5 provides a summary of the selection measures. The measures for Atmos are shown on the bottom line of that schedule.

The average measures for the selected companies are close to the corresponding measure for Atmos. Recall that Atmos had an average common equity ratio of 52.9%. The average common equity ratio for the four companies was 51.8%. Atmos has $0.13 more in sales per dollar of total assets than do the four companies; its 1998 total assets, in thousands, was $1,141,390 compared to an $967,616 average amount of total assets for the four companies. Atmos total assets increased by 4.9% from 1997 and 1998 while the total assets for the four companies increased by 7.1%. The total Liabilities to total assets was 68% for Atmos and 65% for the four companies. The average of the selected companies data is sufficiently close to Atmos to cause the results to meet the comparable risk standard of *Bluefield* and *Hope*.

Q. What are the risk implications of these measures?

A. These measures indicate that Atmos has close to the same amount of risk as the selected companies.

Q. What other risk measures did you examine?

A. I examined the capital structure, the cash flows, and published risk measures from Standard and Poor's and Value Line.

Capital Structure

Q. Please discuss the comparison of Atmos' capital structure with the capital structure for the selected companies.

A. The total capitalization for Atmos is shown on Schedule 6 and the capital structure ratios are shown on schedule 7. The 1968 common equity ratios in Schedule 7 are different than the common equity ratios shown on Schedule 3 because the ones in Schedule 7 include the current portion of long-term debt and short-term debt as a part of the capitalization.

Total leverage includes short-term debt, long-term debt and preferred stock. All three have fixed capital service payments -- interest for debt and preferred dividends for preferred stock. These fixed capital service payments, with the exception of preferred dividends, are a contractual obligation and must be paid, regardless of the level of earnings. As a practical matter, preferred dividends must also be paid or the issuing company will have difficulty obtaining new funds from the capital market.

The fixed charge items in the capital structures are sufficiently alike so that the selected companies will have similar risk from financial leverage. Atmos has 58.5% fixed capital service payment financing (long-term debt, short-term debt, and preferred stock) as compared to 54.9% for the four companies. Atmos has nearly the same amount of short-term debt and more long-term debt but no preferred stock. Atmos, having more fixed charge capital, has somewhat more financial risk than the four companies.

Cash Flow Analysis

Q. Dr. Weaver, would you explain your cash flow analysis?

A. I evaluated cash flow ratios for the years 1997 and 1998. These ratios dealt with the cash flow coverage of interest, total dividends, investing activities, and net income. The data was taken from Compact Disclosure.

Q. Did you use the same cash flow ratios that are used by Standard & Poor's?

A. No. Standard and Poor's excludes changes in working capital accounts in its calculation of the amount of cash available for covering interest, debt, or new plant. The coverage ratios that I use are calculated from "cash flow from operating activities" that is defined by FASB 95.

The exclusion of working capital may be inconsequential when only minor changes occur in the current asset or liability accounts. When large changes occur, however, the amount of cash available for coverage would be either over- or under-stated unless accounted for in the cash flow statement. For this reason, the coverages calculated according to FASB 95 provide better information for the analysis.

Q. Where do you show the cash flow coverages for Atmos and for the four gas distribution companies?

A. Data for the individual companies is shown on Schedules 8 through 12. A summary of the cash flow coverages for Atmos and the four gas companies is shown on Schedule 13.

Q. What does the cash flow coverage of interest indicate?

A. The cash flow coverage of interest expense indicates how many times cash flow from operating activities covers interest. A low ratio would indicate a greater risk that the firm would have difficulty making its contractual interest payments. A higher ratio would indicate less risk. The stability of the cash flow is also important. A company with a very stable cash flow could have a smaller coverage and still be less risky than a company with a larger coverage but a cash flow that has considerable variability.

Q. How does Atmos' cash flow coverage of interest compare to the four companies' coverage?

A. The cash flow coverage of interest expense was determined by adding interest expense back to cash flow from operating activities and this amount was then divided by total interest expense. The average company in the four company group had a 4.02 times coverage and Atmos' cash flow coverage of interest was 3.31 times.

This coverage indicates that neither Atmos nor the four companies have much risk from their use of leverage. Atmos' cash flow from operating activities would have to fall by more than 231% before there would be insufficient cash flow to make all of its interest payments. For the four companies as an average, the cash flow from operating activities would have to fall by 302%. In either case, cash flow would have to decrease substantially before there would be any risk of having insufficient cash flow to make interest payments. Of note, these coverages occurred during years in which the winter heating months were unusually mild. There was good coverage even under the adverse circumstances of lower than average gas sales.

Q. Please proceed to discuss the cash flow coverage of total dividends.

A. The cash flow coverage of dividends shows the number of times that internally generated cash flow covers the amount of total dividend payments. A company with a low coverage might be in danger of having to reduce or even eliminate a dividend payment.

Q. What is the cash flow coverage of the common dividends?

A. Atmos' cash flow of dividend coverage averaged 2.74 times and the four company group averaged 3.19 times. There is little risk of a dividend reduction.

Q. What does the cash flow coverage of investing activities represent?

A. The cash flow coverage of investing activities indicates how many times cash flow from operating activities cover long-term investments in plant and other assets. A ratio greater than 1.0 indicates that internally generated funds are sufficient to cover investments if there were no dividend payments or payments to cover maturing financial assets. When the coverage after dividends and maturities exceed the proportion of equity in the capital structure, the company can perform external financing with debt and not have its capital structure equity ratio decline.

The higher the coverage, the less likely the company will be forced to seek substantial external financing to acquire assets. Therefore, a high ratio indicates greater protection from the vagaries of the capital market.

Q. What were the cash flow coverages of investing activities?

A. Atmos' cash flow coverage of investing activities averaged .67 times as compared to 1.03 times for the four gas distribution companies.

Q. What does this indicate?

A. This shows that, since this measure exceed the equity ratios, both Atmos and the four companies would be able to maintain the current debt ratios without external equity financing if there were no dividend payments or debt maturities. For the four companies, there is little risk associated with having to acquire external equity capital for financing fixed assets acquisitions. Internally generated cash flow is sufficient to provide the equity component of the investments in fixed assets. However, Atmos, with a lower coverage, has a greater likelihood of having to perform external equity financing than the four companies.

Q. **What does the cash flow coverage of net income indicate?**

A. The cash flow coverage of net income is a measure of the quality of earnings. It represents the number of dollars of cash flow from operating activities per dollar of net income reported on the income statement.

Q. **What did you find about this coverage measure?**

A. Atmos' coverage measure averaged 2.27 times while the coverage measure for the four companies averaged 2.35 times.

Q. **What does this indicate?**

A. This indicates that both Atmos' and the four companies' reported net income are of high quality. Atmos, with $2.27 in cash flow for each $1.00 of reported Net Income has a very high quality of reported net income.

Q. **What do you conclude about the cash flow coverage measures?**

A. The cash flow measures indicate that, from a cash flow perspective, Atmos has a little more risk than the four company group. This risk difference is caused by Atmos' smaller interest and dividend coverage, and its greater potential to be required to perform external equity financing for investing activities.

Published Risk Measures

Q. What published risk measures did you examine?

A. The published risk measures are shown in Schedule 14 and 15 of my Exhibit. The comparative measures that I examined were the Standard & Poor's risk evaluation, beta, and Relative Strength and the Value Line Safety Rating and beta.

Q. Why did you examine published risk measures?

A. Many investors rely on published risk measures to make their stock purchase and sell decisions. These measures provide additional information for comparing the risks of the selected companies to the risk of Atmos.

Q. You show both Standard and Poor's and Value Line betas. What is Beta?

A. Beta is a measure of systematic risk; that is, risk that is common to all companies. Systematic risk could be caused by something like a change in the rate of inflation, or a political event, a war, or a change social-economic conditions. Obviously, some companies have greater exposure to the occurrence of any single event than other companies and they have more systematic risk. Systematic risk is caused by an event that affects all companies to some degree but not necessarily the same degree.

Beta is measured from the company's stock sensitivity to general changes in stock market prices. A beta that equals 1 would represent an average company whose stock price changes are nearly identical to the market. These companies are said to have average systematic risk. Companies that are less risky have Betas less than one and companies that are more risky have Betas greater than one.

Q. What are the Betas for the four gas distribution companies?

A. The Betas for the four companies are shown in the center column on Schedules 14 and 15. The S&P Betas for the four companies average .46 versus an S&P beta for Atmos of .18. The Value Line Betas, on Schedule 15, average .61 for the four companies and .55 for Atmos.

Q. In general, what do these Betas for the gas distribution companies indicate?

A. The four gas distribution companies have about half as much systematic risk as an average company. Atmos' beta is slightly lower than the average for the selected companies indicating that it has even less systematic risk.

Q. Would you continue by describing the Standard and Poor's risk evaluation?

A. The S&P risk rating reports the volatility of the stock's price over the past year. Companies whose stock prices are more volatile are perceived to be more risky.

All of the four gas distribution companies's stocks have low volatility. This indicates that these companies are perceived to be less risky than an average company.

Q. What is the S&P relative strength rank and what does it show?

A. The S&P relative strength rank reports, on a scale of 1 to 99, how the stock has performed relative to the other companies that S&P follows. The stocks of the four companies are ranked between 23 and 79. The average ranking for the four companies is 41. This indicates that the four, as a composite, have performed a little poorer than an average company. Atmos is ranked as having a lower relative strength rank than the four companies. Its ranking is 22.

Q. You show a Value Line safety rank. What is this measure?

A. The Value Line Safety Rank is a combination of the Value Line's Financial Strength rating and the Value Line's Stock Price Stability Rating.

Q. What do the Financial Strength and Stock Price Stability ratings indicate?

A. Value Line analysts assess the financial leverage, business risk, company size, and other factors for each of the approximately 1,700 companies that they follow. The result of this assessment is the Financial Strength rating.

The Stock Price Stability Index is based upon a ranking of the standard deviation of weekly percent changes in the price of a stock over the last five years. The top 5% are assigned an index value of 100, the next 5% an index value of 95, and so forth.

Q. How are these combined into a Safety Rating?

A. The approximately 1,700 companies are classified into five groups. Group 1 contains companies that are the safest. The companies in group 5 are the least safe.

Q. What is the Safety Rating for the four gas distribution companies?

A. Three of the four companies have a rating of "2" and one has a rating of "1". The rating "2" represents a safer than average or a below average risk rating and the rating of "1" is in the safest 20% of the companies that Value Line follows. Atmos rating is also a "2" which means that they are in the top 40% group.

Q. What do you conclude from your analysis of the published risk indicators for the four companies?

A. The published market measures indicate that the four companies are less risky than an average company. This indicates that the cost of equity for these companies should be lower than the cost rate for an average company. Since Atmos is similar to these four companies, it also is less risky than an average company. Its cost of equity will also be lower than the cost for an average company.

Risk Analysis Summary

Q. Dr. Weaver, please summarize your risk analysis.

A. The four companies in the gas distribution industry that were selected for this analysis have about half as much risk as an average publicly held company. This is indicated by published risk measures, Betas, and cash flows.

Atmos, prior to considering the forecasted test-year, is similar to these companies but it is somewhat more risky than the four companies. Its published risk analysis was similar all but its relative strength rank. This measure for Atmos indicates more risk. Also, it is a little more risky from its greater use of financial leverage and from its lower cash flow coverages.

The use of the forecasted test-year in this proceeding mitigates that risk. The forecasted capital structure contains less debt leverage than the amount used by the four companies. Atmos' beta as measured by both Standard and Poor's and Value Line is lower than the Beta of the four companies. This offsets some more of the differences in risk. I conclude that Atmos is less risky than the four companies.

The Economic Environment

Q. Dr. Weaver, what economic measures did you consider in your review of present and perspective economic conditions?

A. I considered the business cycle as measured by Gross Domestic Product (GDP), the inflation rate as measured by the Consumer Price Index (CPI), interest rates, and forecasts of economic measures.

Q. What measure of the business cycle did you examine?

A. I examined the percentage real rate of change in GDP. This measure provides the rate, in inflation adjusted values, at which the final output of goods and services are consumed in our domestic economy. Positive values indicate a growing economy and negative values indicate a declining economy.

The rate of economic growth provides a mixed message for investors. Too high a growth rate could be inflationary. The inflation would be caused by the demand for goods and services outstripping the supply. A negative growth indicates recession. An ideal growth rate is in a range from 2% to 4%. The real change in GDP has been in this range since 1992.

Q. What did you find?

A. The data is provided in Schedule 16. This Schedule shows the real rate of change in GDP since 1976. During this period, there have been three downturns in economic activity during this period; in 1980, in 1982, and in 1991. Since 1992, our economy has been growing at a rate between 2.3% and 3.9%. Schedule 17 provides the Value Line forecast for the expected change in GDP through 2003. This forecast indicates that the growth in the economy over the next five years is expected to be similar to the growth of the previous five years and be in a range between 2.3% and 3.8%.

Q. What do the measures show about inflation?

A. Schedule 16 also shows the percentage change in the CPI for the period 1976 through 1998. Since 1992, the rate of change in the CPI has been at 3% or below. Schedule 17 shows that the rate of inflation is expected to be 2.8% in 1999, and below that for the years 2000 through 2003.

Q. Please discuss the interest rate data that you examined.

A. Schedule 18 shows Moody's Public Utility Bond Yields since 1980. This schedule provides the annual average rates from 1980 through 1998 and monthly average rates for January through July, 1999 and August, 1999 month-to-date. So far in 1999, the rates for A rated utility bonds have ranged from a low of 6.97% in January to a high of 7.87% in August.

The interest rates have risen from January to August, 1999 but the yield spread has narrowed. The spread between Aaa rated and Baa rated bonds was 89 basis points in January, 1999 and it has been consistently narrowed in each successive month except between May and June. In August MTD the spread was 61 basis points. Investors are not demanding and receiving a consistently larger risk premium for riskier-lower rated bonds. This indicates that the rise in interest is a result of monetary policy rather than a change in investor confidence.

In contrast, consider 1984, when the growth rate of the economy was 6.2%, a rate at which some analyst thought could kindle inflation, the spread was larger in this year. It ranged from 12.72% to 14.53%, a spread of 181 basis points. A low yield spread generally indicates a high level of investor optimism and a high yield spread indicates pessimism..

Q. What does the forecast for interest rates indicate?

A. Schedule 19 shows the forecast for 3-month Treasury Bills and 10-year Treasury Bonds through the year 2003. The forecast for the Bills indicates that short-term rates are expected to be near the same rate as they have been in the previous five years. Longer-termed rates, as indicated by the Bonds, are expected to be 114 basis points lower over the five year forecast period. The average 10-year T-bond rate for 1994 through 1998 was 6.70% and the average for the five year forecast is 5.56%.

Q. What do you conclude from this analysis?

A. The expected economic growth, inflation, and level of interest rates should permit capital costs rates to remain at or near the existing low levels. The forecasts reflect continued investor optimism and imply that cost of equity rates are expected to be relatively low and remain low for the next five years.

Part Five: Cost of Equity

Q. Dr. Weaver, you stated earlier that you use the DCF, the CAPM method, and the Bond-Yield-Risk-Premium methods. Which method for estimating the cost of equity will you discuss first?

A. I will discuss and present the DCF results first. This will be followed by the CAPM results. The Bond-Yield-Risk-Premium confirmation will follow this.

Q. What is required to implement the DCF method?

A. The DCF method requires an estimate for growth in dividends and market price appreciation, and a dividend yield.

Q. How did you determine the growth estimate for use in the DCF model?

A. There are a variety of ways to estimate the rate of growth for dividend and market price appreciation. These include using analysts' forecast of earnings growth or using historical data to extrapolate growth based what happened in the past. The use of a variety of measures for estimating growth are discussed in Appendix II. I will discuss the historical growth rates first.

Q. What historical growth rates did you use?

A. I used growth rates for earnings per share (EPS), dividends per share (DPS), and book value per share (BVS) from Value Line. The historical growth rates are shown in Schedule 20 of my exhibit. The growth rates for Atmos and for the four company group are similar for all three of these measures. EPS was 4.5% and 4.8% for the four companies; DPS was 4.0% for Atmos and 4.1% for the four companies; and BVS was 4.5% for Atmos and 5.0% for the four companies.

Q. What analysts' forecasts did you use?

A. I used two sources of data for obtaining the growth forecasts, I/B/E/S and Value Line. I obtained the I/B/E/S estimates from Compact Disclosure and the Value Line from their published company reports.

Q. How are these forecasts compiled?

A. I/B/E/S does monthly surveys of security analysts' and averages the estimates. Value Line employs in-house analysts who make three to five year forecasts for revenues, cash flow, EPS, DPS, and BVS.

Q. What were the projected growth rates?

A. The growth forecasts are shown Schedule 21. The average I/B/E/S EPS growth rate over the next five years is projected to be 8.1% for Atmos and 5.6% for the four companies. Value line forecasts for EPS, DPS, and BVS for Atmos are projected to be 11.5% 4.5% and 8.5%. The same values for the four companies are: 6.9%, 3.4%, and 6.5%.

A summary of the growth rates follows:

Analysts' Forecasts

Source	Atmos	Four Companies
I/B/E/S:	8.1%	5.6%
Value Line		
EPS	11.5	6.9
DPS	4.5	3.4
BVS	8.5	6.5
Value Line Average	8.2	5.6

Historical Data

	Atmos	Four Companies
EPS	4.5	4.8
DPS	4.0	4.1
BVS	4.5	5.0
Average	4.3	4.6

Q. **How do you interpret these measures?**

A. The historical results are an indication of the current period's economic stability. The historical growth rate for Atmos was 4.3% and for the four companies, it was 4.6%. The average of the forecasts done by Value Line was very close to the forecasts compiled by I/B/E/S -- for Atmos it was 8.1% and 8.2%, and for the four companies it was 5.6% for both I/B/E/S and Value Line. Atmos' growth estimate is 2.6 percentage points higher than the growth estimate for the four companies.

Q. **How do you use these data to determine a growth rate in the DCF model for determining the cost of equity**

A. I use these measures in the DCF model and estimate a range of values. I use this range to provide information for determining the cost of equity. I do not depend solely on this information to augment my judgement about the cost of equity. I also use information obtained from the CAPM and the bond-yield-risk-premium method when making my recommendation.

Q. **What data did you use to calculate the dividend yield?**

A. The dividend yield was calculated by dividing the current annual dividend rate by the average stock price for August 23 through September 3, 1999. The annual dividend rate was determined by multiplying the most recent quarterly dividend amount by four. Schedule 22 shows the calculation of the dividend yield. The dividend yield was calculated for each of the four gas distribution companies and then it was averaged. The average dividend yield for the four companies in the sample was 4.53%. For Atmos, it was 4.45%.

Q. Why did you use the dividend rate rather than the actual amount of dividends paid the previous year to calculate the dividend yield?

A. Dividends are paid quarterly. The rate, based on the latest quarterly amount, is higher and compensates for not compounding the dividends on a quarterly basis.

Q. How did you apply the dividend yield to the DCF model?

A. The DCF model requires an expected divided yield rather than a historical dividend yield. The expected yield is determined by multiplying the current yield times one plus the growth rate. These are shown in the next to last column of Schedule 23. The adjusted dividend yields are added to the growth rates to form an estimate for the cost of equity.

Q. What do the DCF results show?

The unadjusted DCF results for Atmos average 8.98% using historical growth and 12.96% using forecasted growth. The unadjusted historical growth results for the four companies average 9.37% and it was 10.38% using forecasted growth.

Q. Dr. Weaver, did you make a flotation cost adjustment to dividend yields?

A. No, I did not. A flotation cost adjustment should not be used for this cost of equity determination because, according to the testimony of Mr. John Reddy, Vice

President and Treasurer of Atmos, the company plans a $26 million equity sale in November, 1999 but none beyond that other then through its Direct Stock Purchase Plan and Employee Stock Ownership Plan. Mr. Reddy discusses the financing plans on pages 5, beginning at line 14 through page 7, line 5. The November issue should be consummated prior to the hearing for this case.

Q. Did you make adjustments to the information provided by the analysis?

A. Yes. The filing in the case used a forecasted test year from January 1, 2000 to December 31, 2000. The use of a forecasted reduces the risk to Western Kentucky in two ways. First, the forecasted capital structure has less debt and more equity and second, it increases the likelihood that the actual return will be at least equal to the return that is authorized. This change in risk must be considered when making the final recommendation. However, before I made any adjustments, I also examined the CAPM and bond-yield-risk-premium information.

Q. You indicated that you also used the CAPM. What do these results show?

A. Schedule 24 shows the CAPM results for the selected companies and Schedule 25 shows the CAPM results for Atmos. As has been previously discussed, the CAPM requires a beta, a market return, and a risk-free rate. The Betas that I use are shown in Schedules 14 and 15. For market returns, I use the I/B/E/S and Value Line forecasts. I used a variety of interest rates as the risk free rate. The sources for the interest rates are shown on the second page of Schedule 24.

The various combinations of variables in the CAPM model result in 24 different estimates for the cost of equity. The average rate was 10.85% for the selected companies.

Its range was from a low value of 9.44% to a high value of 12.33%. The standard deviation of the 24 outcomes was 0.12%. The low standard deviation is the result of 17 of the 24 values being between 10.0% and 11.9%.

The CAPM results for Atmos, using the number of combinations, was 9.09% with a standard deviation of 1.58%. Its individual observations range from a low value of 6.43% to a high value of 11.09%. Only twelve of its twenty-four measures fall between 10.0% and 11.9%.

Q. **Dr. Weaver, why do you use so many combinations of data in the CAPM model?**

A. Recall that our purpose is to determine investor thinking regarding the values of the investment alternatives in the capital market. It is the investors in the capital market that determine the cost of equity capital when they make their buy and sell decisions. The various combinations of variables reflect the risk-free rate, market return, and Beta assumptions that investors might use in CAPM to estimate the cost of equity.

Q. **Dr. Weaver, what did the bond-yield-equity-risk-premium model show?**

A. An equity risk premium is required for this approach. I performed a study of the equity risk premium for the four gas distribution companies. To determine the risk premiums, I subtracted the realized returns on equity for the period 1989 through 1998 from the rate of return on long-term government securities. In this determination, I examined combinations of one-year, two-year, through nine-year holding periods. Schedules 26 through 31 shows how that study was made and it provides the results of that study. The four gas distribution company risk premium was 7.0%.

Q. **How did you use the risk premiums?**

A. I added this premium to the current and forecasted 10-year government bond rates to obtain an estimate for the cost of equity.

Q. What current and forecasted rates did you use?

A. I used three rates: a current 10-year government bond rate @ 6.4%; the 1999 and 2000 forecasted 10-year treasury bond rate @5.75%; and a long-term projected 10-year bond rate @ 5.40%.

Q. Where did you obtain these rates?

A. The current rate was obtained form the Federal Reserve Statistical Release on September 3, 1999. The forecasted rates are from the Congressional Budget Office "Update" published on July 1, 1999.

Q. What results did you obtain using these rates?

A. When the current bond rate of 6.4% is added to the 7.0% risk premium, the resulting cost rate is 13.4%. The forecasted 5.75% rate, when added to the risk premium results in a 12.8% rate. When the 5.4% long-term projected rate is used, the resulting cost estimate is 12.4%.

The range that contains the rates obtained using the bond-yield-risk-premium method is from 12.4% to 13.4% and its average is 12.9%.

Q. Please provide a summary of the results of the three methods.

A. The average results for the three methods for the selected companies and Atmos are:

	Selected Companies	Atmos
DCF - forecasted growth	10.38%	12.96%
DCF - historical growth	9.37%	8.98%
CAPM	10.85%	9.09%
Bond-Yield-Risk-Premium	12.90%	

Q. Dr. Weaver, what is the cost of equity for WKGC?

A. The cost of equity for WKGC is in the range from 9.75% to 10.75%. This cost of equity acknowledges that WKGC less risky than it was because of its use of a forecasted test year. First, the forecasted capital structure has about seven percentage points more equity and seven percentage points less debt. The smaller amount of leverage in the capital structure reduces the financial risk and the equity risk premium. Second, the use of a forecasted test-year provides a greater opportunity for the company to earn its authorized rate of return. Rates will go into effect near the beginning of the forecasted test-year and anticipated expenses have been incorporated into that test-year.

Three of the measures obtained from the analytical models are below the 9.75-10.75 range, one is in it and three are above it. One of the three measures that is above it is near the upper bound -- the 10.85% result.

The risk analysis indicated that Atmos was only a little more risky than the four companies that were selected for the analysis. WKGC, because of the reduction in risk from the use of the forecasted test year will be more similar to the four companies. The 9.75% - 10.75% range contains two of the outcomes found using the data from the selected companies. One outcome is below it and one is above it. It is the cost of equity that the WKGC division should be permitted to earn.

Q. Dr. Weaver, what capital structure did you use?

A. I used the thirteen month average capital structure for the period ending December 31, 2000. This is the capital structure determined by the company in the filing requirements. It contains 9.4% short-term debt, 40.4% long-term debt and 50.2% equity. The average capital structure at the end of the base year (September 30, 1999) has 42.7% equity as compared to 50.2% equity for the forecasted test-year. The reduction in debt reduces the risk of WKGC..

Q. What cost rates do you recommend for short-term and long-term debt?

A. I have examined the short-term debt rate of 6.1% and the long-term debt rate of 8.06% that the company has recommended. I have found that the cost of short-term debt should be 5.70%. This rate incorporates income from temporary investments. The 5.7% is the average effective cost rate for short-term debt for the period July, 1998 through June, 1999. These are shown in Schedule 33.

I calculated the yield to maturity for the long-term debt and found it to be close to the 8.06% that Company Witness John Reddy request be adopted as the cost of long-term debt (Page 7, pre-filed testimony).

Q. What did you find the cost of capital to be?

A. The cost of capital is in a range from 8.69% to 9.19%. This is the range for the rate of return that I recommend be used for determining the revenue requirement for WKGC.

Q. Dr. Weaver, does this conclude your testimony?

A. Yes.

AFFIDAVIT

The affiant, Carl G. K. Weaver, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared Direct Testimony of this affiant in Case No. 99-070, in the matter of: Rate Application by Western Kentucky Gas Company and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared Direct Testimony.

Affiant further states that he will be present and available for cross-examination and for such additional direct examination as may be appropriate at the hearing in Case No. 99-070 scheduled by the Commission, at which time affiant will further reaffirm the attached prepared testimony as his direct testimony in such case.

Carl G. K. Weaver

Commonwealth of Virginia)
)
County of Rockingham)

Subscribed and sworn to before my by Carl G. K. Weaver, this the 15th day of October, 1999.

My Commission Expires: 2-28-2000.

Barbara A Heatwole
Notary Public, Commonwealth of Virginia

Statement of Qualifications

for
Carl G. K. Weaver

Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I was with the Virginia State Corporation Commission from June, 1976, to August, 1979. This Commission has regulatory authority over public utilities, banks, insurance companies, railroads, and motor carrier transportation companies operating in Virginia. In July, 1977, I founded the Economic Research and Development Division at the Virginia SCC and became its first Director.

The Economic Research and Development Division was established to provide financial and economic support for other divisions of the Commission. Prior to founding it and becoming its first Director, I served the Commission as a public utility financial and economic analyst in the Public Utility Accounting Division.

During this time, I also was a lecturer in the Graduate School of Business Administration of the College of William and Mary. I taught a course in portfolio theory in the fall semester of 1977 and 1978, and in the spring semester of 1979.

I left the State Corporation Commission and joined the faculty of James Madison University in August, 1979. While at JMU, I worked with M.S. Gerber and Associates, Inc., a utility consulting firm. I participated in the development of the Financial Information Model and the Midas Model which is marketed by EPRI. I also served as

Director of JMU's M.B.A. program for the years 1993-1995. I retired at the end of June, 1998 and am an Emeritus Professor of Finance at JMU. I am also serving as an adjunct professor of finance at Eastern Mennonite University.,

Prior to joining the State Corporation Commission, I was an assistant professor of Finance at Virginia Commonwealth University from 1967 through 1976. I taught courses in financial management, investments, and decision mathematics. I received a leave of absence from V.C.U. from September, 1971, to June, 1973, to pursue and complete the course work for a doctoral degree at Florida State University. I was awarded the Doctor of Business Administration degree in June, 1975. I majored in finance and minored in statistics.

I was a field manager with Ford Motor Company prior to joining Virginia Commonwealth University. A large portion of the job activities consisted of performing financial analysis of dealers in an assigned zone and advising them in financial management so that they would be in a better position to represent Ford Motor Company and sell its products. Other duties included assisting dealers in negotiating financing arrangements. I was employed by Ford in 1964. My military service also provided me with financial experience. I was in the Finance Corps and spent the majority of my active duty at the Finance and Accounting Office at Fort Dix, New Jersey.

Q. DR. WEAVER, PLEASE SUMMARIZE YOUR EXPERIENCE AS AN EXPERT WITNESS.

A. The duties of the Economic Research and Development Division included providing financial and economic expert testimony before the Commission regarding fair rate of return and other matters. As director of the Economic Research and Development Division, I provided financial and economic expert testimony before the Virginia Commission. The topics of testimony included the cost of capital, capital structure, cash flow analysis, attrition, and sale and lease-back financing arrangements. I have also provided testimony before the Kentucky Public Service Commission and in other jurisdictions.

Q. PLEASE IDENTIFY THE CASES FOR WHICH YOU PROVIDED TESTIMONY.

A. I testified in twenty-two cases concerning utility matters before the Virginia State Corporation Commission. These cases and their topical areas are as follows: Virginia Electric and Power Company's application for approval for the financial arrangement for an office building in Case No. 19734; ex parte in regard to investigation of the fuel adjustment clauses of Appalachian Power Company, et al. in Case No. 19526; on attrition on Potomac Electric Power Company's application for an increase in rates in Case No. 19686; on rate of return in Appalachian Power Company's application for an increase in rates in Case No. 19723; on merger and rate of return in Norfolk and Carolina Telephone Company of Virginia's application for an increase in rates in Case No. 19727; on rate of return in General Telephone Company of Southeast's application for an increase in rates in Case No. 19778; on rate of return in Potomac Edison Company's application for an increase in rates in Case No. 19810; on cash flow analysis in Virginia Electric and Power Company's application for an increase in rates in Case No. 19730; on fuel adjustment clause in the investigation of Virginia Electric and Power Company's clause in Case No.

19818; on rate of return in Amelia Telephone Corporation's application for an increase in rates in Case No. 19891; on rate of return in Virginia American Water Company's application for an increase in rates in Case No. 19903; on rate of return in Clifton Forge - Waynesboro Telephone Company's application for an increase in rates in Case No. 19910; on rate of return in Virginia Pipe Line Company and Lynchburg Gas Company's application for an increase in rates in Case No. 19919; on rate of return in Shenandoah Telephone Company's application for an increase in rates in Case No. 19920; on rate of return in Roanoke Gas Company's application for an increase in rates in Case No. 19985; on rate of return in Columbia Gas of Virginia, Inc.'s application for an increase in rates in Case No. 19988; on rate of return in Washington Gas Light Company's application for an increase in rates in Case No. 19992; on rate of return in General Telephone Company of the Southeast's application for an increase in rates in Case No. 20003; on rate of return in Virginia American Water Company's application for an increase in rates in Case No. 20039; on rate of return in Old Dominion Power Company's application for an increase in rates in Case No. 20106; on rate of return in Virginia American Water Company's application for an increase in rates in Case No. 20177; and on rate to return in Virginia American Water Company's application for an increase in rates in Case No. PUE790021.

I presented testimony before the Commonwealth of Kentucky's Public Service Commission on CWIP in Louisville Gas & Electric Company's application for an increase in rates in Case No. 7799; on CWIP in Kentucky Utility Company's application for an increase in rates in Case No. 7804; on Union Light, Heat and Power Company's application for rate increase Case No. 8046 and Case No. 9029; on rate of return in

Louisville Gas & Electric Company's applications for an increase in rates in Case No. 8284, in Case No. 8616, in Case No. 8924; and in Case No. 10064; on rate of return in Kentucky Utility Company's application for an increase in rates in Case No. 8624; on Louisville Gas & Electric Company's continuance of construction on Trimble County Unit Number 1 in Case No. 9243, and on rate of return in General Telephone Company of the South's application for an increase in rates in Case No. 9678, on rate of return in Kentucky-American Water Company's application for an increase in rates in Case No. 89-348, on rate of return in Western Kentucky Gas Company's application for an increase in rates in Case No. 90-013, on rate of return in Union Light, Heat and Power Company's application for an increase in rates in Case No. 90-041, on rate of return in Louisville Gas and Electric Company's application for an increase in rates in Case No. 90-158, on rate of return in Union Light, Heat and Power Company's application for an increase in rates in Case No. 91-370, on rate of return in Union Light, Heat and Power Company's application for an increase in rates in Case No. 92-346, on rate of return in Kentucky-American Water Company's application for an increase in rates in Case No. 95-554, on rate of return in Delta Natural Gas Co., Inc.'s Case No. 97-066 and 99-046 which was merged into Case No. 99-176 and made a presentation on the cost of equity in the conferences held on Louisville Gas and Electric Company's and Kentucky Utilities Company's application for approval of an alternative method of regulation of its rates and services.

Also, I presented testimony in five cases before the Interstate Commerce Commission regarding cash flow analysis and rate of return. These cases were heard on

ICC Docket Numbers 37339F, 37354, 37322, 37507, I&S Docket Number 9242F, Case No. 37516, and Ex Parte hearing numbers 415 and 436.

In addition, I presented testimony in four cases before the Ontario Energy Board. These involved an accounting policy for Union Gas Limited's gas take-or-pay contract in E.B.R.O. 418, and rate design issues involving ICG Utilities, Ltd., Consumers Gas Company, Ltd., and Union Gas Limited in E.B.R.O. 410-2, 411-2, 412-2, 414-2, 429, and 430-1.

I testified in three cases before the Washington, D.C. Public Service Commission and one before the New Hampshire Public Service Commission involving the use of the Regulatory Analysis model (RAm) for analyzing regulatory policies and evaluating the economic feasibility of converting an oil-generating plant to coal. This testimony was presented in Case Numbers 715, 737, and 759 in Washington, D.C. and in Case No. DE80-175 in New Hampshire. I also testified in one case before the Oklahoma Corporation Commission on rate of return for Arkansas-Oklahoma Gas Company in Cause PUD No. 000079.

Q. WHAT OTHER WORK HAVE YOU DONE IN REGARD TO PUBLIC UTILITY REGULATION?

A. I served as a faculty member for the NARUC Annual Regulatory Studies Program held at Michigan State University in the summers of 1982, 1983, 1984, and 1985. I taught the sessions in public utility accounting and financial analysis at this institute.

I have also authored or co-authored the following articles which have appeared in the Public Utilities Fortnightly: "Cash Flow Statement and Risk Evaluation", published

February 15, 1990; "The Future of Competition in the Telecommunications Industry", published March 5, 1987; "Capital Structure Maintenance: A Challenge for Public Utilities", published September 4, 1986; "The Accelerated Cost Recovery System - A Catch 22?", published May 13, 1982; "A Resolution of the Rate Base Construction Work in Progress Controversy", published April 15, 1982.

In addition, I have presented papers to professional associations and have served on several panels in regard to regulatory matters.

VITA

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EDUCATION:

1975, D.B.A., Florida State University, Tallahassee, FL

1969, M.S., Virginia Commonwealth University, Richmond, VA

1964, B.S., Virginia Commonwealth University, Richmond, VA

EXPERIENCE:

September 1999 - Present	Visiting Professor Washington and Lee University
July 1998 - Present	Professor Emeritus James Madison University
August 1979 - June 1998	Professor of Finance James Madison University
January 1993- December 1995	Director of the MBA Program James Madison University
January 1981 - March 1989	Principal, M. S. Gerber & Associates, Inc., Columbus, OH; a utility company consulting firm.
May 1976 - August 1979	Director, Division of Economic Research and Development, Virginia State Corporation Commission, Richmond, VA
August 1977 - May 1979	Lecturer in Finance, College of William and Mary, Williamsburg, VA

August 1968 - March 1976	Assistant Professor of Finance, Virginia Commonwealth University, Richmond, VA
February 1964 - August 1968	Field Manager, Ford Marketing Division, Ford Motor Company.

MILITARY:

October 1959 - February 1962	Finance Corps., U.S. Army

PUBLICATIONS:

Articles (Refereed)

"Bond Ratings: A Poor Predictor of Equity Risk," Public Utilities Fortnightly, October, 1994.

"Risk Evaluation Using the FASB Cash Flow Statement," Public Utilities Fortnightly, February, 1990.

"The Future of Competition in the Telecommunications Industry," Public Utilities Fortnightly, March 1987, Co-author.

"Capital Structure Maintenance: A Challenge for Public Utilities," Public Utilities Fortnightly, September 1986, Co-author.

"The Accelerated Cost Recovery System - A Catch 22?," Public Utilities Fortnightly, May 1982, Co-author.

"A Resolution of the Rate Base Construction Work in Progress Controversy," Public Utilities Fortnightly, April 1982, Co-author.

"Systematic Risk Reduction through International Diversification," Review of Business and Economic Research, XV Fall 1979, Co-author.

"The Organized Options Market," Virginia Social Science Journal, 11, April 1976.

"Evaluation of Portfolio Performance Using a Paired Difference T-Test," Atlantic Economic Journal, IV April 1976, Co-author.

OTHER PUBLICATIONS

"Stable Utility Rates to Benefit Consumers," Lawyers Title News: Economic Forecast Issue, January-February 1984.

Feasibility of the Conversion of Shiller Units 4, 5 and 6 and Newington Station from Oil to Coal Generation, Report to the New Hampshire Public Utilities Commission, May 1981, Co-author.

A Study of the Feasibility of Energy Distributing Companies to Finance Home and Business Insulation, Report to the Governor and General Assembly of Virginia, Richmond: Department of Purchases and Supply, November 1978, Co-author.

"Tax Planning in Real Estate Investments: A Case Study," presented at and published in Proceedings of International Association for Financial Planning, 1986 Academic Symposium, Chicago, Illinois, October 1986.

"Public Utility Diversification and the Cost of Capital," presented and published in Proceedings of NARUC Biennial Regulatory Information Conference, Columbus, Ohio, September 1986.

"The Electric Utility Industry's Financial Challenges for the Ninety's," presented at annual conference, National Association of Regulatory Commissioner's Sub-Committee on Computers, Salt Lake City, Utah, February 1986, Co-author.

"An Evaluation System for Utility Financing Authority Applications," presented and published in Proceedings of NARUC Biennial Regulatory Information Conference, Columbus, Ohio, September 1984, Co-author.

"Micro-Computer Applications for Regulation," presented and published in Proceedings of NARUC Biennial Regulatory Information Conference, Columbus, Ohio, September 1984, Co-author.

"Use of Computer Models in Regulatory Analysis," presented at annual conference, National Association of Regulatory Commissioner's Sub-Committee on Computers, Indianapolis, Indiana, May 1983, Co-author.

"Budgeting and Control in a Not-for-Profit Environment," presented at annual conference, Virginia Association of Children's Homes, Roanoke, Virginia, November 1982.

"Regulatory Considerations for Removal of AFUDC," presented and published in Proceedings of NARUC Biennial Regulatory Information Conference, Columbus, Ohio, September 1978, Co-author.

"A Temporal Evaluation of Risk for Regulated Firms," presented and published in Proceedings of Southwestern Finance Association, New Orleans, Louisiana, March 1977, Co-author.

"An investigation of the Impact of International Diversification on Homogeneous Groupings of Financial Markets," presented and published in Proceedings of Southwestern Finance Association, San Antonio, Texas, March 1976, Co-author.

"Characteristics of Option Premiums: Development of a Valuation Model," presented and published in Proceedings of Atlantic Economic Society, Washington, D.C., September 1975.

PROFESSIONAL ACTIVITIES:

Faculty Marshall, James Madison University, 1997-98.

Speaker, Faculty Senate, James Madison University, 1996-97.

Chair, MBA Program Review Committee, James Madison University.

Member, Presidential Search Committee, James Madison University

Receipient of Graduate Faculty Teaching Award, College of Business, 1990-91 Academic Year.

Chair, Principal Committee on Administrative Processes, Financial Resources, James Madison University Self-Study for Accredation by the Southern Association of Colleges and Schools, 1990-1991 Academic Year.

Founded and became first Director of the Economic Research and Development Division of the Virginia State Corporation Commission.

Co-developer of FIN, the Financial Information Model. This micro computer based, financial simulation, strategic analytical model has been adapted for use by five state regulatory commissions and by the planning departments of nine electric and gas distribution companies. Its logic has been adapted by EPRI in the MIDAS model and by Decision Focus in the LMSTM model.

Developed and conducted three day seminars on the application of financial analytical techniques in regulation for the Staffs of the Pennsylvania Public Utilities Commission, Maryland Public Service Commission, Maine Public Utilities Commission and the Ohio Public Utilities Commission.

Served as expert cost of capital witness on behalf of regulatory commission staffs, regulated companies, and state attorney generals in over forty-five electric utility company, gas distribution company and telephone rate proceedings.

Served as expert cost of capital witness on behalf of regulated companies or industry trade associations in annual generic proceedings before the Interstate Commerce Commission for determining measures of railroad revenue adequacy in years 1981-1984.

Served as a consultant before state regulatory commissions in numerous proceedings for the evaluation of utility accounting procedures, utility company construction programs, and external financing arrangements.

Served as faculty member, NARUC Annual Regulatory Studies Program, Michigan State University for the years 1982-1985.

Served as panelist on:

Competition in the Telecommunications Industry, New England NARUC meeting, Dixville Notch, NH, 1987;

Workshop on Micro-Computers, APPA national meeting, 1983;

Treatment of P & C Insurance Income, Virginia SCC, 1981;

DOE's Workshop on National Energy Act, December, 1978; and

Outlook for Energy Costs, Valley Economic Seminar, 1977.

APPENDIX II

Concepts of
Cost of Capital, Risk, Cost of Equity
and
Cost of Equity Evaluation Methods

Q. Dr. Weaver, would you please briefly discuss the concept of the cost of capital?

A. The cost of capital represents the price paid for acquiring money from the capital market. To obtain capital, a firm issues financial assets such as shares of stock, bonds, or notes to investors. A financial asset represents a claim on the earning power and property of the issuer. The priority and security of the claims depend upon the contractual conditions associated with each type of financial asset. Because of variation in the contracts, risk differs among the shares of stock, bonds, or notes.

The shares of stocks, bonds or notes are generally issued to investors through an investment bank or a commercial bank. An investment bank is the intermediary between the demanders and the suppliers of long term funds. The commercial bank is the intermediary between the demanders of funds and the money market.

In some instances where subsidiary financing is involved, the parent corporation obtains its funds from the capital market. The subsidiary issues financial assets to the parent in exchange for these funds. In other instances, the subsidiary may place bonds and notes directly with an insurance company or other lender. In this direct placement case, the involvement of an investment bank is limited to locating the lender, assisting in the transaction, or may not be used at all.

The capital market differs from the market for real goods because the item traded in exchange for the financial assets, money, is homogeneous. Investors are the suppliers of money to this market. At any moment in time, the financial assets, shares of stock, bonds or notes issued by different firms are competing with one another for investors' funds. Investors are offered a broad range of choices with respect to the selection of the firms in which they invest and with respect to the form of the instruments which describe the rights and obligations of that investment.

A single firm demanding funds is in competition with all other firms that are acquiring capital, and the shares of stock, bonds or notes it issues to acquire those funds are competing with all other forms of securities that are available in the capital market. This is true not only for new issues, but also for existing issues that are traded among investors.

The cost of capital, as applied in regulation, is measured using a weighted average of the costs of debt, preferred stock and common stock that have been previously issued to obtain the funds that are necessary to purchase the assets needed to provide service. To apply the weighted average approach, the cost of each capital component in a firm's capital structure must be determined. The cost of debt and preferred stock are generally determined on the basis of the embedded costs of the actual outstanding amounts. The cost of equity is not contractually fixed and must be estimated.

Q. Dr. Weaver, would you please briefly explain the concept of the cost of equity?

A. Equity cost is based on an expected or future return. The cost of equity capital, unlike the cost of debt or preferred stock, is not contractually fixed at the time of issuance.

Investors in the equity market supply funds to corporate users on the basis of what they either explicitly or implicitly expect the return will be in the future and on how certain they feel that expectation will be realized. The expected return may be realized through the receipt of dividend income, appreciation of the security's market price, or some combination of both dividend income and market price appreciation.

The rate of return is determined by the sum of the future dividend income and price appreciation relative to the amount of investment required. Past returns can be used to forecast the future returns, but actual future returns will differ from those that were estimated when the investment decision was made.

Q. Please describe the risk associated with the return estimate.

A. Risk is the likelihood that the actual return may be less than the expected return. Risk, therefore, is caused by any phenomenon which may result in the actual future return being less than the return anticipated when the investment was made. The greater the likelihood that an actual return will vary on the downside from its anticipated return, the greater the risk. Risk may be caused by conditions external to the firm or from conditions that are, to some degree, within the firm's control. Some examples of external conditions are the prospective state of the economy, inflation, and capital market conditions. Internal factors include management efficiency, technology changes, liquidity, and financial structure.

In regulation, the return which is allowed should be similar to the return that is earned by other companies that have similar risk. Risk, as it applies to the cost of equity, should be considered as total risk rather than the risk that would result from the occurrence of any single factor. Risk that results from any one particular phenomenon could be offset by the occurrence of other phenomena. For example, the state of the economy may improve causing an increase in actual returns. However, if improvement in the economy was accompanied by an increasing inflation rate, the real return may remain the same, or even decrease.

Risk, by definition, stems from differences between the actual future return and the return anticipated when the investment was made. As such, it is a future phenomenon and must be estimated. Past returns to an investor are known with certainty; and therefore, there is no risk associated with their measurement. Evaluation of past data can be used to make implications concerning risk, but past measures are useful only to the extent they correspond to the risk that investors perceive to be embodied in an equity investment.

Q. Please explain how expected return and risk provide the opportunity cost principle framework for determining the cost of equity.

A. Investors consider two measures when choosing among alternative investments. The first is the anticipated or expected return for each investment. The second is risk. These two measures, expected return and risk, are combined into a framework known as the opportunity cost principle. The principle states that, for a given level of risk, investors will choose the alternative which provides the highest expected return.

The opportunity cost principle provides a model which explains a rational risk-averse investor's selection process. An investor is confronted with a large number of investments in the capital market. In order to make a rational choice among these alternatives, the investor must derive for each alternative both the expected return on investment, and the risk or likelihood that the anticipated return will not be realized. The investor will then choose the alternative that promises the highest expected return relative to the level of risk assumed.

Security prices reflect the composite behavior of all investors. If investors do not choose to purchase a particular security, that security's price will fall until its anticipated rate of return is comparable to other investment alternatives at the same risk level. In an efficient market, this process occurs very rapidly so that, market prices reflect investor expectations for return and risk.

Q. Does this same adjustment process hold for securities that have different risk levels?

A. Because investors continually apply the opportunity cost principle to market prices, securities which are perceived to have greater risk also have higher levels of expected returns. An investor requires a risk premium in the form of higher expected returns in order to assume increased risk. Risk premiums enable riskier firms to compete for investor-supplied funds in the capital market with the less risky firms. For example, stocks and bonds compete with one another for capital.

This does not imply that the higher levels of expected returns for the more risky securities will always be realized. If the expected return of a particular common stock were always realized, there would be no risk associated with that investment opportunity.

The security's return, always being realized, would be a certain return and it would have no risk premium in its cost rate. Its return or cost rate would be similar to that of a high grade bond. The more risky the security, the greater the likelihood that its actual return will differ from the return that was expected when the investment was made.

Q. Please explain the problem associated with using past data as an exact measure of the cost of equity.

A. Past returns to a security are known with certainty and there is no risk associated with their measurement. For this reason, it is not correct to use historical data as an absolute measure for the cost of equity. Historical data can provide guidance when estimating expected returns or the cost of equity. However, care must be taken to eliminate biases in the data and judgment must be used when evaluating the derived measures.

For these reasons, no precise formula exists for determining the cost of equity. The cost of equity is based upon the opportunity cost principle; and opportunity cost combines investor expectations (or investor thinking) regarding future returns - that is, future dividends and market price appreciation - and the future risk that the expectations will not be realized. As such, informed judgment is required to formulate the estimate.

Q. What technique did you use to formulate your recommendation for the cost of equity?

A. As I indicated, there is no precise method to determine the cost of equity. Equity valuation models provide information which an analyst uses to form an estimate of the cost of equity. To obtain information, I use the discounted cash flow (DCF) method, the Capital Asset Pricing Model (CAPM) and a bond yield-risk premium method.

Q. Dr. Weaver, please briefly describe the DCF technique.

A. Common stockholders receive a return on their investment through the receipt of dividend income and through increases in the market price of their investment. The DCF technique directly evaluates this return. The DCF model is derived from the premise that the market price of a share of common stock is the present value of the dividend stream during the holding period and the expected market price at the end of that same holding period. This stems directly from the opportunity cost principle. The discount rate that equates the expected dividend income and future market price to the current market price is the investor's opportunity cost. The derivation of the model for various holding periods is presented in the Attachment to this Appendix.

Q. What assumptions are required to implement the technique?

A. One assumption is required for the derivation of the DCF model. The derivation requires that the combination of dividend increases and market price appreciation occur at a constant growth rate. For example, on page 1 of the Attachment, the model is derived for a single period. The underlying assumption for this derivation is that the growth rate is constant over that single period. That is, "f," the growth variable, is the same wherever it appears in the derivation. On page 2 of the Attachment, the model is derived for two periods. In this derivation, "g," the growth variable, is the same wherever it appears and is therefore constant. On page 3 of the Attachment, the model is derived for three periods and the growth variable "h" is the same throughout the derivation and is therefore constant over the three periods.

The assumption of constant growth expectations is not intended to be a description of what has occurred in the past or of what will actually occur in the future. This assumption implies that at a given moment in time, investors have constant growth expectations regarding the future. For example, if an investor were choosing between two stocks of equal risk, he would choose to invest in the stock that he believed would afford the highest return over the holding period. At the moment the investment decision is being made, it is unlikely that the investor would segment the time horizon into several shorter time intervals and determine an expected return for each stock in each sub-interval selected and compare the several returns one to another.

A rational investor would choose to invest in the stock that has the highest expected return in the first sub-interval, and then he would reevaluate the investment alternative prior to the start of the second interval. Thus, the investor would assume a constant return over the shorter interval of time. It follows than that the assumption of constant growth is consistent with rational investor behavior.

Q. **How does the constant growth assumption apply to the rate making process?**

A. Constant growth must be assumed for the length of time between rate cases. For example, if a utility were to seek rate relief every two years, then its cost of equity would be reevaluated every two years as a part of the rate making process. Therefore, the growth rate need only be assumed constant for two years since it is reevaluated and may be changed after that period.

The duration of the constant growth assumption is illustrated on page 5 of the Attachment. In this example, the growth rate variable is not the same over the entire period. It is "g" for two periods and then "g*" for the next two periods. This serves to illustrate that the infinite constant growth assumption is applicable in rate making only if accompanied by the assumption that the utility being evaluated will never become involved in another rate case proceeding.

In summary, the Attachment shows that regardless of the length of time being considered, the DCF model reduces to dividend yield plus growth. However, the original formulation is the better conceptual model. That is, the cost of equity is the return on the price of common stock resulting from dividend income and market price appreciation. This model uses data obtained from the capital market and relies on the opportunity cost principle in its formulation.

Q. Are any other assumptions required when using the DCF technique?

A. No other assumptions are required in its implementation. Cost of capital witnesses sometimes regard the earnings stream to be important in estimating the growth that accrues to the firm (net income) or the growth that accrues to the investors (dividend income and market price appreciation).

Changes in the firm's earnings stream must determine market price appreciation and dividend income when the dividend payout ratio and the price-earnings ratio are constant. However, even if these ratios were not constant, the average income stream accruing to the firm would have to approximate the dividends and price appreciation earnings stream over a long period of time.

The reason that the two earnings streams must be approximately the same in the long run is as follows. If earnings are retained and invested internally at the firm's overall rate of return, future earnings will increase, causing future market price appreciation and future dividend increases. If dividends had been paid out, then additional stock must be sold to finance the same amount of investment. Assuming a constant overall rate of return, earnings on the new investment would be sufficient to provide the new stockholders the same return that is realized by the old stockholders.

In one case, investors enjoy larger future dividends and price appreciation, while in the other they enjoy more sizeable current dividends. With a constant rate of return and a stable risk structure, the present value of the increase in future dividends and price appreciation must equal the present value of the increase in current dividends.

In the short run, the two earnings streams may not be equal. It then becomes a question concerning which expected earnings stream do investors capitalize - the earnings accruing to the firm or the dividends and market price appreciation which accrues to the investors themselves. I believe that investors consider their personal income (i.e., dividends and price appreciation) to be more relevant than the firm's income and they therefore capitalize dividends and price appreciation. The growth estimate I use in the DCF model is for dividend and market price appreciation. Thus, no other assumptions are required.

Q. Dr. Weaver, what other methods are similar to the DCF method?

A. The earnings price (E-P technique) and the comparable earnings technique are similar to the DCF method. The E-P technique is sometimes called the investor's short-term capitalization rate. If there were no expected growth in earnings, it would provide a measure of investor cost of equity rates. The implied zero-growth assumption limits the information content of this measure.

The comparable earnings technique measures the return on the book value of equity. This technique has limited usefulness because it ignores the economic conditions in the capital markets where funds must be obtained, relying completely on accounting data. However, each of the three methods have similar mathematical properties.

Q. Please briefly explain the similarities between the DCF, the E-P, and the comparable earnings techniques.

A. The mathematical similarities among the three methods can be shown without the use of assumptions or without a present value model. All three equity valuation techniques begin with earnings per share (EPS) and relate EPS to either market price per share of equity, book value per share of equity, or both. This is demonstrated at the top of the next page.

METHOD:

Earnings Price	DCF	Comparable Earnings
START WITH EPS FOR EACH METHOD:		
EPS	EPS	EPS

DIVIDE EPS BY MARKET PRICE OR BOOK VALUE OR SPLIT INTO DIVIDENDS AND RETAINED INCOME COMPONENTS AND DIVIDE BY BOTH:

$$\frac{\text{EPS}}{\text{Market Price Per Share}} \qquad \frac{\text{Dividends}}{\text{Market Price Per Share}} + \frac{\text{Retained Income}}{\text{Book Value Per Share}} \qquad \frac{\text{EPS}}{\text{Book Value Per Share}}$$

Please notice that the Earnings-Price Model is a ratio of earnings per share to market price per share. The comparable earnings ratio relates earnings per share to book value per share. The DCF method is a combination of the previous methods. For the DCF method, EPS is split into dividends and retained income. The dividend is related to the market price - as a yield to the investor. The retained income is related to book value - as a return on the book equity of the firm. That is, retained income is invested in new assets and is assumed to earn a return similar to the return being earned by the firm's other assets. This retained income provides for growth to investors while the dividend income provides a current yield.

Q. Dr. Weaver, you have indicated the relationship between the earnings-price, DCF, and comparable earnings techniques. Since the techniques are related, will the results from applying the three techniques be equal?

A. The results of the three techniques will be equal if one assumes that a company's market price for a share of stock is also equal to the book value per share. In this situation, the earnings-Price, DCF, and Comparable Earnings techniques will yield identical results. The reason is quite simple. Each of the respective numerators is earnings per share or dividends and retained income which sums to earnings per share. When the market price is equal to book value, each denominator for the three techniques is also the same.

If the market price were equal to the book value, the analyst would no longer have three techniques to utilize for the evaluation. However, this equality would seldom occur. Differences between the market price and book value therefore permit all three methods to be used in developing a recommended return on equity.

There is no reason why the market price should equal the book value of a firm's stock. A simple example is useful for illustrating this fact. Assume there existed two companies that are identical in every respect except for the accounting methodologies employed. The different accounting methods will cause the companies to have different book values of equity. If the companies are identical, the market price of the common stock should be the same. The different accounting methodologies would, however, cause the book values to differ.

Q. How did you formulate your estimate for the growth variable used in the DCF model?

A. I use a number of different methods to formulate an estimate of growth for use in the DCF model. I do this to obtain information to augment my analysis. I use a variety of sources for estimating growth because the growth estimate in the DCF model represents the rate of increase for dividends and market price between this and the Company's next rate case proceeding before the Commission. There is no single method that provides "the answer."

One way is to use analysts' forecasts for future growth in earning per share, dividends, or book value. Two sources for these forecasts are Value Line and I/B/E/S. Value Line analysts forecast the three to five year growth in earnings, dividends, and book value for each of the approximately 1,700 which they follow. I/B/E/S surveys the investment banking firms research departments to obtain the estimates that are being made by the professional security analysts. Academic studies have shown that analysts' forecast provide reasonably good estimates for use in the DCF model.

Past data may also be used to estimate the future growth rate. Judgement must be exercised when using past data because past events are not perfect predictors of future events. For this reason, several data items should be used to provide insight on the appropriate values for formulating this estimate.

The growth rate of past dividends over some representative period may provide useful information because some investors may use the technique in estimating growth. The appropriate use of this method, however, requires discretion since dividends are declared by the board of directors and may not represent the real growth rate. I will use this method in conjunction with other methods for estimating growth.

The compound growth rate in earnings per share is another estimator which is frequently used. However, only a portion of earnings per share is retained and reinvested in new assets to facilitate future growth. In the case of utilities, the majority of earnings per share is paid out in the form of dividends. The use of the growth rate in earnings per share is based on the assumption that the P/E ratio and dividend payout ratio are constant.

The compound rate of growth in book value per share is also used to estimate growth. The growth in book value represents the amount of earnings per share that are retained and plowed back into the firm and, in this respect, is similar to the growth in EPS. However, this measure generally produces a lower growth estimate than the growth rate in EPS because growth of book value only measures the portion that is retained. A weakness regarding the use of this measure is that no assumption is made concerning the earnings capability of the assets that are associated with the change in book value.

Another measure, the earnings retention ratio multiplied by the return on book value of equity is the estimator for sustainable growth. The portion of earnings that is retained and invested in new assets provides the growth for the equity holders in future periods. The new assets can reasonably be expected to provide a return that is close to the rate that existing assets are currently earning. The return on book value of equity represents the return on assets of the firm after the effect of debt leverage.

The product of the earnings retention ratio times the return on book value of equity is both a logically correct and theoretically sound estimator of future earnings growth. A share of stock represents a residual claim on the firm's earnings stream. Growth is a result of the claim's proportion of earnings increasing, the earnings stream increasing, or some combination of the proportionate claim and earnings stream increasing.

Growth of the proportionate claim or earnings stream can occur in six ways. These are: (1) the firm is able to continuously increase the efficiency of its asset utilization; (2) the firm issues new shares at a market price that is greater than the book value of its equity; (3) the firm is able to purchase existing outstanding stock at a price that is less than the firm's book value of its equity; (4) the firm is able to sell some of its assets for a price that exceeds the respective book value of those assets; (5) the firm employs more leverage; or (6) the firm is able to retain income and invest in new assets that have a return that is greater than, or equal to, the return currently being earned on assets. This sixth method is the only sustainable method for accomplishing growth. The BxR method only captures one way in growth can occur and it ignores these other factors which, although they are not sustainable, are sources of growth.

The method for formulating the growth estimate, the earnings retention ratio times the return on equity, can mathematically be reduced to retained income divided by book value per share. This ratio was used in my previous explanation of the similarities among the earnings-price and DCF methods. This mathematical reduction is as follows:

$$\text{Earnings Retention Ratio:} \quad 1 - \frac{DIV}{EPS}$$

Determining a common denominator and subtracting:

$$1 - \frac{DIV}{EPS} = \frac{EPS}{EPS} - \frac{DIV}{EPS} = \frac{EPS\text{-}DIV}{EPS}$$

Thus retained income can be substituted for EPS-DIV:

$$EPS\text{-}DIV = \text{Retained Income}$$

Multiplying the Earnings Retention Ratio times the Return on Equity provides the following results:

$$\frac{\text{Retained Income}}{EPS} \quad X \quad \frac{EPS}{\text{Equity Book Value}}$$

Cancellation of EPS results in the following:

$$\frac{\text{Retained Income}}{\text{Equity Book Value}}$$

Therefore, the growth rate estimated by using the earnings retention ratio times the return on equity is reduced to the ratio relating the retained income of the firm to the book value of equity.

Q. Since the earnings-price and DCF methods have these mathematical similarities, what are the differences between the methods?

A. The chief difference in the three methods is that the earnings price method is simply a mathematical ratio. The DCF method, while being a mathematical ratio, has been derived from a foundation that simulates investor behavior using a present value analysis.

The DCF method is therefore derived from a theoretical foundation, which justifies its analytical use to evaluate the cost of equity.

CAPITAL ASSET PRICING MODEL

Q. You indicated you use CAPM to also obtain information for estimating the cost of equity. Would you please explain the CAPM?

A. Yes. The CAPM presumes that investors are risk averse. More risky securities must provide a higher expected return or investors would have no reason to include them in their investment portfolios.

This higher-risk/higher-expected-return principle permits the cost of equity to be split into two components: (1) a default-free rate, and (2) a risk premium. The default-free rate is assumed to be the same for all securities. The risk premium is larger for more risky securities and smaller for less risky securities.

According to CAPM, the amount of risk premium can be determined in ;two steps. The first requires that the average risk premium for the equity market be estimated. In the second step, this average risk premium must be adjusted either upward or downward, depending upon whether the security being considered is more or less risky than the average.

The adjustment is made by multiplying the average risk premium by beta. Beta is a measure of the risk of an individual security relative to an average security. A security that has the same risk premium as an average security would have a beta equal to one.

Less risky securities have betas less than one and more risky securities have betas greater than one.

The CAPM is formulated as:

$K_i=R_f+B(K_m-R_f)$ **where:**

K_I = The expected return on security I;
R_f = The expected default-free rate;
K_m = The expected return on an average security;
$K_m - R_f$ = The risk premium for an average security; and
B = Beta

Q. What data are required to implement the CAPM?

A. Three data elements are required to implement the CAPM. These are the expected default-free rate; the expected return on an average security; and beta.

Q. What are the data sources for these data?

A. A short- or a long-term bond rate is generally used as a proxy for the expected default-free rate. A short-term rate is preferred because it is more independent to the market return rate -- that is, there is less covariance.

The variable to use as a proxy for the expected return on an average security is more difficult to determine. Some of the variables that are used include a long-term historical average risk premium, estimates made from data provided by conventional financial information sources such as Value Line, or estimates that were made in published studies by brokerage houses. An estimate of beta can be obtained from numerous sources but these can also vary considerably, depending on the source.

Q. How does the use of data from different sources affect the validity of the CAPM

results?

A. Obviously, using different data will give different results. For this reason, several estimates should be made using data from different sources or different combinations of data. This will result in a range of solutions being determined. Since different investors will use different methods and data to make their buy and sell decisions, this will reflect the market as a whole and provide a range for the cost of equity. The true cost of equity will most likely be somewhere within the bounds of that range.

BOND-YIELD-RISK-PREMIUM METHOD

Q. Please explain the bond-yield-risk-premium method.

A. Yes. The bond-yield-risk-premium method calls for simply adding a risk premium to a bond yield. The risk premium is the difference between the cost of debt at a certain risk level versus the cost of equity at a different risk level. The risk premium is difficult and risk premiums change as investor's risk aversion change. When there are periods of economic optimism for future economic conditions, risk premiums tend to become small. When there is economic uncertainty and pessimissim, risk premiums are larger.

One way to estimate a risk premium is to determine what the total return on a company's common stock has been relative to some particular market bond yield. Another way is to survey analysts to determine what their estimates are. A weakness with this method is that the premiums change over time and surveys become out of date.

Q. How did you implement this method?

A. I select a recent time period which in my judgement reflects the expected economic conditions for the near-term future. I then determine the realized return on a group of companies that have similar risk to the company being analyzed. I used the comparable companies that I used for the DCF analysis and CAPM analysis. I determine the realized return for all possible one-year holding periods during the most recent ten-year time period. I compared all of the possible one-year holding period returns from the group of comparable companies with similar holding period yields on ten-year government bonds. e realized The risk premium is the difference between the average stock returns and the average bond return. I add this risk premium to the forecasted yields on the ten year government bonds to obtain an estimate of the cost of equity.

Q. What does the sum of the risk premium and bond yield represent?

A. The government bond yield represents a default free rate of return that contains only a premium for expected inflation and marketability. The stock risk premium represents the additional return that is required for the risk of the similar public utility companies. The sum of the two represents, according to this method, the return on equity.

Q. Dr. Weaver, did you use the methods you have discussed here in your testimony?

A. Yes. I did.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

In the Matter of	)	
Rate Application by	)	Case No. 99-070
Western Kentucky Gas Company	)	

Exhibit of Carl G. K. Weaver
Appearing on behalf of the Office of
The Attorney General for the Commonwealth of Kentucky
Utility and Rate Intervention Division

October 18, 1999

Exhibit ________
Carl G. K. Weaver
Schedule 1

Western Kentucky Gas Company
Common Equity Ratio
24 Gas Distribution Companies Listed in Value Line

Company Name	1998	1997	1996	1996-98 Average
UGI Corp.	28.7	30.0	30.0	29.6
Southwest Gas Corp.	35.6	31.5	34.4	33.8
MCN Corp.	30.9	39.9	35.2	35.3
SEMCO Energy, Inc.**	43.3	36.2	45.9	41.8
New Jersey Resources Corp.	45.6	47.1	45.8	46.2
NUI Corp.	48.4	47.8	42.7	46.3
South Jersey Industries, Inc.	42.5	44.8	53.2	46.8
AGL Resources, Inc.	47.1	45.9	48.9	47.3
Cascade Natural Gas Corp.	48.7	46.5	50.0	48.4
Energen Corp.	46.9	51.9	49.1	49.3
CTG Resources	36.3	57.0	55.2	49.5
Northwest Natural Gas Co.	51.5	49.0	52.8	51.1
Providence Energy Corp.	51.0	52.1	50.6	51.2
Conn. Energy Corp.	54.1	51.9	49.9	52.0
Piedmont Natural Cas Co.	55.3	52.4	49.7	52.5
Atmos Energy Corp.	48.2	51.9	58.5	52.9
NICOR Inc.	57.0	57.2	58.1	57.4
Keyspan Energy Corp.*	60.0	56.5	55.8	57.4
Washington Gas Light, Co.	57.1	56.2	59.4	57.6
Peoples Energy Corp.	58.9	57.6	56.4	57.6
Laclede Gas Co.	58.6	61.6	57.1	59.1
Indiana Energy, Inc.	62.5	65.0	62.5	63.3
ONEOK Inc.	78.9	58.5	55.1	64.2
WICOR, Inc.	73.0	72.3	68.5	71.3

Source: Value Line

Note: Sorted by Average Common Equity Ratio.

* Keyspan formed in May 1998 by merger of Brooklyn Union and Long Island Lighting

** SEMCO added to Value Line with the publication of the June 25, 1999 analysis.

Exhibit ________
Carl G. K. Weaver
Schedule 2

Western Kentucky Gas Company
Net Sales / Total Assets
24 Gas Distribution Companies Listed in Value Line

Company Name	1998	1997	1996	1996-98 Average
AGL Resources, Inc.	68%	67%	67%	67%
Atmos Energy Corp.	74%	83%	88%	82%
Cascade Natural Gas Corp.	61%	64%	43%	56%
Conn. Energy Corp.	53%	59%	65%	59%
CTG Resources	62%	69%	67%	66%
Energen Corp.	51%	49%	70%	57%
Indiana Energy, Inc.	65%	77%	78%	73%
Keyspan Energy Corp.*	*	59%	63%	61%
Laclede Gas Co.	71%	84%	81%	79%
MCN Corp.	43%	48%	52%	48%
New Jersey Resources Corp.	75%	79%	64%	73%
NICOR Inc.	62%	83%	76%	74%
Northwest Natural Gas Co.	35%	32%	24%	30%
NUI Corp.	107%	76%	69%	84%
ONEOK Inc.	76%	94%	100%	90%
Peoples Energy Corp.	60%	70%	67%	66%
Piedmont Natural Cas Co.	66%	71%	64%	67%
Providence Energy Corp.	87%	86%	86%	86%
SEMCO Energy, Inc.**	130%	153%	115%	133%
South Jersey Industries, Inc.	60%	52%	54%	55%
Southwest Gas Corp.	50%	41%	41%	44%
UGI Corp.	69%	76%	73%	73%
Washington Gas Light, Co.	62%	68%	66%	65%
WICOR, Inc.	93%	99%	98%	97%

Source: Compact Disclosure

* Keyspan formed in May 1998 by merger of Brooklyn Union and Long Island Lighting

** SEMCO added to Value Line with the publication of the June 25, 1999 analysis.

Exhibit_________
Carl G. K. Weaver
Schedule 3

Western Kentucky Gas Company
Total Assets
24 Gas Distribution Companies Listed in Value Line
(thousands of dollars)

Company Name	Fiscal Year Ending	1998	1997	Percentage Increase 1997 to 1998
AGL Resources, Inc.	Sept. 30	1,981,800	1,925,500	2.9
Atmos Energy Corp.	Sept. 30	1,141,390	1,088,311	4.9
Cascade Natural Gas Corp.	Sept. 30	311,511	307,703	1.2
Conn. Energy Corp.	Sept. 30	459,401	424,281	8.3
CTG Resources	Sept. 30	459,181	444,373	3.3
Energen Corp.	Sept. 30	993,455	919,797	8.0
Indiana Energy, Inc.	Sept. 30	712,350	690,845	3.1
Keyspan Energy Corp.*	Sept. 30	2,497,190	228,960	*
Laclede Gas Co.	Sept. 30	771,147	720,710	7.0
MCN Corp.	Dec. 31	4,392,486	4,329,461	1.5
New Jersey Resources Corp.	Sept. 30	943,018	879,061	7.3
NICOR Inc.	Dec. 31	2,364,600	2,394,600	(1.3)
Northwest Natural Gas Co.	Dec. 31	1,191,736	1,111,617	7.2
NUI Corp.	Sept. 30	776,847	803,665	(3.3)
ONEOK Inc.	Aug. 31	2,422,487	1,237,407	95.8
Peoples Energy Corp.	Sept. 30	1,904,500	1,820,805	4.6
Piedmont Natural Gas Co.	Oct. 31	1,162,844	1,098,156	5.9
Providence Energy Corp.	Sept. 30	253,410	255,510	(0.8)
Semco Energy, Inc.**	Dec. 31	489,662	507,160	(3.5)
South Jersey Industries, Inc.	Dec. 31	748,095	670,601	11.6
Southwest Gas Corp.	Dec. 31	1,830,694	1,769,059	3.5
UGI Corp.	Sept. 30	2,074,600	2,151,700	(3.6)
Washington Gas Light, Co.	Sept. 30	1,682,433	1,552,032	8.4
WICOR, Inc.	Dec. 31	1,015,196	1,031,332	(1.6)

Source: Compact Disclosure - April, 1999 CD.

* Keyspan formed by the merger of Brooklyn Union and Long Island Lighting Co. in May, 1998.

** Semco was added to the standard edition of Value Line with the June 25, 1999 update.

Exhibit ________
Carl G. K. Weaver
Schedule 4

Western Kentucky Gas Company
Total Liabilities/ Total Assets
24 Gas Distribution Companies Listed in Value Line

Company Name	1998	1997	1996	1996-98 Average
AGL Resources, Inc.	63%	64%	65%	64%
Atmos Energy Corp.	67%	70%	67%	68%
Cascade Natural Gas Corp.	62%	62%	61%	62%
Conn. Energy Corp.	61%	66%	65%	64%
CTG Resources	73%	62%	64%	66%
Energen Corp.	67%	67%	67%	67%
Indiana Energy, Inc.	57%	58%	57%	57%
Keyspan Energy Corp.*		58%	57%	58%
Laclede Gas Co.	66%	65%	65%	65%
MCN Corp.	70%	61%	73%	68%
New Jersey Resources Corp.	67%	66%	66%	66%
NICOR Inc.	68%	69%	70%	69%
Northwest Natural Gas Co.	61%	64%	61%	62%
NUI Corp.	71%	73%	74%	73%
ONEOK Inc.	52%	63%	65%	60%
Peoples Energy Corp.	34%	61%	62%	52%
Piedmont Natural Cas Co.	61%	62%	64%	62%
Providence Energy Corp.	63%	64%	64%	64%
SEMCO Energy, Inc.**	72%	81%	81%	78%
South Jersey Industries, Inc.	72%	69%	73%	71%
Southwest Gas Corp.	71%	75%	72%	73%
UGI Corp.	70%	69%	67%	69%
Washington Gas Light, Co.	62%	60%	60%	61%
WICOR, Inc.	60%	62%	65%	62%

Source: Compact Disclosure

* Keyspan formed in May 1998 by merger of Brooklyn Union and Long Island Lighting

** SEMCO added to Value Line with the publication of the June 25, 1999 analysis.

Exhibit ________
Carl G. K. Weaver
Schedule 5

Selected Comparable Companies
Summary

Company	1996-98 Avg Common Equity Ratio	1996-98 Avg Net Sales to Total Assets	1998 Total Assets	% Increase 97-'98	96-'98 Avg. Tot. Liab. to Total Assets
Energen	49.3%	57%	$993,455	8.0	67%
Laclede	59.1%	79%	771,147	7.0	65%
New Jersey Res.	46.2%	73%	943,018	7.3	66%
Piedmont	52.5%	67%	1,162,844	5.9	62%
Average	51.8%	69%	967,616	7.1	65%
Atmos	52.9%	82%	1,141,390	4.9	68%

Source: Schedules 1 to 4 of this Exhibit.

Exhibit ________
Carl G. K. Weaver
Schedule 6

Western Kentucky Gas Company
Selected Comparable Companies
1998 Capitalization

Company	Short-term Debt	Long-term Debt *	Preferred Stock	Common Equity	Total
Energen	153,000	379,991		329,249	862,240
Laclede		277,738	1,960	256,785	536,483
New Jersey Res.	60,700	328,698	20,640	290,804	700,842
Piedmont	32,000	381,000		458,268	871,268
Average	81,900	341,857	11,300	333,777	768,833
Atmos	66,400	456,331	0	371,158	893,889

Source: Compact Disclosure, April 1999 CD.
* Includes current portion of long-term debt.

Exhibit ________
Carl G. K. Weaver
Schedule 7

Western Kentucky Gas Company
Selected Comparable Companies
1998 Capital Structure

Company	Short-term Debt	Long-term Debt *	Preferred Stock	Common Equity	Total
Energen	17.7%	44.1%	0.0%	38.2%	100.0%
Laclede	0.0%	51.8%	0.4%	47.9%	100.0%
New Jersey Res.	8.7%	46.9%	2.9%	41.5%	100.0%
Piedmont	3.7%	43.7%	0.0%	52.6%	100.0%
Average	7.5%	46.6%	0.8%	45.0%	100.0%
Atmos	7.4%	51.1%	0.0%	41.5%	100.0%
Atmos Forecasted	9.4%	40.4%	0.0%	50.2%	100.0%

Source: Previous Schedule and Schedule 34.
* includes current portion of long-term debt

Exhibit ______
Carl G. K. Weaver
Schedule 8

Cash Flow Analysis
Gas Distribution Companies
Energen Corp.
(thousands of dollars)

	1997	1998	Average
Cash Flow from Operating Activities	63,099	123,623	93,361
Cash Flow from Investing Activities	(279,846)	(166,308)	(223,077)
Cash Flow from Financing Activities	310,848	40,514	175,681
Change in Cash Flow	94,101	(2,171)	45,965
Cash Flow Coverage of Interest	3.75	5.12	4.44
Cash Flow Coverage of Total Dividends	4.12	6.80	5.46
Cash flow Coverage of Investing Activities	0.23	0.74	0.48
Quality of Earnings	4.38	4.22	4.30

Source: July compact Disclosure

Exhibit ________
Carl G. K. Weaver
Schedule 9

Cash Flow Analysis
Gas Distribution Companies
Laclede Gas Co.
(thousands of dollars)

	1997	1998	Average
Cash Flow from Operating Activities	54,130	48,889	51,510
Cash Flow from Investing Activities	(45,635)	(52,796)	(49,216)
Cash Flow from Financing Activities	(8,347)	3,117	(2,615)
Change in Cash Flow	148	(790)	(321)
Cash Flow Coverage of Interest	3.84	3.30	3.57
Cash Flow Coverage of Total Dividends	2.38	2.11	2.24
Cash flow Coverage of Investing Activities	1.19	0.93	1.06
Quality of Earnings	1.67	1.75	1.71

Source: July compact Disclosure

Exhibit ________
Carl G. K. Weaver
Schedule 10

Cash Flow Analysis
Gas Distribution Companies
New Jersey Resources Corp.
(thousands of dollars)

	1997	1998	Average
Cash Flow from Operating Activities	67,176	21,060	44,118
Cash Flow from Investing Activities	(36,407)	(42,047)	(39,227)
Cash Flow from Financing Activities	(36,110)	17,996	(9,057)
Change in Cash Flow	(5,341)	(2,991)	(4,166)
Cash Flow Coverage of Interest	4.27	2.07	3.17
Cash Flow Coverage of Total Dividends	2.34	0.72	1.53
Cash flow Coverage of Investing Activities	1.85	0.50	1.17
Quality of Earnings	1.68	0.50	1.09

Source: July compact Disclosure

Exhibit ________
Carl G. K. Weaver
Schedule 11

Cash Flow Analysis
Gas Distribution Companies
Piedmont Natural Gas Co., Inc.
(thousands of dollars)

	1997	1998	Average
Cash Flow from Operating Activities	139,455	123,388	131,422
Cash Flow from Investing Activities	(93,651)	(92,010)	(92,831)
Cash Flow from Financing Activities	(45,588)	(26,868)	(36,228)
Change in Cash Flow	216	4,510	2,363
Cash Flow Coverage of Interest	5.10	4.72	4.91
Cash Flow Coverage of Total Dividends	3.87	3.16	3.52
Cash flow Coverage of Investing Activities	1.49	1.34	1.42
Quality of Earnings	2.58	2.05	2.31

Source: July compact Disclosure

Exhibit ________
Carl G. K. Weaver
Schedule 12

Cash Flow Analysis
Gas Distribution Companies
Atmos Energy Corp.
(thousands of dollars)

	1997	1998	Average
Cash Flow from Operating Activities	68,749	91,651	80,200
Cash Flow from Investing Activities	(121,123)	(118,814)	(119,969)
Cash Flow from Financing Activities	47,256	25,882	36,569
Change in Cash Flow	(5,118)	(1,281)	(3,200)
Cash Flow Coverage of Interest	3.05	3.58	3.31
Cash Flow Coverage of Total Dividends	2.60	2.88	2.74
Cash flow Coverage of Investing Activities	0.57	0.77	0.67
Quality of Earnings	2.88	1.66	2.27

Source: July compact Disclosure

Exhibit ________
Carl G. K. Weaver
Schedule 13

Cash Flow Analysis
Selected Comparable Companies
Summary

	Average Cash Flow Coverage of:			
	Interest	Dividends	Investing Activities	Quality of Earnings
Energen	4.44	5.46	0.48	4.30
Laclede	3.57	2.24	1.06	1.71
New Jersey Res.	3.17	1.53	1.17	1.09
Piedmont	4.91	3.52	1.42	2.31
Average	4.02	3.19	1.03	2.35
Atmos	3.31	2.74	0.67	2.27

Source: Schedules 8 to 13 of this Exhibit.

Exhibit ________
Carl G. K. Weaver
Schedule 16

Historical
Economic Indicators
Annual Average Real Rate of Change

Year	Real GDP % Change (1)	CPI % Change (2)
1976	4.9	5.8
1977	4.5	6.5
1978	4.8	7.7
1979	2.5	11.3
1980	-0.5	13.5
1981	1.8	10.3
1982	-2.2	6.2
1983	3.9	3.2
1984	6.2	4.3
1985	3.2	3.6
1986	2.9	1.9
1987	3.1	3.6
1988	3.9	4.1
1989	2.5	4.8
1990	1.2	5.4
1991	-0.6	4.2
1992	2.3	3.0
1993	2.3	3.0
1994	3.5	2.6
1995	2.3	2.8
1996	3.4	2.9
1997	3.9	2.3
1998	3.9	1.6

Sources: (1) 1976 - 1991 from Survey of Current Business, March 1996. 1992 through 1998 from Value Line Selection and Opinion, May 28, 1999, p. 5537.

(2) For all Urban Consumers, Monthly Labor Review. 1992 - 1998 from Value Line Selection and Opinion, May 28, 1999, p. 5537.

Exhibit ________
Carl G. K. Weaver
Schedule 17

Real GDP and CPI
Percentage Change
Actual versus Forecast

		Real GDP	CPI All Urban Consumers
Actual:			
	1994	3.5	2.6
	1995	2.3	2.8
	1996	3.4	2.9
	1997	3.9	2.3
	1998	3.9	1.6
Forecast:			
	1999	*3.8*	*2.8*
	2000	*2.3*	*2.5*
	2001	*2.5*	*2.5*
	2002	*2.7*	*2.6*
	2003	*2.8*	*2.7*

Source: Value Line Selection and Opinion, May 28, 1999
page 5537.

Exhibit ________
Carl G. K. Weaver
Schedule 18

Moody's Public Utility Bond Yields
Annual Average for 1980 - 1998
Monthly January - May 1999

	Year	Aaa	Aa	A	Baa
	1980	12.30	13.00	13.34	13.95
	1981	14.64	15.30	15.95	16.60
	1982	14.22	14.79	15.86	16.45
	1983	12.52	12.83	13.66	14.20
	1984	12.72	13.66	14.03	14.53
	1985	11.68	12.06	12.47	12.96
	1986	8.92	9.30	9.58	10.00
	1987	9.52	9.77	10.10	10.53
	1988	10.05	10.26	10.49	11.00
	1989	9.32	9.56	9.77	9.97
	1990	9.45	9.65	9.86	10.06
	1991	8.85	9.09	9.36	9.55
	1992	8.19	8.55	8.69	8.86
	1993	7.29	7.44	7.59	7.91
	1994	8.07	8.21	8.31	8.63
	1995	7.68	7.77	7.89	8.29
	1996	7.49	7.57	7.75	8.17
	1997	7.62	7.75	7.79	8.34
	1998	6.76	6.84	6.76	7.20
Jan	1999	6.41	6.82	6.97	7.30
Feb	1999	6.56	6.94	7.09	7.41
Mar	1999	6.78	7.11	7.26	7.55
Apr	1999	6.80	7.11	7.22	7.51
May	1999	7.09	7.38	7.47	7.74
June	1999	7.37	7.67	7.74	8.03
July	1999	7.33	7.62	7.71	7.96
Aug. MTD	1999	7.53	7.80	7.87	8.14

Sources: Moody's 1998 Public Utility Manual ; 1998 is the average of the high/low rates; and the monthly rates are from Moody's Credit Survey, August 9, p. 57.

Exhibit ________
Carl G. K. Weaver
Schedule 19

Comparative Interest Rates
Actual versus Forecast

		3-month T-bills	10-year T-bonds
Actual:			
	1994	4.27	7.41
	1995	5.51	6.94
	1996	5.02	6.80
	1997	5.07	6.67
	1998	4.82	5.69
Forecast:			
	1999	*4.6*	*5.6*
	2000	*5.0*	*5.9*
	2001	*4.6*	*5.5*
	2002	*4.5*	*5.4*
	2003	*4.5*	*5.4*

Sources: Actual data from Standard & Poor's Statistical Reports.
Forecast data from Congressional Budget Office, The Economic Outlook, An Update, July 1, 1999, Table 2, Pages 6 & 7 of 24.

Exhibit ________
Carl G. K. Weaver
Schedule 20

Western Kentucky Gas Company
Historical Growth Rates

Company Name	Value Line EPS	Value Line DPS	Value Line BVS
Energen	5.5%	5.0%	7.0%
Laclede	1.0%	2.0%	2.5%
New Jersey Res.	6.5%	3.0%	4.0%
Piedmont	6.0%	6.5%	6.5%
Average	4.8%	4.1%	5.0%
Atmos	4.50%	4.00%	4.50%

Source: Value Line dated June 25, 1999; Annual Rates, past 10 years.

Exhibit ________
Carl G. K. Weaver
Schedule 21

Western Kentucky Gas Company
I/B/E/S and Value Line
Growth Rate Forecasts

Company Name	I/B/E/S EPS	Value Line EPS	Value Line DPS	Value Line BVS
Energen	7.2%	9.0%	3.5%	10.0%
Laclede	2.9%	4.0%	2.0%	3.5%
New Jersey Res.	6.0%	7.5%	3.0%	7.0%
Piedmont	6.1%	7.0%	5.0%	5.5%
Average	5.6%	6.9%	3.4%	6.5%
Atmos	8.1%	11.5%	4.5%	8.5%

Source: Compact Disclosure, May, 1999; and Value Line from June 25, 1999,
Annual Rates, estimated '96-'98 to '02-'04.

Exhibit ________
Carl G. K. Weaver
Schedule 22

Western Kentucky Gas Company
Stock Prices and Dividend Yield

Company Name:	Energen	Laclede	New Jersey Resources	Piedmont	Atmos
Date		Closing Stock Prices			
08/23/99	19.063	22.250	39.813	33.750	25.250
08/24/99	18.875	22.125	39.813	33.563	24.938
08/25/99	19.125	22.375	40.125	33.875	25.750
08/26/99	19.000	22.813	39.625	33.688	25.063
08/27/99	19.063	22.188	39.375	33.375	25.375
08/30/99	18.875	21.625	39.063	33.125	25.063
08/31/99	18.875	21.688	38.750	33.563	25.063
09/01/99	19.438	22.875	38.875	33.375	25.000
09/02/99	19.250	22.313	38.875	32.563	25.000
09/03/99	19.875	22.625	39.250	33.188	25.375
Avg. Prices	19.144	22.288	39.356	33.406	25.188
Dividend Rate	0.680	1.360	1.680	1.400	1.12
Dividend Yields	3.55%	6.10%	4.27%	4.19%	4.45%
Selected Companies Avg. Div.		4.53%			

Source: YAHOO! Finance, Historical Quotes, September 7, 1999; the Dividend Rate is the latest quarterly dividend multiplied times 4.

Exhibit ________
Carl G. K. Weaver
Schedule 23

Western Kentucky Gas Company
Selected Comparable Companies
Discounted Cash Flow Analysis

Source For Estimated Growth	Growth Rates	Dividend Yield	Growth Adjusted Dividend Yield	DCF Estimated Cost of Equity
Forecasted Growth Rates for Selected Companies:				
I/B/E/S	5.6%	4.53%	4.78%	**10.38%**
VL - EPS	6.9%	4.53%	4.84%	**11.74%**
VL - DPS	3.4%	4.53%	4.68%	**8.08%**
VL - BVS	6.5%	4.53%	4.82%	**11.32%**
Average:				**10.38%**
Forecasted Growth Rates for Atmos:				
I/B/E/S	8.1%	4.45%	4.81%	**12.91%**
VL - EPS	11.5%	4.45%	4.96%	**16.46%**
VL - DPS	4.5%	4.45%	4.65%	**9.15%**
VL - BVS	8.5%	4.45%	4.83%	**13.33%**
Average:				**12.96%**
Historical Growth Rates for Selected Companies :				
EPS	4.8%	4.53%	4.75%	**9.55%**
DPS	4.1%	4.53%	4.72%	**8.82%**
BVS	5.0%	4.53%	4.76%	**9.76%**
Average:				**9.37%**
Historical Growth Rates for Atmos:				
EPS	4.5%	4.45%	4.65%	**9.15%**
DPS	4.0%	4.45%	4.63%	**8.63%**
BVS	4.5%	4.45%	4.65%	**9.15%**
Average:				**8.98%**

Sources: Schedules 20,21, and 22, this exhibit.

Exhibit ________
Carl G. K. Weaver
Schedule 24

Western Kentucky Cas Company
Selected Companies
Capital Asset Pricing Model Analysis

Sources			Risk Free Rate		Beta	Market Return		CAPM Estimated Cost of Equity
Rf	***Beta***	***Km***						
Long-term Current	S&P	S&P 500	6.44%	(1)	0.46	16.1%	(7)	**10.88%**
Long-term Current	Value Line	S&P 500	6.44%		0.61	16.1%		**12.33%**
Long-term Current	S&P	Value Line	6.44%		0.46	15.2%	(8)	**10.49%**
Long-term Current	Value Line	Value Line	6.44%		0.61	15.2%		**11.81%**
Long-term Forecast	S&P	S&P 500	5.75%	(2)	0.46	16.1%		**10.51%**
Long-term Forecast	Value Line	S&P 500	5.75%		0.61	16.1%		**12.06%**
Long-term Forecast	S&P	Value Line	5.75%		0.46	15.2%		**10.12%**
Long-term Forecast	Value Line	Value Line	5.75%		0.61	15.2%		**11.54%**
Long-term Projected	S&P	S&P 500	5.40%	(3)	0.46	16.1%		**10.32%**
Long-term Projected	Value Line	S&P 500	5.40%		0.61	16.1%		**11.93%**
Long-term Projected	S&P	Value Line	5.40%		0.46	15.2%		**9.93%**
Long-term Projected	Value Line	Value Line	5.40%		0.61	15.2%		**11.40%**
Short-term Current	S&P	S&P 500	4.97%	(4)	0.46	16.1%		**10.09%**
Short-term Current	Value Line	S&P 500	4.97%		0.61	16.1%		**11.76%**
Short-term Current	S&P	Value Line	4.97%		0.46	15.2%		**9.69%**
Short-term Current	Value Line	Value Line	4.97%		0.61	15.2%		**11.23%**
Short-term Forecast	S&P	S&P 500	4.80%	(5)	0.46	16.1%		**10.00%**
Short-term Forecast	Value Line	S&P 500	4.80%		0.61	16.1%		**11.69%**
Short-term Forecast	S&P	Value Line	4.80%		0.46	15.2%		**9.60%**
Short-term Forecast	Value Line	Value Line	4.80%		0.61	15.2%		**11.17%**
Short-term Projected	S&P	S&P 500	4.50%	(6)	0.46	16.1%		**9.84%**
Short-term Projected	Value Line	S&P 500	4.50%		0.61	16.1%		**11.58%**
Short-term Projected	S&P	Value Line	4.50%		0.46	15.2%		**9.44%**
Short-term Projected	Value Line	Value Line	4.50%		0.61	15.2%		**11.05%**
Average of CAPM Analysis								**10.85%**
Standard Deviation of CAPM Results								**0.12%**

Notes: See next page

Notes to CAPM analysis

1. The 6.44% risk free rate is the average of the August 30-September 2, 1999 Composite (over ten year) rates that were reported in the Federal Reserve Statistical Release H.15, Selected Interest Rates, Release Date 9/3/99, page 2 of 3.

2. The 5.75% risk free rate is the long-term forecasted 1999 and 2000 10-year Treasury Note rate from The Economic Outlook, An Update published 7/1/99 by the Congressional Budget Office, p. 5 of 24.

3. The 5.40% risk free rate is the long-term projected 2001-2009 10-year Treasury Note rate from The Economic Outlook, An Update published 7/1/99 by the Congressional Budget Office, p. 7 of 24.

4. The 4.97% risk free rate is the 3-month constant maturity Treasury Bill rate for August 30-September 2, 1999 reported in the Federal Reserve Statistical Release H.15, Selected Interest Rates, Release Date 9/3/99, page 2 of 3.

5. The 4.80% risk free rate is average of the forecast of the 3 month Treasury Bill Rate for the years 1999-2000, from The Economic Outlook, An Update published 7/1/99 by the Congressional Budget Office, p. 5 of 24.

6. The 4.50% Short-term rate is the average of the projected 3-month Treasury Bill rate for the years 2001-2009 from The Economic Outlook, An Update published by the Congressional Budget Office, p. 6 of 24.

7. The 16.1% market return is from I/B/E/S obtained in the July 1999 Compact Disclosure.

8. The Value Line forecast for the market return @ 15.24% is from the August 27, 1999 Value Line Index cover where the expected dividend Yield is 1.9% and the 4-year price appreciation potential is 65%.

Exhibit ________
Carl G. K. Weaver
Schedule 25

Western Kentucky Cas Company
Atmos
Capital Asset Pricing Model Analysis

	Sources		Risk Free Rate		Beta	Market Return		CAPM Estimated Cost of Equity
Rf	*Beta*	*Km*						
Long-term Current	S&P	S&P 500	6.44%	(1)	0.18	16.1%	(7)	**8.18%**
Long-term Current	Value Line	S&P 500	6.44%		0.55	16.1%		**11.75%**
Long-term Current	S&P	Value Line	6.44%		0.18	15.2%	(8)	**8.02%**
Long-term Current	Value Line	Value Line	6.44%		0.55	15.2%		**11.28%**
Long-term Forecast	S&P	S&P 500	5.75%	(2)	0.18	16.1%		**7.61%**
Long-term Forecast	Value Line	S&P 500	5.75%		0.55	16.1%		**11.44%**
Long-term Forecast	S&P	Value Line	5.75%		0.18	15.2%		**7.46%**
Long-term Forecast	Value Line	Value Line	5.75%		0.55	15.2%		**10.97%**
Long-term Projected	S&P	S&P 500	5.40%	(3)	0.18	16.1%		**7.33%**
Long-term Projected	Value Line	S&P 500	5.40%		0.55	16.1%		**11.29%**
Long-term Projected	S&P	Value Line	5.40%		0.18	15.2%		**7.17%**
Long-term Projected	Value Line	Value Line	5.40%		0.55	15.2%		**10.81%**
Short-term Current	S&P	S&P 500	4.97%	(4)	0.18	16.1%		**6.97%**
Short-term Current	Value Line	S&P 500	4.97%		0.55	16.1%		**11.09%**
Short-term Current	S&P	Value Line	4.97%		0.18	15.2%		**6.82%**
Short-term Current	Value Line	Value Line	4.97%		0.55	15.2%		**10.62%**
Short-term Forecast	S&P	S&P 500	4.80%	(5)	0.18	16.1%		**6.83%**
Short-term Forecast	Value Line	S&P 500	4.80%		0.55	16.1%		**11.02%**
Short-term Forecast	S&P	Value Line	4.80%		0.18	15.2%		**6.68%**
Short-term Forecast	Value Line	Value Line	4.80%		0.55	15.2%		**10.54%**
Short-term Projected	S&P	S&P 500	4.50%	(6)	0.18	16.1%		**6.59%**
Short-term Projected	Value Line	S&P 500	4.50%		0.55	16.1%		**10.88%**
Short-term Projected	S&P	Value Line	4.50%		0.18	15.2%		**6.43%**
Short-term Projected	Value Line	Value Line	4.50%		0.55	15.2%		**10.41%**
Average of CAPM Analysis								**9.09%**
Standard Deviation of CAPM Results								**1.58%**

Notes: See Schedule 24

Exhibit ________
Carl G. K. Weaver
Schedule 26

Bond Yield - Equity Risk Premium
Realized Return on Equity

	Stock Price & Dividend	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Energen	High	12.250	10.250	9.500	9.625	13.375	12.000	12.625	15.625	20.625	22.500
	Low	7.750	8.000	8.000	7.500	9.125	9.625	10.125	10.875	14.125	15.125
	Mid-range	10.000	9.125	8.750	8.563	11.250	10.813	11.375	13.250	17.375	18.813
	Dividend	0.430	0.450	0.480	0.510	0.530	0.550	0.560	0.580	0.600	0.940
	HPR		0.958	1.012	1.037	1.376	1.010	1.104	1.216	1.357	1.137
Laclede	High	17.000	18.000	18.250	20.500	24.875	25.625	23.250	24.875	28.625	27.875
	Low	14.000	14.250	15.000	17.000	20.000	20.250	18.375	20.000	20.250	22.375
	Mid-range	15.500	16.125	16.625	18.750	22.438	22.938	20.813	22.438	24.438	25.125
	Dividend	1.150	1.170	1.200	1.200	1.220	1.220	1.240	1.260	1.300	1.320
	HPR		1.116	1.105	1.200	1.262	1.077	0.961	1.139	1.147	1.082

Source: Standard & Poor's Stock Reports dated May 8, 1999.

Notes: The average annual price is the mid-range of the high and low price for the year.
HPR = (price1 + dividend1)/price0

Exhibit ________
Carl G. K. Weaver
Schedule 27

Bond Yield - Equity Risk Premium
Realized Return on Equity

	Stock Price & Dividend	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
New Jersey Res.	High	21.500	20.875	21.125	25.125	29.500	27.375	30.500	29.875	42.000	40.250
	Low	17.125	17.125	17.000	18.250	24.000	19.750	21.500	26.625	28.125	31.500
	Mid-range	19.313	19.000	19.063	21.688	26.750	23.563	26.000	28.250	35.063	35.875
	Dividend	1.360	1.440	1.500	1.520	1.520	1.520	1.520	1.550	1.600	1.640
	HPR		1.058	1.082	1.217	1.304	0.938	1.168	1.146	1.298	1.070
Piedmont	High	14.750	14.875	16.875	20.125	26.375	23.375	24.875	25.750	36.500	36.125
	Low	11.500	12.750	13.000	15.500	18.750	18.000	18.250	20.500	22.000	27.875
	Mid-range	13.125	13.813	14.938	17.813	22.563	20.688	21.563	23.125	29.250	32.000
	Dividend	0.790	0.830	0.870	0.910	0.960	1.020	1.080	1.150	1.210	1.280
	HPR		1.116	1.144	1.253	1.321	0.962	1.095	1.126	1.317	1.138

Source: Standard & Poor's Stock Reports dated May 8, 1999..

· Notes: The average annual price is the mid-range of the high and low price for the year.
HPR = (price1 + dividend1)/price0

Exhibit ________
Carl G. K. Weaver
Schedule 28

Bond Yield - Equity Risk Premium
Average One Year Holding Period Return

	1990	1991	1992	1993	1994	1995	1996	1997	1998
Energen	0.958	1.012	1.037	1.376	1.010	1.104	1.216	1.357	1.137
Laclede	1.116	1.105	1.200	1.262	1.077	0.961	1.139	1.147	1.082
New Jersey Res.	1.058	1.082	1.217	1.304	0.938	1.168	1.146	1.298	1.070
Piedmont	1.116	1.144	1.253	1.321	0.962	1.095	1.126	1.317	1.138
Average	1.062	1.086	1.177	1.315	0.997	1.082	1.157	1.280	1.107

Source: Prior two schedules.

Exhibit ________
Carl G. K. Weave
Schedule 29

Equity Yield
All Possible Combinations of Returns on Portfolio
Atmos Selected Comparable Companies

Investment Made at end of	1980	1991	1992	1993	1994	1995	1996	1997	1998
1989	6.2	7.4	10.7	15.6	12.2	11.5	12.1	16.1	13.6
1990		8.6	13.0	18.9	13.8	12.6	13.1	15.1	14.6
1991			17.7	24.4	15.6	13.7	14.1	16.3	15.5
1992				31.5	14.5	12.4	13.2	16.0	15.1
1993					-0.3	3.8	7.6	12.4	12.0
1994						8.2	11.9	17.0	15.4
1995							15.7	21.7	17.9
1996								28.0	19.0
1997									10.7

Notes: Investment is assumed to be made at first of the year and return is realized at end of year.

Exhibit ________
Carl G. K. Weaver
Schedule 30

Bond Yield
All Possible Combinations of Returns on Portfolio
Composite Long-term Gov't Securities (over 10 Years)

Investment Made at end of	1990	1991	1992	1993	1994	1995	1996	1997	1998
1989	8.7	8.4	8.1	7.7	7.7	7.5	7.4	7.3	7.2
1990		8.2	7.8	7.4	7.4	7.3	7.2	7.1	7.0
1991			7.5	7.0	7.1	7.1	7.0	7.0	6.8
1992				6.5	6.9	6.9	6.9	6.9	6.7
1993					7.4	7.2	7.0	7.0	6.7
1994						6.9	6.9	6.8	6.5
1995							6.8	6.7	6.4
1996								6.7	6.2
1997									5.7

Notes: Investment is assumed to be made at first of the year and return is realized at end of year.
Returns are calculated as the G-mean of the annual bond yields.

Exhibit ________
Carl G. K. Weaver
Schedule 31

1990 - 1998 Risk Premiums

Investment Made at end of	Return at the end of Year Indicated								
	1990	1991	1992	1993	1994	1995	1996	1997	1998
1989	-2.5	-1.1	2.6	7.9	4.6	4.0	4.7	8.8	6.5
1990		0.4	5.2	11.5	6.4	5.3	5.9	8.0	7.6
1991			10.2	17.4	8.4	6.6	7.0	9.3	8.7
1992				25.1	7.6	5.4	6.3	9.1	8.4
1993					-7.7	-3.3	0.6	5.4	5.3
1994						1.3	5.0	10.2	8.9
1995							8.9	14.9	11.5
1996								21.3	12.8
1997									5.0

Average Risk Premium 7.00

Note: The risk premium is the difference in the prior two schedlules.

Exhibit________
Carl G. K. Weaver
Schedule 15

Western Kentucky Gas Company
Value Line Measures
Selected Comparable Companies

Company Name	**Safety Rating**	**Beta**
Energen	2	0.80
Laclede	1	0.50
New Jersey Res.	2	0.60
Piedmont	2	0.55
Average	2	0.61
Atmos	2	0.55

Source: Value Line, June 25, 1999.

Exhibit________
Carl G. K. Weaver
Schedule 14

Western Kentucky Gas Company
Standard and Poor's Measures
Selected Comparable Companies

Company Name	Risk	Beta	Relative Strength Rank
Energen	Low	0.69	79
Laclede	Low	0.34	23
New Jersey Res.	Low	0.43	32
Piedmont	Low	0.38	28
Average	-	0.46	41
Atmos	Low	0.18	22

Source: Standard & Poor's Stock Reports, May 8, 1999.

Exhibit ________
Carl G. K. Weaver
Schedule 32

Western Kentucky Gas Company
Cost of Long-term Debt
Yield to Maturity

General Debenture Bonds	9/30/98 Principal Amount (1)	Unamort. Debt Expense (2)	Carrying Value (3)	Maturity Date (4)	Settlement Date (5)	Cupon Rate (6)	Price (7)	YTM	13 mo avg Amount Outstanding 12/31/00	Wtd. YTM
First Mortgage Bonds:										
Series J	17,000	508	16,492	5/15/21	9/30/98	9.40%	97.012%	9.72%	17,000	0.43%
Series N	3,000	50	2,950	3/15/00	9/30/98	8.69%	98.336%	9.94%	154	0.00%
Series P	25,000	231	24,769	11/15/17	9/30/98	10.43%	99.075%	10.54%	19,423	0.54%
Series Q	20,000	256	19,744	4/15/20	9/30/98	9.75%	98.720%	9.89%	20,000	0.52%
Series R	12,860	327	12,533	5/15/04	9/30/98	11.32%	97.459%	11.95%	9,403	0.30%
Series T	18,000	115	17,885	6/15/21	9/30/98	9.32%	99.360%	9.39%	18,000	0.44%
Series U	20,000	345	19,655	5/15/22	9/30/98	8.77%	98.276%	8.94%	20,000	0.47%
Series V	10,000	132	9,868	12/15/07	9/30/98	7.50%	98.678%	7.70%	10,000	0.20%
Unsecured Senior Notes:										0.00%
7.95% due 2006	8,000	31	7,969	8/15/06	9/30/98	7.95%	99.616%	8.01%	6,615	0.14%
9.57% due 2006	16,000	62	15,938	9/15/06	9/30/98	9.57%	99.611%	9.64%	13,385	0.34%
9.76% due 2004	21,000	74	20,926	12/15/04	9/30/98	9.76%	99.646%	7.83%	14,769	0.30%
11.2% due 2002	10,000	33	9,967	12/15/02	9/30/98	11.20%	99.671%	11.29%	5,846	0.17%
10.0% due 2011	2,303	0	2,303	12/15/11	9/30/98	10.00%	100.000%	10.00%	1,152	0.03%
6.09% due 1998	40,000	0	40,000	11/15/98	9/30/98	6.09%	100.000%	5.95%	1,152	0.02%
8.07% due 2006	20,000	79	19,921	10/15/06	9/30/98	8.07%	99.606%	8.14%	20,000	0.43%
8.26% due 2014	20,000	95	19,905	10/15/14	9/30/98	8.26%	99.525%	8.31%	20,000	0.44%
6.75% due 2028	150,000	2,959	147,041	7/15/28	9/30/98	6.75%	98.027%	6.91%	150,000	2.73%
Medium ter notes:										0.00%
Series A, 1995-1, 2025	10,000	211	9,789	12/15/05	9/30/98	6.67%	97.891%	7.05%	10,000	0.19%
Series A, 1995-2, 2010	10,000	186	9,814	12/15/10	9/30/98	6.27%	98.136%	6.49%	10,000	0.17%
Series A, 1995-3, 2000	2,000	19	1,981	12/15/00	9/30/98	6.20%	99.064%	6.66%	1,846	0.03%
Other due in installments	21,168	109	21,059					7.00%	11,517	0.21%
	456,331		450,509						380,262	
Cost of Debt										8.11%

Source: Annual Report, FERC Form 2, and Filing Req, vol 10, tab 10, J-3 Fore.

Exhibit ________
Carl G. K. Weaver
Schedule 33

Western Kentucky Gas Company
Cost of Short Term Debt
Monthly Average Effective Rate
July, 1998- June 1999

	Month	Rate
1998	July	5.9692
	August	6.4496
	September	6.1889
	October	6.0146
	November	5.6767
	December	5.9196
1999	January	5.5164
	February	5.2164
	March	5.4396
	April	5.3036
	May	5.3758
	June	5.3319
	Average	5.7002

Source: Company Response to AG Request 1, Question 1.

Exhibit ________
Carl G. K. Weaver
Schedule 34

Western Kentucky Gas Company
Weighted Average Cost of Capital
Atmos

13 month Average
December 31, 2000

	Proportion	Cost	Weighted Cost
Short-term Debt	9.40%	5.70	0.5358
Long-term Debt	40.40%	8.06	3.25624
Common Equity	50.20%	9.75 - 10.75	4.8945 - 5.3965
Total	100.00%		8.687 - 9.189

Source: Filing Requirements, Volume 3, tab 7, FR10(9)(h) 11 Sheet 2 of 3

CASE NUMBER:

99-070

KY. PUBLIC SERVICE COMMISSION
AS OF : 01/19/00

INDEX FOR CASE: 1999-070A
WESTERN KENTUCKY GAS COMPANY
Rates - PGA

IN THE MATTER OF THE PURCHASED GAS ADJUSTMENT OF WESTERN KENTUCKY GAS

SEQ NBR	ENTRY DATE	REMARKS
0001	12/30/1999	Application.
0002	01/05/2000	Acknowledgement letter.
0003	01/19/2000	Final Order approving rates in Appendix.

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

CERTIFICATE OF SERVICE

RE: Case No. 1999-070 A
WESTERN KENTUCKY GAS COMPANY

I, Stephanie Bell, Secretary of the Public Service Commission, hereby certify that the enclosed attested copy of the Commission's Order in the above case was served upon the following by U.S. Mail on January 19, 2000.

Parties of Record:

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

Stephanie J. Bell
Secretary of the Commission

SB/hv
Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE NOTICE OF PURCHASED GAS)
ADJUSTMENT FILING OF WESTERN) CASE NO. 99-070-A
KENTUCKY GAS COMPANY)

ORDER

On December 21, 1999, in Case No. 99-070, the Commission approved certain adjusted rates for Western Kentucky Gas Company ("Western") and provided for their further adjustment on a quarterly basis in accordance with its gas cost adjustment ("GCA") clause.

On December 30, 1999, Western filed its quarterly GCA to be effective from February 1, 2000 to April 30, 2000.

After reviewing the record in this case and being otherwise sufficiently advised, the Commission finds that:

1. Western's notice proposes revised rates designed to pass to its firm sales customers an expected wholesale increase in gas costs. Western's expected gas cost ("EGC") for firm sales customers is $3.2970 per Mcf, an increase of 8 cents per Mcf from the previous EGC. The EGC proposed for high load factor ("HLF") firm customers is $2.7377 per Mcf.

Western also proposes to pass to its interruptible customers a wholesale increase in gas costs. Western's proposed EGC for interruptible sales customers is $2.7377 per Mcf.

2. Western's proposal set out no current period refund adjustment ("RF"). The total refund factors of 4.80 cents per Mcf for firm sales customers and HLF customers and 1.78 cents per Mcf for interruptible customers reflect adjustments from previous months.

Total refund adjustments for T-2 firm and T-2 interruptible transportation customers are 4.12 cents per Mcf and 1.10 cents per Mcf, respectively.

3. Western's notice set out no correction factor ("CF") for this period. The current CF of (22.39) cents per Mcf will remain in effect until April 1, 2000. The CF is designed to return net over-collections of gas cost from the six-month period ending June 30, 1999.

4. Western's notice sets out its Performance Based Rate Recovery Factor ("PBRF") of 9.34 cents per Mcf to be effective for the 12-month period beginning February 1, 2000.

5. These adjustments produce gas cost adjustments of $3.1185 per Mcf for firm sales customers, 2.5592 per Mcf for HLF customers, and $2.5894 per Mcf for interruptible sales customers. The impact on firm sales customers' bills is an increase of 14.87 cents per Mcf from the previous gas cost adjustment of $2.9698.

6. The rate adjustments in the Appendix to this Order are fair, just, and reasonable, in the public interest, and should be effective for final meter readings on and after February 1, 2000.

7. Western included with its notice a petition for confidential protection of the detailed calculation of the amount to be recovered on Exhibit E of its filing. The information on these pages discloses the actual price being paid by Western to individual marketing companies and other suppliers of gas. The disclosure of this information is likely to cause harm to Western's competitive position. The information should, therefore, be held by this Commission and treated as confidential.

IT IS THEREFORE ORDERED that:

1. The rates in the Appendix to this Order are fair, just, and reasonable and are approved effective for final meter readings on and after February 1, 2000.

2. Within 30 days of the date of this Order, Western shall file with the Commission its revised tariffs setting out the rates authorized in this Order.

3. The information for which Western requested confidential protection shall be treated as confidential.

Done at Frankfort, Kentucky, this 19th day of January, 2000.

By the Commission

ATTEST:

Executive Director

APPENDIX

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 99-070-A DATED JANUARY 19, 2000

The following rates and charges are prescribed for the customers in the area served by Western Kentucky Gas Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

RATES:

Applicable to: General Sales Service Rate G-1

Gas Cost Adjustment

To each bill rendered under the above-named rate schedules there shall be added an amount equal to: $3.1185 per Mcf of gas used during the billing period.

Applicable to: HLF General Sales Service

Gas Cost Adjustment

To each bill rendered under the above-named rate schedules there shall be added an amount equal to: $2.5592 per Mcf of gas used during the billing period.

Applicable to: Interruptible Sales Service Rate G-2

Gas Cost Adjustment

To each bill rendered under the above-named rate schedules there shall be added an amount equal to: $2.5894 per Mcf of gas used during the billing period.

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

January 5, 2000

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

RE: Case No. 1999-070 A
WESTERN KENTUCKY GAS COMPANY
(Rates - PGA)

This letter is to acknowledge receipt of initial application in the above case. The application was date-stamped received December 30, 1999 and has been assigned Case No. 1999-070. In all future correspondence or filings in connection with this case, please reference the above case number.

If you need further assistance, please contact my staff at 502/564-3940.

Sincerely,

Stephanie J. Bell

Stephanie Bell
Secretary of the Commission

SB/jc

Western Kentucky Gas Company

RECEIVED

DEC 30 1999

PUBLIC SERVICE
COMMISSION

WESTERN
KENTUCKY
GAS

December 29, 1999

Honorable Helen C. Helton, Executive Director
Kentucky Public Service Commission
730 Schenkel Lane
Frankfort, KY 40602

Re: Case No. 99-070 A

Dear Ms. Helton:

We are filing the enclosed original and three (3) copies of a notice under the provisions of our quarterly Gas Cost Adjustment Clause, Case No. 99-070 A.

Please indicate receipt of this filing by stamping and dating the enclosed duplicate of this letter and returning it in the self-addressed stamped envelope to the following address:

Atmos Energy Corporation
381 Riverside Drive, Suite 440
Franklin, TN 37064

If you have any questions, feel free to call me at 615-595-7700, ext. 235.

Sincerely,

Mark A. Martin

Mark A. Martin
Senior Analyst - Rate Administration

Enclosures

P.O. Box 650205 Dallas, Texas 75265-0205 972-934-9227

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

GAS COST ADJUSTMENT)
FILING OF)
WESTERN KENTUCKY GAS COMPANY)

Case No. 99-070 A

NOTICE

QUARTERLY FILING

For The Period

February 1, 2000 - April 30, 2000

Attorney for Applicant

Mark R. Hutchinson
Sheffer-Hutchinson-Kinney
115 East Second Street
Owensboro, Kentucky 42303

December 29, 1999

Western Kentucky Gas Company, a division of Atmos Energy Corporation, ("the Company"), is duly qualified under the laws of the Commonwealth of Kentucky to do its business. The Company is an operating public utility engaged in the business of purchasing, transporting and distributing natural gas to residential, commercial and industrial users in western and central Kentucky. The Company's principal operating office and place of business is 2401 New Hartford Road, Owensboro, Kentucky 42301. Correspondence and communications with respect to this notice should be directed to:

William J. Senter
Vice President - Rates & Regulatory Affairs
Western Kentucky Gas Company
Post Office Box 866
Owensboro, Kentucky 42302

Mark R. Hutchinson
Attorney for Applicant
Sheffer-Hutchinson-Kinney
115 East Second Street
Owensboro, Kentucky 42303

Mark A. Martin
Senior Analyst - Rate Administration
Atmos Energy Corporation
381 Riverside Drive, Suite 440
Franklin, Tennessee 37064

The Company gives notice to the Kentucky Public Service Commission, hereinafter "the Commission", pursuant to the quarterly Gas Cost Adjustment Clause contained in the Company's settlement gas rate schedules in Case No. 99-070.

The Company hereby files Seventy-eighth Revised Sheet No. 4, Seventy-eighth Revised Sheet No. 5 and Seventy-eighth Revised Sheet No. 6 to its PSC No. 20, Rates, Rules and Regulations for Furnishing Natural Gas to become effective February 1, 2000.

The Gas Cost Adjustment (GCA) for firm sales service is $3.1185 per Mcf, $2.5592 per Mcf for high load factor firm sales service, and $2.5894 per Mcf for interruptible sales service. The supporting calculations for the Seventy-eighth Revised Sheet No. 5 are provided in the following Exhibits:

Exhibit A - Summary of Derivations of Gas Cost Adjustment (GCA) ....
Exhibit B - Expected Gas Cost (EGC) Calculation ....
Exhibit C - Rates used in the Expected Gas Cost (EGC) Calculation .....
Exhibit D - Correction Factor (CF) Calculation .... N/A
Exhibit E - Performance Based Rate Recovery Factor (PBRRF) ....
Exhibit F - LVS Pricing Calculation ....

Since the Company's last GCA filing, Case No. 99-070, the following changes have occurred in its pipeline and gas supply commodity rates for the GCA period.

1. The commodity rates per MMbtu used are based on historical estimates and/or current data for February 2000, as shown in Exhibit C, page 12.

2. The Expected Commodity Gas Cost will be approximately $2.75 per MMbtu for the quarter February 2000 through April 2000, as compared to $2.75 per MMbtu used for January 2000. Adjusting for the one-time effect of the NorAm buyout, the Indexed Gas Cost was discounted to $2.58 per MMbtu for January 2000.

3. The Performance Based Rate Recovery Factor (PBRRF) of $0.0934 per Mcf to be effective for a twelve-month period beginning February 1, 2000 is included in Exhibit E of this filing. The detailed calculation of the amount to be recovered through this factor was filed with the Commission under a Petition for Confidentiality dated December 29, 1999.

The GCA tariff as approved in Case No. 92-558 provides for a Correction Factor (CF) which compensates for the difference between the expected gas cost and the actual gas cost for prior periods. The Company filed in Case No. 95-010 WW its CF to be effective for the six-month period October, 1999 through March, 2000. Therefore, no change in the CF is filed herein.

WHEREFORE, Western Kentucky Gas Company requests this Commission, pursuant to the Commission's order in Case No. 99-070, to approve the Gas Cost Adjustment (GCA) as filed in Seventy-eighth Revised Sheet No. 5; and Seventy-eighth Revised Sheet No. 6 setting out the General Transportation Tariff Rate T-2 for each respective sales rate for meter readings made on and after February 1, 2000.

DATED at Franklin, Tennessee, this 29th Day of December, 1999.

WESTERN KENTUCKY GAS COMPANY

By: Mark A. Martin

Mark A. Martin
Senior Analyst - Rate Administration
Atmos Energy Corporation

For Entire Service Area
P.S.C. No. 20
Seventy-eighth SHEET No. 4
Cancelling
Seventy-seventh SHEET No. 4

WESTERN KENTUCKY GAS COMPANY

Current Rate Summary

Case No. 99-070 A

Firm Service

Base Charge:

Residential	-	$7.50	per meter per month
Non-Residential	-	20.00	per meter per month
Carriage (T-4)	-	220.00	per delivery point per month
Transportation Administration Fee	-	50.00	per customer per meter

		Sales (G-1)	Transport (T-2)	Carriage (T-4)	
First	300[1] Mcf	@ 4.3085 per Mcf	@ 1.9121 per Mcf	@ 1.1900 per Mcf	(I, I, N)
Next	14,700[1] Mcf	@ 3.7775 per Mcf	@ 1.3811 per Mcf	@ 0.6590 per Mcf	(I, I, N)
Over	15,000 Mcf	@ 3.5485 per Mcf	@ 1.1521 per Mcf	@ 0.4300 per Mcf	(I, I, N)

High Load Factor Firm Service

HLF demand charge/Mcf		@ 4.3145	@ 4.3145 per Mcf of daily Contract Demand	(I)
First	300[1] Mcf	@ 3.7492 per Mcf	@ 1.3528 per Mcf	(I, I)
Next	14,700[1] Mcf	@ 3.2182 per Mcf	@ 0.8218 per Mcf	(I, I)
Over	15,000 Mcf	@ 2.9892 per Mcf	@ 0.5928 per Mcf	(I, I)

Interruptible Service

Base Charge	-	$220.00	per delivery point per month
Transportation Administration Fee	-	50.00	per customer per meter

		Sales (G-2)	Transport (T-2)	Carriage (T-3)	
First	15,000[1] Mcf	@ 3.1194 per Mcf	@ 0.7230 per Mcf	@ 0.5300 per Mcf	(I, I, N)
Over	15,000 Mcf	@ 2.9485 per Mcf	@ 0.5521 per Mcf	@ 0.3591 per Mcf	(I, I, N)

[1] All gas consumed by the customer (sales, transportation, and carriage; firm, high load factor, and interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

ISSUED: **December 29, 1999** **Effective:** **February 1, 2000**

(Issued by Authority of an Order of the Public Service Commission in Case No. 99-070 A dated .)

ISSUED BY: **Vice President - Rates & Regulatory Affairs**

For Entire Service Area
P.S.C. No. 20
Seventy-eighth SHEET No. 5
Cancelling
Seventy-seventh SHEET No. 5

WESTERN KENTUCKY GAS COMPANY

Current Gas Cost Adjustments

Case No. 99-070 A

Applicable

For all Mcf billed under General Sales Service (G-1) and Interruptible Sales Service (G-2).

GCA = (EGC - BCOG) + CF + RF + PBRRF

Gas Cost Adjustment Components	G - 1	HLF G - 1	G-2	
EGC (Expected Gas Cost Component)	3.2970	2.7377	2.7377	(I, I, I)
CF (Correction Factor)	(0.2239)	(0.2239)	(0.2239)	(N, N, N)
RF (Refund Adjustment)	(0.0480)	(0.0480)	(0.0178)	(N, N, N)
PBRRF (Peformanced Based Rate Recovery Factor)	0.0934	0.0934	0.0934	(N, N, N)
GCA (Gas Cost Adjustment)	$3.1185	$2.5592	$2.5894	(I, I, I)

ISSUED: **December 29, 1999** **Effective:** **February 1, 2000**

(Issued by Authority of an Order of the Public Service Commission in Case No. 99-070 A dated .)

ISSUED BY: **Vice President - Rates & Regulatory Affairs**

For Entire Service Area
P.S.C. No. 20
Seventy-eighth SHEET No. 6
Cancelling
Seventy-seventh SHEET No. 6

WESTERN KENTUCKY GAS COMPANY

Current Transportation and Carriage

Case No. 99-070 A

The General Transportation Rate T-2 and Carriage Service (Rates T-3 and T-4) for each respective service net monthly rate is as follows:

System Lost and Unaccounted gas percentage: 1.9%

					Simple Margin		Non-Commodity		Gross Margin		
Transportation Service (T-2)[1]											
a) Firm Service											
	First	300[2]	Mcf	@	$1.1900	+	$0.7221	=	$1.9121	per Mcf	(I)
	Next	14,700[2]	Mcf	@	0.6590	+	0.7221	=	1.3811	per Mcf	(I)
	All over	15,000	Mcf	@	0.4300	+	0.7221	=	1.1521	per Mcf	(I)
b) High Load Factor Firm Service (HLF)											
	Demand			@	$0.0000	+	4.3145	=	$4.3145	per Mcf of daily contract demand	(I)
	First	300[2]	Mcf	@	$1.1900	+	$0.1628	=	$1.3528	per Mcf	(I)
	Next	14,700[2]	Mcf	@	0.6590	+	0.1628	=	0.8218	per Mcf	(I)
	All over	15,000	Mcf	@	0.4300	+	0.1628	=	0.5928	per Mcf	(I)
c) Interruptible Service											
	First	15,000[2]	Mcf	@	$0.5300	+	$0.1930	=	$0.7230	per Mcf	(I)
	All over	15,000	Mcf	@	0.3591	+	0.1930	=	0.5521	per Mcf	(I)
Carriage Service[3]											
Firm Service (T-4)											
	First	300	[2] Mcf	@	$1.1900	+	$0.0000	=	$1.1900	per Mcf	(N)
	Next	14,700	[2] Mcf	@	0.6590	+	0.0000	=	0.6590	per Mcf	(N)
	All over	15,000	[2] Mcf	@	0.4300	+	0.0000	=	0.4300	per Mcf	(N)
Interruptible Service (T-3)											
	First	15,000[2]	Mcf	@	$0.5300	+	$0.0000	=	$0.5300	per Mcf	(N)
	All over	15,000	Mcf	@	0.3591	+	0.0000	=	0.3591	per Mcf	(N)

---

[1] Includes standby sales service under corresponding sales rates.

[2] All gas consumed by the customer (Sales and transportation; firm, high load factor, interruptible, and carriage) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

[3] Excludes standby sales service.

ISSUED: **December 29, 1999** **Effective:** **February 1, 2000**

(Issued by Authority of an Order of the Public Service Commission in Case No. 99-070 A dated .)

ISSUED BY: **Vice President - Rates & Regulatory Affairs**

Western Kentucky Gas Company
Comparison of Current and Previous Cases
Firm Sales Service

Exhibit A
Page 1 of 5

Line No.	Description	Case No.		Difference
		99-070	99-070 A	
		$/Mcf	$/Mcf	$/Mcf
1	**G-1**			
2				
3	Commodity Charge (Base Rate per Case No. 99-070):			
4	First 300 Mcf	1.1900	1.1900	0.0000
5	Next 14,700 Mcf	0.6590	0.6590	0.0000
6	Over 15,000 Mcf	0.4300	0.4300	0.0000
7				
8	Gas Cost Adjustment Components			
9	EGC (Expected Gas Cost):			
10	Commodity	2.4572	2.5337	0.0765
11	Demand	0.7568	0.7603	0.0035
12	Take-Or-Pay	0.0000	0.0000	0.0000
13	Transition Costs	0.0030	0.0030	0.0000
14	Total EGC	3.2170	3.2970	0.0800
15	Less: BCOG (Base Cost of Gas)	0.0000	0.0000	0.0000
16	CF (Correction Factor)	(0.2239)	(0.2239)	0.0000
17	RF (Refund Adjustment)	(0.0480)	(0.0480)	0.0000
18	PBRRF (Performance Based Rate Recovery Factor)	0.0247	0.0934	0.0687
19	GCA (Gas Cost Adjustment)	2.9698	3.1185	0.1487
20	Total Billing Cost of Gas	2.9698	3.1185	0.1487
21				
22	Commodity Charge (GCA included):			
23	First 300 Mcf	4.1598	4.3085	0.1487
24	Next 14,700 Mcf	3.6288	3.7775	0.1487
25	Over 15,000 Mcf	3.3998	3.5485	0.1487
26				
27	**HLF (High Load Factor)**			
28				
29	Commodity Charge (Base Rate per Case No. 99-070):			
30	First 300 Mcf	1.1900	1.1900	0.0000
31	Next 14,700 Mcf	0.6590	0.6590	0.0000
32	Over 15,000 Mcf	0.4300	0.4300	0.0000
33				
34	Gas Cost Adjustment Components			
35	EGC (Expected Gas Cost):			
36	Commodity	2.4572	2.5337	0.0765
37	Demand	0.2001	0.2010	0.0009
38	Take-Or-Pay	0.0000	0.0000	0.0000
39	Transition Costs	0.0030	0.0030	0.0000
40	Total EGC	2.6603	2.7377	0.0774
41	Less: BCOG (Base Cost of Gas)	0.0000	0.0000	0.0000
42	CF (Correction Factor)	(0.2239)	(0.2239)	0.0000
43	RF (Refund Adjustment)	(0.0480)	(0.0480)	0.0000
44	PBRRF (Perfornace Based Rate Recovery Factor)	0.0247	0.0934	0.0687
45	GCA (Gas Cost Adjustment)	2.4131	2.5592	0.1461
46	Total Cost of Gas to Bill (excludes MDQ Demand)	2.4131	2.5592	0.1461
47				
48	Commodity Charge (GCA included):			
49	First 300 Mcf	3.6031	3.7492	0.1461
50	Next 14,700 Mcf	3.0721	3.2182	0.1461
51	Over 15,000 Mcf	2.8431	2.9892	0.1461
52				
53	HLF Demand			
54	Contract Demand Factor	4.2945	4.3145	0.0200

Western Kentucky Gas Company
Comparison of Current and Previous Cases
Interruptible Sales Service

Exhibit A

Line		Case No.		
No.	Description	99-070	99-070 A	Difference
		$/Mcf	$/Mcf	$/Mcf
1	G-2			
2				
3	Commodity Charge (Base Rate per Case No. 99-070):			
4	First 15,000 Mcf	0.5300	0.5300	0.0000
5	Over 15,000 Mcf	0.3591	0.3591	0.0000
6				
7	Gas Cost Adjustment Components			
8	Expected Gas Cost (EGC):			
9	Commodity	2.4572	2.5337	0.0765
10	Demand	0.2001	0.2010	0.0009
11	Take-Or-Pay	0.0000	0.0000	0.0000
12	Transition Costs	0.0030	0.0030	0.0000
13	Total EGC	2.6603	2.7377	0.0774
14	Less: Base Cost of Gas (BCOG)	0.0000	0.0000	0.0000
15	Correction Factor (CF)	(0.2239)	(0.2239)	0.0000
16	Refund Adjustment (RF)	(0.0178)	(0.0178)	0.0000
17	Perfornace Based Rate Recovery Factor (PBRRF)	0.0247	0.0934	0.0687
18	Gas Cost Adjustment (GCA)	2.4433	2.5894	0.1461
19	Total Cost of Gas to Bill	2.4433	2.5894	0.1461
20				
21	Commodity Charge (GCA included):			
22	First 15,000 Mcf	2.9733	3.1194	0.1461
23	Over 15,000 Mcf	2.8024	2.9485	0.1461
24				
25				
26	Monthly Refund Factor			

27 28		Case No.	Effective Date	G - 1	G - 1 / HLF	G - 2
29	1 -	95-010 PP	03/01/99	0.0000	0.0000	0.0000
30	2 -	95-010 QQ	04/01/99	(0.0429)	(0.0429)	(0.0127)
31	3 -	95-010 RR	05/01/99	0.0000	0.0000	0.0000
32	4 -	95-010 SS	06/01/99	0.0000	0.0000	0.0000
33	5 -	95-010 TT	07/01/99	0.0000	0.0000	0.0000
34	6 -	95-010 UU	08/01/99	0.0000	0.0000	0.0000
35	7 -	95-010 VV	09/01/99	0.0000	0.0000	0.0000
36	8 -	95-010 WW	10/01/99	(0.0023)	(0.0023)	(0.0023)
37	9 -	95-010 XX	11/01/99	0.0000	0.0000	0.0000
38	10 -	95-010 YY	12/01/99	0.0000	0.0000	0.0000
39	11 -	99-070	01/01/00	(0.0028)	(0.0028)	(0.0028)
40	12 -	99-070 A	02/01/00	0.0000	0.0000	0.0000
41						
42	Total Supplier Refund Adjustment (RF)			(0.0480)	(0.0480)	(0.0178)
43						

Western Kentucky Gas Company
Comparison of Current and Previous Cases
Firm Transportation Service

Exhibit A

Line		Case No.		
No.	Description	99-070	99-070 A	Difference
		$/Mcf	$/Mcf	$/Mcf
1	<u>T-2 \ G-1</u>			
2				
3				
4	<u>Simple Margin (Base Rate per Case No. 99-070):</u>			
5	First 300 Mcf	1.1900	1.1900	0.0000
6	Next 14,700 Mcf	0.6590	0.6590	0.0000
7	Over 15,000 Mcf	0.4300	0.4300	0.0000
8				
9	<u>Non-Commodity Components:</u>			
10	Demand	0.7568	0.7603	0.0035
11	Take-Or-Pay	0.0000	0.0000	0.0000
12	Transition Costs	0.0030	0.0030	0.0000
13	RF (Refund Adjustment)	(0.0412)	(0.0412)	0.0000
14	Total	0.7186	0.7221	0.0035
15				
16	<u>Gross Margin:</u>			
17	First 300 Mcf	1.9086	1.9121	0.0035
18	Next 14,700 Mcf	1.3776	1.3811	0.0035
19	Over 15,000 Mcf	1.1486	1.1521	0.0035
20				
21	<u>T-2\G-1\HLF</u>			
22				
23	<u>Simple Margin (Base Rate per Case No. 99-070):</u>			
24	First 300 Mcf	1.1900	1.1900	0.0000
25	Next 14,700 Mcf	0.6590	0.6590	0.0000
26	Over 15,000 Mcf	0.4300	0.4300	0.0000
27				
28	<u>Non-Commodity Components:</u>			
29	Demand	0.2001	0.2010	0.0009
30	Take-Or-Pay	0.0000	0.0000	0.0000
31	Transition Costs	0.0030	0.0030	0.0000
32	RF (Refund Adjustment)	(0.0412)	(0.0412)	0.0000
33	Total	0.1619	0.1628	0.0009
34				
35	<u>Gross Margin (Excluding HLF Demand):</u>			
36	First 300 Mcf	1.3519	1.3528	0.0009
37	Next 14,700 Mcf	0.8209	0.8218	0.0009
38	Over 15,000 Mcf	0.5919	0.5928	0.0009
39				
40	<u>HLF Demand</u>			
41	Contract Demand Factor	4.2945	4.3145	0.0200
42				

Western Kentucky Gas Company
Comparison of Current and Previous Cases
Firm Transportation Service

Exhibit A

Line		Case No.		
No.	Description	99-070	99-070 A	Difference
		$/Mcf	$/Mcf	$/Mcf
1	**Carriage Service**			
2				
3	Firm Service (T-4)			
4	Simple Margin (Base Rate per Case No. 99-070):			
5	First 300 Mcf	1.1900	1.1900	0.0000
6	Next 14,700 Mcf	0.6590	0.6590	0.0000
7	Over 15,000 Mcf	0.4300	0.4300	0.0000
8				
9	Non-Commodity Components:			
11	Take-Or-Pay	0.0000	0.0000	0.0000
13	RF (Refund Adjustment)	0.0000	0.0000	0.0000
14	Total	0.0000	0.0000	0.0000
15				
16	Gross Margin:			
17	First 300 Mcf	1.1900	1.1900	0.0000
18	Next 14,700 Mcf	0.6590	0.6590	0.0000
19	Over 15,000 Mcf	0.4300	0.4300	0.0000
20				

Western Kentucky Gas Company

Comparison of Current and Previous Cases

Interruptible Transportation and Carriage Service

Exhibit A

Page 5 of 5

Line No.	Description	Case No.		
		99-070	99-070 A	Difference
		$/Mcf	$/Mcf	$/Mcf
1	**General Transporation (T-2)**			
2				
3	Interruptible Service (G-2)			
4	Simple Margin (Base Rate per Case No. 99-070):			
5	First 15,000 Mcf	0.5300	0.5300	0.0000
6	Over 15,000 Mcf	0.3591	0.3591	0.0000
7				
8	Non-Commodity Components:			
9	Demand	0.2001	0.2010	0.0009
10	Take-Or-Pay	0.0000	0.0000	0.0000
11	Transition Costs	0.0030	0.0030	0.0000
12	RF (Refund Adjustment)	(0.0110)	(0.0110)	0.0000
13	Total	0.1921	0.1930	0.0009
14				
15	Gross Margin:			
16	First 15,000 Mcf	0.7221	0.7230	0.0009
17	Over 15,000 Mcf	0.5512	0.5521	0.0009
18				
19	**Carriage Service**			
20				
21	Carriage Service (T-3)			
22	Simple Margin (Base Rate per Case No. 99-070):			
23	First 15,000 Mcf	0.5300	0.5300	0.0000
24	Over 15,000 Mcf	0.3591	0.3591	0.0000
25				
26	Non-Commodity Components:			
28	Take-Or-Pay	0.0000	0.0000	0.0000
30	RF (Refund Adjustment)	0.0000	0.0000	0.0000
31	Total	0.0000	0.0000	0.0000
32				
33	Gross Margin:			
34	First 15,000 Mcf	0.5300	0.5300	0.0000
35	Over 15,000 Mcf	0.3591	0.3591	0.0000
36				

Western Kentucky Gas Company
Expected Gas Cost - Non Commodity
Texas Gas

Exhibit B

				(1)	(2)	(3)	(4)	(5)
							Non-Commodity	
Line No.	**Description**		**Tariff Sheet No.**	**Annual Units**	**Rate**	**Total**	**Demand**	**Transition Costs**
				MMbtu	$/MMbtu	$	$	$
1	**SL to Zone 2**							
2	NNS Contract #	N0210		12,617,673				
3	Base Rate		10		0.3158	3,984,660	3,984,660	
4	GSR		10		0.0000	0		0
5	TCA Adjustment		10		0.0000	0	0	
6	Unrec TCA Surch		10		0.0000	0	0	
7	ISS Credit		10		0.0000	0	0	
8	Misc Rev Cr Adj		10		(0.0010)	(12,618)	(12,618)	
9	GRI		10		0.0076	95,894	95,894	
6								
7	Total SL to Zone 2			12,617,673		4,067,936	4,067,936	0
8								
9	**SL to Zone 3**							
10	NNS Contract #	N0340		27,480,375				
11	Base Rate		10		0.3498	9,612,635	9,612,635	
12	GSR		10		0.0000	0		0
13	TCA Adjustment		10		0.0000	0	0	
14	Unrec TCA Surch		10		0.0000	0	0	
15	ISS Credit		10		0.0000	0	0	
16	Misc Rev Cr Adj		10		(0.0010)	(27,480)	(27,480)	
17	GRI		10		0.0076	208,851	208,851	
18								
19	FT Contract #	3355		3,130,605				
20	Base Rate		11		0.2529	791,730	791,730	
21	GSR		11		0.0000	0		0
22	TCA Adjustment		11		0.0000	0	0	
23	Unrec TCA Surch		11		0.0000	0	0	
24	ISS Credit		11		0.0000	0	0	
25	Misc Rev Cr Adj		11		(0.0010)	(3,131)	(3,131)	
26	GRI		11		0.0076	23,793	23,793	
27								
28								
29	Total SL to Zone 3			30,610,980		10,606,398	10,606,398	0
30								
31								
32								
33								
34								
35								
36								
37								
38								
39								
40								

Western Kentucky Gas Company
Expected Gas Cost - Non Commodity
Texas Gas

Exhibit B

			(1)	(2)	(3)	(4)	(5)
					Non-Commodity		
Line No.	**Description**	**Tariff Sheet No.**	**Annual Units**	**Rate**	**Total**	**Demand**	**Transition Costs**
			MMbtu	$/MMbtu	$	$	$
1	**Zone 1 to Zone 3**						
2	FT Contract # 3355		2,344,395				
3	Base Rate	11		0.2227	522,097	522,097	
4	GSR	11		0.0000	0		0
5	TCA Adjustment	11		0.0000	0	0	
6	Unrec TCA Surch	11		0.0000	0	0	
7	ISS Credit	11		0.0000	0	0	
8	Misc Rev Cr Adj	11		(0.0010)	(2,344)	(2,344)	
9	GRI	11		0.0076	17,817	17,817	
6							
7	Total Zone 1 to Zone 3		2,344,395		537,570	537,570	0
8							
9	**SL to Zone 4**						
10	NNS Contract # N0410		3,320,769				
11	Base Rate	10		0.4096	1,360,187	1,360,187	
12	GSR	10		0.0000	0		0
13	TCA Adjustment	10		0.0000	0	0	
14	Unrec TCA Surch	10		0.0000	0	0	
15	ISS Credit	10		0.0000	0	0	
16	Misc Rev Cr Adj	10		(0.0010)	(3,321)	(3,321)	
17	GRI	10		0.0076	25,238	25,238	
18							
19	FT Contract # 3819		1,277,500				
20	Base Rate	11		0.3043	388,743	388,743	
21	GSR	11		0.0000	0		0
22	TCA Adjustment	11		0.0000	0	0	
23	Unrec TCA Surch	11		0.0000	0	0	
24	ISS Credit	11		0.0000	0	0	
25	Misc Rev Cr Adj	11		(0.0010)	(1,278)	(1,278)	
26	GRI	11		0.0076	9,709	9,709	
27							
28	Total SL to Zone 4		4,598,269		1,779,278	1,779,278	0
29							
30	Total SL to Zone 2		12,617,673		4,067,936	4,067,936	0
31	Total SL to Zone 3		30,610,980		10,606,398	10,606,398	0
32	Total Zone 1 to Zone 3		2,344,395		537,570	537,570	0
33							
34	Total Texas Gas		50,171,317		16,991,182	16,991,182	0
35							
36							
37	Vendor Reservation Fees (Fixed)				166,842	166,842	
38							
39	TOP & Direct Billed Transition costs				0		
40							
41	Total Texas Gas Area Non-Commodity				17,158,024	17,158,024	0
42							
43							

Western Kentucky Gas Company
Expected Gas Cost - Non Commodity
Tennessee Gas

			(1)	(2)	(3)	(4)	(5)
					Non-Commodity		
Line No.	**Description**	**Tariff Sheet No.**	**Annual Units**	**Rate**	**Total**	**Demand**	**Transition Costs**
			MMbtu	$/MMbtu	$	$	$
1	**0 to Zone 2**						
2	FT-G Contract # 2546.1		13,046	9.4100			
3	Base Rate	23B		9.0600	118,197	118,197	
4	Settlement Surcharge	23B		0.0000	0		0
5	PCB Adjustment	23B		0.3500	4,566		4,566
6							
7	FT-G Contract # 2548.1		4,186	9.4100			
8	Base Rate	23B		9.0600	37,925	37,925	
9	Settlement Surcharge	23B		0.0000	0		0
10	PCB Adjustment	23B		0.3500	1,465		1,465
11							
12	FT-G Contract # 2550.1		5,870	9.4100			
13	Base Rate	23B		9.0600	53,182	53,182	
14	Settlement Surcharge	23B		0.0000	0		0
15	PCB Adjustment	23B		0.3500	2,055		2,055
16							
17	FT-G Contract # 2551.1		4,222	9.4100			
18	Base Rate	23B		9.0600	38,251	38,251	
19	Settlement Surcharge	23B		0.0000	0		0
20	PCB Adjustment	23B		0.3500	1,478		1,478
21							
22							
23	Total Zone 0 to 2		27,324		257,119	247,555	9,564
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							

Western Kentucky Gas Company
Expected Gas Cost - Non Commodity
Tennessee Gas

Exhibit B

			(1)	(2)	(3)	(4)	(5)
					Non-Commodity		
Line No.	**Description**	**Tariff Sheet No.**	**Annual Units**	**Rate**	**Total**	**Demand**	**Transition Costs**
			MMbtu	$/MMbtu	$	$	$
1	**1 to Zone 2**						
2	FT-G Contract # 2546		115,954	7.9300			
3	Base Rate	23B		7.6200	883,569	883,569	
4	Settlement Surcharge	23B		0.0000	0		0
5	PCB Adjustment	23B		0.3100	35,946		35,946
6							
7	FT-G Contract # 2548		43,174	7.9300			
8	Base Rate	23B		7.6200	328,986	328,986	
9	Settlement Surcharge	23B		0.0000	0		0
10	PCB Adjustment	23B		0.3100	13,384		13,384
11							
12	FT-G Contract # 2550		61,110	7.9300			
13	Base Rate	23B		7.6200	465,658	465,658	
14	Settlement Surcharge	23B		0.0000	0		0
15	PCB Adjustment	23B		0.3100	18,944		18,944
16							
17	FT-G Contract # 2551		42,783	7.9300			
18	Base Rate	23B		7.6200	326,006	326,006	
19	Settlement Surcharge	23B		0.0000	0		0
20	PCB Adjustment	23B		0.3100	13,263		13,263
21							
22	Total Zone 1 to 2		263,021		2,085,756	2,004,219	81,537
23							
24	Total Zone 0 to 2		27,324		257,119	247,555	9,564
25							
26	Total Zone 1 to 2 and Zone 0 to 2		290,345		2,342,875	2,251,774	91,101
27							
28	**Gas Storage**						
29	Production Area:						
30	Demand	27	34,968	2.0200	70,635	70,635	
31	Space Charge	27	4,916,148	0.0248	121,920	121,920	
32	Market Area:						
33	Demand	27	237,408	1.1700	277,767	277,767	
34	Space Charge	27	10,846,308	0.0187	202,826	202,826	
35	Total Storage				673,148	673,148	
36							
37	Vendor Reservation Fees (Fixed)				94,151	94,151	
38							
39	TOP & Direct Billed Transition costs				0	0	0
40							
41	Total Tennessee Gas Area FT-G Non-Commodity				3,110,174	3,019,073	91,101
42							
43							
44							
45							
46							
47							
48							
49							
50							
51							

Western Kentucky Gas Company
Expected Gas Cost - Commodity
Purchases in Texas Gas Service Area

Exhibit B

				(1)	(2)	(3)	(4)
Line No.	**Description**	**Tariff Sheet No.**		**Purchases**		**Rate**	**Total**
				Mcf	MMbtu	$/MMbtu	$
1	No Notice Service				511,500		
2	Indexed Gas Cost					2.7500	1,406,625
3	Commodity	10				0.0412	21,074
4	Fuel and Loss Retention @	14	3.33%			0.0947	48,439
5						2.8859	1,476,138
6							
7	Firm Transportation				1,314,500		
8	Indexed Gas Cost					2.7500	3,614,875
9	Base (Weighted on MDQs)	11A				0.0268	35,229
10	TCA Adjustment	11A				0.0000	0
11	Unrecovered TCA Surcharge	11A				0.0000	0
12	Cash-out Adjustment	11A				0.0000	0
13	GRI	11A				0.0075	9,859
14	ACA	11A				0.0022	2,892
15	Fuel and Loss Retention @	14	2.93%			0.0830	109,104
16						2.8695	3,771,959
17	No Notice Storage						
18	Net (Injections)/Withdrawals				1,080,000		
19	Indexed Gas Cost					2.7500	2,970,000
20	Commodity (Zone 3)	10				0.0412	44,496
21	Fuel and Loss Retention @	14	3.33%			0.0947	102,276
22						2.8859	3,116,772
23							
24							
25	Total Purchases in Texas Area				2,906,000	2.8785	8,364,869
26							
27							
28	Used to allocate transportation non-commodity						

29					
30		Annualized		Commodity	
31		MDQs in		Charge	Weighted
32	Texas Gas	MMbtu	Allocation	$/MMbtu	Average
33	SL to Zone 2	12,617,673	25.15%	$0.0221	$ 0.0056
34	SL to Zone 3	30,610,980	61.01%	0.0281	0.0171
35	1 to Zone 3	2,344,395	4.67%	0.0262	0.0012
36	SL to Zone 4	4,598,269	9.17%	0.0312	0.0029
37	Total	50,171,317	100.00%		$ 0.0268
38					
39	Tennessee Gas				
40	0 to Zone 2	27,324	9.41%	0.0880	$ 0.0083
41	1 to Zone 2	263,021	90.59%	0.0776	0.0703
42	Total	290,345	100.00%		$ 0.0786
43					

Western Kentucky Gas Company
Expected Gas Cost - Commodity
Purchases in Tennessee Gas Service Area

Exhibit B

Line No.	Description	Tariff Sheet No.		(1) Purchases Mcf	(2) Purchases MMbtu	(3) Rate $/MMbtu	(4) Total $
1	FT-A and FT-G				215,800		
2	Indexed Gas Cost					2.7500	593,450
3	Base Commodity (Weighted on MDQs)					0.0786	16,962
4	GRI	23C				0.0180	3,884
5	ACA	23C				0.0022	475
6	Transition Cost	23C				0.0225	4,856
7	Fuel and Loss Retention	29	4.28%			0.1230	26,543
8						2.9943	646,170
9							
10							
11	FT-GS				44,200		
12	Indexed Gas Cost					2.7500	121,550
13	Base Rate	20				0.5844	25,830
14	GRI	20				0.0180	796
15	ACA	20				0.0022	97
16	PCB Adjustment	20				0.0192	849
17	Settlement Surcharge	20				0.0000	0
18	Fuel and Loss Retention	29	4.28%			0.1230	5,437
19						3.4968	154,559
20							
21							
22	Gas Storage						
23	FT-A & FT-G Market Area (Injections)/Withdrawals				249,000		
24	Indexed Gas Cost	(Line 8 - Line 7)				2.8713	714,954
25	Injection Rate	27				0.0102	2,540
26	Fuel and Loss Retention	27	1.49%			0.0434	10,807
27	Total					2.9249	728,301
28							
29							
30	FT-GS Market Area (Injections)/Withdrawals				51,000		
31	Indexed Gas Cost	(Line 19- Line 18)				3.3738	172,064
32	Injection Rate	27				0.0102	520
33	Fuel and Loss Retention	27	1.49%			0.0510	2,601
34	Total					3.4350	175,185
35							
36							
37	Total Tennessee Gas Zones				560,000	3.0432	1,704,215
38							
39							

Western Kentucky Gas Company

Expected Gas Cost

Trunkline Gas

Exhibit B

Commodity

				(1)	(2)	(3)	(4)
Line No.	Description	Tariff Sheet No.		Purchases		Rate	Total
				Mcf	MMbtu	$/MMbtu	$
1	Firm Transportation						
2	Expected Volumes				174,000		
3	Indexed Gas Cost					2.7500	478,500
4	Base Commodity					0.0251	4,367
5	GRI	6				0.0073	1,270
6	ACA	6				0.0022	383
7	Fuel and Loss Retention	6	0.98%			0.0272	4,733
8						2.8118	489,253
9							
10							

Non-Commodity

		(1)	(2)	(3)	(4)	(5)	(6)
				Non-Commodity			
Line No.	Description	Tariff Sheet No.	Annual Units	Rate	Total	Demand	Transition Costs
			MMbtu	$/MMbtu	$	$	$
11	FT-G Contract # 014573		2,032,600				
12	Discount Rate on MDQs			0.2679	544,534	544,534	
13							
14			92,125				
15	GRI Surcharge	6		0.2300	21,189	21,189	
16							
17	Reservation Fee				20,480	20,480	
18							
19	Total Trunkline Area Non-Commodity				586,203	586,203	
20							
21							

Western Kentucky Gas Company
Demand Charge Calculation

Exhibit B

Line No.		(1)	(2)	(3)	(4)	(5)	(6)
1	Total Demand Cost:						
2	Texas Gas	$16,991,182					
3	Reservation Fees (Fixed)	166,842					
4	Tennessee Gas	3,019,073					
5	Trunkline	586,203					
6	Total	$20,763,300					
7							
8			Allocated	Related	Monthly Demand Charge		
9	Demand Cost Allocation:	Factors	Demand	Volumes	Firm	Interruptible	HLF
10	All	0.2943	$6,110,639	30,400,000	0.2010	0.2010	0.2010
11	Firm	0.7057	14,652,661	26,200,000	0.5593	NA	NA
12	Total	1.0000	$20,763,300		0.7603	0.2010	0.2010
13							
14			Volumetric Basis for				
15		Annualized	Monthly Demand Charge				
16		Mcf @14.65	All	Firm			
17	Firm Service						
18	Sales:						
19	G-1	24,200,000	24,200,000	24,200,000	0.7603		
20	HLF	300,000	300,000		0.2010 + HLF MDQ Demand		
21	LVS-1	1,500,000	1,500,000	1,500,000	0.7603		
22	Total Firm Sales	26,000,000	26,000,000	25,700,000			
23							
24	Transportation:						
25	T-2 \ G-1	500,000	500,000	500,000	0.7603		
26	HLF	0	0		0.2010		
27	Total Firm Service	26,500,000	26,500,000	26,200,000			
28							
29	Interruptible Service						
30	Sales:						
31	G-2	2,000,000	2,000,000		0.7603	0.2010	
32	LVS-2	1,200,000	1,200,000		0.7603	0.2010	
33	Total Sales	3,200,000	3,200,000				
34							
35	Transportation:						
36	T-2 \ G-2	700,000	700,000		0.7603	0.2010	
37							
38	Total Interruptible Service	3,900,000	3,900,000				
39							
40	Carriage Service						
41	T-3 & T-4	20,100,000					
42							
43	Total	50,500,000	30,400,000	26,200,000			
44							
45	HLF MDQ Demand						
46	Firm Demand Cost		$14,652,661				
47	Peak Day Thru-put		283,011	Mcf/Peak Day			
48	Times:		12	Months/Year			
49	Total Annualized Peak Day Demand		3,396,132				
50	Demand Charge per MDQ		$4.3145	/ MDQ of Customer's Contract			
51							
52							
53	Note: LVS Credit =	($1,381,650)					

Western Kentucky Gas Company
Take-or-Pay and Transition Charge Calculation

Exhibit B

Line No.		(1)	(2)	(3)	(4)	(5)	(6)
1	Other Fixed Charges	Take-or-Pay	Transition				
2	Texas Gas		$0				
3	Tennessee Gas		91,101				
4	Total	$0	$91,101				
5							
6							
7			Related	Charge			
8	Other Fixed Charges	Amount	Volumes	$/Mcf			
9	Take-or-Pay	0	50,500,000	0.0000			
10	Transition	91,101	30,400,000	0.0030			
11	Total	$91,101		0.0030			
12							
13							
14			Volumetric Basis for				
15		Annual	Other Fixed Charges			Other Fixed Charges	
16		Expected Mcf	Take-or-Pay	Transition		Take-or-Pay	Transition
17	Firm Service						
18	Sales:						
19	G-1	24,200,000	24,200,000	24,200,000			0.0030
20	HLF	300,000	300,000	300,000			0.0030
21	LVS-1	1,500,000	1,500,000	1,500,000			0.0030
22	Total Firm Sales	26,000,000	26,000,000	26,000,000			
23							
24	Transportation:						
25	T-2 \ G-1	500,000	500,000	500,000			0.0030
26	T-2 \ G-1 \ HLF	0					0.0030
27	Total Firm Service	26,500,000	26,500,000	26,500,000			
28							
29	Interruptible Service						
30	Sales:						
31	G-2	2,000,000	2,000,000	2,000,000			0.0030
32	LVS-2	1,200,000	1,200,000	1,200,000			0.0030
33	Total Sales	3,200,000	3,200,000	3,200,000			
34							
35	Transportation:						
36	T-2 \ G-2	700,000	700,000	700,000			0.0030
37							
38	Total Interruptible Service	3,900,000	3,900,000	3,900,000			
39							
40	Carriage Service						
41	T-3 & T-4	20,100,000	20,100,000	NA			
42							
43	Total	50,500,000	50,500,000	30,400,000			
44							
45							
46	Note: LVS Credit =	($8,100)					
47							

Western Kentucky Gas Company
Expected Gas Cost - Commodity
Total System

Line No.	Description	(1)	(2)	(3)	(4)
		Purchases		**Rate**	**Total**
		Mcf	MMbtu	$/MMbtu	$
1	**Texas Gas Area**				
2	No Notice Service	499,024	511,500	2.8859	1,476,138
3	Firm Transportation	1,282,439	1,314,500	2.8695	3,771,959
4	No Notice Storage	1,053,659	1,080,000	2.8859	3,116,772
5	Total Texas Gas Area	2,835,122	2,906,000	2.8785	8,364,869
6					
7	**Tennessee Gas Area**				
8	FT-A and FT-G	207,500	215,800	2.9943	646,170
9	FT-GS	42,500	44,200	3.4968	154,559
10	Gas Storage				
11	FT-A and FT-G Injections	239,423	249,000	2.9249	728,301
12	FT-GS Withdrawals	49,038	51,000	3.4350	175,185
13		538,461	560,000	3.0432	1,704,215
14	**Trunkline Gas Area**				
15	Firm Transportation	168,116	174,000	2.8118	489,253
16					
17					
18	**WKG System Storage**				
19	Injections	0	0	0.0000	0
20	Withdrawals	702,439	720,000	0.0000	0
21	Net WKG Storage	702,439	720,000	0.0000	0
22					
23					
24	Local Production	34,146	35,000	2.8695	100,433
25					
26					
27					
28	Total Commodity Purchases	4,278,284	4,395,000	2.4252	10,658,770
29					
30	Lost & Unaccounted for @ 1.9%	81,287	83,505		
31					
32	Total Deliveries	4,196,997	4,311,495	2.4722	10,658,770
33					
34	LVS Commodity Credit to System				
35	LVS Sales	(50,000)	(51,364)	2.9490	(151,472)
36					
37					
38	Total Expected Commodity Cost	4,146,997	4,260,131	2.4664	10,507,298
39					
40	Expected Commodity Cost ($/Mcf)			2.5337	
41					
42					
43					

Western Kentucky Gas Company

Load Factor Calculation for Demand Allocation

Line No.	Description	MCF	
	Annualized Volumes Subject to Demand Charges		
1	Sales Volume	26,500,000	
2	Large Volume Sales (Annualized)	2,700,000	
3	Transportation	1,200,000	
4	Total Mcf Billed Demand Charges	30,400,000	
5	Divided by: Days/Year	365	
7	Average Daily Sales and Transport Volumes	83,288	
8			
10	Peak Day Sales and Transportation Volume		
11	Estimated total company firm requirements for 5 degree average		
12	temperature day from Peak Day Book - with adjustments per rate filing	283,011	Mcf/Peak Day
13			
14			
15	New Load Factor (line 7 / line 12)	**0.2943**	

Exhibit C
Page 1 of 13

as Gas Transmission Corporation
C Gas Tariff
st Revised Volume No. 1

Thirtieth Revised Sheet No. 10
Superseding Twenty-ninth Revised Sheet No. 10

Currently Effective Maximum Transportation Rates ($ per MMBtu) For Service Under Rate Schedule NNS

	Base Tariff Rates (1)	Sec. 33.3 Surcharge (2)	RP97-344 MRCA (3)	GRI (1) (4)	FERC ACA (5)	Currently Effective Rates (6)
ie SL						
Daily Demand	0.1123		(0.0010)	0.0076		0.1186
ommodity	0.0061			0.0075	0.0022	0.0158
verrun	0.1181	0.0175	(0.0010)	0.0075	0.0022	0.1443
e 1						
aily Demand	0.2844		(0.0010)	0.0076		0.2910
ommodity	0.0217			0.0075	0.0022	0.0314
verrun	0.3061	0.0175	(0.0010)	0.0075	0.0022	0.3323
e 2						
aily Demand	0.3158		(0.0010)	0.0076		0.3224
ommodity	0.0268			0.0075	0.0022	0.0365
errun	0.3426	0.0175	(0.0010)	0.0075	0.0022	0.3688
3						
ily Demand	0.3498		(0.0010)	0.0076		0.3564
mmodity	0.0315			0.0075	0.0022	0.0412
errun	0.3813	0.0175	(0.0010)	0.0075	0.0022	0.4075
4						
ily Demand	0.4096		(0.0010)	0.0076		0.4162
mmodity	0.0366			0.0075	0.0022	0.0463
errun	0.4462	0.0175	(0.0010)	0.0075	0.0022	0.4724

mum Rate: Demand $-0-; NNS minimum commodity base rates equal applicable NNS maximum commodity base rates.

The maximum reservation charge component of the maximum firm volumetric capacity release rate shall be the applicable maximum daily demand herein pursuant to Section 25 of the General Terms and Conditions.

GRI surcharge applicable pursuant to Section 22 of the General Terms and Conditions. The NNS daily demand adjustment for low load factor customers (load factor of 50% or less) is $0.0047.

By: K.R.Cocklin, Vice President, Rates
on: December 31st, 1998

Effective: February 1st, 1999

ED 10-25-99

Exhibit C
Page 2 of 13

Texas Gas Transmission Corporation
FERC Gas Tariff
First Revised Volume No. 1

Twenty-seventh Revised Sheet No. 11
Superseding Twenty-sixth Revised Sheet No. 11

Currently Effective Maximum Daily Demand Rates ($ per MMBtu) For Service Under Rate Schedule FT

	Base Tariff Rates (1)	RP97-344 MRCA (2)	GRI (1) (3)	Currently Effective Rates (4)
SL-SL	0.0834	(0.0010)	0.0076	0.0900
SL-1	0.1748	(0.0010)	0.0076	0.1824
SL-2	0.2122	(0.0010)	0.0076	0.2188
SL-3	0.2529	(0.0010)	0.0076	0.2595
SL-4	0.3043	(0.0010)	0.0076	0.3109
1-1	0.1448	(0.0010)	0.0076	0.1514
1-2	0.1823	(0.0010)	0.0076	0.1889
1-3	0.2227	(0.0010)	0.0076	0.2293
1-4	0.2745	(0.0010)	0.0076	0.2811
2-2	0.1248	(0.0010)	0.0076	0.1314
2-3	0.1652	(0.0010)	0.0076	0.1718
2-4	0.2170	(0.0010)	0.0076	0.2236
3-3	0.1293	(0.0010)	0.0076	0.1359
3-4	0.1811	(0.0010)	0.0076	0.1877
4-4	0.1358	(0.0010)	0.0076	0.1424

Minimum Rates: Demand $-0-

Backhaul rates equal fronthaul rates to zone of delivery.

Note: The maximum reservation charge component of the maximum firm volumetric capacity release rate shall be the applicable maximum daily demand rate herein pursuant to Section 25 of the General Terms and Conditions.

(1) GRI surcharge applicable pursuant to Section 22 of the General Terms and Conditions. The FT daily demand adjustment for low load factor customers (load factor of 50% or less) is $0.0047.

ued By: K.R.Cocklin, Vice President, Rates
ued on: December 31st. 1998

Effective: February 1st, 1999

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25-99

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Texas Gas Transmission Corporation
FERC Gas Tariff
First Revised Volume No. 1

Eighteenth Revised Sheet No. 11A
Superseding Seventeenth Revised Sheet No. 11A

Currently Effective Maximum Commodity Rates ($ per MMBtu) For Service Under Rate Schedule FT

	Base Tariff Rates (1)	GRI (2)	FERC ACA (3)	Currently Effective Rates (4)
SL-SL	0.0059	0.0075	0.0022	0.0156
SL-1	0.0161	0.0075	0.0022	0.0258
SL-2	0.0221	0.0075	0.0022	0.0318
SL-3	0.0281	0.0075	0.0022	0.0378
SL-4	0.0312	0.0075	0.0022	0.0409
1-1	0.0141	0.0075	0.0022	0.0238
1-2	0.0205	0.0075	0.0022	0.0302
1-3	0.0262	0.0075	0.0022	0.0359
1-4	0.0284	0.0075	0.0022	0.0381
2-2	0.0112	0.0075	0.0022	0.0209
2-3	0.0169	0.0075	0.0022	0.0266
2-4	0.0191	0.0075	0.0022	0.0288
3-3	0.0105	0.0075	0.0022	0.0202
3-4	0.0127	0.0075	0.0022	0.0224
4-4	0.0071	0.0075	0.0022	0.0168

Minimum Rates: Commodity minimum rates equal maximum rates.

Backhaul rates equal fronthaul rates to zone of delivery.

Issued By: K.R.Cocklin, Vice President, Rates
Issued on: November 30th, 1998

Effective: January 1st, 1999

FAXED

Texas Gas Transmission Corporation
FERC Gas Tariff
First Revised Volume No. 1

Exhibit C
Page 4 of 13

Seventh Revised Sheet No. 14
Superseding
Sixth Revised Sheet No. 14

Schedule of Currently Effective Fuel Retention Percentages Pursuant to Section 16 of the General Terms and Conditions

NNS/SGT RATE SCHEDULES

WINTER				SUMMER			
Delivery Zone	Projected Fuel Retention Percentage (PFRP)	Fuel Adjustment Percentage (FAP)	Effective Fuel Retention Percentage (EFRP)	Delivery Zone	Projected Fuel Retention Percentage (PFRP)	Fuel Adjustment Percentage (FAP)	Effective Fuel Retention Percentage (EFRP)
SL	0.20%	(0.02%)	0.18%	SL	0.15%	(0.07%)	0.08%
1	2.24%	0.27%	2.51%	1	2.08%	(0.17%)	1.91%
2	2.62%	0.09%	2.71%	2	2.27%	(0.37%)	1.90%
3	3.11%	0.22%	3.33%	3	2.45%	(0.31%)	2.14%
4	4.06%	0.25%	4.31%	4	2.73%	0.18%	2.91%

FT/IT RATE SCHEDULES

WINTER				SUMMER			
Rec/Del Zone	PFRP	FAP	EFRP	Rec/Del Zone	PFRP	FAP	EFRP
SL/SL	0.23%	0.17%	0.40%	SL/SL	0.15%	0.07%	0.22%
SL or 1/1	1.60%	0.53%	2.13%	SL or 1/1	1.53%	0.16%	1.69%
SL or 1/2	1.90%	0.33%	2.23%	SL or 1/2	1.99%	0.09%	2.08%
SL or 1/3	2.44%	0.49%	2.93%	SL or 1/3	2.32%	0.34%	2.66%
SL or 1/4	2.84%	0.53%	3.37%	SL or 1/4	2.82%	(0.14%)	2.68%
2/2	0.27%	0.08%	0.35%	2/2	0.17%	0.12%	0.29%
2/3	0.54%	0.16%	0.70%	2/3	0.33%	0.25%	0.58%
2/4	0.94%	0.20%	1.14%	2/4	0.83%	0.00%	0.83%
3/3	0.27%	0.08%	0.35%	3/3	0.17%	0.12%	0.29%
3/4	0.40%	0.04%	0.44%	3/4	0.50%	0.00%	0.50%
4/4	0.20%	0.02%	0.22%	4/4	0.25%	0.00%	0.25%

FSS/ISS RATE SCHEDULES

Withdrawal			Injection		
PFRP	FAP	EFRP	PFRP	FAP	EFRP
0.94%	0.24%	1.18%	0.46%	0.08%	0.54%

Issued by: K.R.Cocklin, Vice President, Rates
Issued on: August 30, 1999

Effective: November 1, 199

FAXED
10/25

TENNESSEE GAS PIPELINE COMPANY
FERC Gas Tariff
FIFTH REVISED VOLUME NO. 1

Exhibit C

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Twentieth Revised Sheet No. 20
Superseding
Nineteenth Revised Sheet No. 20

RATES PER DEKATHERM

FIRM TRANSPORTATION - GS RATES (FT-GS)

Base Rates

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.2138		$0.4203	$0.5844	$0.6748	$0.7814	$0.8952	$1.0698
L		$0.1771						
1	$0.4318		$0.3268	$0.4951	$0.5849	$0.6915	$0.8052	$0.9804
2	$0.5844		$0.4951	$0.2000	$0.2897	$0.4144	$0.5106	$0.6852
3	$0.6748		$0.5849	$0.2897	$0.1489	$0.3995	$0.4951	$0.6698
4	$0.7995		$0.7096	$0.4144	$0.3995	$0.1886	$0.2311	$0.4061
5	$0.8952		$0.8052	$0.5106	$0.4951	$0.2311	$0.1989	$0.3466
6	$1.0698		$0.9804	$0.6852	$0.6698	$0.4061	$0.3466	$0.2374

Surcharges

DELIVERY ZONE

	RECEIPT ZONE	0	L	1	2	3	4	5	6
PCB Adjustment: 1/	0	$0.0110		$0.0159	$0.0192	$0.0208	$0.0236	$0.0258	$0.0301
	L		$0.0069						
	1	$0.0159		$0.0137	$0.0170	$0.0192	$0.0219	$0.0241	$0.0279
	2	$0.0192		$0.0170	$0.0104	$0.0126	$0.0153	$0.0175	$0.0214
	3	$0.0208		$0.0192	$0.0126	$0.0093	$0.0148	$0.0170	$0.0214
	4	$0.0236		$0.0219	$0.0153	$0.0148	$0.0104	$0.0110	$0.0153
	5	$0.0258		$0.0241	$0.0175	$0.0170	$0.0110	$0.0104	$0.0137
	6	$0.0301		$0.0279	$0.0214	$0.0214	$0.0153	$0.0137	$0.0115

Annual Charge Adjustment (ACA): $0.0022

Maximum Rates 2/, 3/, 4/

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.2270		$0.4384	$0.6058	$0.6978	$0.8072	$0.9232	$1.1021
L		$0.1862						
1	$0.4499		$0.3427	$0.5143	$0.6063	$0.7156	$0.8315	$1.0105
2	$0.6058		$0.5143	$0.2126	$0.3045	$0.4319	$0.5303	$0.7088
3	$0.6978		$0.6063	$0.3045	$0.1604	$0.4165	$0.5143	$0.6934
4	$0.8253		$0.7337	$0.4319	$0.4165	$0.2012	$0.2443	$0.4236
5	$0.9232		$0.8315	$0.5303	$0.5143	$0.2443	$0.2115	$0.3625
6	$1.1021		$1.0105	$0.7088	$0.6934	$0.4236	$0.3625	$0.2511

Minimum Rates

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Notes:

1/ PCB adjustment surcharge is effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, subject to extension, revision or termination as required by the Stipulation & Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

2/ Maximum rates are inclusive of base rates and above surcharges.

3/ Gas Research Institute Charge (GRI) of $0.0180 and Transition Cost Surcharge - Supply Area (TCSS) of $0.0225 are not included in the above stated maximum rates.

4/ The applicable fuel retention percentages are listed on Sheet No. 29, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

Issued by: Jake Hiatt, Agent and Attorney-in-Fact
Issued on: April 30, 1999
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Filed to comply with order of the Federal Energy Regulatory Commission,
Docket No. RP91-203 , issued April 16, 1999, 87 FERC ¶ 61,086

TENNESSEE GAS PIPELINE COMPANY
FERC Gas Tariff
FIFTH REVISED VOLUME NO. 1

Exhibit C
Page 6 of 13

Eighth Revised Sheet No. 23A
Superseding
Seventh Revised Sheet No. 23A

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0439		$0.0669	$0.0860	$0.0978	$0.1118	$0.1231	$0.1608
L		$0.0286						
1	$0.0669		$0.0572	$0.0776	$0.0874	$0.1014	$0.1126	$0.1503
2	$0.0880		$0.0776	$0.0433	$0.0530	$0.0681	$0.0783	$0.1159
3	$0.0978		$0.0874	$0.0530	$0.0366	$0.0663	$0.0765	$0.1142
4	$0.1129		$0.1025	$0.0681	$0.0663	$0.0401	$0.0459	$0.0834
5	$0.1231		$0.1126	$0.0783	$0.0765	$0.0459	$0.0427	$0.0765
6	$0.1608		$0.1503	$0.1159	$0.1142	$0.0834	$0.0765	$0.0642

Minimum
Commodity Rates 3/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Maximum
Commodity Rates 1/, 2/, 3/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0536		$0.0766	$0.0977	$0.1075	$0.1215	$0.1328	$0.1705
L		$0.0383						
1	$0.0766		$0.0669	$0.0873	$0.0971	$0.1111	$0.1223	$0.1600
2	$0.0977		$0.0873	$0.0530	$0.0627	$0.0778	$0.0880	$0.1256
3	$0.1075		$0.0971	$0.0627	$0.0463	$0.0760	$0.0862	$0.1239
4	$0.1226		$0.1122	$0.0778	$0.0760	$0.0498	$0.0556	$0.0931
5	$0.1328		$0.1223	$0.0880	$0.0862	$0.0556	$0.0524	$0.0862
6	$0.1705		$0.1600	$0.1256	$0.1239	$0.0931	$0.0862	$0.0739

Notes:

1/ The above maximum rates include a per Dth charge for:

(ACA) Annual Charge Adjustment	$0.0022
(GRI) Gas Research Institute charge	$0.0075

GRI will not be assessed if it is currently being paid on another pipeline.

2/ The TCSS Surcharge is only applicable to deliveries in the supply area as defined on Sheet No. 390. This surcharge is not included in the Maximum Rates Matrix.

(TCSS) Transition Cost Surcharge - Supply Area	$0.0225

3/ The applicable fuel retention percentages are listed on Sheet No. 29, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

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Issued on: April 30, 1999
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Filed to comply with order of the Federal Energy Regulatory Commission,
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TENNESSEE GAS PIPELINE COMPANY
FERC Gas Tariff
FIFTH REVISED VOLUME NO. 1

Exhibit C
Page 7 of 13

Eleventh Revised Sheet No. 23B
Superseding
Tenth Revised Sheet No. 23B

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-G

Base Reservation Rates

RECEIPT	DELIVERY ZONE							
ZONE	0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14
4	$12.53		$11.08	$6.32	$6.08	$2.71	$3.38	$5.87
5	$14.09		$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59		$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Surcharges

PCB Adjustment: 1/

RECEIPT	DELIVERY ZONE							
ZONE	0	L	1	2	3	4	5	6
0	$0.20		$0.29	$0.35	$0.38	$0.43	$0.47	$0.55
L		$0.13						
1	$0.29		$0.25	$0.31	$0.35	$0.40	$0.44	$0.51
2	$0.35		$0.31	$0.19	$0.23	$0.28	$0.32	$0.39
3	$0.38		$0.35	$0.23	$0.17	$0.27	$0.31	$0.39
4	$0.43		$0.40	$0.28	$0.27	$0.19	$0.20	$0.28
5	$0.47		$0.44	$0.32	$0.31	$0.20	$0.19	$0.25
6	$0.55		$0.51	$0.39	$0.39	$0.28	$0.25	$0.21

Maximum Reservation Rates 2/

RECEIPT	DELIVERY ZONE							
ZONE	0	L	1	2	3	4	5	6
0	$3.30		$6.74	$9.41	$10.91	$12.65	$14.56	$17.14
L		$2.84						
1	$6.95		$5.17	$7.93	$9.43	$11.17	$13.08	$15.66
2	$9.41		$7.93	$3.05	$4.55	$6.60	$8.21	$10.78
3	$10.91		$9.43	$4.55	$2.22	$6.35	$7.95	$10.53
4	$12.96		$11.48	$6.60	$6.35	$2.90	$3.58	$6.17
5	$14.56		$13.08	$8.21	$7.95	$3.58	$3.04	$5.18
6	$17.14		$15.66	$10.78	$10.53	$6.17	$5.18	$3.37

Minimum Base Reservation Rates The minimum FT-G Reservation Rate is $0.00 per Dth

Notes:

1/ PCB adjustment surcharge is effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, subject to extension, revision or termination as required by the Stipulation & Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

2/ Maximum rates are inclusive of base rates and above surcharges.

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Issued on: April 30, 1999
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TENNESSEE GAS PIPELINE COMPANY
FERC Gas Tariff
FIFTH REVISED VOLUME NO. 1

Sixth Revised Sheet No. 23C
Superseding
Fifth Revised Sheet No. 23C

Exhibit C
Page 8 of 13

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-G

Base Commodity Rat

RECEIPT	DELIVERY ZONE							
ZONE	0	L	1	2	3	4	5	6
0	$0.0439		$0.0669	$0.0880	$0.0978	$0.1118	$0.1231	$0.1608
L		$0.0286						
1	$0.0669		$0.0572	$0.0776	$0.0874	$0.1014	$0.1126	$0.1503
2	$0.0880		$0.0776	$0.0433	$0.0530	$0.0681	$0.0783	$0.1159
3	$0.0978		$0.0874	$0.0530	$0.0366	$0.0663	$0.0765	$0.1142
4	$0.1129		$0.1025	$0.0681	$0.0663	$0.0401	$0.0459	$0.0834
5	$0.1231		$0.1126	$0.0783	$0.0765	$0.0459	$0.0427	$0.0765
6	$0.1608		$0.1503	$0.1159	$0.1142	$0.0834	$0.0765	$0.0642

Minimum
Commodity Rates 3/

RECEIPT	DELIVERY ZONE							
ZONE	0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0164
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0164	$0.0090	$0.0069	$0.0031

Maximum
Commodity Rates 1/, 2/, 3/

RECEIPT	DELIVERY ZONE							
ZONE	0	L	1	2	3	4	5	6
0	$0.0641		$0.0871	$0.1082	$0.1180	$0.1320	$0.1433	$0.1810
L		$0.0488						
1	$0.0871		$0.0774	$0.3978	$0.1076	$0.1216	$0.1328	$0.1705
2	$0.1082		$0.0978	$0.0635	$0.0732	$0.0883	$0.0965	$0.1361
3	$0.1180		$0.1076	$0.0732	$0.0568	$0.0865	$0.0967	$0.1344
4	$0.1331		$0.1227	$0.0883	$0.0865	$0.0603	$0.0661	$0.1036
5	$0.1433		$0.1328	$0.0985	$0.0967	$0.0661	$0.0629	$0.0967
6	$0.1810		$0.1705	$0.1361	$0.1344	$0.1036	$0.0967	$0.0844

Notes:

1/ The above maximum rates include a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0022
(GRI) Gas Research Institute Charge $0.0180
GRI will not be assessed if it is currently being paid on another pipeline.

2/ The TCSS Surcharge is only applicable to deliveries in the supply area as defined on sheet no. 390.
This surcharge is not included in the Maximum Rates Matrix.
(TCSS) Transition Cost Surcharge - Supply Area $0.0225

3/ The applicable fuel retention percentages are listed on Sheet No. 29, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

Issued by: Jake Hiatt, Agent and Attorney-in-Fact
Issued on: April 30, 1999

Effective: May 1, 1999

Filed to comply with order of the Federal Energy Regulatory Commission,
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TENNESSEE GAS PIPELINE COMPANY
FERC Gas Tariff
FIFTH REVISED VOLUME NO. 1

Exhibit C
Page 9 of 13

Eighth Revised Sheet No. 27
Superseding
Seventh Revised Sheet No. 27

RATES PER DEKATHERM

STORAGE SERVICE

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (GRI) 2/	(ACA)	(TCSM)	(PCB) 3/	Current Adjustment	Retention Percent 1/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA							
Deliverability Rate	$2.02				$0.00	$2.02	
Space Rate	$0.0248				$0.0000	$0.0248	
Injection Rate	$0.0053					$0.0053	
Withdrawal Rate	$0.0053					$0.0053	1.49%
Overrun Rate	$0.2427					$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA							
Deliverability Rate	$1.15				$0.02	$1.17	
Space Rate	$0.0185				$0.0002	$0.0187	
Injection Rate	$0.0102					$0.0102	
Withdrawal Rate	$0.0102					$0.0102	1.49%
Overrun Rate	$0.1380					$0.1380	
INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA							
Space Rate	$0.0848				$0.0009	$0.0857	
Injection Rate	$0.0102					$0.0102	
Withdrawal Rate	$0.0102					$0.0102	1.49%
INTERRUPTIBLE STORAGE SERVICE (IS) - PRODUCTION AREA							
Space Rate	$0.0993				$0.0000	$0.0993	
Injection Rate	$0.0053					$0.0053	
Withdrawal Rate	$0.0053					$0.0053	1.49%
SS - Storage Service							
SS-E							
Deliverability	$4.20				$0.05	$4.25	
Space Rate	$0.0132				$0.0005	$0.0137	
Injection Rate	$0.0102					$0.0102	
Withdrawal Rate	$0.0561					$0.0561	2.41%
Excess Withdrawal Rate	$0.7800		$0.0022			$0.7822	
SS-NE							
Deliverability	$6.71				$0.06	$6.77	
Space Rate	$0.0132				$0.0007	$0.0139	
Injection Rate	$0.0102					$0.0102	
Withdrawal Rate	$0.0936					$0.0936	3.25%
Excess Withdrawal Rate	$1.1600		$0.0022			$1.1622	

1/ The quantity of gas associated with losses is 0.5%.

2/ The Rates After Current Adjustment for services for Consolidated Gas Supply Corp., Columbia Gas Transmission Corp., East Tennessee Natural Gas Co., Midwestern Gas Transmission Co., National Fuel Gas Supply Corp., Texas Gas Transmission Corp., and Equitrans, Inc. are exclusive of adjustments under Tennessee's FERC Gas Tariff.

3/ PCB adjustment surcharge is effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, subject to extension, revision or termination as required by the Stipulation & Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

Issued by: Jake Hiatt, Agent and Attorney-in-Fact
Issued on: April 30, 1999
Effective: May 1, 1999
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Docket No. RP91-203 , issued April 16, 1999, 87 FERC ¶ 61,086

Exhibit C
Page 10 of 13

TENNESSEE GAS PIPELINE COMPANY
FERC Gas Tariff
FIFTH REVISED VOLUME NO. 1

First Revis
Superseding
Substitute Original Sheet No. 29

FUEL AND LOSS RETENTION PERCENTAGE 1\,2\,3\

NOVEMBER - MARCH

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.89%		2.79%	5.16%	5.85%	6.79%	7.88%	8.71%
L		1.01%						
1	1.74%		1.91%	4.23%	4.99%	5.90%	6.99%	7.22%
2	4.59%		2.13%	1.43%	2.15%	3.05%	4.15%	4.95%
3	6.06%		3.60%	1.23%	0.89%	2.64%	3.69%	4.52%
4	7.43%		4.97%	2.63%	3.07%	1.59%	1.33%	2.17%
5	7.51%		5.05%	2.76%	3.14%	1.14%	1.25%	2.09%
6	8.93%		6.47%	4.15%	4.56%	2.50%	1.40%	0.89%

APRIL - OCTOBER

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.84%		2.44%	4.43%	5.04%	5.80%	6.72%	7.42%
L		0.95%						
1	1.56%		1.70%	3.59%	4.29%	5.05%	5.97%	6.67%
2	3.95%		1.25%	1.30%	1.90%	2.65%	3.53%	4.25%
3	5.19%		3.17%	1.13%	0.57%	2.32%	3.19%	3.90%
4	6.34%		4.25%	2.35%	2.67%	1.01%	1.21%	1.92%
5	6.41%		4.34%	2.41%	2.74%	1.07%	1.17%	1.85%
6	7.61%		5.53%	3.51%	3.93%	2.20%	1.27%	0.55%

1\ Included in the above Fuel and Loss Retention Percentages is the quantity of gas associated with losses of 0.5%.

2\ For service that is rendered entirely by displacement shipper shall render only the quantity of gas associated with losses of 0.5%.

3\ The above percentages are applicable to (IT) Interruptible Transportation, (FT-A) Firm Transportation, (FT-GS) Firm Transportation-GS, (PAT) Preferred Access Transportation, (IT-X) Interruptible Transportation-X, (FT-G) Firm Transportation-G, (EDS/ERS) FT- A Extended Transportation Service.

Issued by: E. J. Holm, Agent and Attorney-in-Fact
Issued on: February 13, 1997
Effective: March 1, 1997
Filed to comply with order of the Federal Energy Regulatory Commission,
Docket No. RP95-112 , Issued January 29, 1997, 78 FERC ¶ 61,069

Exhibit C
Page 11 of 13

TRUNKLINE GAS COMPANY
FERC GAS TARIFF
First Revised Volume No. 1

Thirty-First Revised Sheet No. 6
Superseding Thirtieth Revised Sheet No. 6

CURRENTLY EFFECTIVE RATES

Each rate set forth in this Tariff is the currently effective rate pertaining to the particular rate schedule to which it is referenced, but each such rate is separate and independent and the change in any such rate shall not thereby effect a change in any other rate or rate schedule.

	Base Rate Per Dt	Adjustments		Maximum Rate Per Dt	Minimum Rate Per Dt	Fuel Reimbursement
		Sec. 23	Sec. 24			
	(1)	(2)	(3)	(4)	(5)	(6)
RATE SCHEDULE FT						
Field Zone to Zone 2						
- Reservation Rate (1)	$13.9124	-	-	$13.9124	-	-
- Usage Rate (2)(3)	0.0170	-	-	0.0170	$ 0.0170	3.09 % (4)
- Overrun Rate (5)	0.4575	-	-	0.4575	-	-
Zone 1A to Zone 2						
- Reservation Rate (1)	$ 8.9984	-	-	$ 8.9984	-	-
- Usage Rate (2)(3)	0.0133	-	-	0.0133	$ 0.0133	2.28 %
- Overrun Rate (5)	0.2959	-	-	0.2959	-	-
Zone 1B to Zone 2						
- Reservation Rate (1)	$ 6.8341	-	-	$ 6.8341	-	-
- Usage Rate (2)(3)	0.0074	-	-	0.0074	$ 0.0074	1.28 %
- Overrun Rate (5)	0.2247	-	-	0.2247	-	-
Zone 2 Only						
- Reservation Rate (1)	$ 5.1379	-	-	$ 5.1379	-	-
- Usage Rate (2)(3)	0.0018	-	-	0.0018	$ 0.0018	0.68 %
- Overrun Rate (5)	0.1689	-	-	0.1689	-	-
Field Zone to Zone 1B						
- Reservation Rate (1)	$12.1150	-	-	$12.1150	-	-
- Usage Rate (2)(3)	0.0152	-	-	0.0152	$ 0.0152	2.79 %
- Overrun Rate (5)	0.3984	-	-	0.3984	-	-
Zone 1A to Zone 1B						
- Reservation Rate (1)	$ 7.2010	-	-	$ 7.2010	-	-
- Usage Rate (2)(3)	0.0115	-	-	0.0115	$ 0.0115	1.98 %
- Overrun Rate (5)	0.2368	-	-	0.2368	-	-
Zone 1B Only						
- Reservation Rate (1)	$ 5.0367	-	-	$ 5.0367	-	-
- Usage Rate (2)(3)	0.0056	-	-	0.0056	$ 0.0056	0.98 %
- Overrun Rate (5)	0.1656	-	-	0.1656	-	-
Field Zone to Zone 1A						
- Reservation Rate (1)	$10.4188	-	-	$10.4188	-	-
- Usage Rate (2)(3)	0.0096	-	-	0.0096	$ 0.0096	2.19 %
- Overrun Rate (5)	0.3426	-	-	0.3426	-	-
Zone 1A Only						
- Reservation Rate (1)	$ 5.5048	-	-	$ 5.5048	-	-
- Usage Rate (2)(3)	0.0059	-	-	0.0059	$ 0.0059	1.38 %
- Overrun Rate (5)	0.1810	-	-	0.1810	-	-
Field Zone Only						
- Reservation Rate (1)	$ 6.0608	-	-	$ 6.0608	-	-
- Usage Rate (2)(3)	0.0037	-	-	0.0037	$ 0.0037	1.19 %
- Overrun Rate (5)	0.1986	-	-	0.1986	-	-
Gathering Charge (All Zones)						
- Reservation Rate	$ 0.4123			$ 0.4123		
- Overrun Rate (5)	0.0136			0.0136		

(1) Excludes Section 20 GRI Reservation Surcharge: $0.230 High Load Factor (greater than 50%);
$0.142 Low Load Factor (less than or equal to 50%)
(2) Excludes Section 20 GRI Usage Surcharge: $0.0075
(3) Excludes Section 21 Annual Charge Adjustment: $0.0022
(4) Fuel reimbursement for backhauls from Zone 2 to Field Zone is 0.36%
(5) Maximum firm volumetric rate applicable for capacity release

Issued by: William W. Grygar
Vice President
Issued on: October 1, 1999

Effective: November 1, 1999

FAXED 10-25-99

Exhibit C

Western Kentucky Gas Company
Basis for Indexed Gas Cost
For the Month of February, 2000
Case No. 99-070 A

The projected February, 2000 commodity price was provided by the Gas Supply Department and was based upon the following:

A. The Gas Supply Department reviewed the NYMEX futures close prices for February, 2000 for the period December 17, 1999 through December 28, 1999 which are listed below:

		Feb-00 ($/MMBTU)
Friday	17-Dec	2.626
Monday	20-Dec	2.609
Tuesday	21-Dec	2.519
Wednesday	22-Dec	2.445
Thursday	23-Dec	2.396
Monday	27-Dec	2.296
Tuesday	28-Dec	2.369
		$2.466

B. Gas Supply believes prices will remain stable and February prices will settle at $2.75 per Mmbtu for the period that the GCA is to be effective.

Western Kentucky Gas Company
Current "Cash-out" Prices
For the Month of November, 1999

For WKG customers served in:			**Indexed [1] Cash-out Price**		**Transport Charge [2,3]**		**WKG Cash-out Price**
A.	**Texas Gas:**						
	Zone 2 Area	100% of Index Price	$2.4700	+	$0.0365	=	$2.5065
		90% of Index Price	2.2230	+	0.0365	=	2.2595
		80% of Index Price	1.9760	+	0.0365	=	2.0125
	Zone 3 Area	100% of Index Price	$2.4700	+	$0.0412	=	$2.5112
		90% of Index Price	2.2230	+	0.0412	=	2.2642
		80% of Index Price	1.9760	+	0.0412	=	2.0172
	Zone 4 Area	100% of Index Price	$2.4700	+	$0.0463	=	$2.5163
		90% of Index Price	2.2230	+	0.0463	=	2.2693
		80% of Index Price	1.9760	+	0.0463	=	2.0223
B.	**Tennessee Gas:**						
	Zone 2 Area	100% of Index Price	$2.4413	+	$0.0258	=	$2.4671
		90% of Index Price	2.1972	+	0.0258	=	2.2230
		80% of Index Price	1.9530	+	0.0258	=	1.9788

[1] Indexed cash-out price is from the pipeline's Electronic Bulletin Board.

[2] Transport charge used for Texas Gas is its tariff sheet no. 10 commodity rate.

[3] Transport charge used for Tennessee Gas is its tariff sheet no. 23A maximum commodity rate from zone 0 to zone 2.

Western Kentucky Gas Company
Performance Based Rate Recovery Factor
Case No. 99-070 A
(PBRRF)

Exhibit E
Page 1 of 1

Line No.	Amounts Reported:	AMOUNT
1	Company Share of 11/98 - 10/99 PBR Activity	$ 2,474,127.26
2		
3		-
4		
5	Total	$ 2,474,127.26
6		
7		
8	Total	$ 2,474,127.26
9	Less: amount related to specific end users	0.00
10	Amount to flow-through	$ 2,474,127.26
11		
12	Average of the 3-Month Commercial Paper Rates for the immediately	0.0000%
13	preceding 12-month period less 1/2 of 1% to cover the costs of refunding.	
14		

Line No.		(1) Demand	(2) Commodity	(3) Total
15				
16	**Allocation**			
17		$0	$0	$0
18	Company Share of 11/98 - 10/99 PBR Activity	0	2,474,127	2,474,127
19				
20	Total (w/o interest)	0	2,474,127	2,474,127
21	Interest (Line 20 x Line 12)	0	0	0
22	Total	$0	$2,474,127	$2,474,127
23				
24	**PBRRF Calculation**			
25	Demand Allocator - All			
26	(See Exh. B, p. 9, line 18)	0.2943		
27	Demand Allocator - Firm			
28	(1 - Demand Allocator - All)	0.7057		
29	MCF Sales (annual normalized)			
30	(See Exh. B, p. 9, line 1)	26,500,000		
31	Firm Volumes (normalized)			
32	(See Exh. B, p. 6, col. 1, line 26)	26,500,000		
33	Total Throughput			
34	(See Exh. B, p. 6, col. 1, line 42 - line 40)	30,400,000		
35				
36	Demand Factor - All (Principal)	$ -	$0.0000 / MCF	
37	Demand Factor - All (Interest)	$ -	$0.0000 / MCF	
38	Demand Factor - Firm (Principal)	$ -	$0.0000 / MCF	
39	Demand Factor - Firm (Interest)	$ -	$0.0000 / MCF	
40	Commodity Factor - Principal			$ 0.0934 / MCF
41	Commodity Factor - Interest			$ - / MCF
42	Total Demand Firm Factor			
43	(Col. 2, line 36 + 37 + 38 + 39)		**$0.0000 / MCF**	
44	Total Demand Interruptible Factor			
45	(Col. 2, line 36 + 37)		**$0.0000 / MCF**	
46	Total Firm Sales Factor			
47	(Col. 3, line 40 + line 41 + col. 2, line 43)	**$ 0.0934 / MCF**		
48	Total Interruptible Sales Factor			
49	(Col. 3, line 40 + line 41 + col. 2, line 45)	**$ 0.0934 / MCF**		
50				

Exhibit F

Western Kentucky Gas Company
Large Volume Sales
For the Month of November, 1999

The net monthly rates for Large Volume Sales service is as follows:

Base Charge:

LVS-1 Service	$ 13.60	per Meter
LVS-2 Service	150.00	per Meter
Combined Service	150.00	per Meter

LVS-1

				Simple Margin		Non-Commodity Component [2]		Estimated Weighted Average Commodity Gas Cost		Sales Rate	
Firm Service											
First	300 [1]	Mcf	@	$1.0615	+	$0.7232	+	$2.6151	=	$4.3998	per Mcf
Next	14,700 [1]	Mcf	@	0.5585	+	0.7232	+	2.6151	=	3.8968	per Mcf
All over	15,000	Mcf	@	0.4085	+	0.7232	+	2.6151	=	3.7468	per Mcf
High Load Factor Firm Service											
Demand						$ 4.3211	+	$0.0000	=	$4.3211	per Mcf of daily contract demand
First	300 [1]	Mcf	@	$1.0615	+	$ 0.1631	+	$2.6151	=	$3.8397	per Mcf
Next	14,700 [1]	Mcf	@	0.5585	+	0.1631	+	2.6151	=	3.3367	per Mcf
All over	15,000	Mcf	@	0.4085	+	0.1631	+	2.6151	=	3.1867	per Mcf

LVS-2

Interruptible Service											
First	15,000	Mcf	@	$0.4936	+	$0.1933	+	$2.6151	=	$3.3020	per Mcf
All over	15,000	Mcf	@	0.3436	+	0.1933	+	2.6151	=	3.1520	per Mcf

True-up Adjustment for previous billing period (s): (0.0998) per Mcf

[1] All gas consumed by the customer will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

[2] The Non-Commodity Component is from P.S.C. No. 20 Sheet No. 6, effective November 1, 1999.

Western Kentucky Gas Company
Large Volume Sales
Estimated WACOG used for Billing
For the Month of November, 1999

Exhibit F

Line No.	Supplier/Type of Service	(A) Estimated MCF Purchased @14.65	(B) Estimated Commodity Cost
1	**Estimated Purchases:**		
2	Texas Gas Area	1,433,454	$3,679,398.75
3	Tennessee Gas Area	293,313	757,681.60
4	Trunkline Gas Area	61,147	158,219.79
5	ANR Pipeline Area	0	0.00
6	Total Estimated Purchases	1,787,914	4,595,300.14
7			
8	**Transportation Costs:**		
9	Texas Gas Transmission		148,162.43
10	Tennessee Gas Pipeline		0.00
11	Trunkline Gas Area		0.00
11	ANR Pipeline Area		0.00
12			
13	Local Production	54,380	50,396.05
14			
15	WKG End-User Cash Outs	13,316	(33,923.25)
16			
17	Total Current Month Gas Cost	1,855,610	$4,759,935.37
18			
19	Less: Lost & Unaccounted for @ 1.9%	35,257	
20			
21	Total Deliveries	1,820,353	$4,759,935.37
22			
23	Estimated LVS Weighted Average Commodity Rate		**$2.6148**

Western Kentucky Gas Company
Expected Purchases
LVS Commodity Purchase Basis
For Month of February, 2000

Exhibit F
Page 3 of 3

Line No.			(1) Mcf	(2) MMbtu	(3) Gas Cost
1	**Texas Gas Area**				
2	No Notice Service		499,024	511,500	1,476,138
3	Firm Transportation		1,282,439	1,314,500	3,771,959
4	Total Texas Gas Area		1,781,463	1,826,000	5,248,097
5					
6					
7	**Tennessee Gas Area**				
8	FT-A&G Commodity		207,500	215,800	646,170
9	FT-GS Commodity		42,500	44,200	154,559
10	Total Tennessee Gas Area		250,000	260,000	800,729
11					
12	**Trunkline Gas Area**				
13	Firm Transportation		168,116	174,000	489,253
14					
15					
16	**Local Production**				
17	Commodity		34,146	35,000	100,433
18					
19					
20	Expected WKG End-User Cash Outs		0	0	0
21					
22	**Total LVS Commodity Purchase Basis**		2,233,725	2,610,253	6,638,512
23					
24	Lost & Unaccounted for @	1.9%	42,441	49,595	
25					
26	Total Deliveries		2,191,284	2,560,658	6,638,512
27					
28	Estimated LVS Weighted Average Commodity Rate (per MMbtu)				$2.5925
29					
30	Estimated LVS Weighted Average Commodity Rate (per Mcf)				$3.0295
31	(To only be used to calculate commodity credit back on Exhibit B)				
32					
33					

1999-0052

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

RECEIVED
DEC 30 1999
PUBLIC SERVICE
COMMISSION

In the Matter of:

GAS COST ADJUSTMENT)
FILING OF)
WESTERN KENTUCKY GAS COMPANY)

CASE NO. 99-070 A

PETITION FOR CONFIDENTIALITY

Attorney for Applicant

Mark R. Hutchinson
Sheffer-Hutchinson-Kinney
115 East Second Street
Owensboro, Kentucky 42303

December 29, 1999

Comes now Western Kentucky Gas Company ("Western") pursuant to 807 KAR 5:001, Section 7, and all other applicable law, and states as follows:

BACKGROUND

By order issued June 1, 1998, the Kentucky Public Service Commission ("Commission") concluded that publication of information for the matters contained in Exhibit E to various PBR filings (Case Number 97-513), is likely to cause substantial harm to Western's competitive position and the information should be protected from disclosure.

The detailed calculation of the amount to be recovered is excluded from Exhibit "E" to this GCA filing, which pages are attached hereto and stamped "Confidential." Western requests that this information, which discloses the actual price being paid by Western to individual marketing companies and other suppliers of gas, be treated as confidential.

Consistent with the Commission's June 1, 1998 order, Western has included in its GCA filing in the instant case the total Company's PBR activity amount for inclusion in the public record.

WHEREFORE, Western petitions the Commission to treat as confidential the detailed calculation of the amount to be recovered through the PBR factor. Western believes it to be in the best interest of all of its customers for that information to be treated as confidential.

Respectfully submitted, this 29th day of December, 1999.

WESTERN KENTUCKY GAS COMPANY

By: Mark A. Martin

Mark A. Martin
Sr. Analyst - Rate Administration
Atmos Energy Corporation