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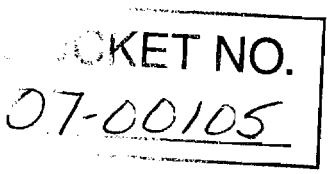
CYNTHIA S. PARSON
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J. AARON MORRIS
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MASAMI I. TYSON
LYNDSAY C. SMITH
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STAFF ATTORNEY
KRISTEN V. DYER

OF COUNSEL
LARRY W. LINDEEN

May 4, 2007

VIA HAND DELIVERY



Sharla Dillon, Docket Manager
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, TN 37238

Re: *Atmos Energy Corporation Petition for Approval of Adjustment of Its Rules as Revises Tariff*

Dear Ms. Dillon:

Enclosed is a new rate case Petition, being filed by Atmos Energy Corporation, along with the Company's responses to the minimum filing requirements (MFRs). A set of two disks and four copies are enclosed. There are no confidential documents on these disks. Some of the documents are confidential and the Company has included a proposed Confidentiality Order, which you will find behind the Petition. The confidential documents are enclosed in separate sealed envelopes, and should be filed under seal.

As always, thank you for your assistance in this matter.

Sincerely,

Bill Ramsey

William T. Ramsey

/jm
enclosures

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

Pursuant to Tennessee Code Annotated § 65-5-203 and the Rules of the Tennessee Regulatory Authority ("TRA" or "Authority"), Atmos Energy Corporation, a Texas corporation, ("Atmos" or the "Company") respectfully requests that the TRA approve its Petition for an adjustment in its rates and charges for natural gas service for the purpose of obtaining a general increase in its rates and for authority to place into effect revised tariffs.

In support of this Petition, Atmos submits the following:

1. Full name and address of the principal place of business of the Company are:

Atmos Energy Corporation
5430 LBJ Frwy S1800
Dallas, TX 75240

2. All correspondence and communications with respect to this Petition should be sent to the following:

John Paris, President
Kentucky/Mid-States Division
Atmos Energy Corporation
2401 New Hartford Road
Owensboro, KY 42303.

William T. Ramsey, Esq.
Jon D. Ross, Esq.
Neal & Harwell, PLC
2000 One Nashville Place
150 Fourth Avenue North
Nashville, TN 37219-2498

Douglas C. Walther
Associate General Counsel
Atmos Energy Corporation
P.O. Box 650205
Dallas, TX 75265-0205

3. Atmos is incorporated under the laws of the State of Texas and is engaged in the business of transporting, distributing and selling natural gas in twelve states. Atmos' Kentucky/Mid-States Division provides natural gas distribution service in Tennessee, Kentucky Missouri, Virginia, Georgia, Illinois and Iowa. A map of Atmos' Tennessee service territory is shown on Schedule JP-1 to this Petition. Atmos is a public utility pursuant to the laws of the State of Tennessee, and its public utility operations are subject to the jurisdiction of this Authority. Atmos consists of the utility and various subsidiaries. The company conducts its unregulated operations through its subsidiaries. The various divisions (there are currently seven) are a part of the Company's management control structure that is utilized in the company's shared costs allocation processes. A chart showing the current corporate structure is shown on Exhibit JCC-2 to this Petition.

4. Atmos' existing rates for natural gas service are not adequate to permit it an opportunity to recover its reasonable operating costs and to earn a fair and reasonable rate of return on its investment. In order for Atmos to maintain its facilities and provide services in accordance with the reasonable requirements of its customers and the requirements of the TRA, attract capital on terms which are reasonable, attract and maintain investors, and to produce a reasonable rate of return for its stockholders, Atmos must be granted a general increase in its rates.

5. Using current rates during the attrition period (the 12 months ending October 31, 2008), Atmos is projected to earn net operating income of $9,849,823 on a rate base of

$188,920,055, which results in an overall rate of return of 5.21%. Such a return is not fair and reasonable and is confiscatory. Without rate relief, Atmos will incur a revenue deficiency during the attrition period of approximately $11,055,188.

6. Atmos proposes rates that will allow it a reasonable opportunity to alleviate the projected deficit of approximately $11,055,188 and to achieve an overall rate of return of 8.84% and a return on equity of 11.75%. Atmos has filed tariffs with rates to produce the needed revenue requirement.

7. Atmos seeks approval of an increase in revenues of $11,055,188. The increase to the bill of an average residential customer at current gas prices would be approximately $4.27 per month. Atmos is not simply asking the Authority to rehear rulings made in Docket No. 05-00258. While approximately $2.6 million of the total requested increase results from the Company's disagreements with some of the rulings in that docket, new investments, inflation, updated cost studies, and other items result in an increase in revenue requirement for the test year of approximately $6.5 million. This includes a reduction in depreciation expense of about $2.1 million due to reduced depreciation rates. It also includes an increase in state gross receipts taxes of approximately $1.3 million, due primarily to a tax anomaly. Also, Atmos projects it would realize about $2.0 million less gross margin at present rates than what was provided for by the Authority's ruling in Docket No. 05-00258.

8. In further support of its Petition, Atmos has attached prepared direct testimony from the witnesses listed below. The exhibits to each witness's prepared direct testimony also are listed.

Witness Name	*Exhibit No.*	*Description*	*Comments*
Cagle, James C.	JCC-1	List of prior testimony and jurisdictions	
	JCC-2	Atmos Energy corporate organizational chart	
	JCC-3	Composite factors for common cost allocation	
	JCC-4	Weather normalized margin for attrition period	

	JCC-5	Updated heat sensitive and base load factors for WNA	
Childers, Patricia J.	PJC - 1	Proposed Rates	
Cook, Jr., Robert R.	None		
Ellis, Michael H.	MHE-1	Service order revenue projection	
Edelstein, Ronald B.	RBE-1	Gas Technology Institute	
Hutzler, Chris	None		Towers Perrin
Meziere, Daniel M.	DMM-1	Atmos Energy Cost Allocation Manual (CAM)	
Murry, Donald A.	DAM-1	Real GDP consensus forecast	CH Guernsey
	DAM-2	Historical economic statistics	
	DAM-3	History of long-term bond interest	
	DAM-4.1	Bond interest rate forecast chart	
	DAM-4.2	Bond interest rate forecasts	
	DAM-5.1	Value Line interest rates and forecasts	
	DAM-5.2	Comparison of Value Line's interest rates	
	DAM-6	Projected capital structure	
	DAM-7	Comparison of common equity ratios	
	DAM-8	Short-term debt balances	
	DAM-9	Comparison of common shares outstanding	
	DAM-10	Embedded cost of long-term debt	
	DAM-11	Comparison of Standard & Poor's and Value Line financial ratings	
	DAM-12	Comparison of Value Line's safety and timeliness rank	
	DAM-13	Comparison of returns on common equity	
	DAM-14	Comparison of returns on capital	
	DAM-15	Comparison of dividends per share	
	DAM-16	Comparison of dividend payout ratios	
	DAM-17	Comparison of average annual P/E ratio	
	DAM-18	Stock price responses to dividend and EPS announcements	
	DAM-19	Discounted Cash Flow growth rate summary	
	DAM-20	Dividend growth rate DCF using 52-week share prices	
	DAM-21	Dividend growth rate DCF using current share prices	
	DAM-22	Earnings growth rate DCF using 52-week share prices	
	DAM-23	Earnings growth rate DCF using current share prices	
	DAM-24	Projected growth rate DCF using 52-week share prices	
	DAM-25	Projected growth rate DCF using current share prices	
	DAM-26	Size adjusted Capital Asset Pricing Model	
	DAM-27	Historical CAPM	
	DAM-28	Summary of DCF and CAPM analysis	

	DAM-29	Recent increase in returns on common equity	
	DAM-30	Projected cost of capital	
	DAM-31	Comparison of after-tax times interest earned ratios	
Paris, John	JP-1	Map of Atmos Energy's service territory in Tennessee	
Petersen, Thomas H.	THP-1	Cost of service and revenue deficiency	
	THP-2	Summary of revenue at present rates for 12 mos. ended 10/31/08	
	THP-3	Cost of gas for 12 mos. ended 10/31/08	
	THP-4	O&M expense for 12 mos. ended 10/31/08	
	THP-5	Taxes other than income taxes for 12 mos. ended 10/31/08	
	THP-6	Depreciation and amortization expense for 12 mos. ended 10/31/08	
	THP-7	Rate base and return 13-month average for 12 mos. ended 10/31/08	
	THP-8	State excise and federal incomes taxes for 12 mos. ended 10/31/08	
	THP-9	Overall cost of capital for 12 mos. ended 10/31/08	
	THP-10	Rate of return for 12 mos. ended 10/31/08	
	THP-CWC1 A	Cash working capital lead/lag analysis for attrition period	
	THP-CWC1 B	Cash working capital lead/lag analysis for test year ended 12/31/06	
	THP-CWC2	Revenue lag study for test year ended 12/3/106	
	THP-CWC3	Lag relating to purchased gas cost	
	THP-CWC4	Payroll expense lag	
	THP-CWC5	Other O&M expense payment lag	
	THP-CWC6	Lag relating to taxes other than income taxes	
	THP-CWC7	Lag relating to federal income taxes	
	THP-CWC8	Lag relating to state income taxes	
	THP-CWC9	Lag relating to sales taxes	
	THP-CWC10	Lag relating to interest payments on long-term debt	
Roff, Donald S.	DSR-1	Qualifications and experience	Depr. Specialty Res.
	DSR-2	List of regulatory appearances as witness	
	DSR-3	Tennessee depreciation study	
	DSR-4	SSU depreciation study	
Sherwood, Laurie M.	LMS-1	Weighted average cost of long-term debt as of 12/31/06	
	LMS-2	Projected cost of long-term debt as of 10/31/08	
	LMS-3	Projected cost of short-term debt as of 10/31/08	
Smith, Gary L.	GLS-1	Joint statement of AGA and NRDC of July 2004	
	GLS-2	NARUC resolution on gas and electric energy efficiency of 7/14/04	
	GLS-3	NARUC resolution on energy efficiency and innovative rate design of 11/16/05	
Ellerman, John R.	None		Towers Perrin

Waller, Gregory K.	GKW-1	Summary of total operating expenses – test year and attrition period	
	GKW-2	O&M expense by cost element	
	GKW-3	Summary of taxes other than income taxes	

WHEREFORE, Atmos Prays:

1. That Notice be issued and a hearing be set regarding the Petition;

2. That the Authority find that the existing rates of Atmos Energy are inadequate and that the rates proposed by the Company are fair, just and reasonable and in the public interest;

3. That the Authority approve Atmos' revised tariff implementing the proposed rates filed as Exhibit TAR-1, to become effective on November 1, 2007.

4. That Atmos be granted such other and/or further relief as may be warranted.

Respectfully submitted,

Atmos Energy Corporation

By: Jon D. Ross (by WTR)
Jon D. Ross, #4452

By: WTR
William T. Ramsey, #9245
NEAL & HARWELL, PLC
2000 One Nashville Place
150 Fourth Avenue, North
Nashville, TN 37219-2498
(615) 244-1713 – Telephone
(615) 726-0573 – Facsimile

Counsel for Atmos Energy Corporation

VERIFICATION

STATE OF TENNESSEE)
)
COUNTY OF WILLIAMSON)

I, John Paris, being duly sworn, state that I am authorized to make this verification on behalf of Atmos Energy Corporation, the Petitioner in the subject proceeding; that I have read the foregoing Petition and Exhibits and know the content thereof; that the same are true and correct to the best of my knowledge, information and belief.

John Paris

SWORN to and subscribed before me
this 3rd day of MAY, 2007.

Notary Public

My Commission Expires:
May 24, 2008

PAMELA TODD
NOTARY PUBLIC
STATE OF TENNESSEE
WILLIAMSON COUNTY

My Commission Expires 05-24-08

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

PROTECTIVE ORDER

To expedite the flow of filings, discovery, exhibits and other materials, and to facilitate the prompt resolution of disputes regarding confidentiality of the material, adequately protect material entitled to be kept confidential and to ensure that protection is afforded only to material so entitled, and the parties being in agreement as to the entry of this Protective Order, the Hearing Officer, as appointed by the Tennessee Regulatory Authority ("TRA"), hereby orders the following:

1. For the purposes of this Protective Order (the "Order"), proprietary or confidential information, hereinafter referred to as "CONFIDENTIAL INFORMATION," shall mean documents and information, in whatever form, that the producing party, in good faith, deems to contain or constitute trade secrets, confidential commercial information, confidential research and development, financial statements, or other commercially sensitive information, and which has been designated specifically by the producing party. A "Producing Party" is defined to include the party creating the confidential information, as well as the party having actual physical possession of information produced pursuant to this Order. All summaries, notes, extracts, compilations or other direct or indirect reproduction from or of any protected materials shall be entitled to protection under this Order. Documents containing CONFIDENTIAL

INFORMATION shall be marked specifically as confidential on the cover. Any document so designated shall be regarded as CONFIDENTIAL INFORMATION and handled in accordance with the limitations imposed by this Order, unless and until it is de-classified by an order of this Authority, the Hearing Officer, or Administrative Judge herein or a court of competent jurisdiction. The designation of a document as CONFIDENTIAL INFORMATION may be challenged under Paragraph 10 of this Order.

2. Any individual or company subject to this Order, including producing parties or persons reviewing CONFIDENTIAL INFORMATION, shall act in good faith in discharging their obligations hereunder. Parties or nonparties subject to this Order shall include, without limitation, the Consumer Advocate, and parties who are allowed by the TRA to intervene.

3. CONFIDENTIAL INFORMATION shall be used only for the purposes of this proceeding, and may be disclosed only to the following persons:

(a) Counsel of record for the parties and other legal counsel for the parties in this case and associates, secretaries and paralegals actively engaged in assisting counsel of record in this proceeding;

(b) TRA Directors and members of the staff of the TRA;

(c) Employees of the parties, but only under the conditions and with the further limitations imposed in this Order;

(d) Outside consultants and expert witnesses employed or retained by the parties or their counsel, who need access to CONFIDENTIAL INFORMATION for evaluation, testing, testimony, preparation for trial or other services related to this docket, provided that to the extent that any party seeks to disclose CONFIDENTIAL INFORMATION to any outside consultant or expert witness who is expected to testify on that party's behalf, the party shall give ten (10) days written notice to the Producing Party of intention to disclose CONFIDENTIAL INFORMATION, the person(s) to whom the information will be disclosed, and the reasons for disclosure. During such notice period, the Producing Party may move to prevent or limit disclosure for cause, in which case no disclosure shall be made until the TRA, the Hearing Officer, the Administrative Law Judge or court rules on the motion. Any such motion shall be filed within seven (7) days after service of the notice. Any response shall be filed within seven (7) days after

service of the Motion. A Pre-hearing conference may be called to confer with the parties on the Motions to Limit Disclosure. All service shall be by hand delivery or by facsimile.

Under no circumstances shall any CONFIDENTIAL INFORMATION be disclosed to or discussed with anyone associated with the marketing of products, goods, or services that may compete with the products, goods, or services of the Producing Party. Counsel are expressly prohibited from disclosing CONFIDENTIAL INFORMATION produced by another party to their respective clients, except for in-house counsel, and persons who need to know in order to assist counsel of record with preparation of the case. Such persons are forbidden to use such information for any purpose other than the litigation of this case, and are forbidden to make any further disclosure of such information.

4. Prior to disclosure of CONFIDENTIAL INFORMATION to any employee of a party, TRA Director, or TRA staff member, the counsel representing the party who is to receive the CONFIDENTIAL INFORMATION shall provide a copy of this Order to the recipient employee, TRA Director or staff member, who shall be bound by the terms of this Order. Prior to disclosure of CONFIDENTIAL INFORMATION to any outside consultant or expert witness employed or retained by a party, counsel shall provide a copy of this Order to such outside consultant or expert witness, who shall sign an Affidavit in the form of that attached to this Order attesting that he or she has read a copy of this Order, and that he or she understands and agrees to be bound by the terms of this Order. This Affidavit shall be signed in the presence of and be notarized by a notary public. Counsel of record for each party shall provide the Producing Party a copy of each such Affidavit, except with respect to the parties' experts and consultants, which shall be kept on file in the offices of counsel.

5. If any party or non-party subject to this Order inadvertently produces documents protected by the attorney-client privilege or work product doctrine, or inadvertently fails to designate documents as CONFIDENTIAL in accordance with the provisions of this Order when producing such documents, the failure shall not constitute a waiver. The party or non-party who has produced the document shall notify the recipient of the document, in writing, within five (5) business days of discovery of such inadvertent failure to designate the document as CONFIDENTIAL. At that time, the recipients immediately will treat the subject document as CONFIDENTIAL. A party, by written or oral motion, may request return of the documents or designation of the documents as CONFIDENTIAL, and if the motion is granted by the Hearing Officer, Administrative Law Judge or the Authority, the recipients immediately shall return the documents or treat the documents as CONFIDENTIAL, according to the terms of this Order.

6. The Tennessee Regulatory Authority, the Hearing Officer or Administrative Law Judge may at his or her discretion, either before or during the Pre-Hearing Conference or Hearing on the merits of the case, allow testimony or other information to be designated CONFIDENTIAL and treated as such in accordance with the terms of this Order.

7. Any papers filed in this proceeding that contain, quote, paraphrase, compile or otherwise disclose documents covered by the terms of this Order, or any information contained therein, shall be filed and maintained in the TRA Docket Room in sealed envelopes marked CONFIDENTIAL and labeled to reflect the style of this proceeding, the docket number, the contents of the envelope sufficient to identify its subject matter and this Protective Order. The envelopes shall be maintained in a locked filing cabinet. The envelopes shall not be opened or their contents reviewed by anyone except upon order of the TRA, Hearing Officer, or Administrative Law Judge after due notice to counsel of record. Notwithstanding the foregoing,

the Directors and the Staff of the TRA may review any paper filed as CONFIDENTIAL without obtaining an order of the TRA, Hearing Officer of Administrative Law Judge, provided the Directors and Staff maintain the confidentiality of the paper in accordance with the terms of this Order.

8. Documents, information and testimony designated as CONFIDENTIAL or PROTECTED SECURITY MATERIALS (as defined in Paragraph 18) in accordance with this Order, may be used in testimony at the Hearing of this proceeding and offered into evidence used in any hearing related to this action in a manner that protects the confidentiality of the information, subject to the Tennessee Rules of Evidence and to such future orders as the TRA, the Hearing Officer, or the Administrative Law Judge may enter. Any party intending to use documents, information, or testimony designated CONFIDENTIAL or PROTECTED SECURITY MATERIALS shall inform the Producing Party and the TRA, the Hearing Officer, or the Administrative Law Judge, prior to the Hearing on the merits of the case, of the proposed use; and shall advise the TRA, the Hearing Officer, or the Administrative Law Judge, and the Producing Party before use of the information during witness examinations so that appropriate measures can be taken by the TRA, the Hearing Officer, or the Administrative Law Judge to protect the confidential nature of the information.

9. Nothing herein shall be construed as preventing any party from continuing to use and disclose any information (a) that is in the public domain, or (b) that subsequently becomes part of the public domain through no act in violation of an Order, or any contractual or legal obligation; (c) that is disclosed to it by a third party, where said disclosure does not itself violate any Order, or any contractual or legal obligation, or (d) that is independently developed by a

party, or (e) that is known or used by it prior to this proceeding. The burden of establishing the existence of (a) through (e) shall be upon the party attempting to use or disclose the information.

10. Any party may contest the designation of any document or information as CONFIDENTIAL or PROTECTED SECURITY MATERIALS by filing a Motion with the TRA, Hearing Officer, Administrative Law Judge, or the courts, as appropriate, for a ruling that the documents, information or testimony should not be so treated. All documents, information, and testimony designated as CONFIDENTIAL or PROTECTED SECURITY MATERIALS, however, shall be maintained as such until the TRA, the Hearing Officer, the Administrative Law Judge, or a court orders otherwise. A Motion to contest must be filed not later than thirty (30) days prior to the Hearing on the Merits. Any Reply from the Company seeking to protect the status of their CONFIDENTIAL INFORMATION or PROTECTED SECURITY MATERIALS must be received not later than ten (10) days prior to the Hearing on the Merits and shall be presented to the Authority at the Hearing on the Merits for a ruling.

11. Nothing in this Order shall prevent any party from asserting any objection to discovery other than an objection based upon grounds of confidentiality. In the event the Consumer Advocate and Protection Division of the Office of the Attorney General becomes a party to this proceeding, nothing in this Order is intended to limit or expand the statutory authority of the Attorney General or the Consumer Advocate and Protection Division as expressed in *T.C.A. § 10-7-504(a)* titled *Confidential Records,* and *T.C.A. § 65-4-118* titled *Consumer Advocate and Protection Division.* The Attorney General will provide timely notice of filing or intent to disclose in the discharge of the duties of the Office of the Attorney General and Reporter, pursuant to T.C.A. § 10-7-504(a)(5)(C), so that the Producing Party may take action relating to disclosure.

The obligations of the Attorney General under this Order are further subject to Tennessee's Public Records Act. Nothing in this Order is intended to violate Tennessee's Public Records Act or Freedom of Information Act ("FOIA"). In the event that the Attorney General is served with a subpoena, public records, freedom of information act request, or other request that calls for the production of CONFIDENTIAL INFORMATION, the Attorney General, will notify the Producing Party by notifying the undersigned of the existence of the subpoena, public records request, FOIA request, or other request, at least five (5) business days before responding to the request. Following the five day notice period, the Attorney General may elect to wait to produce such information as allowed by state law in order to provide the Producing Party an opportunity to challenge said subpoena or request or to make arrangements to preserve the confidentiality of the CONFIDENTIAL INFORMATION that is subject to such request.

12. Non-party witnesses shall be entitled to invoke the provisions of this Order by designating information disclosed or documents produced for use in this action as CONFIDENTIAL, in which event the provisions of this Order shall govern the disclosure of information or documents provided by the non-party witness. A non-party witness' designation of information as CONFIDENTIAL may be challenged under Paragraph 10 of this Order.

13. No person authorized under the terms herein to receive access to documents, information, or testimony designated as CONFIDENTIAL shall be granted access until such person has complied with the requirements set forth in Paragraph 4 of this Order.

14. Any person to whom disclosure or inspection is made in violation of this Order shall be bound by the terms of this Order.

15. Upon the final resolution of this matter, including all appeals, all filings, exhibits, and other materials and information designated CONFIDENTIAL or PROTECTED SECURITY

MATERIALS and all copies thereof shall be returned to counsel for the party who produced (or originally created) the filings, exhibits, and other materials, within thirty (30) days. Subject to the requirements of Paragraph 7 above, the TRA may retain, under seal, copies of information designated as CONFIDENTIAL or PROTECTED SECURITY MATERIALS as may be necessary to maintain the record of this cause intact. Counsel who received the filings, exhibits, and other materials designated as CONFIDENTIAL or PROTECTED SECURITY MATERIALS shall certify to counsel for the Producing Party that all documents containing CONFIDENTIAL INFORMATION, and all copies, have been delivered to counsel for the Producing Party or destroyed, and that all electronic copies of CONFIDENTIAL INFORMATION and PROTECTED SECURITY MATERIALS received or mentioned by the receiving party have been eliminated.

16. After termination of this proceeding, the provisions of this Order shall continue to be binding upon parties herein and their officers, employers, employees, agents, and/or others.

17. Nothing herein shall prevent entry of a subsequent order, upon an appropriate showing, requiring that any documents, information or testimony designated as CONFIDENTIAL shall receive protection other than that provided herein.

18. In addition to the other provisions of this Order, Atmos Energy Corporation (the "Company") may designate and label as "PROTECTED SECURITY MATERIALS" documents and information related to security measures undertaken to protect public health and safety. The Company shall provide access to PROTECTED SECURITY MATERIALS to TRA Directors and Authorized Representatives, as hereafter defined. Authorized Representatives shall be limited to the following: in the event that TRA staff becomes a party, one counsel of record and one other staff member or person under contract to the staff, each authorized in writing by a

senior official of the TRA to have such access; and with respect to any other party (including intervenors), two counsel of record and a single other person, employed by or under contract to the party, authorized by that party in a written certification mutually agreeable to the parties.

19. The Company shall provide access to an Authorized Representative to PROTECTED SECURITY MATERIALS only after such Authorized Representative has executed an Affidavit in the form of that attached to this Order and provided a copy to the Company. Except with consent of the Company: (i) access shall be at the offices of the Company or its counsel of record and under supervision of the Company; (ii) PROTECTED SECURITY MATERIALS shall not be removed from the offices of the Company or its counsel; (iii) no copies shall be provided to an Authorized Representative except as provided herein. Authorized Representatives may make notes or memoranda from a review of the PROTECTED SECURITY MATERIALS and may remove such notes and memoranda. In all other respects such notes and memoranda shall remain PROTECTED SECURITY MATERIALS and subject to the provisions herein. PROTECTED SECURITY MATERIALS shall be used only to assist TRA staff or any other party to prepare for and to try this proceeding and shall not be used for any other purpose in this or any other jurisdiction.

20. Except as provided in this Order, the contents of PROTECTED SECURITY MATERIALS to which the TRA staff or other party is given access, and any notes, memoranda, and any form or information or opinions regarding or derived from the PROTECTED SECURITY MATERIALS shall not be disclosed to anyone other than an authorized Representative in accordance with this Order, except that an Authorized Representative may disclose his or her conclusions or findings solely within, and for the purposes of, this proceeding and in accordance with this Order. PROTECTED SECURITY MATERIALS shall not otherwise

be published, disclosed, or divulged except as expressly provided herein. The TRA Directors, TRA staff, and all other parties shall treat all notes, memoranda, or opinions regarding or derived from PROTECTED SECURITY MATERIALS, as highly confidential and shall keep them in a secure location with access limited to an authorized representative and the contents of PROTECTED SECURITY MATERIALS and any information derived from them shall be considered highly confidential, and shall not be deemed public records. The TRA staff, any party, Hearing Officer, or the TRA Directors may discuss any position or conclusion regarding security expenditures and testimony in briefs, orders, pleadings, or hearings in this proceeding without disclosing protected information to the public in accordance with this Order.

_____
Hearing Officer

APPROVED FOR ENTRY:

NEAL & HARWELL, PLC

By: _____
William T. Ramsey, #9245

2000 One Nashville Place
150 Fourth Avenue North
Nashville, TN 37219-2498
(615) 244-1713 – Telephone
(615) 726-0573 – Facsimile

Counsel for Atmos Energy Corporation

VERIFICATION

STATE OF TENNESSEE)
)
COUNTY OF WILLIAMSON)

I, John Paris, being duly sworn, state that I am authorized to make this verification on behalf of Atmos Energy Corporation, the Petitioner in the subject proceeding; that I have read the foregoing Petition and Exhibits and know the content thereof; that the same are true and correct to the best of my knowledge, information and belief.

John Paris

SWORN to and subscribed before me
this 3rd day of MAY, 2007.

Notary Public

My Commission Expires:

May 24, 2008

PAMELA TODD
NOTARY PUBLIC
STATE OF TENNESSEE
WILLIAMSON COUNTY, TENN.

My Commission Expires 05-24-08

Exhibit TAR-1

Proposed Tariffs

RESIDENTIAL GAS SERVICE

Schedule 210: All Service Areas

Availability

Residential service is available within the Company's service area to single private residences, including the separate private units of apartment houses and other multiple dwellings, actually used for residential purposes, which are separately metered.

Character of Service

Natural gas, with a heating value of approximately 1,000 Btu per cubic foot, supplied through a single delivery point and a single meter, at the delivery pressure of the distribution system in the area.

Customer Charge

A monthly customer charge of $13.00 for the months of October through April is payable regardless of the usage of gas.

A customer charge of $10.00 for the months of May through September is payable regardless of the usage of gas.

Monthly

All consumption, per Ccf $.1838

Minimum Bill

The minimum net monthly bill shall be the customer charge per month as described above.

Payment

Each monthly bill for service is due and payable on the date it is issued. A charge of five percent (5%) may be added to the amount of any bill remaining unpaid at the close of the first business day after fifteen (15) days following such date of issue.

Gas Lights

For all gas light services, the charge for such services shall be based on actual usage through a metered source at this tariff rate. For all unmetered gas light services prior to August 17, 1990 the customer will be billed for twenty (20) Ccf per standard residential gas light. For all unmetered gas light service after August 17, 1990 the Company may estimate and determine the appropriate consumption of the light and charge the applicable rate under this rate schedule.

RESIDENTIAL GAS SERVICE

Schedule 210: All Service Areas (Continued)

Purchased Gas Cost Adjustment

Bills for service are subject to the cost of purchased gas in accordance with the Purchased Gas Adjustment (PGA) Rider approved by the Tennessee Regulatory Authority.

Service Regulations

Gas service at these schedules will be furnished in accordance with the Company's General Rules and Regulations, copies of which are available for public reference during business hours at each of the Company's offices.

Senior Citizen- Low Income Discount

Qualifying customers certified by the Company will be eligible for the waiver of the customer charge and activation charge. To qualify, the customer must be 65 years of age or older with total household income of $12,000 or less per year

COMMERCIAL/INDUSTRIAL GAS SERVICE

Schedule 220: All Service Areas

Availability

This schedule is available within the Company's service area to commercial/industrial customers using less than 135,000 Ccf per year for any purpose at the option of the Company, to the extent gas is available. This schedule is not available to residences, apartment or federal housing projects.

Character of Service

Natural gas, with a heating value of approximately 1,000 Btu per cubic foot, supplied through a single delivery point and a single meter, at the delivery pressure of the distribution system in the area, or such higher delivery pressure as agreed upon by customer and Company.

Customer Charge

A monthly customer charge of $27.50 is payable regardless of the usage of gas.

Monthly Rate

All Consumption, per Ccf $.2422

Minimum Bill

The minimum net monthly bill shall be the customer charge per meter as described above.

Payment

Each monthly bill for service is due and payable on the date it is issued. A charge of five percent (5%) may be added to the amount of any bill remaining unpaid at the close of the first business day after fifteen (15) days following such date of issue.

Gas Lights

For all metered gas light services under this tariff, the charge for such service shall be based on actual usage through a metered source at this tariff rate. It shall be within the Company's discretion whether a gas light should be metered, however if the gas light is unmetered, the Company may estimate and determine the appropriate consumption of the light and charge the applicable rate under this rate schedule.

PUBLIC HOUSING AUTHORITY GAS SERVICE

Schedule 225: All Service Areas

Availability

This service is available within the Company's service area to any customer in a housing project using gas primarily for domestic purposes and under the ownership and control of a public housing authority or other governmental agency, which are master metered.

Character of Service

Natural gas, with a heating value of approximately 1,000 Btu per cubic foot, supplied through a single delivery point and a single meter, at the delivery pressure of the distribution system in the area.

Customer Charge

A monthly customer charge of $13.00 for the months of October through April is payable regardless of the usage of gas.

A customer charge of $10.00 for the months of May through September is payable regardless of the usage of gas.

Minimum Bill

The minimum net monthly bill shall be the customer charge as described above.

Monthly Rate

All consumption, per Ccf $.1838

Payment

Each monthly bill for service is due and payable on the date it is issued. A charge of five percent (5%) may be added to the amount of any bill remaining unpaid at the close of the first business day after fifteen (15) days following such date of issue.

LARGE COMMERCIAL/INDUSTRIAL GAS SERVICE

Schedule 230: All Service Areas

Availability

This service is available within the Company's service area to any commercial/industrial customers using more than 135,000 Ccf per year for any purpose at the option of the Company, to the extent gas is available.

Character of Service

Natural gas, with a heating value of approximately 1,000 Btu per cubic foot, supplied through a single delivery point and a single meter, at the delivery pressure of the distribution system in the area, or at such higher delivery pressure as agreed upon by Customer and Company. Service under this rate schedule may be terminated by either party following twelve (12) months notice to the other party.

Customer Charge

A monthly customer charge of $200.00 is payable regardless of the usage of gas.

Monthly Rate

All Consumption, per Ccf $.2172

Minimum Bill

The minimum net monthly bill shall be the customer charge per meter as described above.

Payment

Each monthly bill for service is due and payable on the date it is issued. A charge of five percent (5%) may be added to the amount of any bill remaining unpaid at the close of the first business day after fifteen (15) days following such date of issue.

Gas Lights

For all metered gas light services under this tariff, the charge for such service shall be based on actual usage through a metered source at this tariff rate. It shall be within the Company's discretion whether a gas light should be metered, however if the gas light is unmetered, the Company may estimate and determine the appropriate consumption of the light and charge the applicable rate under this rate schedule.

DEMAND/COMMODITY GAS SERVICE

Schedule 240: All Service Areas

Availability

This service is available within the Company's service area to any commercial/industrial customers using at least 270,000 Ccf per year for any purpose at the option of the Company, to the extent gas is available.

Character of Service

Natural gas, with a heating value of approximately 1,000 Btu per cubic foot, supplied through a single delivery point and a single meter, at the delivery pressure of the distribution system in the area, or at such higher delivery pressure as agreed upon by Customer and Company. Service under this rate schedule may be terminated by either party following twelve (12) months notice to the other party.

Customer Charge

A monthly Customer Charge of $310.00 is payable regardless of the usage of gas.

Monthly Rate

Demand Charge
Per Unit of Billing Demand $1.6293 per Ccf

Commodity Charge

First	20,000	Ccf Per Month	$ .1038
Next	480,000	Ccf Per Month	$ .0713
Over	500,000	Ccf Per Month	$ .0371

Minimum Bill

The minimum net monthly bill shall be the Customer Charge per meter plus the Monthly Demand Charge as described above.

Payment

Each monthly bill for service is due and payable on the date it is issued. A charge of five percent (5%) may be added to the amount of any bill remaining unpaid at the close of the first business day after fifteen (15) days following such date of issue.

DEMAND/COMMODITY GAS SERVICE

Schedule 240: All Service Areas (Continued)

Billing Demand

The Billing Demand for the current month is effective October 1, 1992 and shall be redetermined effective November 1 of each successive year. The Billing Demand is the highest demand day in any of the previous billing months of November, December, January, February, and March.

Whenever a customer commences taking service under this Rate Schedule, the Billing Demand shall be 6% of monthly consumption in each month until redetermined as stated above.

Determination of Demand Day

The demand day shall be determined at the option of the Company by one of the following methods:

1. By measuring the maximum volume of gas taken by the Customer in any one day through the use of volume and pressure recording and measuring equipment installed by the Company.

2. When gas is delivered to a Customer through a positive displacement meter without the use of daily recording and measuring equipment, the maximum volume of gas taken in any one day during the billing month shall be 6% of the total volume of gas used by the customer during such billing month.

The Company retains the option of installing recording and measuring equipment to determine the maximum volume of gas taken in any one day on the meter of any customer purchasing gas service under this Rate Schedule.

Measurement Data Collection Equipment

New customers served under this Rate Schedule after October 1, 1992 shall be required to pay for the cost and installation of measurement data collection and verification equipment, including applicable income taxes. All customers shall also be required to pay the cost of installation, maintenance and any monthly usage charges associated with telephone, power or other utilities or energy sources required for the operation of the data collection and verification equipment, including applicable taxes. All customers shall also be required to provide adequate space in new or existing facilities for the installation of the data collection equipment.

Gas Lights

For all metered gas light services under this tariff, the charge for such service shall be based on actual usage through a metered source at this tariff rate. It shall be within the Company's discretion whether a gas light should be metered, however if the gas light is unmetered, the Company may estimate and determine the appropriate consumption of the light and charge the applicable rate under this rate schedule.

INTERRUPTIBLE GAS SERVICE

Schedule 250: All Service Areas

Availability

To any commercial or industrial customer using 270,000 Ccf or more per year, or 1,000 Ccf per day during off-peak periods. The Company recommends that the Customer has and maintains adequate standby facilities and an alternate fuel supply in order that gas deliveries hereunder may be interrupted at any time.

Customers that will utilize natural gas during off-peak periods only do not need to meet the volumetric annual requirement (i.e. 270,000 ccf or more per year)for eligibility under this schedule. Examples of customers utilizing natural gas during off-peak periods only would include, but is not limited to the following: asphalt plants, electric generating facilities, grain drying facilities, and farm irrigation systems. The Company recommends an adequate standby facility and alternate fuel supply for off-peak customers served under this schedule.

Deliveries to such customers shall be subject to curtailment at any time. Deliveries to such customers shall be subject to curtailment in whole or in part upon one-half (1/2) hour's notice.

Character of Service

Natural gas, with a heating value of approximately 1,000 Btu per cubic foot, supplied through a single delivery point and a single meter, at the delivery pressure of the distribution system in the area, or such higher delivery pressure as agreed upon by customer and Company.

Customer Charge

A monthly customer charge of $310.00 is payable regardless of the usage of gas.

Monthly Rate

First	20,000	Ccf used per month	$.1038
Next	480,000	Ccf used per month	$.0713
Over	500,000	Ccf used per month	$.0371

Minimum Bill

The minimum net monthly bill shall be $310.00

Payment

Each monthly bill for service is due and payable on the date it is issued. A charge of five percent (5%) may be added to the amount of any bill remaining unpaid at the close of the first business day after fifteen (15) days following such date of issue.

ATMOS ENERGY CORPORATION

INTERRUPTIBLE GAS SERVICE

Schedule 250: All Service Areas (Continued)

Purchased Gas Adjustment

Bills for service are subject to the cost of purchased gas in accordance with the Purchased Gas Adjustment (PGA) Rider approved by the Tennessee Regulatory Authority.

Curtailment Procedures

Notice of curtailment of service hereunder shall be given by the Company by telephone or otherwise not less than one-half (1/2) hour from time of curtailment. Upon receipt of such notice, the Customer shall immediately proceed to discontinue the use of service at the time and to the extent of the order. The Company shall notify the Customer by telephone or otherwise when service hereunder is to be restored and the Customer shall not resume service until such time as stated in the restoration notice.

Overrun Penalty

Volumes of gas taken at any time in excess of the amount stipulated by the Company in the curtailment notice as being available to Customer shall constitute overrun gas. A penalty of $2.50 per Ccf of such overrun volumes shall be paid by Customer in addition to all over charges payable hereunder provided; however, Company has the right to waive any portion of the overrun penalty on a non-discriminatory basis for good cause.

Terms of Contract

Customer shall contract for service hereunder for a term of not less than one (1) year. Upon the expiration of any contract term, the contract shall be automatically renewed for a period of one (1) year. At any time following the first contract year, service may be terminated by either party following at least twelve (12) months notice to the other party.

Terms and Provisions of Service Under This Rate Schedule

Customers served under this Rate Schedule shall be required to pay for the cost and installation of measurement data collection and verification equipment, including applicable income taxes. Customers shall also be required to pay the cost of installation, maintenance and any monthly usage charges associated with telephone, power or other utilities or energy sources required for the operation of the data collection and verification equipment, including applicable taxes. Customers shall also be required to provide adequate space in new or existing facilities for the installation of the data collection equipment.

Service Regulations

Gas service at these schedules will be furnished in accordance with the Company's General Rules and Regulations, copies of which are available for public reference during business hours at each of the Company's offices.

TRANSPORTATION SERVICE (Continued)

Schedule 260: All Service Areas

C. Terms and Provisions of Service Under This Rate Schedule (Continued)

(vii) The Company shall not be obligated to provide delivery service hereunder, whether for the purpose of delivering a previous transportation imbalance, or otherwise, during an hourly, daily, or monthly period in excess of the levels specified in the Firm Contract.

(viii) A percentage adjustment for unaccounted for gas shall be made to the volumes of gas delivered into the Company's facilities for the Customer's account, and the volumes of gas deliverable to the Customer under this rate schedule shall be reduced by such percentage. Such percentage shall be equal to the percent that unaccounted-for gas bore to total sendout as recorded by the Company during its most recent 12 months ending June.

(ix) Company reserves the right to refuse to accept gas for the account of the Customer into Company's facilities if the same would reduce the volumes of the gas otherwise available to Company from the Connecting Pipeline Company.

(x) If the rendition of service to Customer under this rate schedule causes the Company to incur additional charges from the Connecting Pipeline Company, Customer shall reimburse Company for all such charges.

(xi) All volumes transported under the terms of this rate schedule shall be included in the Purchased Gas Adjustment computations and included in the sales volumes of the Purchased Gas Adjustment computations.

(xii) Customers served under this Rate Schedule shall be required to pay for the cost and installation of measurement data collection and verification equipment, including applicable income taxes. Customers shall also be required to pay the cost of installation, maintenance and any monthly usage charges associated with telephone, power or other utilities or energy sources required for the operation of the data collection and verification equipment, including applicable taxes. Customers shall also be required to provide adequate space in new or existing facilities for the installation of the data collection equipment.

TRANSPORTATION SERVICE (Continued)

Schedule 260: All Service Areas

C. Terms and Provisions of Service Under This Rate Schedule (Continued)

(xiii) Once a customer elects and has qualified for service under this rate schedule, all services will be provided under the terms and conditions of this rate schedule for a term of no less than 12 months. At any time following the first six months of service under this rate schedule, service may be terminated by either party following at least six months written notice to the other party.

D. Rate

Customer Charge

A monthly customer charge of $310.00 per meter is payable regardless of the usage of gas.

Monthly Demand Charge

Customers eligible to receive sales service under Rate Schedule 240 shall be billed the applicable Monthly Demand Charge.

Commodity Charge

The Customer shall be billed for the quantity of gas delivered under this rate schedule at the companion rate schedule less the Connecting Pipeline Company's commodity cost of gas, plus an adjusted Purchased Gas Adjustment factor, multiplied by the quantity of gas delivered under this rate schedule.

Minimum Bill

The minimum monthly bill shall be the Customer Charge plus the Monthly Demand Charge, if any, as described above.

Payment

Each monthly bill for service is due and payable on the date it is issued. A charge of five percent (5%) may be added to the amount of any bill remaining unpaid at the close of the first business day after fifteen (15) days following such date of issue.

COGENERATION, COMPRESSED NATURAL GAS, PRIME MOVERS, FUEL CELL SERVICE

Schedule 292: All Service Areas

Purpose

The purpose of providing service under this schedule is to increase utilization of system supplies and system capacity.

Applicability

This schedule is available to the extent gas supply and delivery capacity is available to commercial and industrial customers, existing or new, for use as a single prime fuel source to generate electrical and thermal energy in order to optimize efficiency. This schedule is also available for compressed natural gas for automobile and truck fleets and fuel cell service.

Eligibility

Eligible customers shall include those who are currently connected to the Company's gas main or who will become newly connected. In either case, service will be provided, at the Company's option, through a separate meter.

Character of Service

Natural gas with a heating value of approximately 100,000 Btu per hundred cubic feet, supplied through a single delivery point meter, at the standard equipment utilization pressure, or at such higher delivery pressure as approved by Company.

Rate

Customer Charge

A monthly charge of $25.00 for each customer regardless of the usage of gas.

Customer charge for adjacent connected load will not be duplicated, otherwise the facilities charge will be at the customer's regular schedule charge.

Monthly Charge

First	20,000	Ccf used per month	$ .1038
Next	480,000	Ccf used per month	$ .0713
Over	500,000	Ccf used per month	$ .0371

ATMOS ENERGY CORPORATION

LARGE TONNAGE AIR CONDITIONING GAS SERVICE

Schedule 293: All Service Areas

Purpose

The purpose of providing service under this schedule is to increase utilization of system supplies and system capacity.

Applicability

This schedule is available to the extent gas supply and delivery capacity is available to commercial and industrial customers whose requirements may include high load factor systems that provide chilled water, space conditioning, processing, and/or humidity control. These conditions may be accomplished by the utilization of absorption, gas engine driven or desiccant systems.

Eligibility

Eligible customers shall include those who are currently connected to the Company's gas main or who will become newly connected. In either case, service will be provided, at the Company's option, through a separate meter.

Character of Service

Natural gas with a heating value of approximately 100,000 Btu per hundred cubic feet, supplied through a single delivery point and a single meter, at the standard equipment utilization pressure or at such higher delivery pressure as approved by Company.

Rate

Customer Charge

A monthly charge of $25.00 for each customer is payable regardless of the usage of gas.

Customer charge for adjacent connected load will not be duplicated, otherwise the facilities charge will be at the customers regular schedule charge.

Monthly Charge

First	20,000	Ccf used per month	$ .1038
Next	480,000	Ccf used per month	$ .0713
Over	500,000	Ccf used per month	$ .0371

GENERAL RULES AND REGULATIONS (Continued)

The Company shall promptly refund or credit the deposit, with interest as provided in this service regulation, and may require the surrender of the Customer's receipt of certificate of deposit properly endorsed, or the delivery of a cancellation receipt for such deposit, whenever:

(a) The Customer establishes credit by other means; or

(b) The service is discontinued and the bills therefore are paid in full; or

(c) The service is discontinued and there are charges due (including construction charges related to main extensions) to the Company for service to the Customer, in which case the cash deposit plus any accrued interest will be applied to the payment of such charges, and the balance remaining of the deposit and interest, if any, will be returned to the Customer. When the deposit is applied to the liquidation of unpaid bills, the Company will mail or deliver to the Customer a statement showing the amount of the original deposit, including accrued interest if any, the amount of the unpaid bills liquidated by the deposit; and the balance remaining due either to the Customer or to the Company.

In either case, and in any event, if there is a balance due the Customer when service is discontinued, it shall then be promptly and automatically refunded to the Customer.

Commercial/Industrial Customer Deposits

Commercial and Industrial Customer deposits and applicable interest, less any amounts owing the Company by the Customer, will be refunded by the Company when the customer's account is closed.

3.5 Interest to be Accrued on Deposits

Interest on deposits shall be paid on a per annum rate equal to the prime bank lending Rateplus one percentage point as published in The Wall Street Journal for the last business day of the preceding calendar year, compounded annually. In no case will interest be accrued for a period extending beyond the date of refund or the date service is terminated, whichever date is earlier. No interest will be paid on deposits held for a period of less than six (6) months.

3.6 Payment of Interest Accruals

Interest accruing on cash deposits will be computed and prompt settlement made:

(a) By paying the amount of interest accrued on the demand of the Customer, but not more often than once in any 12 month period; or

GENERAL RULES AND REGULATIONS (Continued)

5.3 Activation Charge

Service which is discontinued by the Company, or at the Customer's request, may be restored upon payment by customer of all indebtedness for gas service and an activation charge which shall be $40 for activation during normal business hours. (Additional charges may apply if after-hours service is requested and performed). This activation charge will apply to all meter turn-ons at existing locations and all reconnections of service and shall apply to all rate schedules.

5.4 Limitations on Discontinuance

Gas service to any Customer will not be terminated without reasonable prior notice and the Customer being given reasonable opportunity to dispute the reasons for such termination.

(a) Prior reasonable notice will be sent to a Customer informing of the date of any proposed termination of service unless such Customer takes appropriate action. The date of the proposed termination shall be at least seven (7) days after the Company sends the notice by first class mail.

(b) The Company shall postpone the physical termination of gas service to a residential Customer for a period of thirty (30) days in the event a physician, public health officer, or social service official certifies in writing that discontinuation of service will aggravate an existing medical emergency of the Customer or other permanent resident of the premises where service is rendered. The Company shall refer the Customer or other permanent resident of the premises to social service agencies for investigation, confirmation of need and guarantee of payment. The Company shall supply

GENERAL RULES AND REGULATIONS (Continued)

(b) In the event of stoppage or failure of any meter to register properly, Customer will be billed for such period on an estimated consumption based upon his use of gas in a similar period of like use or on the basis of check meter readings, if available and accurate, but such adjustment shall not be made for more than six months.

(c) In the event of tampering or unauthorized use of Company's facilities, the probable gas consumption shall be estimated by Company and billed to Customer. If the duration of such tampering or unauthorized use is not known, it shall be conclusively presumed to be since the commencement of Customer's service but for a period of not more than six months.

(d) All property of Company installed in or upon premises of, or occupied by Customer is under Customer's protection. All reasonable care shall be exercised by Customer to prevent loss of or damage to such property, ordinary wear and tear excepted. Customer will be liable for any loss of property or damage thereto and shall pay to Company the cost of appropriate repairs or replacements for such loss or damage to property.

7. Extension and Installation of Company Facilities

This Company will, upon written application, extend its gas mains to serve bona fide applicants of a permanent and established character in accordance with the provisions of this Service Regulation. Gas main extensions shall be made only along public streets, roads or highways and upon private property across which satisfactory rights of way or easements have been provided without cost to the Company. All gas mains constructed pursuant to this service regulation shall be owned, operated, and maintained by the Company.

7.1 Main Extensions

Any extension from existing mains to the point of connection with Customer's service line, whether on public property or on private property, is considered to be an extension of a main. Any extension, from existing mains or from an extension of a main as defined above, to Customer's property for service to Customer shall be considered a part of the service line to service such Customer.

GENERAL RULES AND REGULATIONS (Continued)

The Company will install all mains, service lines, metering, and regulating equipment necessary to serve the customer(s) free of charge, provided the revenue expected to be realized produces a rate of return on the investment that is equal to or greater than the minimum allowed rate of return on equity approved in the Company's most recent rate case. This rate of return analysis will be based on a feasibility study performed by the company. This study will include consideration of all costs needed to provide service (materials, company and/ or contract labor, overheads, and applicable taxes). These costs will be compared to the revenue that is either contracted for or can be reasonably expected to be generated by the customers served by the extension. Should this analysis result in a rate of return (ROE) less than the minimum allowed rate of return approved in the Company's most recent rate case, then the customer(s) may be required to remit to the company an Aid-in-Construction (AIC), including any applicable taxes, to make up the difference in the actual and allowable rate of return.

General

1. The Company may, at its sole discretion, choose to waive payment for AIC when system improvements are realized by the extension or when the extension would enhance the opportunity of adding new customers in the future.

2. Individual customers may elect to spread the payment of any required AIC up to, but not to exceed, a three year period at no interest provided that the Customer shall enter into a "Main Extension Contract" and also subject to the following conditions:

   a. The Company shall approve the Customer's credit prior to the signing of the "Main Extension Contract".

   b. Default by the Customer under the terms of the "Main Extension Contract may result in discontinuance of service as per the current provisions of Section 5 of these General Rules and Regulations.

   c. If a Customer cancels service prior to payment of the total AIC required, the unpaid balance shall become due and payable immediately. The Company may use any deposit or credit owed to the Customer to offset the balance due under the "Main Extension Contract".

   d. In no case will the Company build without cost to the applicant more service line than is necessary to reach the acceptable meter location by the most economical route.

ATMOS ENERGY CORPORATION

RESERVE FOR FUTURE USE

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RESERVE FOR FUTURE USE

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RESERVE FOR FUTURE USE

GENERAL RULES AND REGULATIONS (Continued)

7.2 Meters and Service

1. Upon written application, Company will install necessary meter connections and meter without charge subject to the provisions of Service Regulation No. 2.

2. New service piping, up to and including a size 3/4 inch in diameter, will be installed by the Company free of charge for residential and for commercial Customers whose annual consumption is 500 Mcf or less, from its distribution main to the private property line of the applicant or other private property line through which the service shall be constructed, and for an additional length, from such property line to the meter location, determined in accordance with Service Regulation No. 2, as is determined by the allowance per Customer for each major use of gas appliances and equipment specified below:

Residential and Commercial Service	Allowance
Gas Space Heating Equipment	60 feet
Automatic Gas Water Heater and/or Gas Range	40 feet

Residential and commercial customers whose annual consumption is estimated by the Company to be over 100 Mcf and less than 500 Mcf for commercial customers, the free length will equal one foot per Mcf of estimated total gas consumption.

This free service piping allowance will not apply for temporary service.

3. For each industrial Customer and commercial Customer whose annual consumption is over 500 Mcf, the Free Length of service, if any, will be determined on an individual feasibility basis considering the required investment, character, and economic life of the load, and other appropriate information.

4. For service piping in excess of the portion installed at Company expense pursuant to paragraph (2) above, Customer will be charged for such excess footage, based on the average cost to the Company, for installing service piping the preceding calendar year. The rate per linear foot of service will be the average cost incurred during the preceding calendar year for installing such service pipe. Any charges for installing excess service piping are payable in advance. For excess service piping pursuant to paragraph (2) above, the Customer will be charged for the actual cost of such excess service piping.

5. Upon request from the Customer, the Company will provide the following services without charge:
   (i) Leak Investigation
   (ii) Burner or Pilot Light adjustment (during normal working hours)

GENERAL RULES AND REGULATIONS (Continued)

8. Curtailment of Gas Service

Service will be curtailed in accordance with the order of priorities set forth below, beginning with optional service 1 a. and descending as required.

1. All Interruptible Service
   a. Industrial Customers (Over 3,000 Mcf/day)
   b. Industrial Customers (Over 1,500 Mcf/day)
   c. Industrial Customers (Over 300 Mcf/day)
   d. Industrial Customers (Less than 300 Mcf/day)
   e. Large Commercial Customers (Over 50 Mcf/day)
   f. Small Commercial Customers (Less than 50 Mcf/day)

2. Large Industrial Firm Customers (Over 50 Mcf/day)
3. Small Industrial Firm Customers (Less than 50 Mcf/day)
4. Large Commercial Firm Customers (Over 50 Mcf/day)
5. Small Commercial Firm Customers (Less than 50 Mcf/day)
6. Essential Agricultural Use
7. Public Schools and Hospitals on Firm Service
8. Public Housing Authorities and Residential Customers

Notwithstanding the provisions of this paragraph, the Company shall not be liable for any damages that may result to Customers or any other persons, firm or corporation by reason of the Company's limiting annual, monthly, or peak day volumes or by curtailing service in accordance with the above order of priorities which may be deemed practicable under existing conditions by Company. Company will make every reasonable effort to deliver plant protection volumes to firm industrial customers sufficient to prevent damage to facilities or danger to personnel. This includes the protection of such material in process as would otherwise be destroyed, but does not include deliveries required to maintain plant protection.

CUSTOMER UTILIZATION ADJUSTMENT (CUA) RIDER

Provisions for Adjustment

This Rider shall apply to and become part of Atmos Energy Corporation's (Company's) Rate Schedules 210, 220, 225 and 230. The base rate per Ccf for gas service set forth in the referenced Rate Schedules shall be adjusted by an amount hereinafter described, which is referred to as the "Customer Utilization Adjustment" (CUA). The CUA shall apply to all residential, commercial and public authority bills within the above referenced Rate Schedules. This CUA Rider is intended to authorize the Company to recover or refund (positively or negatively) margins associated with volume changes other than those related to weather (which are corrected through the Company's Weather Normalization Adjustment Rider).

Definitions

For purpose of this Rider:

"Regulatory Authority" means the Tennessee Regulatory Authority

"Relevant Rate Order" means the final order of the Regulatory Authority in the most recent litigated rate case of the Company fixing the rates of the Company or the most recent final order of the Regulatory Authority specifically prescribing the factors and procedures to be used in the application of this Rider.

Computation of Customer Utilization Adjustment

The CUA shall be computed to the nearest one-hundredth cent per Ccf by the following manner:

1) The CUA shall be calculated for each customer class in the referenced rate schedules as the difference between the test-year average margin per customer as determined in the Relevant Rate Order and the actual average margin per customer (including margins from the Weather Normalization Adjustment), multiplied by monthly average number of billing units for the CUA accounting/recovery period.
2) The annual CUA factor shall be obtained by dividing the total margin difference less cumulative collections as of the CUA accounting/recovery period by the number of Ccf for each class in the referenced rate schedules distributed by the Company during the CUA accounting/recovery period.

The annual CUA factor shall be recovered in addition to the commodity/volumetric charges for the Company's Rate Schedules 210, 220, 225 and 230.

Filing with the Authority

Each CUA accounting/recovery period shall correspond with the Company's Fiscal Year which ends September 30 each year.
The Company shall charge all authorized CUA margins to the "Deferred Margin" account and shall file supplemental sheets as may be required by the Authority showing the calculation of the CUA factors and activities.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY CORPORATION FOR APPROVAL OF ADJUSTMENT OF ITS RATES AND REFISED TARIFF	))))	**DOCKET NO. 07-_____**

I. INTRODUCTION OF WITNESS

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

A. My name is John Paris. I am President of the Kentucky/Mid-States Division of Atmos Energy Corporation ("Atmos" or "Company"). My business address is 2401 New Hartford Road, Owensboro, Kentucky 42303.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The primary purpose of my testimony is to set forth the principal factors requiring Atmos to request an increase in rates and explain why this request is coming so quickly after TRA's recent decision in Phase I of Docket No. 05-00258. I will also address the Company's request for a Customer Utilization Adjustment (CUA), which will complement our existing WNA rider, and discuss some of the tariff changes we are proposing in this docket. In addition, I will provide an overview of the Company's history and its operations in Tennessee and across the United States with a particular focus on its commitment to customer service and safety. Finally, I will introduce the Company's other witnesses in this docket.

II. BACKGROUND AND QUALIFICATIONS

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

A. I earned a Bachelor of Arts degree in History from Berea College in 1985. That same year, I became an operations aide for Western Kentucky Gas Company ("WKG"). WKG was acquired by Atmos in December of 1987 and is now part of Atmos' Kentucky/Mid-States division. I worked in a variety of jobs for WKG during summer recess while attending college. After joining the company full time in 1985, I held positions of increasing responsibility before being named Assistant District Manager of the Bowling Green District in 1993. I became the Southern Colorado District Manager for Atmos in 1995. In 1997, I was named Vice President of Operations for the Colorado Region. In that position, I was responsible for safety, maintenance, construction, and customer service to Atmos' Colorado customers. From 1999 to 2001, I served as Chairman of the Atmos Marketing Council, which has the responsibility for developing and executing the Company's utility marketing strategy.

In 2001, I was named President of Atmos' Kentucky division and in February 2005, my responsibilities were increased to include Atmos' Mid-States division. As President of Atmos' Kentucky/Mid-States division, I have responsibility for customer services, operations, regulatory and community relations and the financial performance of those divisions.

Q. Have you ever testified before the Tennessee Regulatory Authority (TRA)?

A. Yes, I recently testified before the TRA in the Company's Phase I of Docket No. 05-00258 in August 2006. In addition, I have previously provided testimony before the

Colorado Public Utilities Commission, the Georgia Public Service Commission, the Missouri Public Service Commission, and the Kentucky Public Service Commission in Atmos rate cases.

III. PURPOSE OF THIS PROCEEDING

Q. What does Atmos seek in this rate case?

A. Atmos seeks approval of an increase in revenues of approximately $11 million. The increase to the bill of an average residential customer at current gas prices would be approximately $4.27 per month. Although we operate very efficiently, we are not achieving a fair return on our investment with the rates currently in effect. The proposed increase will allow the Company to establish new rates that will provide it a fair return and offset the continued plant investment we have made in our system.

Let me explain the components that make up this increase. We are not simply seeking a rehearing on the Authority's rulings in Docket No. 05-00258. Only about $2.6 million of the requested increase results from our disagreements with some of the rulings in that Docket. Additional investments, inflation, and updated information from cost and depreciation studies created the need for approximately $6.5 million of the increase. This includes a net reduction in depreciation expense of about $2.1 million due to reduced depreciation rates, as well as an increase in state gross receipts taxes of approximately $1.3 million, due primarily to a tax anomaly. The remaining $2.0 million of the requested increase is necessary because, at present rates, gross margin is projected to be $2.0 million lower in the test year than that provided for in the Authority's ruling in Docket No. 05-00258. The net result of all of these items leads to a total increase request of $11,055,188.

Q. When was the Company's last general rate proceeding in Tennessee?

A. Atmos has not filed for a general rate increase in Tennessee since 1995. The Company's last rate proceeding in Tennessee concluded in November 2006 with a motion approved by the TRA ordering the Company to reduce rates by $6.1 million, effective December 1, 2006. That proceeding, which was Phase I of Docket No. 05-00258, was a contested rate case initiated by the Consumer Advocate Protection Division (CAPD) of the Attorney General's office. As I said, the Company has not filed for a general rate increase in Tennessee since 1995, when United Cities Gas Company filed a rate application prior to its acquisition by Atmos. For more than 10 years Atmos has made a continual effort to provide the highest quality service to its customers at the lowest possible cost. As a result the Company is proud that it has been able to operate in Tennessee for over 10 years without requesting a rate increase.

Q. Has Atmos complied with all of the orders and directives from the TRA's recent motion in Docket No. 05-00258?

A. Yes, the Company implemented the newly approved rates for all customers, effective December 1, 2006. In addition, Atmos is also on track to replace 45,000 feet of bare steel pipe this year, as ordered in Director Miller's Motion. Further, the Company is now waiving the customer charge for qualifying low income and/or senior citizen customers. A message line was included with January 2007 bills, to explain eligibility and provide information concerning this discount. In order to properly notify our customers about the rate changes resulting from Docket No. 05-00258, we included a detailed bill insert, which explained that the new rates were reflected in the current bills.

Q. Why is Atmos requesting a rate increase less than one year after the conclusion of the recent Contested Case?

A. While the Company has no doubt that Phase I of Docket No. 05-00258 was conducted in a fair and reasonable manner, the rates resulting from that case are simply not sufficient to allow the Company to earn a reasonable return for its shareholders on its investment in Tennessee. Consequently, Atmos believes that it has an obligation to those shareholders to seek immediate rate relief. Atmos' testimony and the information requested in the filing requirements in Docket No. 05-00258 demonstrated that the Company would experience a significant revenue deficiency during the attrition period, and we continue to believe this to be the case. Nevertheless, the Company was ordered to decrease its rates to its customers by $6.1 million. We would also respectfully note that in that recent proceeding, Atmos was awarded a return on equity (ROE) of 10.48%, which not only was much lower than the 12% proposed by the Company, but which also was lower than the TRA Staff's recommendation of 10.75%. Consequently, prompt and adequate rate relief is now essential if we are to continue to provide high-quality, safe and reliable service to our customers while achieving a reasonable rate of return for our shareholders.

Atmos wants to emphasize that the timing of this filing so soon after the resolution of Phase I of Docket No. 05-00258 is not meant in any way to show disrespect to the TRA or to its decision in that case. As I stated above, the urgency behind the timing of this filing is driven by the fact that the Company believes that it has an obligation to its shareholders to begin receiving a reasonable return on its investment in Tennessee as soon as it possibly can. We have detailed above the components that make up this requested increase.

Since the Company's last request for a rate increase in 1995, Atmos has increased its rate base in Tennessee by more than $70 million dollars, while continuing to invest in customer growth projects and increasing its replacement of bare steel pipe each year. Further, while Atmos makes every effort to control its expenses, a portion of the requested increase is necessary to cover increased costs for items such as salary and wage increases, increased medical costs and higher pension benefits. At the same time, steady declines in customer usage caused by energy conservation, more efficient homes and appliances, and changes in lifestyles continue to erode our margins in Tennessee. In the past few years, some of the Company's large customers in Tennessee have decreased production or closed their plants and are therefore contributing less margin each year. We simply cannot continue to absorb these higher costs and maintain the current level of investment while margins continue to decline.

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

A. We are asking the Authority to approve new rate schedules that would increase our revenues to provide a projected rate of return of 8.84% on a projected net rate base of $188,920,055.

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

A. We have requested a rate of return on projected common equity of 11.75 %.

Q. How much will Atmos' proposed rate filing increase the bill of an average residential customer?

A. The increase to the bill of an average residential customer at current gas prices would be approximately $4.27 per month. I believe that this is a modest rate increase given that the

Consumer Price Index has increased approximately 30% since our 1995 rate filing in Tennessee.

Q. Other than the requested increase in rates, are there any other proposals in this filing that you would like to address?

A. Yes. The Company is requesting authorization to incorporate a Customer Utilization Adjustment ("CUA"). The CUA will complement the Company's WNA rider by compensating for variances in customer usage related to factors other than weather. Although Company witness Mr. Gary Smith will address this proposal in depth in his testimony, I will briefly discuss why I believe the proposed CUA should be approved.

Q. Please discuss the proposed Customer Utilization Adjustment (CUA).

A. As the Authority is aware, a WNA addresses variances in the recovery of revenues resulting from deviations from normal weather. Since its inception in 1991, both the Company and its customers have enjoyed the success of this mechanism, yet there is a fundamental issue that the current WNA does not address. The existing tariff rider does not consider variables that impact customer usage other than weather, such as the increasing energy-efficiency of appliances, more efficient new homes, and conservation. Energy conservation has become increasingly important as utilities and their customers, as well as local, state, and federal government agencies, seek to find ways to place downward pressure on natural gas prices and make efforts to ensure adequate energy supplies to meet the needs of future generations of Americans. However, under traditional rate design a utility typically recovers its cost of service through a monthly customer charge and a volumetric charge. This structure dictates a need for continued growth in sales volume in order to recover fixed costs and authorized revenue requirement. In the current environment this

acts as a built-in disincentive for local distribution companies to encourage conservation, and thereby falls short of aligning the interests of utilities and their customers on this important issue. The proposed CUA will compliment the existing WNA and address these problems by accurately adjusting actual non-gas revenues to the level established in this docket, thereby providing the Company with the opportunity to recover its allowed return on investment regardless of fluctuations in sales resulting from the variables mentioned above. Since the revised mechanism will decouple the Company's revenues from the volume of gas consumed, the disincentive that currently exists for the Company to encourage energy efficiency and conservation would be removed.

Q. Are there any other changes to existing tariffs or additional tariffs requested in this proceeding?

A. Yes. The Company is requesting authority to change its monthly customer charges and the volumetric charges applicable to monthly consumption. We propose to spread the new revenue requirement proportionately across all customer classes based on the current revenues of each class. These changes are discussed further in the testimony of Company witness Patricia Childers. The Company is also requesting the authority to apply the current $40 activation charge for reconnection of service to all rate schedules. The charge currently applies only to residential customers in rate schedule 210. In addition, the Company is requesting changes to the existing Optional Gas Service tariff, the interest rate paid on customer deposits, and the Company's main extension policy. A more detailed discussion of the proposed tariff and General Service Rules changes is contained in the testimony of Company witness Michael Ellis.

III. AN OVERVIEW OF ATMOS ENERGY

Q. Can you provide the TRA with a general description and background of Atmos' natural gas distribution business in the United States?

A. Yes. Atmos Energy is the largest pure natural gas distribution company in the United States. It delivers natural gas to approximately 3.2 million residential, commercial, industrial, and public-authority customers in twelve states. Atmos has six gas utility operating divisions. They are located in Denver, Colorado (Colorado/Kansas division); Baton Rouge, Louisiana (Louisiana division); Jackson, Mississippi (Mississippi division); Lubbock, Texas (West Texas division); Dallas, Texas (Mid-Tex division); and Franklin, Tennessee and Owensboro, Kentucky (Kentucky/Mid-States division). In addition, Atmos has an operating division consisting of a regulated intrastate pipeline that functions only within the state of Texas.

Atmos' history dates back to 1906 in the panhandle of Texas. Over the years, through various business combinations and mergers, the company became part of Pioneer Corp., a large diversified West Texas energy company. In 1983, Energas Company, the natural gas distribution division of Pioneer and formerly known as Pioneer Natural Gas, was spun off and became an independent, publicly held natural gas distribution company. In October 1988, Energas changed its corporate name to Atmos Energy Corporation and began trading on the New York Stock Exchange.

Since 1986, Atmos has completed numerous significant acquisitions. In 1986, Atmos expanded its natural gas distribution business to Louisiana with the acquisition of Trans Louisiana Gas Company. In 1987, Atmos further expanded its operations by moving into Kentucky with the acquisition of WKG. In 1993, Atmos acquired Greeley Gas Company's Kansas, Colorado and Missouri operations and, in 1997, it acquired United

Cities Gas Company, which operated in eight states including Tennessee. That acquisition was approved by the TRA. Atmos acquired the Missouri assets of Arkansas Western Gas Company known as Associated Natural Gas Company in 2000 and, in 2001, it completed its purchase of the assets of Louisiana Gas Service Company and LGS Natural Gas Company. In December of 2002, Atmos expanded its operations into Mississippi with the acquisition of Mississippi Valley Gas Company. Most recently, in 2004, Atmos acquired the natural gas distribution and pipeline operations of TXU Gas Company from TXU Corp. The operations acquired in this transaction serve approximately 1.5 million customers in the Dallas-Forth Worth metroplex and more than 500 other communities in north and central Texas.

Atmos' corporate offices are located in Dallas, Texas, and provide services such as accounting, legal, human resources, rates administration, procurement, information technology, and a customer support center. These centralized services, commonly referred to as Shared Services, are shared with the other Atmos operating divisions in order to avoid having to staff and maintain these functions at each division level. These centralized services are the technical and administrative services that would be required if each division was a stand-alone company today. Atmos believes that this structure gives it an economic advantage and enables it be a low-cost, high-quality service provider of natural gas. Each of the Company's six utility divisions has its own divisional office that is responsible for the day-to-day operations of that division.

Q. Can you provide the TRA with a general description and background of Atmos' operations in Tennessee?

A. Yes. Atmos' Kentucky/Mid-States Division serves customers in Tennessee, Kentucky, Missouri, Virginia, Georgia, Illinois, and Iowa. This Division provides natural gas service to approximately 475,000 customers across those seven states. Atmos serves approximately 128,000 residential, commercial, and industrial customers in Tennessee. The Company has a Tennessee-based work force of over 200 employees including 31 employees in the Mid-States division office in Cool Springs. Our utility plant in Tennessee includes over 3,000 miles of transmission and distribution lines. I have included a map of Atmos' Tennessee service territory as Schedule JP-1.

IV. ATMOS' COMMITMENT TO CUSTOMER SERVICE

Q. Please discuss the Company commitment to serving its Tennessee customers?

A. Over the past several years the Company has made a substantial investment to ensure that it provides the best customer service possible. To demonstrate this commitment, the Company has introduced and implemented state-of-the-art technology to enable it to provide customers with the best possible service at the lowest possible cost. These enhancements facilitate customer service through the streamlining of billing inquiries and service orders, allow for efficient billing and processing of customer payments, and provide support to the Company's Customer Support Center. This technology provides ratepayers with many benefits including, but not limited to:

- Availability of customer service representatives 24 hours a day, seven days a week.
- Enhanced ability to respond quickly to leaks and other safety related events.
- More accurate bills.
- Faster response to service requests.
- More efficient use of labor and materials

- Ability for customers to make check and credit card payments by telephone or payments using bank drafts

- Enhancements to Company's ability to monitor the quality of its customer service.

Q. Please describe these enhancements in greater detail.

A. One of the key enhancements related to this initiative was the implementation of a new Customer Information System (CIS) using SCT Banner software. The CIS facilitates customer service and accounting functions through the streamlining of billing inquiries and service orders and allows efficient billing and processing of customer payments in all of Atmos' operating jurisdictions. In addition, it provides support for Atmos' Customer Support Center. The Customer Support Center accepts service order requests, answers billing and other customer inquiries as well as emergency calls 24 hours a day, 7 days a week. Further, the Customer Support Center provides for a system that better measures the quantity and content of customer calls, as well as the quality of service provided to customers when they call. This includes recording of customer calls, the measurement of call lengths, and the tracking of the number and type of calls by the hour, day, week and month. It enables Atmos to continually monitor the quality of its customer service and also assists in forecasting call loads and scheduling customer service personnel to ensure that the Customer Support Center operates as effectively and efficiently as possible. The system also provides Atmos with the enhanced ability to respond to leaks and other safety-related events faster than ever before by enabling all field service employees to re-ceive orders while in the field.

Q. Are there other aspects of these enhancements to customer services that you would like to discuss?

A. Yes. The system also allows customers to pay their bills using bank drafts. Customers who opt for this service have a draft issued to their bank and their bills are then deducted from their bank account each month. This has proven to be an attractive option for customers who do not want to spend the time and postage each month required to pay their bill. In addition, the system uses Speedpay and Telepay to provide customers with alternative means of paying their bills. Speedpay allows the Customer Service Associates at the Customer Support Center to participate in check-by-phone transactions with customers. Telepay is similar, but it uses an Interactive Voice Response system to enable customers to pay their bills using their credit cards. While not every customer chooses these services, Atmos has found many customers prefer the ease and convenience they offer.

The system also provides customers with the ability to choose the due date of their bills. This is important to many customers, particularly those on fixed incomes, because it allows them to plan their payments at the time that best meets their needs and monthly budgets. In addition, it allows for summary billing which enables the Company to send customers with service at multiple locations one (1) bill.

Q. Please describe some of the other features of how the Company has upgraded customer service to its Tennessee customers since its last request for an increase in rates.

A. Atmos has introduced a number of technological enhancements since it acquired United Cities Gas Company to be used by its field personnel including the use of hand-held computers known as ITRONs for automated meter reading and mobile data terminals (MDT) installed in the vehicles of our field service employees. The ITRONs eliminate the need for meter readers to carry meter-reading sheets and enter each meter reading on those

sheets. Instead, the employee simply reads the meter and enters the readings into the ITRON. This reduces the potential for errors in customers' bills.

Each MDT is equipped with the capability to communicate directly with the Customer Support Center. Our field service technicians use this feature to process field service work orders while on-site or traveling in the field. Field service work orders are transmitted directly to the MDT units, thereby eliminating the paperwork order system and the delay inherent in having to go through a third-person dispatcher. Further, the MDTs allow our field service employees to be even more responsive to customers by providing them with direct access to customer information stored in Atmos' customer database. Once the field service employee completes the work detailed on the work order, he is able to input the work order or completion information in his vehicle rather than submitting a bundle of paperwork at the end of each shift. In the case of emergency work orders, the MDTs enable field service employees to receive the orders directly while already in the field and thereby provide a faster response. In short, the MDTs enable Atmos to respond more directly, more efficiently, and more quickly to our customer's needs. There is far less chance of orders going astray or being mis-communicated and field service employees are freed up to spend more time in the field meeting the needs of our customers and less time doing cumbersome paperwork.

Q. Have there been any additions or improvements to the Company's customer service since the conclusion of Phase I of Docket No. 05-00258?

A. Yes. Atmos is in the process of forming a new Customer Advisory Board (CAB) in Tennessee to begin work in the spring of 2007. In the past, Atmos had one CAB for the entire Mid-States division. This year, Atmos will have four CABs, which will allow each

group to focus more directly on customer concerns and needs in specific states. Tennessee will have a CAB made up primarily of Tennessee customers who will meet twice a year to share their ideas concerning customer service and discuss ways the Company can improve service and other processes. I believe that the information received from this process will be invaluable in helping the Company to assure that it is aware of and responsive to the needs and concerns of its customers.

In addition, Atmos has also developed a donation program for energy assistance dollars, which began in January 2007. The Company will match up to approximately $46,000 in energy assistance dollars that are donated by our customers. These dollars go to energy assistance agencies throughout Atmos' service territory in Tennessee who then distribute the funds to qualified customers to pay their utility bills.

Another enhancement to our customer service is the addition of the "Managing Your Energy Use" area on the Company's website. This useful tool allows our customers to conduct a personalized on-line energy audit of their home or business to assist them in managing their energy needs in the most efficient manner possible. The site also contains home energy and weatherization tips along with other valuable information designed to promote conservation and help customers reduce energy bills.

Q. Have ratepayers benefited from these enhancements to service?

A. Absolutely. The investment that Atmos has made in enhanced technology and superior customer service is a driving force behind its continued success as a low-cost, high-quality provider of natural gas service and is one of the reasons it has not required a rate increase since 1995.

V. ATMOS' COMMITMENT TO SAFETY

Q. Would you please discuss the Company's commitment to safety?

A. Atmos is fully committed to delivering safe and reliable service. In early 2005, Atmos had consulting firm Towers Perrin Tillinghaust conduct a study of the Company's workers' compensation and safety policies and procedures. In this study, it was recommended that the employee development/safety coordinator positions in each utility division be split out into stand-alone areas (safety, employee development, and training). Consequently, in July 2005, in order to enhance our commitment to a culture in which the safety of our customers, employees, and communities is a vital part of our success, the Company created a Manager of Safety for each of its divisions. These safety managers work with the Atmos Utility Operations Safety Committee and members of each division's safety leadership team to develop and implement industry-best safety programs. The Kentucky/Mid-States division safety manager is also the chairman of Atmos' Utility Operations Safety Committee.

Q. Does Atmos work closely with the TRA on safety issues?

A. Yes. In February 2006, the Company submitted an action plan to the TRA and committed to accomplishing several things during the course of 2006. Below is a progress report concerning these initiatives, which have been, and continue to be, an important part of the Company's education concerning issues of safety.

1. Periodically address the safety "lessons learned" with employees during future safety meetings:

Each local in office Tennessee received a number of AEGIS (Associated Energy and Gas Insurance Services) Lessons Learned videos that focus on safety issues.

The Company also continues to emphasize safety policies at monthly safety meetings held in each of its local offices.

2. Perform a comprehensive safety and operations and maintenance compliance audit of the Company's operations in each of the towns in Tennessee in which Atmos operates and conduct quarterly meetings to discuss results of the audits:

In 2006, the Company performed the audits in each town it serves and conducted two meetings in Tennessee with selected employees and TRA safety staff to discuss the results of the audits performed.

3. Conduct at least two unannounced inspections in 2006 in each town served by the Company.

The Company accomplished this task.

4. Re-emphasize the importance of daily work execution with all Company personnel through periodic employee, staff, and safety meetings.

Sections of the Company's safety manual were reviewed each month during regularly scheduled safety meetings for employees in 2006. In addition, operations supervisors and operations managers conducted periodic meetings with employees, which emphasized safety during work activities.

5. Use best efforts to complete the procedures manuals project by January 2007.

The Company's Operations and Maintenance procedure for Department of Transportation (DOT) regulations 192.605 (b)(9) and 192.751 was revised to include

procedures for Prevention of Accidental Ignition. The Company also provided classroom training for employees on Preventing Accidental Ignition.

In addition to what was submitted to the TRA in the action plan, the Company implemented a plan to conduct OSHA construction classes for employees at central sites in Tennessee. To date, the several classes have been completed in Franklin, Maryville, and Morristown. The Company also has conducted safety, compliance, and environmental audits in each town in Tennessee served by Atmos. For each of the inspections, the Company used forms from the Company's safety manual or DOT 192 standards. The inspection forms were summarized with a cover sheet that lists "action to be taken" and a responsible employee(s) with a completion date that was assigned to each item needing attention. The TRA was invited to attend every audit as well as the OSHA classes, and did in fact attend several of the inspections conducted.

Q. Does Atmos benchmark its safety performance with like operations within the industry?

A. Yes. Atmos benchmarks the Company's reportable OSHA employee injury Lost Workday Rate (DART) based on the total injuries times 200,000 hours divided by actual hours worked and preventable vehicle accident (PVAR) based on total number of preventable vehicle accidents times 1,000,000 divided by actual miles driven, statistics with annually published information by the American Gas Association (AGA). AGA collects statistics from natural gas utilities throughout the United States and publishes a summary of their findings of reporting companies on an annual basis. The most current AGA reporting is for calendar year 2005 indicating a DART rate of 3.62 and a PVAR of 3.12. While At-

mos benchmarks AGA's information, Atmos actually establishes its DART and PVAR reduction target based on its most current three years of history with respect to accumulated reportable employee injury and vehicle accident information and then further reduces that rate by 10 percent. These targeted reduction rates are currently better than the AGA existing calendar rate for both DART and PVAR. For example, AGA's most current calendar year statistics for reporting member companies of our size in 2005 reflects an employee injury DART rate of 2.90 and a vehicle accident PVAR of 3.12 while Atmos' targeted reduction DART rate for our fiscal year 2007 (October – September) is 2.90 and PVAR is 3.00. As of December 31, 2006 the Kentucky/Mid-States division's FY07 DART rate is 2.51 and the PVAR of 3.27. As a result, the Kentucky/Mid-States division was awarded an Atmos "Leaders in Safety" certificate for exceeding the established reduction target of 2.90. While the division did not meet or exceed the established PVAR target by posting a 3.27 as compared the PVAR reduction target of 3.00 during the first quarter its management as well as employees have recommitted themselves to meet or exceed the reduction-targeted rate by the end of the second quarter.

VI. OVERVIEW OF COMPANY WITNESS TESTIMONY

Q. Please briefly summarize the testimony of the other Atmos witnesses in this case.

A. In addition to my testimony, Atmos will present the direct testimony and exhibits of 14 witnesses.

Mr. Thomas H. Petersen, Director of Rates (Shared Services), will sponsor the determination of the revenue deficiency indicated in Atmos' projected cost of service.

Mr. Greg Waller, Vice President of Finance (Kentucky/Mid-States Division), will sponsor the projected test period cost of service and the assumptions on which the projections are based.

Mr. Robert R. Cook, Jr., Vice President – Technical Services (Kentucky/Mid-States Division), will sponsor the projected capital expenditures and the assumptions on which the projections are based.

Mr. Daniel Meziere, Director of Accounting Services (Shared Services), will sponsor the Company's books and records, as well as testimony concerning the Company's Cost Allocation Manual (CAM).

Mr. James Cagle, Manager of Rates (Shared Services), will sponsor the Company's method of allocating shared services costs to the various Atmos divisions including the Kentucky/Mid-States Division. He will also sponsor the Company's update of the WNA mechanism's base and heat load factors.

Mr. Donald Roff, President of Depreciation Specialty Resources, will sponsor the Company's depreciation studies for Shared Services and Tennessee.

Ms. Laurie Sherwood, Atmos' Vice President, Corporate Development and Treasurer, will sponsor the proposed capital structure and embedded cost of debt.

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

Mr. John Ellerman, a consultant with Towers Perrin, will sponsor a study concerning the Company's compensation and benefits, including an analysis of incentive pay.

Mr. Chris Hutzler, also of Towers Perrin will address the company's pension benefits.

Mr. Gary L. Smith, Vice President – Marketing and Regulatory Affairs (Kentucky/Mid-States Division), will sponsor the Company's CUA proposal and will also support the forecast of growth, volumes and revenues as used in the Company's projections and various cost studies.

Mrs. Patricia J. Childers, Vice President – Rates and Regulatory Affairs (Kentucky/Mid-States Division), will support the Company's rate design proposal to allocate the requested revenue requirement proportionately across all customer classes.

Mr. Michael Ellis, Vice President – Marketing (Kentucky/Mid-States Division), will sponsor the Company's proposed new tariff charges, changes to existing utility tariffs, changes to Atmos' Service Rules and Regulations, and changes to the Company's main extension policy.

Mr. Ronald Edelstein, Director, State Regulatory Programs with the Gas Technology Institute (GTI), presents the benefits that Tennessee natural gas consumers receive from GTI and its gas consumer benefits research and development program (R&D), and recommends that Atmos be granted authority to fund natural gas consumer benefits R&D.

VII. CONCLUSION

Q. Do you have any closing remarks?

A. Yes. We are not simply seeking a rehearing on the Authority's rulings in Docket No. 05-00258. Only about $2.6 million of the requested increase results from our disagreements with some of the rulings in that Docket. Additional investments, inflation, and updated

information from cost and depreciation studies created the need for approximately $6.5 million of the requested increase. As a result, the rates produced by the outcome of Phase I of Docket No. 05-00258 will not afford the Company an opportunity to recover its investment and earn a reasonable return. It is therefore necessary to pursue the rate relief proposed in this filing. It is my opinion that the rates requested in this filing are just, reasonable, and in the public interest and I would encourage the Authority to provide prompt and adequate rate relief.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

VERIFICATION

STATE OF KENTUCKY)
)
COUNTY OF DAVIESS)

I, John Paris, being first duly sworn, state that I am President of the Kentucky/Mid-States Division of Atmos Energy Corporation, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Testimony of John Paris in support of Atmos Energy Corporation's Petition and the Exhibits thereto pre-filed in this docket on the date of filing of this Petition are true and correct to the best of my knowledge, information and belief.

John Paris

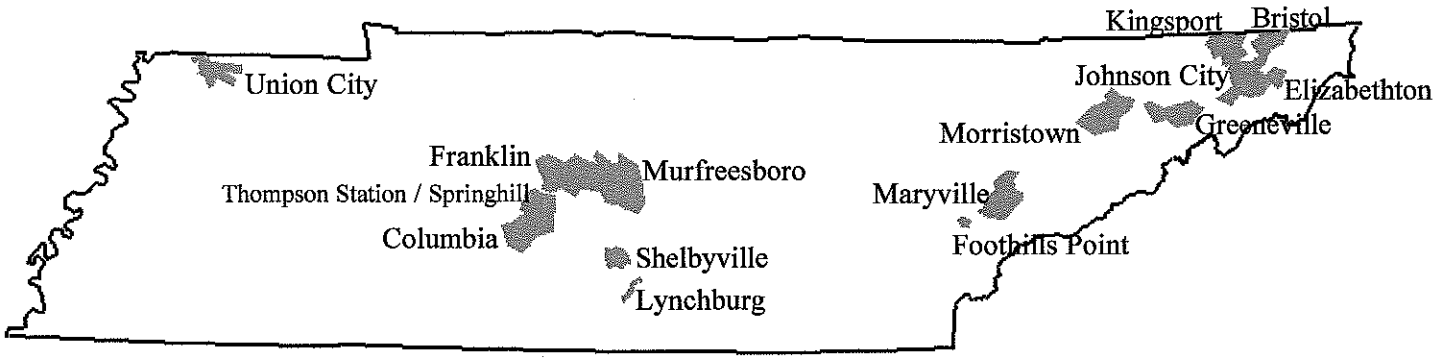
Sworn and subscribed before me this 9th day of April, 2007.

Notary Public - State of KY at Large

My Commission Expires: September 26, 2009

Schedule JP-1

Atmos Energy Tennessee Service Territory



BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REFISED TARIFF	)	**DOCKET NO. 2006-00464**

JAMES C. CAGLE

I. INTRODUCTION OF WITNESS

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is James C. Cagle. I am the Manager of Rates and Revenue Requirements for Atmos Energy Corporation ("Atmos" or the "Company"). My business address is 5430 LBJ Freeway, Suite 700, Dallas, Texas 75240.

II. SUMMARY OF TESTIMONY

Q. PLEASE BRIEFLY SUMMARIZE THE TESTIMONY YOU INTEND TO GIVE IN THIS MATTER.

A. I am sponsoring the following analyses and calculations:

- common cost allocations made for ratemaking purposes;
- the adjustment to accumulated deferred income tax;
- the weather normalized margin projection for the attrition period; and
- the update to the Company's Weather Normalization Adjustment (WNA) base load and heat sensitive factors.

Q. ARE YOU SPONSORING ANY SCHEDULES IN CONNECTION WITH YOUR TESTIMONY?

A. Attached to my testimony are the following Exhibits:

- Exhibit JCC-1 (listing the states and dockets in which I have testified);
- Exhibit JCC-2 (showing the Company's overall corporate structure);
- Exhibit JCC-3 (the composite factors used to allocate common costs for purposes of this rate proceeding);
- Exhibit JCC-4 (schedules showing the weather normalized margin for the attrition period); and
- Exhibit JCC-5 (update to the base load and heat sensitive factors for the Company's Weather Normalization Adjustment).

III. WITNESS QUALIFICATIONS

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Accountancy degree from the University of Oklahoma in 1987. I am a Certified Public Accountant licensed in the state of Texas. I have been employed by Atmos since 1989. I was initially employed in Atmos' financial reporting department. For the past thirteen years, except for the period from September 1997 through February 1998 when I was employed by GTE in its Costing department, I have worked in Atmos' rates department.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES AND QUALIFICATIONS.

A. As Manager of Rates and Revenue Requirements, I am primarily responsible for rate studies of and assisting in the design and implementation of rates for Atmos' regulated utility operations. I am also responsible for oversight of certain rate related compliance and reporting requirements prescribed by Atmos' various regulatory commissions. Part of my responsibilities also include participation in the preparation, updating and implementation of the Company's Cost Allocation Manual (CAM), which is filed at least yearly with the Kentucky Public Service Commission ("KPSC") and is further discussed in the testimony of Company witness Daniel M. Meziere. For a significant portion of the

past thirteen years, I have performed rate studies or portions of rate studies for the design and implementation of rates for a majority of the Atmos' operations.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE TENNESSEE REGULATORY AUTHORITY (TRA)?

A. Yes. I provided testimony before the TRA in Docket No. 05-000258. I have also provided testimony before several other state commissions. Exhibit JCC-1 attached hereto lists the various states and dockets in which I have testified.

IV. ATMOS CORPORATE STRUCTURE

Q. **ARE YOU FAMILIAR WITH THE COMPANY'S CORPORATE STRUCTURE?**

A. Yes. Atmos Energy Corporation consists of the utility (Atmos Energy Corporation) and various subsidiaries. The utility is the parent company. The Company conducts its unregulated operations through its subsidiaries. A chart showing the current corporate structure is included as Exhibit JCC-2. .

Q IN THE TOP BOX OF EXHIBIT JCC-2 REPRESENTING ATMOS ENERGY CORPORATION, WHAT DO THE VARIOUS DIVISIONS REPRESENT?

A. The various divisions are a part of the Company's management control structure that is utilized in the Company's shared costs allocation processes. Section 1a of the CAM describes the corporate structure in detail. There are currently seven such divisions – six of which are regulated gas local distribution operations and one of which is a regulated intrastate pipeline operation. We commonly refer to these divisions as "Operating Divisions" or "Business Units." The Company's Tennessee operation is contained within the Kentucky/Mid-States Operating Division/Business Unit.[1] Also, Operating Divisions or Business Units are comprised of rate divisions (described later herein).

Q. DO THESE OPERATING DIVISIONS CONSTITUTE SEPARATE LEGAL ENTITIES?

[1] Effective October 1, 2006, the Company's Kentucky and Mid-States Divisions were organizationally consolidated and are now, in effect, one division – the Kentucky/Mid-States Division. "Division" as used in my testimony means the Company's Kentucky/Mid-States Division. "Tennessee" when used in my testimony, unless otherwise indicated, refers exclusively to the Company's operations in Tennessee.

A. No. They are merely unincorporated operating divisions within the organizational structure that the Company has chosen. None of the Operating Divisions are subsidiary entities that have a separate legal existence apart from the Company, they are not distinct legal entities, and they do not have separate equity or debt. Additionally, the divisions do not keep separate books and records.

V. COST ALLOCATION PROCESS FOR COMMON COSTS

Q. WHAT IS COST ALLOCATION WITH REGARD TO COMMON COSTS?

A. Cost allocation is the process of allocating various common costs that are incurred for the benefit of two or more of the Company's rate divisions and are therefore allocable to those rate divisions.

Q. WHAT DO YOU MEAN WHEN YOU REFER TO "RATE DIVISION"?

A. "Rate division" denotes the Company's regulatory jurisdictions that are defined by state boundaries or, where applicable, geographic areas within states and which comprise an Operating Division. The term rate division also denotes the Company's various Shared Services, as well as a particular Operating Division's general and regional office rate divisions, whose costs are common to more than one operating rate division and are therefore allocable to those operating rate divisions. For example, an Operating Division may encompass multiple rate divisions, particularly if the operations of the Business Unit include multiple states. Basically, each rate division represents an accumulation of accounting data applicable to an area in which rates have been set by a regulatory authority such as the TRA. The Company refers to this accumulated data as a rate division.

Q. ARE THERE DIFFERENT TYPES OF RATE DIVISIONS?

A. Yes, there are operating rate divisions and office rate divisions. An operating rate division represents a regulated operation such as the Company's utility operations in Tennessee. An office rate division is one that provides common services to operating

rate divisions (as more fully explained herein). The costs of the office rate divisions are allocated to the operating rate divisions in accordance with the methodology described by the CAM, as will be more fully explained later in my testimony.

Q. HOW MANY OPERATING RATE DIVISIONS COMPRISE THE COMPANY'S KENTUCKY/MID-STATES DIVISION?

A. Currently, there are eleven rate divisions in the Kentucky/Mid-States Operating Division, of which Tennessee is one.

Q. HOW DOES THE ACCOUNTING SYSTEM ALLOW FOR THE SEPARATE RECORDING AND TRACKING OF COSTS FOR ATMOS ENERGY'S RATE DIVISIONS?

A. Direct costs are charged directly to the operating rate division that has incurred the costs. For example, if Tennessee hires an outside contractor to perform leak survey services, then those costs are charged directly, and only, to Tennessee because the work is done only for Tennessee. Costs for the Shared Services (hereinafter defined), by contrast, are allocated to the operating rate divisions that receive the benefit of those services. Detailed transactions are recorded by rate division in the general ledger for all utility divisions of Atmos Energy.

Q. WHAT OFFICE RATE DIVISIONS PROVIDE SERVICES TO THE COMPANY'S TENNESSEE RATE DIVISION?

A. Tennessee receives allocations of common costs from Shared Services. Shared Services is comprised of two parts: Shared Services - General Office, and Shared Services – Customer Support. Tennessee also receives an allocation of common costs from the Kentucky/Mid-States Division general office.

Q. WHAT ARE THE COMMON COSTS TO WHICH YOU REFER?

A. Common costs include costs related to technical and support services that are provided to the Company's operating rate divisions by centralized shared services ("Shared Services" or "SSU"). Shared Services – General Office includes, for example, accounting, human resources, legal, rates, information technology and numerous others functions. Shared Services – Customer Support includes customer call center services, billing, collections,

and other customer support related functions. The costs for these Shared Services are allocated to the Company's rate divisions.

Q. ARE THERE ADDITIONAL COMMON COST ALLOCATIONS OTHER THAN SHARED SERVICES?

A. Yes. If an office rate division encompasses more than one jurisdiction, such as the Company's Kentucky/Mid-States rate division, which provides services to the Company's utility operations in Georgia, Iowa, Illinois, Missouri, Kentucky, Virginia and Tennessee, then the costs from that office rate division are allocated to the separate rate divisions to which it provides services.

Q. DOES THE COMPANY HAVE ANY METHODOLOGY FOR ALLOCATING COMMON COSTS TO A RATE DIVISION?

A. Yes. The rate division designation is incorporated into the Company's account coding string. As such, costs are accumulated for various operating areas or office rate divisions within the Company's general ledger. This could represent the Company's operations in a particular state or a particular area within a state and/or various office rate divisions, which would appropriately allocate costs to operating rate divisions.

Q. ARE COMMON COST ALLOCATIONS NECESSARY IN THE CONTEXT OF THE COMPANY'S RATE FILINGS?

A. Yes. It is appropriate and necessary to allocate the common costs incurred for the benefit of ratepayers in multiple regulatory jurisdictions to the various jurisdictions that receive those services. For example, the Company's Shared Services – General Office provides the various support services discussed above to its utility operations in the twelve states in which the Company operates. Some of these shared services are also provided to the Company's unregulated subsidiaries. Similarly, the Shared Services - Customer Support provides customer service functions to the Company's utility operations and is the utility customer's point of contact with the Company for service activations, billing issues, emergency reporting, etc. Tennessee rate division customers receive the benefits of these services, and the allocations of these costs are fairly and justly apportioned to the Tennessee rate division. In addition to Shared Services, the Kentucky/Mid-States Division headquarters office provides services to Tennessee and, as a result, costs from

the Kentucky/Mid-States division headquarters office (the Kentucky/Mid-States Division general office rate division) are allocated to the Company's Tennessee rate division.

Q. PLEASE DESCRIBE THE COMPANY'S COST ALLOCATION METHODOLOGY.

A. The Company allocates certain types of common costs to its operating rate divisions for management purposes as well as for reporting and ratemaking purposes. Operations and Maintenance ("O&M") expense, depreciation expense, and taxes, other than income taxes, expense that represent common costs are allocated on the books of the Company. Other common costs such as commonly utilized plant in service and other ratebase items are not allocated on the books of the Company but are allocated for ratemaking purposes. These costs are allocated based on accepted methodologies which are further outlined below, in order to fully show the costs of providing utility service in each of the regulatory jurisdictions within which the Company serves customers.

Q. IN YOUR ANSWER, YOU DIFFERENTIATE BETWEEN COMMON COSTS THAT ARE ALLOCATED ON THE BOOKS OF THE COMPANY AND THOSE THAT ARE ALLOCATED FOR RATEMAKING PURPOSES. CAN YOU EXPLAIN THE DIFFERENCE?

A. Yes. Operations and Maintenance (O&M) expense, depreciation expense, and taxes, other than income taxes, expense related to Shared Services, and the Mid-states division's headquarters office are allocated on the Company's books and records utilizing the allocation methodologies described in detail in the CAM referenced above. The Company allocates these expenses within its books and records as a part of its normal accounting cycle. The allocation factors used are generally calculated once per year, updated at the beginning of the Company's fiscal year (October 1), and utilized for the entire year unless a material event occurs that would significantly change the factors.

For those Shared Services costs that are not allocated on the Company's books and records, either a composite factor for Shared Service – General Office or a customer factor for Shared Service – Customer Support is used to allocate costs. Some examples of Shared Services costs for which composite factors or the customer factor, as appropriate,

are used for allocating such expenses for ratemaking purposes would include plant in service and accumulated deferred income taxes, as well as other rate base items.

Q. HOW ARE COMPOSITE FACTORS DERIVED?

A. The composite factors are derived based upon a three-factor formula comprised of:

1. The simple average of the relative percentage of gross plant in service for each of the Company's business units to the total gross plant in service for all of Atmos' business units (excluding Shared Services);
2. The ratio of the number of customers in each of the Company's business units to the total number of the Company's customers; and
3. The ratio of direct O&M expense for each of the Company's business units to the total direct operation and maintenance expenses of all Atmos business units (excluding Shared Services).

Q. HOW IS THE CUSTOMER FACTOR DERIVED?

A. The Customer Factor is derived based on the average number of customers of the Operating Divisions that receive allocable costs for the services provided.

Q. WHY IS THE CUSTOMER FACTOR USED TO ALLOCATE SHARED SERVICES – CUSTOMER SUPPORT INSTEAD OF THE COMPOSITE FACTOR?

A. This office rate division provides services exclusively to the Company's regulated utility customers, and does not perform any function for the Company's subsidiaries or the Atmos Pipeline Texas division. As a result, Shared Services – Customer Support costs are allocated only to the Company's regulated local distribution Operating Divisions/Business Units. The use of the Customer Factor to allocate the costs of this office rate division, instead of the Composite Factors, is reasonable and appropriate because the need for, and level of services required are primarily driven by the number of customers within an Operating Division.

Q. HOW ARE SHARED SERVICES COSTS THEN ALLOCATED OUT TO A RATE DIVISION?

A. Shared Services allocations to the business unit are added to the business unit's general office costs and then further allocated to the applicable office rate divisions within the

business unit. For the Kentucky/Mid-States business unit, the factors utilized for further allocating applicable Shared Services and Kentucky/Mid-States general office costs are based on the composite factor, developed utilizing the same formula as described above, but limited to only those jurisdictions served by the Kentucky/Mid-States General Office. Other costs not allocated on the Company's books and records are also allocated using the same methodology.

Q. HOW ARE SHARED SERVICES COSTS ALLOCATED WITHIN THE COMPANY'S TENNESSEE RATE FILING?

A. O&M expense, depreciation expense, and taxes, other than income taxes, are allocated in the Company's filing utilizing the methodologies memorialized in the CAM. As previously stated, the Company does not allocate ratebase items for Shared Services (such as plant in service or accumulated deferred income taxes) within its books and records. Instead, these items are allocated in the context of rate proceedings such as this one and for certain reporting purposes. In this filing, ratebase items and ratemaking adjustments were allocated utilizing the composite factors set forth and described in Exhibit JCC-3 attached to my testimony. Such factors were derived utilizing the methodology described herein.

VI. ACCUMULATED DEFERRED INCOME TAX

Q. DOES THE COMPANY'S RATE FILING REFLECT A PROJECTION OF ACCUMULATED DEFERRED INCOME TAX (ADIT)?

A. Yes. A projection of ADIT appears in the Schedules sponsored by and attached to the testimony of Mr. Thomas Petersen.

Q. WERE ANY ITEMS EXCLUDED FROM THIS PROJECTION FOR RATEMAKING PURPOSES?

A. Yes. Beginning October 2006, within the base period, this projection excludes any estimated amount for over/under recovery of gas cost, in order to normalize the tax effect thereof to zero. Additionally, the projection excludes book to tax differences in Shared Services that specifically relate to jurisdictions other than Tennessee.

VII. ATTRITION YEAR BILLING DETERMINANTS AND MARGIN REVENUES

Q. PLEASE DESCRIBE THE PROJECTION OF BILLING DETERMINANTS FOR THE ATTRITION YEAR.

A. The initial data utilized in the projection was the 12-month period ended February 2007. From those actual billing determinants, the weather normalization calculation based upon the Company's current WNA was developed and added to the actual amounts to arrive at weather normalized volume information.

Q. WHY DID YOU USE THE 12 MONTHS ENDED FEBRUARY 2007 FOR THE PROJECTION INSTEAD OF THE 12 MONTHS ENDED DECEMBER 2006.

A. The 12 months ended February provided an additional two months of actual data. Thus, for projecting the attrition year, the projection was only 20 months forward instead of 22 months forward as would have been the case had December 2006 been used. By using the 12 months ended February, the projection is more current.

Q. DID YOU MAKE ANY VOLUME ADJUSTMENTS IN CONNECTION WITH YOUR CALCULATIONS?

A. Yes. Certain adjustments to those volumes were made to reflect tariff changes to Rate Schedule 210 implemented in December 2006. These tariff changes provided relief from the monthly customer charge for elderly customers who meet a low-income threshold. Other adjustments were made to reflect changes to certain commercial and industrial customer volumes, to arrive at normalized volumes for the 12 months ended February 2007.

Q. DID YOU MAKE ANY OTHER FORWARD-LOOKING ADJUSTMENTS?

A. Yes. In projecting forward, the declining usage factor of 1.5%, the customer growth factor of 2.4% for summer months, and a winter-months customer growth factor of 2.5% were utilized. These are the same seasonal growth and declining use factors that were used by the TRA in Docket No. 05-00258.

Q. DO THE RESULTS OF YOUR ANALYSIS APPEAR IN EXHIBIT JCC-4?

A. Yes. Exhibit JCC-4 sets forth the applicable billing determinants and weather normalized margin projections for the attrition period used in this rate proceeding.

VIII. WNA HEAT LOAD AND BASE LOAD FACTORS

Q. WHY IS THE COMPANY PROPOSING TO UPDATE HEAT LOAD AND BASE LOAD FACTORS FOR THE WNA IN THIS FILING?

A. The factors currently in use are based from normal Heating Degree Days (HDDs) calculated during the early 1990s. Since that time, the National Oceanic and Atmospheric Administration (NOAA) has published normal HDDs for the 30 years beginning in 1971 and ending in the year 2000. The Company is updating the WNA's base load and heat load factors using these more recent normal HDDs, in order to better reflect more recent weather pattern data.

Q. WHAT IS A HEATING DEGREE DAYS?

A. An Heating Degree Day (HDD) is a measure of relative coldness expressed as an index. As the temperature drops below a certain level, the demand for energy to heat homes and businesses increases. HDDs are derived from daily temperature observations using 65° F as the baseline for the computation. They are calculated using the difference between 65° F and the average daily temperature. For example, if at the Nashville weather station, the high temperature on a particular day was 40 F° and the low was 30 F°, then the average daily temperature would be +35 F°. The difference between 65 F° and 35 F° is 30 F°, thereby yielding 30 Heating Degree Days. An HDD is never less than zero.

Q. WHICH WEATHER STATIONS' HDD DATA ARE USED IN THE COMPUTATIONS?

A. The stations used are the same as those used in the current WNA calculations. These stations are located in Bristol, Knoxville, and Nashville, Tennessee and Paducah, Kentucky.

Q. WHAT IS THE EFFECT OF UPDATING THE HEAT LOAD AND BASE LOAD FACTORS?

A. The current WNA tariff calculates a weather adjustment on each applicable customer's bill using the actual and normal Heating Degree Days occurring between the billing cycles for the customer. This calculation adjusts the customer's bill to match the normal

HDDs which were used to develop the tariff rates, thereby theoretically adjusting the revenues received by the Company to the levels approved in the Company's last rate filing. Over time, the approved heat load and base load factors become more and more out of sync with customer's overall usage patterns. Therefore, it is prudent to update these factors periodically using more recent normal HDDs and current consumption data.

Q. WHY WOULD SUCH FACTORS GET "OUT OF SYNC"?

A. Over time, a customer's usage pattern changes. With more efficient space heating units, water heaters, and other appliances, a customer's base load will drop over time as older, less efficient units are replaced. Also, with newer, more energy efficient construction, more insulation, energy efficient windows etc., a customer's heat load factors will change over time. The changes in factors from those currently being applied to the factors requested in this filing are:

Heat Use/Base Use Factors

Town	Weather Station	Current Base Use CCF	Current Heat Use CCF/HDD	Proposed Base Use CCF	Proposed Heat Use CCF/HDD
Union City -	Paducah				
Res./PA		13.906292	0.156369	10.43	0.124185
Commercial		124.595029	0.453633	112.80	0.416839
Columbia, Shelbyville, Franklin Murfreesboro	Nashville				
Res./PA		13.035323	0.173948	11.34	0.147091
Commercial		99.021858	0.624513	112.93	0.473009
Maryville, Morristown	Knoxville				
Res./PA		13.88633	0.153366	11.39	0.122329
Commercial		111.454966	0.658649	195.74	0.392082
Johnson City, Elizabethton, Kingsport, Greeneville, Bristol	Bristol				
Res./PA		10.696903	0.162066	11.51	0.112572
Commercial		169.773651	0.611201	125.95	0.489418

The current factors have been in effect since the Company's last rate case, in the 1990s.

Q. WHAT IS THE EFFECT ON THE COMPANY'S MARGIN REVENUE RESULTING FROM UPDATING THE WNA FACTORS?

A. The change in WNA factors results in a decrease to the Company's normalized revenues of approximately $45,000.

Q. HAVE OTHER GAS COMPANIES IN TENNESSEE UPDATED WNA FACTORS?

A. Yes. Just recently, Chattanooga Gas updated factors in their rate filing. As in that case, the change in WNA factors causes a shift in how revenues are recovered from the WNA rider calculations to the base rates. The impact on the requested increase in this case is minimal.

Q. HOW WERE THE UPDATED FACTORS CALCULATED?

A. The factors were calculated by weather zone using regression analyses of the billing determinants as compared to the applicable Heating Degree Days during the WNA months. This analysis derives a heat sensitive factor and a base load factor for each weather zone. A heat load factor and a base load factor are calculated for residential and public authority combined, and separately for commercial customers. Each area's customer billing determinants encompassed the 24 months of data from March 2005 through February 2007.

Q. IS THERE AN INDICATION OF HOW WELL THESE FACTORS RELATE TO COLD WEATHER?

A. Yes. As the factors are determined, a correlation measure, or R^2, is computed as a part of the regression analysis. R^2 is the percentage variation in the dependent variable (HDDs) from the mean that is explained by the x to y (HDD to weather sensitive usage) relationship expressed by the regression equation. The R^2 for residential customers shows a range by weather station from .9745 to .9888, with a correlation of 1.0000 being a "perfect" fit. This indicates that the resulting heat load and base load factors resulting from the regression analysis have a very high correlation to customer usage as it relates to weather. The results of the regression calculation and a graph of the results are provided in Attachment JCC-5.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

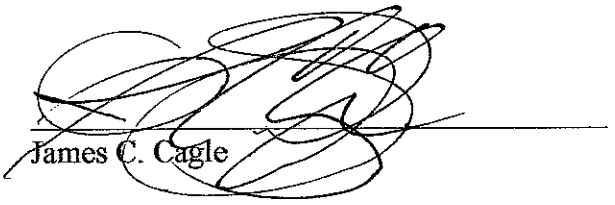
BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

VERIFICATION

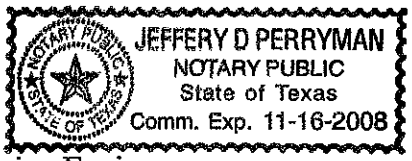
STATE OF TEXAS)
)
COUNTY OF DALLAS)

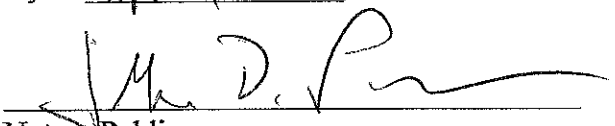
I, James C. Cagle, being first duly sworn, state that I am Manager of Rates and Revenue Requirements for Atmos Energy Corporation, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Testimony of James C. Cagle in support of Atmos Energy Corporation's Petition and the Exhibits thereto pre-filed in this docket on the date of filing of this Petition are true and correct to the best of my knowledge, information and belief.



James C. Cagle

Sworn and subscribed before me this 6th day of April, 2007.

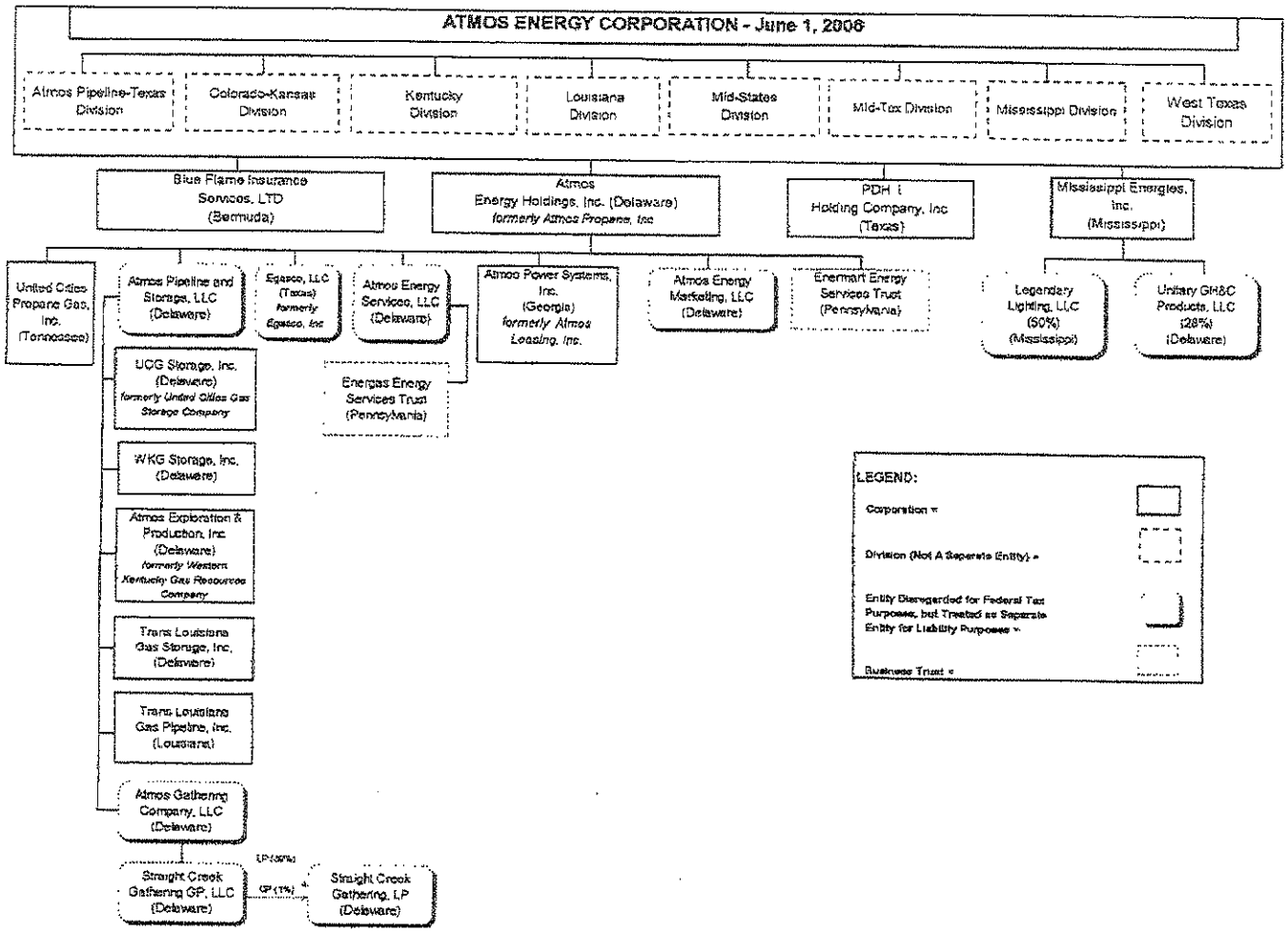




Notary Public

My Commission Expires: _____

DOCKET	TESTIMONY STYLED AS	TYPE	DATE
Virginia Corporation Commission			
PUE 000171	Atmos Energy Corporation for an increase in rates.	Direct	March-00
PUE 2003-00507	Atmos Energy Corporation for an increase in rates.	Direct	February-04
Colorado Public Utility Commission			
00S-668G	In the matter of the tariff sheets filed by Greeley Gas Company, a Division of Atmos Energy Corp with Advice Letter No. 419 regarding comprehensive changes to the rates, terms and conditions for natural gas sales, and transportation services	Direct	November-00
Kansas Corporation Commission			
03-ATMG-1036-RTS	In the Matter of the Application of Atmos Energy for Adjustment of its Natural Gas Rates in the States of Kansas	Direct and Rebuttal	June-03
Railroad Commission of Texas			
9002 -- 9135	Statement of Intent Filed by Energas Company to Increase Rates Charged in the 67 West Texas Cities: Petition by Energas for Review of 67 Municipal Rate Decisions	Direct and Rebuttal	March-00
9670, 9676	Petition for de novo review of the reduction of the gas utility rates of Atmos Energy Corp., Mid-tex division, by the cities of Addison, Benbrook, Blue Ridge, Et Al., and statement of intent filed by Atmos Energy Corp., Mid-tex division to change rates in the company's statewide gas utility system.	Direct	May-06
Louisiana Public Service Commission			
U-21922, U-23508 Consolidated	Louisiana Public Service Commission, ex parte, Consolidated Docket U-21922 and U-23508, In re: Docket No. U-21922, In re: Investigation of the Rates and Charges of Trans Louisiana Gas Company, A Division of Atmos Energy Corp. etc.	Direct and Rebuttal	March-99
U-28814	Petition of Trans Louisiana Gas Company, a regulatory division of Atmos Energy Corporation, requesting approval of a Conservation and Consumer Cost Stabilization rider.	Direct	May-05
Georgia Public Utility Commission			
20298-U	Filing of Increased Rates for Natural Gas Service	Direct	May-05
Missouri Public Service Commission			
GR-2006-0387	Atmos Energy Corporation's tariff revision designed to consolidate rates and implement a general rate increase for natural gas service	Direct	April-06
Tennessee Regulatory Authority			
05-00258	Petition of the Consumer Advocate to open an investigation to determine whether Atmos Energy Corp. should be required by the Tennessee Regulatory Authority to appear and show cause that Atmos Energy Corp. is not overearning in violation of Tennessee Law and that it is charging rates that are just and reasonable.	Direct and Rebuttal	July-06
Kentucky Public Service Commission			
2006-00464	Application of Atmos Energy Corporation for an adjustment of gas rates	Direct	December-06
2005-00057	Office of the Attorney General Commonwealth of Kentucky	Rebuttal	February-07


ATMOS ENERGY CORPORATION - June 1, 2006
Atmos Pipeline-Texas Division
Colorado-Kansas Division
Kentucky Division
Louisiana Division
Mid-States Division
Mid-Tex Division
Mississippi Division
West Texas Division
Blue Flame Insurance Services, LTD (Bermuda)
Atmos Energy Holdings, Inc. (Delaware) formerly Atmos Propane, Inc
PDH I Holding Company, Inc (Texas)
Mississippi Energies, Inc. (Mississippi)
United Cities Propane Gas, Inc. (Tennessee)
Atmos Pipeline and Storage, LLC (Delaware)
Egasco, LLC (Texas) formerly Egasco, Inc
Atmos Energy Services, LLC (Delaware)
Atmos Power Systems, Inc. (Georgia) formerly Atmos Leasing, Inc.
Atmos Energy Marketing, LLC (Delaware)
Enermart Energy Services Trust (Pennsylvania)
Legendary Lighting, LLC (50%) (Mississippi)
Unitary GH&C Products, LLC (28%) (Delaware)
UCG Storage, Inc. (Delaware) formerly United Cities Gas Storage Company
Energas Energy Services Trust (Pennsylvania)
WKG Storage, Inc. (Delaware)
Atmos Exploration & Production, Inc. (Delaware) formerly Western Kentucky Gas Resources Company
Trans Louisiana Gas Storage, Inc. (Delaware)
Trans Louisiana Gas Pipeline, Inc. (Louisiana)
Atmos Gathering Company, LLC (Delaware)
LP (99%)
GP (1%)
Straight Creek Gathering GP, LLC (Delaware)
Straight Creek Gathering, LP (Delaware)
LEGEND:
Corporation =
Division (Not A Separate Entity) =
Entity Disregarded for Federal Tax Purposes, but Treated as Separate Entity for Liability Purposes =
Business Trust =

Atmos Energy Corp.
Summary of Allocation Factors
to Tennessee Rate Division

Line No.	Description	Factor
1	Shared Services - General Office	4.13%
2	Shared Services - Customer Support	4.03%
3	Mid-States General Office	27.17%

ATMOS ENERGY CORPORATION
Allocation of Atmos Corporate (Co. # 10) Cost Based on 12 Month Period Ended 9/30/06

A. Composite Allocation Factor:		Total	West Tex Div	CO/KS Div	LA Div 007	LA Div 077	MidStates Div	MVG	Mid-Tex Div	Atmos P/L Mid Tex
Gross Direct PP&E	$	**5,370,692,810**	398,740,964	354,701,307	152,641,872	376,265,849	915,901,270	323,787,054	1,988,757,546	859,896,947
Average Number of Customers	#	**3,090,662**	297,240	235,655	74,661	252,901	464,841	250,184	1,514,844	336
Total O&M Expense *	$	**328,510,711**	25,920,364	22,493,532	7,426,747	24,809,531	44,312,982	36,818,964	118,929,678	47,798,914
(* w/o Allocation)										
Total Composite Factor										
Gross Direct PP&E	%	**100.00%**	**7.43%**	**6.60%**	**2.84%**	**7.01%**	**17.05%**	**6.03%**	**37.03%**	**16.01%**
Average Number of Customers	%	**100.00%**	**9.63%**	**7.62%**	**2.42%**	**8.18%**	**15.04%**	**8.09%**	**49.01%**	**0.01%**
Total O&M Expense	%	**100.00%**	**7.89%**	**6.85%**	**2.26%**	**7.55%**	**13.49%**	**11.21%**	**36.20%**	**14.55%**
Total Composite Factor for FY 2	%	**100.00%**	**8.32%**	**7.02%**	**2.51%**	**7.58%**	**15.19%**	**8.44%**	**40.75%**	**10.19%**
All Utility Companies	%	100.00%	8.32%	7.02%	2.51%	7.58%	15.19%	8.44%	40.75%	10.19%
All Utility 25% to Mid Tex		100.00	14.80%	12.49%	4.46%	13.48%	27.02%	15.01%	10.19%	2.55%
Average Number of Customers	%	100.00%	9.62%	7.62%	2.42%	8.18%	15.04%	8.10%	49.02%	
LA Division	%	100.00%	0.00%	0.00%	24.90%	75.10%	0.00%	0.00%	0.00%	0.00%
Utility No Mid Tex	%	100.00%	16.89%	14.31%	5.13%	15.44%	31.07%	17.16%	0.00%	0.00%
Gas Control	%	100.00%	21.28%	18.01%	0.00%	0.00%	39.14%	21.57%	0.00%	0.00%

ATMOS ENERGY CORPORATION
Allocation of Atmos Corporate (Co. # 10) Cost Based on 12 Month Period Ended 9/30/06

A. Composite Allocation Factor:		Total	West Tex Div	CO/KS Div	LA Div 007	LA Div 077	MidStates Div	MVG	Mid-Tex Div	Atmos P/L Mid Tex	AESI	Atmos P/L & Storage	Atmos Energy Power Systems	Atmos Energy Holdings	Atmos Energy Marketing
Gross Direct PP&E	$	5,439,711,534	398,740,964	354,701,307	152,641,872	376,265,849	915,901,270	323,787,054	1,988,757,546	859,896,947	52,369	49,971,843	3,610,397	-	15,384,115
Average Number of Customers	#	3,091,479	297,240	235,655	74,661	252,901	464,841	250,184	1,514,844	336	-	2	2	-	813
Total O&M Expense *	$	356,620,544	25,920,364	22,493,532	7,426,747	24,809,531	44,312,982	36,818,964	118,929,678	47,798,914	458,775	1,916,926	1,019,370	-	24,714,763
(* w/o Allocation)															
Total Composite Factor															
Gross Direct PP&E	%	100.00%	7.32%	6.52%	2.81%	6.92%	16.84%	5.95%	36.56%	15.81%	0.00%	0.92%	0.07%	0.00%	0.28%
Average Number of Customers	%	100.00%	9.61%	7.62%	2.42%	8.18%	15.04%	8.09%	49.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.03%
Total O&M Expense	%	100.00%	7.26%	6.31%	2.08%	6.96%	12.43%	10.32%	33.35%	13.40%	0.13%	0.54%	0.29%	0.00%	6.93%
Total Composite Factor for FY	**%**	100.00%	8.06%	6.82%	2.44%	7.35%	14.77%	8.12%	39.64%	9.74%	0.04%	0.49%	0.12%	0.00%	2.41%

Atmos Energy Corporation
Atmos Energy Mid States Div
Development of Allocation Factors
For Fiscal Year 2007

Div #	Division Name	Sept ' 06 Direct Property Plant & Equipment	Percent of MidStates Property	YE Sept'06 Total O &M w/o 922	Percent of MidStates O & M	YE Sept '06 Avg Number of Customers	Percent of MidStates Customers	**MidStates Allocation Percent**
		(1)	(2)	(3)	(4)	(5)	(6)	**(7)**
70	KIRKSVILLE	7,270,981.92	0.79990	406204.7	1.10369	5,898	1.26882	**1.05747**
72	SE MISSOURI	43,034,064.30	4.73430	2292504.09	6.22889	34,414	7.40340	**6.12220**
92	ILLINOIS	43,536,393.19	4.78957	1,880,061.54	5.10826	22,858	4.91743	**4.93842**
93	TENNESSEE	299,907,053.52	32.99366	8,007,924.70	21.75808	124,423	26.76680	**27.17285**
95	GEORGIA	123,230,080.69	13.55691	5,398,591.16	14.66834	63,746	13.71344	**13.97956**
96	VIRGINIA	55,038,301.37	6.05493	1,739,831.53	4.72724	21,771	4.68347	**5.15521**
97	MISSOURI	34,972,138.73	3.84739	1,289,814.30	3.50451	14,260	3.06774	**3.47321**
98	IOWA	12,727,547.48	1.40020	551,751.90	1.49915	4,267	0.91791	**1.27242**
99	FT. BENNING	634,326.42	0.06978	32,030.65	0.08703	0	0.00000	**0.05227**
09	KENTUCKY	288,632,910.39	31.75336	15,205,659.00	41.31482	173,204	37.26098	**36.77639**
	Total	908,983,798.01	100.00	36,804,373.57	100.00	464,840	100.00	100.00

Atmos Energy Corp - Tennessee Distribution System
Margin Revenue at Present Rates, with weather adjustment (Existing WNA)
Actual Twelve Months Ended December 31, 2006 and February 28, 2007

Exhibit JCC-4.1

Line No.	Description	12 Mths Ended Feb07 Base Count	12 Mths Ended Feb07 Volumes Cof	Rates effective Dec06 Monthly Customer chg	Rates effective Dec06 Commodity Charge/Cof	12 mths Feb07 Margin at Dec06 rates	Weather Adjustment Volumes Cof	12 mths Feb07 WNA Adjusted Volumes Cof	12 mths Feb07 Weather adj Margin at Dec06 rates	12 mths Feb07 WNA $ Adj at Dec06 rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**RESIDENTIAL**									
2	210 RGS SUMMER	543,829	7,392,839	$9.00	$0.1207	$5,786,780		7,392,839	$5,786,780	$0
3	210 RGS WINTER (weather sensitive)	772,039	58,740,950	12.00	0.1207	16,354,501	3,801,648	62,542,598	16,813,360	458,859
4	210 RGS SR CIT SUMMER			0.00	0.1207	0		0	0	
5	210 RGS SR CIT WINTER (weather sensitive)	31	3,405	0.00	0.1207	411		3,405	411	
6	211 HVAC	25	4,285	9.00	0.0667	511		4,285	511	
7	Total Residential	1,315,924	66,141,479			22,142,203	3,801,648	69,943,127	22,601,062	458,859
8										
9	**COMMERCIAL**									
10	211 HVAC	5	76	9.00	0.0667	50		76	50	0
11	220 COM/IND GS (weather sensitive)	180,556	46,121,913	24.00	0.1851	12,870,503	1,734,404	47,856,317	13,191,541	321,038
12	230 LRG COM/IND GS (weather sensitive)	71	909,283	200.00	0.1966	192,965	44,107	953,390	201,636	8,671
13	240 DEMAND/COMM GS	10		310.00		3,100		0	3,100	
14	Block 1 Volumes		200,000		0.0901	18,020		200,000	18,020	
15	Block 2 Volumes		61,960		0.0576	3,569		61,960	3,569	
16	Block 3 Volumes		0		0.0234	0		0	0	
17	Demand Volumes		19,234		1.6293	31,338		19,234	31,338	
18	250 OPT GS	39		310.00		12,090		0	12,090	
19	Block 1 Volumes		631,610		0.0901	56,908		631,610	56,908	
20	Block 2 Volumes		748,095		0.0576	43,090		748,095	43,090	
21	Block 3 Volumes				0.0234	0		0	0	
22	293 LRG TONN HVAC GS	12		25.00		300		0	300	
23	Block 1 Volumes		159,982		0.0901	14,414		159,982	14,414	
24	Block 2 Volumes		14,088		0.0576	811		14,088	811	
25	Block 3 Volumes				0.0234	0		0	0	
26	Total Commercial	180,693	48,847,007			13,247,159	1,778,511	50,625,518	13,576,868	329,710
27										
28	**INDUSTRIAL**									
29	220 COM/IND GS	3,409	5,358,946	24.00	0.1851	1,073,757		5,358,946	1,073,757	
30	230 LRG COM/IND GS	202	2,304,866	200.00	0.1966	493,537		2,304,866	493,537	
31	240 DEMAND/COMM GS	12		310.00		3,720		0	3,720	
32	Block 1 Volumes		240,000		0.0901	21,624		240,000	21,624	
33	Block 2 Volumes		403,380		0.0576	23,235		403,380	23,235	
34	Block 3 Volumes		0		0.0234	0		0	0	
35	Demand Volumes		40,596		1.6293	66,143		40,596	66,143	
36	250 OPT GS	565		310.00		175,066		0	175,066	
37	Block 1 Volumes		6,087,350		0.0901	548,470		6,087,350	548,470	
38	Block 2 Volumes		6,157,590		0.0576	354,677		6,157,590	354,677	
39	Block 3 Volumes				0.0234	0		0	0	
40	280 - ECONOMIC DEV GS (250 OPT)	1		310.00		310		0	310	
41	Block 1 Volumes		20,000		0.0675	1,350		20,000	1,350	
42	Block 2 Volumes		93,900		0.0432	4,056		93,900	4,056	
43	Block 3 Volumes				0.0175	0		0	0	
44	292 CNG/Prime Mover	12		0.00		0		0	0	
45	Block 1 Volumes		25,133		0.0901	2,264		25,133	2,264	
46	Block 2 Volumes		-		0.0576	0		0	0	
47	Block 3 Volumes				0.0234	0		0	0	
48	292 COGEN/CNG	24		25.00		600		0	600	
49	Block 1 Volumes		175,397		0.0901	15,803		175,397	15,803	
50	Block 2 Volumes		5,372		0.0576	309		5,372	309	
51	Block 3 Volumes				0.0234	0		0	0	
52		4,225	20,871,934			2,784,923	0	20,871,934	2,784,923	
53										
54	**PUBLIC AUTHORITY**									
55	211 HVAC			9.00	0.1207	0		0	0	
56	221 EXPERIMENTAL SGS	72	677,504	25.00	0.0995	69,212		677,504	69,212	
57	225 PAG SR CIT SUMMER			0.00	0.1207	0		0	0	
58	225 PAG SR CIT WINTER (weather sensitive)			0.00	0.1207	0		0	0	
59	225 PAG GS - SUMMER	2,475	111,438	9.00	0.1207	35,726		111,438	35,726	
60	225 PAG GS - WINTER (weather sensitive)	3,475	474,135	12.00	0.1207	98,922	72,446	546,581	107,666	8,744
61		6,022	1,263,078			203,859	72,446	1,335,523	212,604	8,744
62										
63	**TRANSPORTATION**									
64	260 - TRANSP (220 SML COM/INDG)	22	153,483	310.00	0.1851	35,230		153,483	35,230	
65	260 - TRANSP (230 LRG COM/INDG)	393	8,529,546	310.00	0.1966	1,798,739		8,529,546	1,798,739	
66	260 - TRANSP (240 DEMAND/COMM GS)	13		310.00		4,030		0	4,030	
67	Block 1 Volumes		253,230		0.0901	22,816		253,230	22,816	
68	Block 2 Volumes		593,290		0.0576	34,174		593,290	34,174	
69	Block 3 Volumes		-		0.0234	0		0	0	
70	Demand Volumes		51,635		1.6293	84,129		51,635	84,129	
71	260 - TRANSP (280/240 ECON DEV - DEMAND/COMM)	12		310.00		3,720		0	3,720	
72	Block 1 Volumes		240,000		0.0675	16,200		240,000	16,200	
73	Block 2 Volumes		410,760		0.0432	17,745		410,760	17,745	
74	Block 3 Volumes		-		0.0175	0		0	0	
75	Demand Volumes		35,626		1.2220	43,535		35,626	43,535	
76	260 - TRANSP (250 OPT GS MASS METER)	15		310.00		4,650		0	4,650	
77	Block 1 Volumes		212,170		0.0901	19,117		212,170	19,117	

Atmos Energy Corp - Tennessee Distribution System
Margin Revenue at Present Rates, with weather adjustment (Existing WNA)
Actual Twelve Months Ended December 31, 2006 and February 28, 2007

Exhibit JCC-4.1

Line No.	Description	12 Mths Ended Feb07 Base Count	12 Mths Ended Feb07 Volumes Ccf	Rates effective Dec06 Monthly Customer chg	Rates effective Dec06 Commodity Charge/Ccf	12 mths Feb07 Margin at Dec06 rates	Weather Adjustment Volumes Ccf	12 mths Feb07 WNA Adjusted Volumes Ccf	12 mths Feb07 Weather adj Margin at Dec06 rates	12 mths Feb07 WNA $ Adj at Dec06 rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
78	Block 2 Volumes		204,680		0.0576	11,790		204,680	11,790	
79	Block 3 Volumes				0.0234	0		0	0	
80	260 - TRANSP (250 OPT GS)	521		310.00		161,510		0	161,510	
81	Block 1 Volumes		9,867,168		0.0901	889,032		9,867,168	889,032	
82	Block 2 Volumes		27,776,288		0.0576	1,599,914		27,776,288	1,599,914	
83	Block 3 Volumes				0.0234	0		0	0	
84	260 - TRANSP (280/250 ECON DEV - OPT GS)	28		310.00		8,680		0	8,680	
85	Block 1 Volumes		473,690		0.0675	31,974		473,690	31,974	
86	Block 2 Volumes		1,657,600		0.0432	71,608		1,657,600	71,608	
87	Block 3 Volumes				0.0175	0		0	0	
88	SPECIAL CONTRACTS	82	38,656,840			1,059,233		38,656,840	1,059,233	
89										
90	Total Transportation	1,086	89,028,746			5,917,824	0	89,028,746	5,917,824	
91										
92	TOTALS	1,507,949	226,152,244			$44,295,968	5,652,604	231,804,848	$45,093,281	$797,313
93										
94	4870 - Forfeited Discount					$1,366,814			$1,366,814	
95	4880 - Miscellaneous Service charges					175,696			175,696	
96	TOTAL MARGIN REVENUES					$45,838,478			$46,635,791	

Atmos Energy Corp - Tennessee Distribution System
Summary of Weather Normalized Margin Revenue at Present Rates - Current WNA Factors
Actual Twelve Months Ended February 28, 2007 and Attrition Period Twelve Months Ended October 31, 2008

Exhibit JCC-4.2

										Summer	2.40%				
										Winter	2.50%	-1.50%			
		12 mths Feb07		Rates effective Dec08		12mths Feb07	C	Customer Changes		Customer Growth		Declining	Adjusted	Adjusted	Total
Line		Base	Weather Adj.	Monthly	Commodity	Weather adj Margin	*	Base	Volumes	Base	Volumes	Usage	Base	Volumes	Adjusted
No.	Description	Count	Vol Ccf	Customer chg	Charge/Ccf	at Dec06 rates		Count	Ccf	Count	Ccf	Volumes Ccf	Count	Ccf	Margin Rev
	(a)	(b)	(c)	(d)	(e)	(f)		(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	RESIDENTIAL														
2	210 RGS SUMMER	543,829	7,392,839	$9.00	$0.1207	$5,786,780	A	(16,315)	(221,785)	21,101	286,842	(166,447)	548,615	7,271,449	$5,815,200
3	210 RGS WINTER (weather sensitive)	772,039	62,542,598	12.00	0.1207	16,813,369	A	(23,161)	(1,876,278)	31,203	2,527,763	(1,579,852)	780,081	61,614,231	16,797,811
4	210 RGS SR CIT SUMMER			0.00	0.1207	0	A	16,315	221,785	653	8,871	(5,766)	16,967	224,890	27,144
5	210 RGS SR CIT WINTER (weather sensitive)	31	3,405	0.00	0.1207	411	A	23,161	1,876,278	966	78,320	(48,950)	24,159	1,909,053	230,423
6	211 HVAC	25	4,285	9.00	0.0667	511							25	4,285	511
7	Total Residential	1,315,924	69,943,127			22,601,062		0	0	53,923	2,901,797	(1,821,016)	1,369,847	71,023,908	22,871,088
8															
9	COMMERCIAL														
10	211 HVAC	5	76	9.00	0.0667	50							5	76	50
11	220 COM/IND GS (weather sensitive)	180,556	47,856,317	24.00	0.1851	13,191,541							180,556	47,856,317	13,191,541
12	230 LRG COM/IND GS (weather sensitive)	71	953,390	200.00	0.1966	201,636							71	953,390	201,636
13	240 DEMAND/COMM GS	10	0	310.00		3,100	B	(10)					0	0	0
14	Block 1 Volumes		200,000		0.0901	18,020			(200,000)				0	0	0
15	Block 2 Volumes		61,960		0.0576	3,569			(61,960)				0	0	0
16	Block 3 Volumes		0		0.0234	0			0				0	0	0
17	Demand Volumes		19,234		1.6293	31,338			(19,234)				0	0	0
18	250 OPT GS	39	0	310.00		12,090							39	0	12,090
19	Block 1 Volumes		631,610		0.0901	56,908							0	631,610	56,908
20	Block 2 Volumes		748,095		0.0576	43,090							0	748,095	43,090
21	Block 3 Volumes		0		0.0234	0							0	0	0
22	293 LRG TONN HVAC GS	12	0	25.00		300							12	0	300
23	Block 1 Volumes		159,982		0.0901	14,414							0	159,982	14,414
24	Block 2 Volumes		14,086		0.0576	811							0	14,086	811
25	Block 3 Volumes		0		0.0234	0							0	0	0
26	Total Commercial	180,693	50,625,518			13,576,868		(10)	(261,960)				180,683	50,363,558	13,520,842
27															
28	INDUSTRIAL														
29	220 COM/IND GS	3,409	5,358,946	24.00	0.1851	1,073,757							3,409	5,358,946	1,073,757
30	230 LRG COM/IND GS	202	2,304,866	200.00	0.1966	493,537	C	(7)	(212,010)				195	2,092,856	450,455
31	240 DEMAND/COMM GS	12	0	310.00		3,720							12	0	3,720
32	Block 1 Volumes		240,000		0.0901	21,624							0	240,000	21,624
33	Block 2 Volumes		403,380		0.0576	23,235							0	403,380	23,235
34	Block 3 Volumes		0		0.0234	0							0	0	0
35	Demand Volumes		40,596		1.6293	66,143							0	40,596	66,143
36	250 OPT GS	565	0	310.00		175,066							565	0	175,066
37	Block 1 Volumes		6,087,350		0.0901	548,470							0	6,087,350	548,470
38	Block 2 Volumes		6,157,590		0.0576	354,677							0	6,157,590	354,677
39	Block 3 Volumes		0		0.0234	0							0	0	0
40	280 - ECONOMIC DEV GS (250 OPT)	1	0	310.00		310	D	12					13	0	4,030
41	Block 1 Volumes		20,000		0.0675	1,350			240,000				0	260,000	17,550
42	Block 2 Volumes		93,900		0.0432	4,056			1,751,870				0	1,845,770	79,737
43	Block 3 Volumes		0		0.0175	0							0	0	0
44	292 CNG/Prime Mover	12	0	0.00		0							12	0	0
45	Block 1 Volumes		25,133		0.0901	2,264							0	25,133	2,264
46	Block 2 Volumes		0		0.0576	0							0	0	0
47	Block 3 Volumes		0		0.0234	0							0	0	0
48	292 COGEN/CNG	24	0	25.00		600							24	0	600
49	Block 1 Volumes		175,397		0.0901	15,803							0	175,397	15,803
50	Block 2 Volumes		5,372		0.0576	309							0	5,372	309
51	Block 3 Volumes		0		0.0234	0							0	0	0
52		4,225	20,871,934			2,784,923		5	1,779,860				4,230	22,651,794	2,837,442
53															
54	PUBLIC AUTHORITY														
55	211 HVAC		0	9.00	0.1207	0							0	0	0
56	221 EXPERIMENTAL SGS	72	677,504	25.00	0.0995	69,212							72	677,504	69,212
57	225 PAG SR CIT SUMMER			0.00	0.1207	0	A	74	3,343				74	3,343	404
58	225 PAG SR CIT WINTER (weather sensitive)			0.00	0.1207	0	A	104	16,397				104	16,397	1,979
59	225 PAG GS - SUMMER	2,475	111,438	9.00	0.1207	35,726	A	(74)	(3,343)				2,401	108,095	34,654
60	225 PAG GS - WINTER (weather sensitive)	3,475	546,581	12.00	0.1207	107,866	A	(104)	(16,397)				3,370	530,184	104,436
61		6,022	1,335,523			212,804		0	0				6,022	1,335,523	210,684
62															
63	TRANSPORTATION														
64	260 - TRANSP (220 SML COM/INDG)	22	153,463	310.00	0.1851	35,230							22	153,463	35,230
65	260 - TRANSP (230 LRG COM/INDG)	393	8,529,546	310.00	0.1966	1,798,739	C	(14)	(563,760)				379	7,965,786	1,683,566
66	260 - TRANSP (240 DEMAND/COMM GS)	13	0	310.00		4,030	E						13	0	4,030
67	Block 1 Volumes		253,230		0.0901	22,816							0	253,230	22,816
68	Block 2 Volumes		593,290		0.0576	34,174							0	593,290	34,174
69	Block 3 Volumes		0		0.0234	0							0	0	0
70	Demand Volumes		51,635		1.6293	84,129							0	51,635	84,129
71	260 - TRANSP (280/240 ECON DEV - DEMAND/COMM)	12	0	310.00		3,720							12	0	3,720
72	Block 1 Volumes		240,000		0.0675	16,200							0	240,000	16,200
73	Block 2 Volumes		410,760		0.0432	17,745							0	410,760	17,745
74	Block 3 Volumes		0		0.0175	0							0	0	0
75	Demand Volumes		35,626		1.2220	43,535							0	35,626	43,535
76	260 - TRANSP (250 OPT GS MASS METER)	15	0	310.00		4,650	C	9					24	0	7,440
77	Block 1 Volumes		212,170		0.0901	19,117	E		180,000				0	392,170	35,335
78	Block 2 Volumes		204,680		0.0576	11,790			161,790				0	366,470	21,109
79	Block 3 Volumes		0		0.0234	0							0	0	0
80	260 - TRANSP (250 OPT GS)	521	0	310.00		161,510	F	20					541	0	167,710
81	Block 1 Volumes		9,867,168		0.0901	889,032	B		280,000				0	10,147,168	914,260
82	Block 2 Volumes		27,776,288		0.0576	1,599,914	G		216,780				0	27,993,068	1,612,401
83	Block 3 Volumes		0		0.0234	0			0				0	0	0
84	260 - TRANSP (280/250 ECON DEV - OPT GS)	28	0	310.00		8,680							28	0	8,680
85	Block 1 Volumes		473,690		0.0675	31,974							0	473,690	31,974
86	Block 2 Volumes		1,657,600		0.0432	71,608							0	1,657,600	71,608
87	Block 3 Volumes		0		0.0175	0							0	0	0
88	SPECIAL CONTRACT (facility chg only)	82	38,656,840			1,059,233		(22)	(20,404,673)	0	0	0	60	18,252,167	592,474
89															

Atmos Energy Corp - Tennessee Distribution System
Summary of Weather Normalized Margin Revenue at Present Rates - Current WNA Factors
Actual Twelve Months Ended February 28, 2007 and Attrition Period Twelve Months Ended October 31, 2008

Exhibit JCC-4.2

										Summer	2.40%				
										Winter	2.50%	-1.60%			
		12 mths Feb07		Rates effective Dec06		12mths Feb07		Customer Changes		Customer Growth		Declining	Adjusted	Adjusted	Total
Line		Base	Weather Adj.	Monthly	Commodity	Weather adj Margin		Base	Volumes	Base	Volumes	Usage	Base	Volumes	Adjusted
No.	Description	Count	Vol Ccf	Customer chg	Charge/Ccf	at Dec06 rates		Count	Ccf	Count	Ccf	Volumes Ccf	Count	Ccf	Margin Rev
	(a)	(b)	(c)	(d)	(e)	(f)		(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
90	Total Transportation	1,086	89,026,746			5,917,824		(7)	(20,129,853)				1,079	68,896,893	5,408,134
91															
92	TOTALS	1,507,949	231,804,848			$45,093,281		(12)	(18,611,953)	53,923	2,901,797	(1,821,016)	1,561,860	214,273,676	$44,848,191
93															
94	4870 - Forfeited Discount					$1,366,814									$1,366,814
95	4880 - Miscellaneous Service charges					175,696									175,696
96	TOTAL MARGIN REVENUES					$46,635,791									$46,390,701

Atmos Energy Corp - Tennessee Distribution System
Margin Revenue at Present Rates, with weather adjustment (Existing WNA)
Actual Twelve Months Ended December 31, 2006 and February 28, 2007

Exhibit JCC-4.3

Line No.	Description	12 Mths Ended Feb07 Base Count	12 Mths Ended Feb07 Volumes Ccf	Rates effective Dec06 Monthly Customer chg	Rates effective Dec06 Commodity Charge/Ccf	12 mths Feb07 Margin at Dec06 rates	Weather Adjustment Volumes Ccf	12 mths Feb07 WNA Adjusted Volumes Ccf	12 mths Feb07 Weather adj Margin at Dec06 rates	12 mths Feb07 WNA $ Adj at Dec06 rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	RESIDENTIAL									
2	210 RGS SUMMER	543,829	7,392,839	$9.00	$0.1207	$5,786,780		7,392,839	$5,786,780	
3	210 RGS WINTER (weather sensitive)	772,039	58,740,950	12.00	0.1207	16,354,501	3,716,792	62,457,742	16,803,118	448,617
4	210 RGS SR CIT SUMMER			0.00	0.1207	0		0	0	
5	210 RGS SR CIT WINTER (weather sensitive)	31	3,405	0.00	0.1207	411		3,405	411	
6	211 HVAC	25	4,285	9.00	0.0667	511		4,285	511	
7	Total Residential	1,315,924	66,141,479			22,142,203	3,716,782	69,858,271	22,590,820	448,617
8										
9	COMMERCIAL									
10	211 HVAC	5	76	9.00	0.0667	50		76	50	
11	220 COM/IND GS (weather sensitive)	180,556	46,121,913	24.00	0.1851	12,870,503	1,552,948	47,674,861	13,157,953	287,451
12	230 LRG COM/IND GS (weather sensitive)	71	909,283	200.00	0.1966	192,965	39,435	948,718	200,718	7,753
13	240 DEMAND/COMM GS	10		310.00		3,100		0	3,100	
14	Block 1 Volumes		200,000		0.0901	18,020		200,000	18,020	
15	Block 2 Volumes		61,960		0.0576	3,569		61,960	3,569	
16	Block 3 Volumes		0		0.0234	0		0	0	
17	Demand Volumes		19,234		1.6293	31,338		19,234	31,338	
18	250 OPT GS	39		310.00		12,090		0	12,090	
19	Block 1 Volumes		631,610		0.0901	56,908		631,610	56,908	
20	Block 2 Volumes		748,095		0.0576	43,090		748,095	43,090	
21	Block 3 Volumes				0.0234	0		0	0	
22	293 LRG TONN HVAC GS	12		25.00		300		0	300	
23	Block 1 Volumes		159,982		0.0901	14,414		159,982	14,414	
24	Block 2 Volumes		14,088		0.0576	811		14,088	811	
25	Block 3 Volumes				0.0234	0		0	0	
26	Total Commercial	180,693	48,847,007			13,247,159	1,592,383	50,439,390	13,542,362	295,204
27										
28	INDUSTRIAL									
29	220 COM/IND GS	3,409	5,358,946	24.00	0.1851	1,073,757		5,358,946	1,073,757	
30	230 LRG COM/IND GS	202	2,304,866	200.00	0.1966	493,537		2,304,866	493,537	
31	240 DEMAND/COMM GS	12		310.00		3,720		0	3,720	
32	Block 1 Volumes		240,000		0.0901	21,624		240,000	21,624	
33	Block 2 Volumes		403,380		0.0576	23,235		403,380	23,235	
34	Block 3 Volumes		0		0.0234	0		0	0	
35	Demand Volumes		40,596		1.6293	66,143		40,596	66,143	
36	250 OPT GS	565		310.00		175,066		0	175,066	
37	Block 1 Volumes		6,087,350		0.0901	548,470		6,087,350	548,470	
38	Block 2 Volumes		6,157,590		0.0576	354,677		6,157,590	354,677	
39	Block 3 Volumes				0.0234	0		0	0	
40	280 - ECONOMIC DEV GS (250 OPT)	1		310.00		310		0	310	
41	Block 1 Volumes		20,000		0.0675	1,350		20,000	1,350	
42	Block 2 Volumes		93,900		0.0432	4,056		93,900	4,056	
43	Block 3 Volumes				0.0175	0		0	0	
44	292 CNG/Prime Mover	12		0.00		0		0	0	
45	Block 1 Volumes		25,133		0.0901	2,264		25,133	2,264	
46	Block 2 Volumes		-		0.0576	0		0	0	
47	Block 3 Volumes				0.0234	0		0	0	
48	292 COGEN/CNG	24		25.00		600		0	600	
49	Block 1 Volumes		175,397		0.0901	15,803		175,397	15,803	
50	Block 2 Volumes		5,372		0.0576	309		5,372	309	
51	Block 3 Volumes				0.0234	0		0	0	
52		4,225	20,871,934			2,784,923	0	20,871,934	2,784,923	
53										
54	PUBLIC AUTHORITY									
55	211 HVAC			9.00	0.1207	0		0	0	
56	221 EXPERIMENTAL SGS	72	677,504	25.00	0.0995	69,212		677,504	69,212	
57	225 PAG SR CIT SUMMER			0.00	0.1207	0		0	0	
58	225 PAG SR CIT WINTER (weather sensitive)			0.00	0.1207	0		0	0	
59	225 PAG GS - SUMMER	2,475	111,438	9.00	0.1207	35,726		111,438	35,726	
60	225 PAG GS - WINTER (weather sensitive)	3,475	474,135	12.00	0.1207	98,922	70,919	545,054	107,482	8,560
61		6,022	1,263,078			203,859	70,919	1,333,997	212,419	8,560
62										
63	TRANSPORTATION									
64	260 - TRANSP (220 SML COM/INDG)	22	153,483	310.00	0.1851	35,230		153,483	35,230	
65	260 - TRANSP (230 LRG COM/INDG)	393	8,529,546	310.00	0.1966	1,798,739		8,529,546	1,798,739	
66	260 - TRANSP (240 DEMAND/COMM GS)	13		310.00		4,030		0	4,030	
67	Block 1 Volumes		253,230		0.0901	22,816		253,230	22,816	
68	Block 2 Volumes		593,290		0.0576	34,174		593,290	34,174	
69	Block 3 Volumes		-		0.0234	0		0	0	
70	Demand Volumes		51,635		1.6293	84,129		51,635	84,129	
71	260 - TRANSP (280/240 ECON DEV - DEMAND/COMM)	12		310.00		3,720		0	3,720	
72	Block 1 Volumes		240,000		0.0675	16,200		240,000	16,200	
73	Block 2 Volumes		410,760		0.0432	17,745		410,760	17,745	
74	Block 3 Volumes		-		0.0175	0		0	0	
75	Demand Volumes		35,626		1.2220	43,535		35,626	43,535	
76	260 - TRANSP (250 OPT GS MASS METER)	15		310.00		4,650		0	4,650	

Atmos Energy Corp - Tennessee Distribution System
Margin Revenue at Present Rates, with weather adjustment (Existing WNA)
Actual Twelve Months Ended December 31, 2006 and February 28, 2007

Exhibit JCC-4.3

Line No.	Description	12 Mths Ended Feb07 Base Count	12 Mths Ended Feb07 Volumes Ccf	Rates effective Dec06 Monthly Customer chg	Rates effective Dec06 Commodity Charge/Ccf	12 mths Feb07 Margin at Dec06 rates	Weather Adjustment Volumes Ccf	12 mths Feb07 WNA Adjusted Volumes Ccf	12 mths Feb07 Weather adj Margin at Dec06 rates	12 mths Feb07 WNA $ Adj at Dec06 rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
77	Block 1 Volumes		212,170		0.0901	19,117		212,170	19,117	
78	Block 2 Volumes		204,680		0.0576	11,790		204,680	11,790	
79	Block 3 Volumes				0.0234	0		0	0	
80	260 - TRANSP (250 OPT GS)	521		310.00		161,510		0	161,510	
81	Block 1 Volumes		9,867,168		0.0901	889,032		9,867,168	889,032	
82	Block 2 Volumes		27,776,288		0.0576	1,599,914		27,776,288	1,599,914	
83	Block 3 Volumes				0.0234	0		0	0	
84	260 - TRANSP (260/250 ECON DEV - OPT GS)	28		310.00		8,680		0	8,680	
85	Block 1 Volumes		473,690		0.0675	31,974		473,690	31,974	
86	Block 2 Volumes		1,657,600		0.0432	71,608		1,657,600	71,608	
87	Block 3 Volumes				0.0175	0		0	0	
88	SPECIAL CONTRACT (facility chg only)	82	38,656,840			1,059,233		38,656,840	1,059,233	
89										
90	Total Transportation	1,086	89,028,746			5,917,824	0	89,028,746	5,917,824	
91										
92	TOTALS	1,507,949	226,152,244			$44,295,868	5,380,094	231,532,338	$45,048,348	$752,380
93										
94	4870 - Forfeited Discount					$1,386,814			$1,386,814	
95	4880 - Miscellaneous Service charges					175,696			175,696	
96	TOTAL MARGIN REVENUES					$45,838,478			$46,590,858	

Atmos Energy Corp - Tennessee Distribution System

Exhibit JCC-4.4

Summary of Weather Normalized Margin Revenue at Present Rates - with Updated WNA factors.

Actual Twelve Months Ended February 28, 2007 and Attrition Period Twelve Months Ended October 31, 2008

										Summer	2.40%				
										Winter	2.50%	-1.50%			
		12 mths Feb07		Rates effective Dec08		12mths Feb07		Customer Changes		Customer Growth		Declining	Adjusted	Adjusted	Total
Line		Base	Weather Adj.	Monthly	Commodity	Weather adj Margin		Base	Volumes	Base	Volumes	Usage	Base	Volumes	Adjusted
No.	Description	Count	Vol Ccf	Customer chg	Charge/Ccf	at Dec06 rates		Count	Ccf	Count	Ccf	Volumes Ccf	Count	Ccf	Margin Rev
	(a)	(b)	(c)	(d)	(e)	(f)		(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	RESIDENTIAL														
2	210 RGS SUMMER	543,829	7,392,839	$9.00	$0.1207	$5,786,780	A	(16,315)	(221,785)	21,101	286,842	(186,447)	548,615	7,271,449	$5,815,200
3	210 RGS WINTER (weather sensitive)	772,039	62,457,742	12.00	0.1207	16,803,118	A	(23,161)	(1,873,732)	31,203	2,524,334	(1,577,709)	780,081	61,530,635	16,787,721
4	210 RGS SR CIT SUMMER			0.00	0.1207	0	A	16,315	221,785	653	8,871	(5,766)	16,967	224,890	27,144
5	210 RGS SR CIT WINTER (weather sensitive)	31	3,405	0.00	0.1207	411	A	23,161	1,873,732	966	78,214	(48,884)	24,159	1,906,468	230,111
6	211 HVAC	25	4,285	9.00	0.0667	511							25	4,285	511
7	Total Residential	1,315,924	69,858,271			22,590,820		0	0	53,923	2,898,261	(1,818,806)	1,369,847	70,937,726	22,860,686
8															
9	COMMERCIAL														
10	211 HVAC	5	76	9.00	0.0667	50							5	76	50
11	220 COM/IND GS (weather sensitive)	160,556	47,674,861	24.00	0.1851	13,157,953							160,556	47,674,861	13,157,953
12	230 LRG COM/IND GS (weather sensitive)	71	948,718	200.00	0.1966	200,718							71	948,718	200,718
13	240 DEMAND/COMM GS	10	0	310.00		3,100	B	(10)					0	0	0
14	Block 1 Volumes		200,000		0.0901	18,020			(200,000)				0	0	0
15	Block 2 Volumes		61,960		0.0576	3,569			(61,960)				0	0	0
16	Block 3 Volumes		0		0.0234	0			0				0	0	0
17	Demand Volumes		19,234		1.6293	31,338			(19,234)				0	0	0
18	250 OPT GS	39	0	310.00		12,090							39	0	12,090
19	Block 1 Volumes		631,610		0.0901	56,908							0	631,610	56,908
20	Block 2 Volumes		748,095		0.0576	43,090							0	748,095	43,090
21	Block 3 Volumes		0		0.0234	0							0	0	0
22	293 LRG TONN HVAC GS	12	0	25.00		300							12	0	300
23	Block 1 Volumes		159,982		0.0901	14,414							0	159,982	14,414
24	Block 2 Volumes		14,088		0.0576	811							0	14,088	811
25	Block 3 Volumes		0		0.0234	0							0	0	0
26	Total Commercial	160,693	50,439,390			13,542,362		(10)	(261,960)	0	0	0	160,683	50,177,430	13,486,336
27															
28	INDUSTRIAL														
29	220 COM/IND GS	3,409	5,358,946	24.00	0.1851	1,073,757							3,409	5,358,946	1,073,757
30	230 LRG COM/IND GS	202	2,304,866	200.00	0.1966	493,537	C	(7)	(212,010)				195	2,092,856	450,455
31	240 DEMAND/COMM GS	12	0	310.00		3,720							12	0	3,720
32	Block 1 Volumes		240,000		0.0901	21,624							0	240,000	21,624
33	Block 2 Volumes		403,380		0.0576	23,235							0	403,380	23,235
34	Block 3 Volumes		0		0.0234	0							0	0	0
35	Demand Volumes		40,596		1.6293	66,143							0	40,596	66,143
36	250 OPT GS	565	0	310.00		175,066							565	0	175,066
37	Block 1 Volumes		6,087,350		0.0901	548,470							0	6,087,350	548,470
38	Block 2 Volumes		6,157,590		0.0576	354,677							0	6,157,590	354,677
39	Block 3 Volumes		0		0.0234	0							0	0	0
40	260 - ECONOMIC DEV GS (250 OPT)	1	0	310.00		310	D	12					13	0	4,030
41	Block 1 Volumes		20,000		0.0675	1,350			240,000				0	260,000	17,550
42	Block 2 Volumes		93,900		0.0432	4,056			1,751,870				0	1,845,770	79,737
43	Block 3 Volumes		0		0.0175	0							0	0	0
44	292 CNG/Prime Mover	12	0	0.00		0							12	0	0
45	Block 1 Volumes		25,133		0.0901	2,264							0	25,133	2,264
46	Block 2 Volumes		0		0.0576	0							0	0	0
47	Block 3 Volumes		0		0.0234	0							0	0	0
48	292 COGEN/CNG	24	0	25.00		600							24	0	600
49	Block 1 Volumes		175,397		0.0901	15,803							0	175,397	15,803
50	Block 2 Volumes		5,372		0.0576	309							0	5,372	309
51	Block 3 Volumes		0		0.0234	0							0	0	0
52		4,225	20,871,934			2,784,923		5	1,779,860	0	0	0	4,230	22,651,794	2,837,442
53															
54	PUBLIC AUTHORITY														
55	211 HVAC		0	9.00	0.1207	0							0	0	0
56	221 EXPERIMENTAL SGS	72	677,504	25.00	0.0995	69,212							72	677,504	69,212
57	225 PAG SR CIT SUMMER			0.00	0.1207	0	A	74	3,343				74	3,343	404
58	225 PAG SR CIT WINTER (weather sensitive)			0.00	0.1207	0	A	104	16,352				104	16,352	1,974
59	225 PAG GS - SUMMER	2,475	111,438	9.00	0.1207	35,726	A	(74)	(3,343)				2,401	108,095	34,654
60	225 PAG GS - WINTER (weather sensitive)	3,475	545,054	12.00	0.1207	107,482	A	(104)	(16,352)				3,370	528,703	104,258
61		6,022	1,333,997			212,419		0	0	0	0	0	6,022	1,333,997	210,500
62															
63	TRANSPORTATION														
64	260 - TRANSP (220 SML COM/INDG)	22	153,483	310.00	0.1851	35,230							22	153,483	35,230
65	260 - TRANSP (230 LRG COM/INDG)	393	8,529,546	310.00	0.1966	1,798,739	C	(14)	(563,750)				379	7,965,796	1,683,566
66	260 - TRANSP (240 DEMAND/COMM GS)	13	0	310.00		4,030	E						13	0	4,030
67	Block 1 Volumes		253,230		0.0901	22,816							0	253,230	22,816
68	Block 2 Volumes		593,290		0.0576	34,174							0	593,290	34,174
69	Block 3 Volumes		0		0.0234	0							0	0	0
70	Demand Volumes		51,635		1.6293	84,129							0	51,635	84,129
71	260 - TRANSP (280/240 ECON DEV - DEMAND/COMM)	12	0	310.00		3,720							12	0	3,720
72	Block 1 Volumes		240,000		0.0675	16,200							0	240,000	16,200
73	Block 2 Volumes		410,760		0.0432	17,745							0	410,760	17,745
74	Block 3 Volumes		0		0.0175	0							0	0	0
75	Demand Volumes		35,626		1.2220	43,535							0	35,626	43,535
76	260 - TRANSP (250 OPT GS MASS METER)	15	0	310.00		4,650	C	9					24	0	7,440
77	Block 1 Volumes		212,170		0.0901	19,117	E		180,000				0	392,170	35,335
78	Block 2 Volumes		204,680		0.0576	11,790			161,790				0	366,470	21,109
79	Block 3 Volumes		0		0.0234	0							0	0	0
80	260 - TRANSP (250 OPT GS)	521	0	310.00		161,510	F	20					541	0	167,710
81	Block 1 Volumes		9,867,168		0.0901	889,032	B		280,000				0	10,147,168	914,260
82	Block 2 Volumes		27,776,288		0.0576	1,599,914	G		216,780				0	27,993,068	1,612,401
83	Block 3 Volumes		0		0.0234	0			0				0	0	0
84	260 - TRANSP (280/250 ECON DEV - OPT GS)	28	0	310.00		8,680							28	0	8,680

Atmos Energy Corp - Tennessee Distribution System

Summary of Weather Normalized Margin Revenue at Present Rates - with Updated WNA factors.

Actual Twelve Months Ended February 28, 2007 and Attrition Period Twelve Months Ended October 31, 2008

Exhibit JCC-4.4

									Summer	2.40%				
									Winter	2.50%	-1.50%			
		12 mths Feb07		Rates effective Dec06		12mths Feb07		Customer Changes		Customer Growth		Declining	Adjusted	Adjusted	Total
Line		Base	Weather Adj.	Monthly	Commodity	Weather adj Margin		Base	Volumes	Base	Volumes	Usage	Base	Volumes	Adjusted
No.	Description	Count	Vol Ccf	Customer chg	Charge/Ccf	at Dec06 rates		Count	Ccf	Count	Ccf	Volumes Ccf	Count	Ccf	Margin Rev
	(a)	(b)	(c)	(d)	(e)	(f)		(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
85	Block 1 Volumes		473,690		0.0675	31,974							0	473,690	31,974
86	Block 2 Volumes		1,657,600		0.0432	71,608							0	1,657,600	71,608
87	Block 3 Volumes		0		0.0175	0							0	0	0
88	SPECIAL CONTRACTS	82	38,656,840			1,059,233		(22)	(20,404,673)				60	18,252,167	592,474
89															
90	Total Transportation	1,086	89,028,746			5,917,824		(7)	(20,129,853)	0	0	0	1,079	68,898,893	5,408,134
91															
92	TOTALS	1,507,949	231,532,338			$45,048,348		(12)	(18,611,953)	53,923	2,898,261	(1,818,808)	1,561,860	213,999,840	$44,603,098
93															
94	4870 - Forfeited Discount					$1,366,814									$1,366,814
95	4880 - Miscellaneous Service charges					175,696									175,696
96	TOTAL MARGIN REVENUES					$46,590,858									$46,345,608

Exhibit JCC-5

Heat Use/Base Use Factors

Town	Weather Station	Current Base Use CCF	Current Heat Use CCF/HDD	Proposed Base Use CCF	Proposed Heat Use CCF/HDD
Union City -	Paducah				
Residential		13.906292	0.156369	10.43	0.124185
Commercial		124.595029	0.453633	112.80	0.416839
Columbia, shelbyville, Franklin Murfreesboro	Nashville				
Residential		13.035323	0.173948	11.34	0.147091
Commercial		99.021858	0.624513	112.93	0.473009
Maryville, Morristown	Knoxville				
Residential		13.88633	0.153366	11.39	0.122329
Commercial		111.454966	0.658649	195.74	0.392082
Johnson City, Elizabethton, Kingsport, Greeneville, Bristol	Bristol				
Residential		10.696903	0.162066	11.51	0.112572
Commercial		169.773651	0.611201	125.95	0.489418

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

PATRICIA J. CHILDERS

I. INTRODUCTION OF WITNESS

Q. PLEASE INTRODUCE YOURSELF.

A. My name is Patricia J. Childers. I am Vice President – Rates and Regulatory Affairs of the Kentucky/Mid-States Division of Atmos Energy Corporation. My business address is 810 Crescent Centre Drive, Suite 600, Franklin, Tennessee, 37067.

II. SUMMARY OF TESTIMONY

Q. WHAT SUBJECTS DO YOU PLAN TO COVER IN YOUR TESTIMONY?

A. I will testify on three subjects:

1. The overall rate design and rates proposed in this proceeding, including an explanation of how the revenue requirement changes are distributed among the various customer classes;
2. The proposed payment provision changes to Rate Schedule 260 for transportation service; and
3. Changing the pricing methodology for gas in storage.

Q. PLEASE SUMMARIZE YOUR TESTIMONY IN EACH OF THESE AREAS.

A. At current rates, the Company has a revenue deficiency of $11,055,188, and is requesting a change in revenue requirement to correct this deficiency.

The Company proposes several incremental changes to the overall rate design recently approved in Docket No. 05-00258. These include:

- Implementation of a Customer Utilization Adjustment mechanism (as discussed in the testimony of Gary Smith);
- Updating weather normalization factors (as discussed in testimony from James Cagle); and
- Certain miscellaneous changes (discussed in testimony from Michael Ellis).

On the Transportation Tariff, the Company proposes a revenue neutral change designed to make payment terms consistent with other rate schedules.

Finally, the Company proposes to change from the pricing methodology for gas in storage from the first in first out (FIFO) methodology to the weighted average cost of gas (WACOG) methodology. This will result in a minimal impact to rate base and a smoothing effect on gas price volatility as reflected in the Purchased Gas Adjustment (PGA) mechanism.

III. WITNESS QUALIFICATIONS

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND, AND CURRENT RESPONSIBILITIES.

A. I have a Bachelor of Science in Business Administration from Middle Tennessee Statue University. I have worked for Atmos and its predecessors since 1979. In 2001, I assumed my current position, Vice President – Rates and Regulatory Affairs Atmos' Mid-States Division (now the Kentucky/Mid-States Division). My job responsibilities include oversight of rates and regulatory affairs for the Company's regulated utility operations in the States of Tennessee, Iowa, Illinois, Missouri, Virginia and Georgia. I also serve on internal and external committees involved in monitoring and addressing developments and trends in regulated gas utility rates.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS AUTHORITY?

A. Yes. Throughout my years with the Company I have provided testimony in several dockets, most recently in Docket No. 05-00258.

Q. HAVE YOU TESTIFIED ON MATTERS BEFORE OTHER STATE REGULATORY COMMISSIONS?

A. Yes, I have testified before the Illinois State Corporation Commission, the Missouri Public Service Commission, the Virginia State Corporation Commission and the Georgia Public Service Commission.

IV. OVERALL RATE DESIGN

Q. PLEASE DISCUSS THE PROPOSED OVERALL RATE DESIGN.

A. The Company proposes to keep essentially the same rate design recently approved in Docket No. 05-00258 with a few modifications. These modifications include the Customer Utilization Adjustment (CUA) mechanism that is discussed in the direct testimony of Mr. Gary Smith, the changes to certain miscellaneous tariff charges discussed in the direct testimony of Mr. Michael H. Ellis and updating the 30-year weather normalization

factors discussed in the direct testimony of Mr. James C. Cagle. Other proposed changes also include adoption of the transportation tariff payment provision changes discussed later in my testimony as well as changing the pricing methodology for gas in storage (which will have a *de minimus* base rate impact).

Q. WHAT IS THE COMPANY'S CURRENT RATE DESIGN?

A. The Company's current rate design, most recently approved in Docket No. 05-00258, apportions the Company's revenue requirement between a monthly fixed customer charge and a volumetric rate. Except for the modifications and adjustments proposed in this rate case, which also include a proposed increase to base rates (both the monthly customer charge and volumetric rate component), the Company intends to keep essentially the same rate design.

Q. WHY HAS THE COMPANY PROPOSED AN INCREASE IN BASE RATES?

A. As shown in the direct testimony of Mr. Thomas Petersen, the Company has a revenue deficiency of $11,055,188 at current rates. Current rates are therefore insufficient to permit the Company the opportunity to earn a reasonable return on its invested capital over and above its reasonable and necessary operating expenses. The changes to rates proposed by the Company in this filing, coupled with the rate design changes proposed by the Company, will allow the Company to earn a reasonable return.

Q. PLEASE DISCUSS THE PROPOSED CHANGES TO RESIDENTIAL BASE RATES.

A. The Company is proposing that any change in revenue requirement ordered by the TRA in this proceeding be distributed among the rate schedules proportionately based on projected revenues from each rate schedule at existing rates. The Company proposes to in-

crease the residential (Rate Schedule 210) and public authority (Rate Schedule 225) monthly customer charge by $1 each month for a winter customer charge of $13 and a summer customer charge of $10. The remaining proportionate share of any approved increase will be recovered through the volumetric rate per Ccf.

Q. IS THERE ANY PROPOSED EXEMPTION FROM THE MONTHLY CUSTOMER CHARGE?

A. Yes, residential customers 65 or older meeting the threshold for low-income will continue to be exempt from the proposed monthly customer charge as previously approved by the TRA in Docket No. 05-00258.

Q. HOW ARE OTHER RATE SCHEDULES AFFECTED BY THIS FILING?

A. In Docket No. 05-00258, customer charges and volumetric charges for Rate Schedules 220 (small commercial/industrial firm) and 230 (large commercial/industrial firms) were adjusted such that larger users (those served under Rate Schedule 230) are currently paying more (through the combination of the monthly customer charge and the volumetric rate) than they would if served under rate schedule 220. As the Company's intent is to recognize larger users through the offering of a slightly lesser rate, the Company is seeking to correct the existing inequity in this case.

Q. HOW DOES THE COMPANY PROPOSE TO CORRECT THIS?

A. The Company proposes to increase the monthly customer charge for small commercial and industrial firm customers on Rate Schedule 220 from $24.00 to $27.50. The remaining proportionate share of any approved rate increase will be recovered through the volumetric rates per Ccf for both Rate Schedules 220 and 230.

Q. THUS FAR YOU HAVE DESCRIBED BASE RATE CHANGES THAT WILL AFFECT RATE SCHEDULES 210, 225, 220 AND 230. ARE ANY OTHER RATE SCHEDULES AFFECTED BY THE PROPOSED INCREASE?

A. Yes, volumetric rates for the remaining rate schedules will be adjusted proportionately. However, no increase in the monthly customer charge is being proposed for the remaining rate schedules.

Q. PLEASE SHOW THE IMPACT OF THE PROPOSED RATE INCREASE UPON ALL RATE SCHEDULES.

A. Attached to my testimony as Exhibit PJC-1 is a table that shows the impact on each rate schedule based on average normalized consumption for that class.

V. TRANSPORTATION TARIFF PAYMENT PROVISIONS

Q. EXPLAIN WHAT THE COMPANY PROPOSES ADDING TO RATE SCHEDULE 260 WITH REGARD TO PAYMENT.

A. The Company proposes to amend this tariff to add payment language that is consistent with all of the Company's other Rate Schedules. The new language specifies when payment is due and provides for the assessment of a 5% late charge on delinquent accounts.

VI. STORAGE GAS PRICING METHODOLOGY

Q. IS THE COMPANY PROPOSING TO CHANGE ITS METHOLODOLOGY FOR PRICING ITS GAS STORAGE INVENTORY?

A. Yes. The Company currently utilizes the FIFO (first in first out) methodology in Tennessee. It proposes to change to the WACOG (weighted average cost of gas) methodology, to be consistent with the methodology used in the Company's other jurisdictions.

Q. HOW DOES WACOG DIFFER FROM FIFO?

A. Using the FIFO methodology, the value of gas billed is skewed by a lag between the time the gas is purchased and stored and the time it is sold. For example, gas purchase prices were higher than average in the fall of 2005. Gas purchased at that time for injection into storage would be used at a later date, at which time the ratepayer would be impacted by that higher commodity cost. Since 2005, however, the Company has been able at times to purchase gas at lower prices. Using the WACOG method, the gas in storage would be valued based on the average purchase price, rather than billing a high commodity cost reflective of late 2005 pricing for a period of time, followed by a lower commodity cost.

Q. DOES THIS CHANGE IN PRICING METHODOLOGY PRESENT ANY ADVANTAGES FOR THE RATEPAYER?

A. Yes. Using the WACOG method, customers are billed for the average cost of the gas in storage. This provides balance in the amount charged to the ratepayer. Using this average cost will smooth the effects of gas price volatility through the actual cost adjustment mechanism of the purchased gas adjustment clause and make the commodity price reflected on the bill more reliable.

Q. DOES THIS CHANGE HAVE ANY IMPACT ON BASE RATES?

A. This change will slightly adjust base rates, but any impact will be minimal. Currently, an average balance of storage gas is included in Company's base rates as investment. The WACOG methodology will affect the amount of investment included in base rates to the extent that it determines the value assigned to the storage gas at the time of a rate case.

Q. SHOULD THE TRA APPROVE A FUNDING MECHANISM OF 1.74 CENTS PER MMBTU AS REQUESTED IN THE TESTIMONY OF MR. RONALD B.

EDELSTEIN, HOW WOULD THE COMPANY PROPOSE TO COLLECT THIS FUNDING FROM ITS CUSTOMERS?

A. Yes. The Company proposes to collect the 1.74 cents per MMBtu through a surcharge mechanism from its existing sales customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

VERIFICATION

STATE OF TENNESSEE)
)
COUNTY OF WILLIAMSON)

I, Patricia J. Childers, being first duly sworn, state that I am Vice President of Rates and Regulatory Affairs for the Kentucky/Mid-States Division of Atmos Energy Corporation, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Testimony of Patricia J. Childers in support of Atmos Energy Corporation's Petition and the Exhibits thereto pre-filed in this docket on the date of filing of this Petition are true and correct to the best of my knowledge, information and belief.

Patricia J Childers
Patricia J. Childers

Sworn and subscribed before me this 17th day of April, 2007.

Pamela Todd
Notary Public

PAMELA TODD
STATE OF TENNESSEE NOTARY PUBLIC
DAVIDSON COUNTY

My Commission Expires: 05-24-08

My Commission Expires 05-24-08

Atmos Energy Corporation
Exhibit PJC-1

	Rates effective Dec06		Adjusted	Adjusted	Current	Proposed Rates				
	Monthly	Commodity	Base	Volumes	Adjusted	Monthly	Commodity	Total		Percent
	Customer chg	Charge/Ccf	Count	Ccf	Margin Rev	Customer chg	Charge/Ccf	Revenues	Increase	Change
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(k)	(l)	(m)
RESIDENTIAL										
210 RGS SUMMER	$9.00	$ 0.1207	548,615	7,271,449	$ 5,815,200	$ 10.00	$ 0.1838	$ 6,822,643	$ 1,007,444	17%
210 RGS WINTER (weather sensitive)	12.00	$ 0.1207	780,081	61,530,635	$ 16,787,721	$ 13.00	$ 0.1838	$ 21,450,385	$ 4,662,664	28%
210 RGS SR CIT SUMMER	0.00	$ 0.1207	16,967	224,890	$ 27,144	$ -	$ 0.1838	$ 41,335	$ 14,191	52%
210 RGS SR CIT WINTER (weather sensitive)	0.00	$ 0.1207	24,159	1,906,468	$ 230,111	$ -	$ 0.1838	$ 350,409	$ 120,298	52%
211 HVAC	9.00	$ 0.0667	25	4,285	$ 511	$ 9.00	$ 0.0667	$ 511	$ -	0%
Total Residential			1,369,847	70,937,726	$ 22,860,686			$ 28,665,283	$ 5,804,596	25%
Avg. Residential Customer			12	621	$ 204			$ 255	$ 51	25%
COMMERCIAL										
211 HVAC	9.00	$ 0.0667	5	76	$ 50	$ 9.00	$ 0.0667	$ 50	$ -	0%
220 COM/IND GS (weather sensitive)	24.00	$ 0.1851	180,556	47,674,861	$ 13,157,953	$ 27.50	$ 0.2422	$ 16,512,133	$ 3,354,179	25%
230 LRG COM/IND GS (weather sensitive)	200.00	$ 0.1966	71	948,718	$ 200,718	$ 200.00	$ 0.2172	$ 220,262	$ 19,544	10%
250 OPT GS	310.00		39	0	$ 12,090	$ 310.00		$ 12,090	$ -	0%
Block 1 Volumes		$ 0.0901	0	631,610	$ 56,908		$ 0.1038	$ 65,561	$ 8,653	15%
Block 2 Volumes		$ 0.0576	0	748,095	$ 43,090		$ 0.0713	$ 53,339	$ 10,249	24%
Block 3 Volumes		$ 0.0234	0	0	$ -		$ 0.0371	$ -	$ -	N/A
293 LRG TONN HVAC GS	25.00		12	0	$ 300	$ 25.00		$ 300	$ -	0%
Block 1 Volumes		$ 0.0901	0	159,982	$ 14,414		$ 0.1038	$ 16,606	$ 2,192	15%
Block 2 Volumes		$ 0.0576	0	14,088	$ 811		$ 0.0713	$ 1,004	$ 193	24%
Block 3 Volumes		$ 0.0234	0	0	$ -		$ 0.0371	$ -	$ -	N/A
Total Commercial			180,683	50,177,430	$ 13,486,336			$ 16,881,345	$ 3,395,010	25%
INDUSTRIAL										
220 COM/IND GS	24.00	$ 0.1851	3,409	5,358,946	$ 1,073,757	$ 24.00	$ 0.2422	$ 1,379,753	$ 305,996	28%
230 LRG COM/IND GS	200.00	$ 0.1966	195	2,092,856	$ 450,455	$ 200.00	$ 0.2172	$ 493,568	$ 43,113	10%
240 DEMAND/COMM GS	310.00		12	0	$ 3,720	$ 310.00		$ 3,720	$ -	0%
Block 1 Volumes		$ 0.0901	0	240,000	$ 21,624		$ 0.1038	$ 24,912	$ 3,288	15%
Block 2 Volumes		$ 0.0576	0	403,380	$ 23,235		$ 0.0713	$ 28,761	$ 5,526	24%
Block 3 Volumes		$ 0.0234	0	0	$ -		$ 0.0371	$ -	$ -	N/A
Demand Volumes		$ 1.6293	0	40,596	$ 66,143		$ 1.6293	$ 66,143	$ -	0%
250 OPT GS	310.00		565	0	$ 175,066	$ 310.00		$ 175,066	$ -	0%
Block 1 Volumes		$ 0.0901	0	6,087,350	$ 548,470		$ 0.1038	$ 631,867	$ 83,397	15%
Block 2 Volumes		$ 0.0576	0	6,157,590	$ 354,677		$ 0.0713	$ 439,036	$ 84,359	24%
Block 3 Volumes		$ 0.0234	0	0	$ -		$ 0.0371	$ -	$ -	N/A
280 - ECONOMIC DEV GS (250 OPT)	310.00		13	0	$ 4,030	$ 310.00		$ 4,030	$ -	0%
Block 1 Volumes		$ 0.0675	0	260,000	$ 17,550		$ 0.0779	$ 20,241	$ 2,691	15%
Block 2 Volumes		$ 0.0432	0	1,845,770	$ 79,737		$ 0.0535	$ 98,703	$ 18,965	24%
Block 3 Volumes		$ 0.0175	0	0	$ -		$ 0.0278	$ -	$ -	N/A
292 CNG/Prime Mover	0.00		12	0	$ -	$ -		$ -	$ -	N/A
Block 1 Volumes		$ 0.0901	0	25,133	$ 2,264		$ 0.1038	$ 2,609	$ 344	15%
Block 2 Volumes		$ 0.0576	0	0	$ -		$ 0.0713	$ -	$ -	N/A
Block 3 Volumes		$ 0.0234	0	0	$ -		$ 0.0371	$ -	$ -	N/A
292 COGEN/CNG	25.00		24	0	$ 600	$ 25.00		$ 600	$ -	0%
Block 1 Volumes		$ 0.0901	0	175,397	$ 15,803		$ 0.1038	$ 18,206	$ 2,403	15%
Block 2 Volumes		$ 0.0576	0	5,372	$ 309		$ 0.0713	$ 383	$ 74	24%
Block 3 Volumes		$ 0.0234	0	0	$ -		$ 0.0371	$ -	$ -	N/A
			4,230	22,651,794	$ 2,837,442			$ 3,387,598	$ 550,156	19%
PUBLIC AUTHORITY										
211 HVAC	9.00	$ 0.1207	0	0	$ -	$ 9.00	$ 0.1838	$ -	$ -	N/A
221 EXPERIMENTAL SGS	25.00	$ 0.0995	72	677,504	$ 69,212	$ 25.00	$ 0.0995	$ 69,212	$ -	0%
225 PAG SR CIT SUMMER	0.00	$ 0.1207	74	3,343	$ 404	$ -	$ 0.1838	$ 614	$ 211	52%
225 PAG SR CIT WINTER (weather sensitive)	0.00	$ 0.1207	104	16,352	$ 1,974	$ -	$ 0.1838	$ 3,005	$ 1,032	52%
225 PAG GS - SUMMER	9.00	$ 0.1207	2,401	108,095	$ 34,654	$ 10.00	$ 0.1838	$ 43,875	$ 9,222	27%
225 PAG GS - WINTER (weather sensitive)	12.00	$ 0.1207	3,370	528,703	$ 104,258	$ 13.00	$ 0.1838	$ 140,989	$ 36,731	35%
			6,022	1,333,997	$ 210,500			$ 257,696	$ 47,196	22%
TRANSPORTATION										
260 - TRANSP (220 SML COM/INDG)	310.00	$ 0.1851	22	153,483	$ 35,230	$ 310.00	$ 0.2422	$ 43,994	$ 8,764	25%
260 - TRANSP (230 LRG COM/INDG)	310.00	$ 0.1966	379	7,965,796	$ 1,683,566	$ 310.00	$ 0.2172	$ 1,847,661	$ 164,095	10%
260 - TRANSP (240 DEMAND/COMM GS)	310.00		13	0	$ 4,030	$ 310.00		$ 4,030	$ -	0%
Block 1 Volumes		$ 0.0901	0	253,230	$ 22,816		$ 0.1038	$ 26,285	$ 3,469	15%
Block 2 Volumes		$ 0.0576	0	593,290	$ 34,174		$ 0.0713	$ 42,302	$ 8,128	24%
Block 3 Volumes		$ 0.0234	0	0	$ -		$ 0.0371	$ -	$ -	N/A
Demand Volumes		$ 1.6293	0	51,635	$ 84,129		$ 1.6293	$ 84,129	$ -	0%

Atmos Energy Corporation
Exhibit PJC-1

	Rates effective Dec06		Adjusted	Adjusted	Current	Proposed Rates				
	Monthly	Commodity	Base	Volumes	Adjusted	Monthly	Commodity	Total		Percent
	Customer chg	Charge/Ccf	Count	Ccf	Margin Rev	Customer chg	Charge/Ccf	Revenues	Increase	Change
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(k)	(l)	(m)
260 - TRANSP (280/240 ECON DEV - DEMAND/C	310.00		12	0	$ 3,720	$ 310.00		$ 3,720	$ -	0%
Block 1 Volumes		$ 0.0675	0	240,000	$ 16,200		$ 0.0779	$ 18,684	$ 2,484	15%
Block 2 Volumes		$ 0.0432	0	410,760	$ 17,745		$ 0.0535	$ 21,965	$ 4,221	24%
Block 3 Volumes		$ 0.0175	0	0	$ -		$ 0.0278	$ -	$ -	N/A
Demand Volumes		$ 1.2220	0	35,626	$ 43,535		$ 1.2220	$ 43,535	$ -	0%
260 - TRANSP (250 OPT GS MASS METER)	310.00		24	0	$ 7,440	$ 310.00		$ 7,440	$ -	0%
Block 1 Volumes		$ 0.0901	0	392,170	$ 35,335		$ 0.1038	$ 40,707	$ 5,373	15%
Block 2 Volumes		$ 0.0576	0	366,470	$ 21,109		$ 0.0713	$ 26,129	$ 5,021	24%
Block 3 Volumes		$ 0.0234	0	0	$ -		$ 0.0371	$ -	$ -	N/A
260 - TRANSP (250 OPT GS)	310.00		541	0	$ 167,710	$ 310.00		$ 167,710	$ -	0%
Block 1 Volumes		$ 0.0901	0	10,147,168	$ 914,260		$ 0.1038	$ 1,053,276	$ 139,016	15%
Block 2 Volumes		$ 0.0576	0	27,993,068	$ 1,612,401		$ 0.0713	$ 1,995,906	$ 383,505	24%
Block 3 Volumes		$ 0.0234	0	0	$ -		$ 0.0371	$ -	$ -	N/A
260 - TRANSP (280/250 ECON DEV - OPT GS)	310.00		28	0	$ 8,680	$ 310.00		$ 8,680	$ -	0%
Block 1 Volumes		$ 0.0675	0	473,690	$ 31,974		$ 0.0779	$ 36,877	$ 4,903	15%
Block 2 Volumes		$ 0.0432	0	1,657,600	$ 71,608		$ 0.0535	$ 88,640	$ 17,032	24%
Block 3 Volumes		$ 0.0175	0	0	$ -		$ 0.0278	$ -	$ -	N/A
Total Transportation				50,733,987	$ 4,815,660			$ 5,561,670	$ 1,940,713	40%
Sub Total				195,834,934	$ 44,210,624			$ 54,753,592	$ 11,737,671	
Special Contracts					$ -			$ -	N/A	N/A
4870 - Forfeited Discount					$ 1,366,814			$ 1,433,015	$ 66,201	
4880 - Miscellaneous Service charges					$ 175,696			$ 621,140	$ 445,444	
TOTAL MARGIN REVENUES					$ 46,345,608			$ 57,400,221	$ 11,054,613	24%

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

ROBERT R. COOK, JR.

I. INTRODUCTION OF WITNESS

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Robert R. Cook Jr. I am Vice President Technical Services of the KY/Mid-States Division of Atmos Energy Corporation ("Atmos Energy" or "Company"). My business address is 2401 New Hartford Road, Owensboro, Kentucky, 42303.

II. SUMMARY OF TESTIMONY

Q. PLEASE BRIEFLY SUMMARIZE THE TESTIMONY YOU INTEND TO GIVE IN THIS MATTER.

A. In my testimony, I will describe Atmos Energy's budgeting process for capital expenses ("Capex"). My testimony will describe how the Company decides upon and prioritizes its capital expenditures.

Specifically, I will discuss the Company's budget for capital expenditures relating to Tennessee for the attrition period and as forecast for future years.

III. WITNESS QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Civil Engineering from Murray State University in 1990.

I have been employed in the utility industry for 16 years, predominantly in the natural gas transmission field. I have been employed by Atmos Energy Corporation for approximately three (3) years. My previous employer was Williams Gas Pipeline Company – Texas Gas.

During my time at Williams Gas Pipeline Company, I worked in design and construction as a project engineer in Kentucky from 1990 until 1999. I then worked as a project manager in the engineering department overseeing pipeline and compression projects in Kentucky until 2000. From 2000 until 2003, I worked in Houston, Texas as manager of construction/mapping for Williams Gas Pipeline Company.

In 2004, I returned to Kentucky to join Atmos Energy as Vice President of Technical Services for its Kentucky Division. Effective October 1, 2006, I assumed the responsibility of Vice President of Technical Services for the consolidated KY/Mid-States Division.[1]

Q. WHAT ARE YOUR RESPONSIBILITIES AS THE VICE PRESIDENT OF TECHNICAL SERVICES?

A. I have overall responsibility for decision-making related to technical operations. This includes engineering and system design, safety, compliance, procurement, environmental, measurement, communications, technological infrastructure, and storage operations. I also sponsor Atmos' safety committee and am a member of the Atmos' Utility Operations Council, which sets the Company's standard practices and procedures for construction, maintenance and service. In addition, I am responsible for developing the Division's (including Tennessee) annual capital

[1] Effective October 1, 2006, the Company's Kentucky and Mid-States Divisions were organizationally consolidated and are now the KY/Mid-States Division.

budget and monitoring capital budgetary compliance. In this regard, it is my role to ensure that the Company's investment in new plant and equipment in Tennessee is targeted towards meeting the important goals of public safety, system reliability and efficiency.

IV. CAPITAL BUDGETING PROCESS

Q. WHAT ARE THE OBJECTIVES OF THE COMPANY'S CAPITAL BUDGETING PROCESS?

A. The objectives of the Company's capital budgeting process are to:

(1) Formalize the process of identifying construction needs and prioritizing capital expenditures;

(2) Assess the economic feasibility of individual construction projects;

(3) Determine overall capital requirements for the planning periods;

(4) Reassess long term system maintenance requirements annually; and

(5) Review past construction projects and work practices, and apply procedural improvements as appropriate.

Q. PLEASE DESCRIBE THE PLANNING AND BUDGET PROCESS FOR THE COMPANY'S CAPITAL CONSTRUCTION PROGRAM?

A. The Company plans its capital expenditures over five fiscal years, with a focused emphasis on the first year of that five-year period. We normally begin this process during our third fiscal quarter (April-May) of each year, some 4 to 5 months prior to the beginning of the next fiscal year. The process is initiated within the Division by a request from my office for a "bottom-up" submission of projects from our operations supervisors and operations managers in Tennessee. All proposed projects, vehicles, and equipment must be identified at a high level by need and cost, and all budgets are prepared based upon meeting the five objectives described above. The proposed projects, vehicles, and equipment are reviewed by the KY/Mid-States Division's regional vice presidents of operations for collaborative agreements between the regional vice presidents, operations managers, and myself.

After review, additional information is requested for projects that are determined to be the most eligible for funding and more detailed documentation is requested from the operations and technical services managers on those particular projects. The process is largely complete by late June when projects are entered into the Atmos Energy capital budget system (PlanIt), although finalization of capital expenditures is not completed until late July. During this time, the agreed-to projects have been further substantiated to ensure they meet the appropriate financial criteria and the stated objectives.

The final proposed budget must be reviewed by the Division's senior management, including the Division President. Additional reviews are performed by corporate executive operations management and their staff. High level reviews of the division budgets are also performed by the Company's senior executives who are presiding members of the Company's Management Committee. The Capex budget for Tennessee is not officially approved until it, as part of the Company's total Capex budget, is presented to the Company's Board of Directors in September of each year. Upon this approval, all approved projects are transferred into the Atmos Energy capital tracking system (POWERPLANT) and are ready for appropriation.

Q. HOW DOES ATMOS PRIORITIZE ITS CAPITAL EXPENDITURES?

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

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

Typically, the funds for customer growth constitute about 33% of our annual capital expenditures. The other components comprising our non-growth capital expenditures, including our technology investments, make up the balance of our spending.

Q. WHAT FINANCIAL CRITERIA ARE THE MOST SIGNIFICANT IN APPROVING A PROJECT DURING THE CAPITAL BUDGETING PROCESS?

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

Q. MUST ALL PROJECTS MEET THE SAME FINANCIAL CRITERIA?

A. No. We separate projects into growth and non-growth capital expenditures. Growth projects are revenue-producing investments for which we can identify a stream of revenues, cash flow, return, payback and other standard investment criteria. Non-growth capital expenditures involve system integrity, equipment, structures, pipeline integrity, system maintenance and reliability projects which are evaluated on a cost/benefit basis. We endeavor to keep our annual non-growth capital expenditures below the level of depreciation. Since these expenditures do not have an associated stream of revenues, our goal is to fund these expenditures through internal financial cash flow. Obviously, there are certain non-growth expenditures that do not impact public safety that can be scheduled into our five-year investment program to ensure that we properly maintain our system while still operating within overall cash flow constraints. Expenditures that impact public safety always have had and will continue to have the highest priority. To help manage and prioritize our System Integrity pipeline replacements projects, we use our Atmos Risk Management Model ("ARMM"). ARMM is computer software that was developed to identify and prioritize pipeline replacements, primarily our bare steel pipelines. We take our obligation to build and operate a safe and reliable gas system very seriously. Finally, there

are also a number of projects we must fund over which we have little control as to timing, such as public works projects and highway relocations.

Q. HOW CAN THE COMPANY JUSTIFY ADDITIONAL EXPENDITURES BEYOND ITS REGULAR CAPITAL BUDGET PROJECTIONS?

A. The KY/Mid-States Division can secure additional funding through Atmos Energy if we can demonstrate that we have potential investments which compare more favorably to competing expenditures in other Atmos business units and are, therefore, more worthy of immediate funding from a purely financial standpoint. Unbudgeted expenditures that impact public safety, system capacity, or reliability, or compliance projects have the highest priority, and are considered mandatory capital projects. Unbudgeted expenditures greater than twenty-five thousand dollars must be reviewed by the Division's senior management, including the Division President. If applicable, high-level reviews of unbudgeted expenditures also are performed by the Company's senior executives, who are presiding members of the Company's Management Committee.

V. CONTROL & MONITORING OF CAPITAL EXPENDITURES

Q. WHAT ARE THE GOALS OF THE COMPANY'S PROCESS OF CONTROLLING AND MONITORING CAPITAL EXPENDITURE VARIANCES?

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

Q. PLEASE DESCRIBE THE COMPANY'S PROCESS FOR CONTROLLING AND MONITORING CAPITAL EXPENDITURE VARIANCES.

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

Once a project has been entered in the capital budget system an appropriation Purpose and Necessity (P&N) may be submitted for authorization. Projects are then monitored to ensure they stay within budgeted levels. If during the course of a project, field management identifies that the costs of the project will exceed approved amounts, a request for supplemental funding may be submitted. All expenditures above authorized appropriation, and all expenditures for unbudgeted projects or variances on budgeted and approved projects, must be approved at the appropriate levels within the Company.

Each month, various project variance reports are published. Each budget center manager is responsible and held accountable for managing his overall approved capital budget.

Q. DISCUSS THE VARIANCES INCURRED DURING THE MOST RECENT FISCAL YEAR'S CAPITAL BUDGETING PROGRAM.

A. In fiscal year 2006, the Company's actual capital expenditures in Tennessee were $17.76 million, resulting in a variance of 37.8% over the 2006 budget. There were several factors contributing to this overage. Contractor costs related to the mandated replacement of 45,000 feet of bare steel pipe annually were unbudgeted and higher than expected. Growth in the Franklin, Murfreesboro, and Spring Hill areas of Tennessee required unbudgeted system reinforcements to support the added load. This area of Middle Tennessee will require additional unbudgeted

capital expenditures for system capacity of $7.5 million in fiscal year 2007. In general, the pace of construction and the corresponding capital expenditures normally increase as we progress into summer.

VI. ATTRITION PERIOD CAPITAL BUDGET

Q. WHAT IS THE ATTRITION PERIOD USED IN THIS RATE APPLICATION?

A. The attrition period is November 1, 2007 through October 31, 2008. This represents 11 months of Tennessee's fiscal year 2008 (FY2008) and 1 month of Tennessee's fiscal year 2009 (FY2009).

Q. WHAT IS TENNESSEE'S ATTRITION PERIOD CAPITAL BUDGET?

A. Tennessee's attrition period's capital budget is $18.7 million. Tennessee's capital budget is comprised of three components: (1) the capital spending for Tennessee for the forecasted period; (2) the amount allocated to Tennessee resulting from capital spending by the KY/Mid-States Division's general office; and (3) the amount allocated to Tennessee resulting from capital spending by the Company's Shared Services (SSU) during the forecasted test period. The budgeting process for SSU Capex is described in the direct testimony of Company witness Mr. Greg Waller and the amounts projected to be closed to plant and comprising additions to SSU ratebase are sponsored by Company witness Mr. Thomas Petersen. The methodology for allocating SSU and the Division general office ratebase amounts to Tennessee is described in the testimony of Company witness Mr. James C. Cagle.

Q. HOW WAS TENNESSEE'S CAPITAL BUDGET FOR THE ATTRITION PERIOD DEVELOPED?

A. We relied upon the FY2007 capital budget as a baseline for projecting FY2008 through FY2009 capital expenditures for purposes of the attrition period in this rate application.

Q. WHAT IS TENNESSEE'S FY2007 DIRECT CAPITAL BUDGET?

A. The original approved FY2007 direct capital budget for Tennessee was $16.97

million. The Atmos Energy Board of Director's approved an additional $6.5 million in capital expenditures for system reinforcements in the Middle Tennessee area. This brings the total approved FY2007 direct capital budget for Tennessee to $23.47 million.

Q. WHAT IS TENNESSEE'S FY2008 DIRECT CAPITAL BUDGET AS ESTIMATED IN THE FIVE YEAR PLANNING PROCESS?

A. Tennessee's FY2008 direct capital budget is estimated at $18.88 million.

Q. HOW DID YOU ADJUST TENNESSEE'S FY2007 CAPITAL BUDGET IN ORDER TO PREPARE THE FY2008 CAPITAL BUDGET?

A. The estimated cost of budgeted projects planned for FY2007, before the application of overheads, was used as a baseline. Three factors were evaluated and used to adjust the baseline. These adjustments were necessary in order to reflect the most current information available that would impact our future level of capital spending, and thus ensure that the capital budget is accurate. These three factors are:

1. Changes related to system integrity and system improvement projects;
2. Cost increases in materials and labor tied to inflation; and
3. An application of overheads attributable to capital projects.

Q. PLEASE DISCUSS EACH OF THESE FACTORS.

A. The change in system integrity and system improvements reflects an anticipated increase in capital spending above FY2007 levels for leak repairs, bare steel replacement, and cathodic protection. Spending levels for system improvements for increased system capacity and reliability are expected to return to normal after the completion of the system improvement project in Middle Tennessee. We expect to sustain this level of work in FY2008 and FY2009 with an anticipated increase in cost of material and labor. No major changes in overhead rates are anticipated.

Q. HOW WAS THE DIVISION'S GENERAL OFFICE CAPITAL BUDGET DEVELOPED?

A. The capital budget for the KY/Mid-States Division general office was developed in conjunction with Tennessee's capital budget as well as the capital budgets for all other rate jurisdictions within the Division, as part of the Division's total capital budget. The budgeting processes I have described herein applied to all rate division capital budgets that roll up into the Division's total capital budget, including Tennessee and the Division general office.

Q. WHAT IS THE PORTION OF THE DIVISION'S FY2007 CAPITAL BUDGET ALLOCATED TO TENNESSEE?

A. The portion of the approved FY2007 Division's general office capital budget allocated to Tennessee is $37,935.

Q. WHAT ABOUT SUBSEQUENT FISCAL YEARS?

A. Those forecasted amounts are $39,832 for FY2008 and $41,824 for FY2009.

Q. HOW WAS THE SHARED SERVICES TEST PERIOD CAPITAL BUDGET DEVELOPED?

A. The development of the Shared Service capital budget for the forecasted test period is described in Company witness Mr. Greg Waller's direct testimony.

Q. WHAT IS THE SHARED SERVICES FY2007 CAPITAL BUDGET ATTRIBUTABLE TO TENNESSEE?

A. The portion of the approved FY2007 Shared Services capital budget allocated to Tennessee is $647,399.

Q. WHAT ABOUT SUBSEQUENT FISCAL YEARS?

A. Those forecasted amounts are $679,769 for FY2008 and $713,757 for FY2009.

Q. PLEASE DISCUSS TENNESSEE'S OVERALL FORECASTED CONSTRUCTION PROGRAM.

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

1. Equipment
2. Growth
3. Information Technology (IT)
4. Pipeline Integrity
5. Public Improvements

6. Structures
7. System Improvements
8. System Integrity
9. Vehicles

Q. WHAT KEY NEEDS ARE MET THROUGH THIS PARTICULAR BUDGET?

A. System improvement, pipeline integrity, and system integrity investments focus on customer safety and system reliability, and are the highest priorities for capital budgeting. Next are public improvements and state and local public works projects such as highway relocations. Customer growth follows. Atmos Energy continues to build good working relationships with developers, economic development boards, and growing communities to meet the needs of the customer and to accommodate customer growth on its system. Next in order of priority, a modern fleet of vehicles and equipment (backhoes, safety equipment, ditchers, first responder equipment, air compressors, welding machines, etc.) allows us to maintain our system and continue to provide a reliable level of service to our customers. To enhance the level of customer service provided in the field, we also continue to make investments in new technology. Technology is a strategic investment that will enable us to continue improving our business processes, hold down operating costs, and meet the changing expectations of our customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

VERIFICATION

STATE OF KENTUCKY)
)
COUNTY OF DAVIESS)

I, Robert R. Cook, Jr., first duly sworn, state that I am Vice President Technical Services of Mid-States Division of Atmos Energy Corporation, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Testimony of Robert R. Cook, Jr. in support of Atmos Energy Corporation's Petition thereto pre-filed in this docket on the date of filing of this Petition are true and correct to the best of my knowledge, information and belief.

Robert R. Cook, Jr.

Sworn and subscribed before me this 9th day of April, 2007.

Notary Public - State of KY at Large

My Commission Expires: September 26, 2009

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REFISED TARIFF	)	**DOCKET NO. 07-_____**

MICHAEL H. ELLIS

I. POSITION

Q. PLEASE INTRODUCE YOURSELF.

A. My name is Michael H. Ellis. I am Vice President of Marketing of the Kentucky/Mid-States Division of Atmos Energy Corporation.

II. SUMMARY

Q. WHAT SUBJECTS DO YOU PLAN TO COVER IN YOUR TESTIMONY?

A. I will testify on four basic subjects:

1. The Service Activation Charge
2. The Optional Service Tariff (Rate Schedule 250)
3. Interest Paid on Customer Deposits, and
4. The Main Extension Policy.

Q. PLEASE SUMMARIZE YOUR TESTIMONY IN EACH OF THOSE FIVE AREAS:

A. **Service Activation Charge**. Atmos should be allowed to implement a uniform service activation charge of $40 to all rate schedules. It costs no more to turn on a meter at a residence than at a business, yet currently residential customers are charged $40, while all

others are charged $35. Customers who activate service should bear the resulting costs. Residential customers should not subsidize the activation costs incurred by business customers. And a uniform fee is more economical to administer.

Optional Service Tariff (Rate Schedule 250). This tariff should be renamed "Interruptible Sales," because this better describes the substance of the tariff and it is how the company and customers refer to it. Interruptible Sales customers no longer should be required to maintain standby facilities (designed to keep a plant operating during periods of gas curtailment). Curtailments rarely occur anymore, and some of these large, sophisticated customers have decided that the cost of standby facilities outweighs the benefit. Interruptible Sales customers should be required to pay for Measurement Data Collection and Verification equipment, just as Transportation customers are required to do. Both types of customers require the same daily and hourly flow measurement monitoring provided by this equipment.

Interest Paid on Customer Deposits. Atmos currently pays a fixed rate of 6% interest on all customer deposits. This should be changed to a flexible rate of 1% over prime, in order to track interest rate changes (increases or decreases) without the need for further administrative proceedings.

Atmos Main Extension Policy. Atmos should be allowed to change its main extension policy from a footage allowance based upon historical ballpark gas revenue estimates (one foot of 2" gas pipe per thousand cubic foot of estimated annual gas usage) to a policy that better accounts for the actual cost of installing gas pipe from the main to a new customer, the expected revenue from that customer, and Atmos' allowed rate of return.

Using a formula that more accurately reflects the actual costs and benefits of adding a new customer will help to keep existing customers from having to subsidize the cost of adding new customers to the system.

III. EDUCATIONAL AND PROFESSIONAL BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND, AND CURRENT RESPONSIBILITIES.

A. I have an Associates Degree from Hiwassee College and a Bachelor of General Studies from East Tennessee State University. I have worked in the natural gas industry since 1980 and have held various positions in the marketing area. I serve on the Tennessee Gas Association's Board of Directors, where I am currently First Vice President. I have served on the Southeastern Gas Association's Board of Directors and on many other marketing related committees in various state and regional associations.

I have worked for Atmos and its predecessors since 1980. In 2000, I assumed my current position, Vice President of Marketing of Atmos' Mid-States division. My job responsibilities include developing, coordinating, and implementing marketing programs to increase market share, sales and revenue for the Company. I also serve on internal and external committees involved in monitoring technological advances in gas equipment and efficiencies and the resulting change in customer consumption profiles.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS AUTHORITY?

A. No. However, I have filed testimony in support of the Company's past general rate cases in Georgia, Missouri and Virginia.

IV. UNIFORM ACTIVATION CHARGE

Q. PLEASE DISCUSS THE PROPOSED ACTIVATION CHARGE.

A. The Company is currently permitted to assess a $40.00 activation charge for residential customers (Rate Schedule 210), and a $35.00 reconnection charge during normal business hours for all other Rate Schedules.[1] The Company proposes to implement a uniform $40 Activation Charge across all service rate schedules.[2]

Q. WHY SHOULD A UNIFORM ACTIVATION CHARGE BE ADOPTED?

A. Activation of gas service, particularly to customers who have been shut off as a result of delinquency or based upon a seasonal request, is a labor-intensive task. The labor and other costs of service re-activation should be borne by those customers who require such service. It costs no more to re-activate service to a Residential customer than to a Commercial or other type of customer. But Residential customers currently pay more for this service. A commercial establishment (whether it receives sales or transportation service from the Company) should be required to pay the same charge that Residential Customers pay when activation is required.

Implementing a uniform Activation Charge across all rate schedules will bring parity to the Company's tariffs. Customers who use this service should pay what it costs. In addition, a uniform fee is more efficient to administer, thus helping the Company to reduce costs to the benefit of all of its customers.

Q. WHY SHOULD THE ACTIVATION CHARGE BE $40?

A. The TRA has found $40.00 to be a reasonable Activation Charge for Residential Customers (Rate Schedule 210). Atmos merely asks that Commercial and other customers be required to pay the same amount, so that Residential Customers no longer subsidize the cost of this service.

[1] See 2nd Revised Tariff Sheet No. 60 currently on file with the TRA.

Q. EXACTLY WHAT DOES ATMOS PROPOSE FOR THE ACTIVATION CHARGE?

A. Atmos proposes a uniform Activation Charge of $40 applicable to all meter turn-ons at an existing meter location, and also applicable whenever the Company performs a reconnect at a location where gas service has been disconnected. The Activation Charge would not apply for the initial, first time activation of service for a home or business that has not previously had gas service, nor would the charge apply to builders activating gas service on new construction.

V. OPTIONAL SERVICE TARIFF (INTERRUPTIBLE SALES)

Q. PLEASE EXPLAIN THE PROPOSED CHANGES TO THE COMPANY'S OPTIONAL SERVICE TARIFF?

A. The Optional Service Tariff is Rate Schedule 250. We propose changes to three areas of this tariff:

i) Changing the name of this tariff from "Optional" to "Interruptible Sales;"

ii) Elimination of the current requirement for stand-by facilities; and

iii) Addition of a provision that requires customers on this tariff to pay for Measurement Data Collection and Verification equipment.

Q. WHY CHANGE THE NAME TO "INTERRUPTIBLE SALES"?

A. The Company and customers both refer to this as the "Interruptible Sales" rate tariff. The term "interruptible" sales has a commonly understood meaning within the industry. The term "optional" does not.

[2] In Docket No. 05-000258, the TRA authorized an increase in the activation charge for Rate Schedule 210, but denied the request for Rate Schedules 220, 221, 222, 230, 250, 260, 280, 292 and 293.

Q. WHY IS THE COMPANY PROPOSING TO ELIMINATE THE REQUIREMENT FOR CUSTOMER STANDBY FACILITIES?

A. To qualify for interruptible sales service, the current tariff requires that a customer install and operate an alternate-fuel stand-by system, to be used during gas curtailment. Historically, this provision was intended to prevent large volume customers from experiencing plant shutdowns during periods of curtailment. However, curtailments rarely if ever occur anymore and consequently some customers have determined that the cost of constructing and maintaining standby facilities is not warranted. Customers that receive interruptible gas sales service under Rate Schedule 250 are sophisticated large volume customers. They are in the best position to evaluate the risks involved with curtailment of service and decide whether to accept such risks in order to obtain a lower rate and also avoid the cost of constructing and maintaining standby facilities. These large customers have expressed a desire to eliminate the standby facilities requirement. The Company does not want to be in the business of dictating operational practices to its large volume customers, and although the revised tariff *recommends* the maintenance of standby facilities, they should no longer be *required* to qualify for interruptible gas sales service.

Q. WHAT DOES THE COMPANY PROPOSE REGARDING ELECTRONIC FLOW MEASUREMENT?

A. The Company proposes that customers served under Rate Schedule 250 pay to install and maintain Measurement Data Collection and Verification equipment. The tariffs currently require this for the Company's transportation customers. Interruptible sales customers require the same daily and hourly flow measurement monitoring that this equipment pro-

vides. The Company believes that this requirement should be extended to the interruptible sales customers as well.

VI. INTEREST PAID ON CUSTOMER DEPOSITS

Q.

Q. EXPLAIN WHAT THE COMPANY PROPOSES FOR THE INTEREST RATE ON CUSTOMER DEPOSITS?

A. Currently, the tariffs provide for the payment of a flat rate of 6% interest on customer deposits. The Company proposes to substitute a flexible rate of interest, pegged to the prime rate. The new proposed rate would be one percentage point over the prime bank lending rate as published in *The Wall Street Journal* for the last business day of the preceding calendar year. Such a flexible rate would more accurately reflect prevailing interest rates, without the need for further proceedings to amend the fixed rate currently prescribed by the Company's tariffs.

VI. PROJECTED SERVICE ORDER REVENUE

Q. HAVE YOU PREPARED ANY REVENUE PROJECTIONS FOR THE TARIFF CHANGES YOU HAVE DISCUSSED?

A. Yes. Attached to my testimony as Schedule MHE-1 is a report which I, with the assistance of Company employees under my direction, prepared showing such revenue projections.

Q. WHAT IS SHOWN IN THIS REPORT?

A. This report contains a compilation of all service orders by type for all of the Company's Tennessee service areas for a 2-year period from January 1, 2005 to December 31, 2006.

From this compilation, the total number of service orders that would be impacted by the new and/or changed tariff charges for the period was averaged to determine an estimated number of service orders per year. This estimated number was then multiplied by the requested new tariff charge and/or change to yield an estimated annual revenue associated with each charge. The results for each type of affected service order were then totaled to yield the total estimated annual revenue from such charges in the amount of $621,140. This represents a $83,680 increase over the current annual revenues for such charges.

VI. MAIN EXTENSION POLICY

Q. EXPLAIN YOUR PROPOSED CHANGES TO THE MAIN EXTENSION POLICY?

A. The Extension Policy can be found in the General Rules and Regulations. Currently, the Company will run to a Residential customer, free of charge, one foot of 2" gas main per thousand cubic feet of estimated annual gas consumption. This practice was derived based upon the average installation costs and the average customer consumption of many years ago. Labor and material costs have increased substantially since that time, while the average annual consumption of all customers has continued to decline at a steady rate. Rather than derive another blanket rule of thumb, which too ultimately will become obsolete and need to be changed, the Company proposes to replace the stock free footage allowance for Residential customers based strictly on consumption with a procedure requiring the Company to conduct a feasibility study for each and every project. The results of the feasibility study will guide the company's investment decision in this regard. This will ensure that the customer requesting the service will pay, or otherwise justify, the cost to serve them, and lift the investment burden currently borne by existing customers and

rate payers. The feasibility study is the same procedure used currently for all Commercial or Industrial customers who use more than 500 mcf per year, as seen on Sheet No. 63 of the Company's current Rules and Regulations.

The main extension policy has been amended to read simply as follows;

"The Company will install all mains, service lines, metering, and regulating equipment necessary to serve the customer(s) free of charge, provided the revenue expected to be realized produces a rate of return on the investment that is equal to or greater than the minimum allowed rate of return on equity approved in the Company's most recent rate case. This rate of return analysis will be based on a feasibility study performed by the company. This study will include consideration of all costs needed to provide service (materials, company and/ or contract labor, overheads, and applicable taxes). These costs will be compared to the revenue that is either contracted for or can be reasonably expected to be generated by the customers served by the extension. Should this analysis result in a rate of return (ROE) less than the minimum allowed rate of return approved in the Company's most recent rate case, then the customer(s) may be required to remit to the company an Aid-in-Construction, including any applicable taxes, to make up the difference in the actual and allowable rate of return.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

VERIFICATION

STATE OF TENNESSEE)
)
COUNTY OF WILLIAMSON)

I, Michael H. Ellis, being first duly sworn, state that I am Vice President of Marketing for the Mid-States Division of Atmos Energy Corporation, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Testimony of Michael H. Ellis in support of Atmos Energy Corporation's Petition and the Exhibits thereto pre-filed in this docket on the date of filing of this Petition are true and correct to the best of my knowledge, information and belief.

Michael H. Ellis

Sworn and subscribed before me this 5th day of April, 2007.

Notary Public

EILEEN HENDRIX
STATE OF TENNESSEE NOTARY PUBLIC
WASHINGTON COUNTY

My Commission Expires: 10/27/08

Atmos Energy Corporation
Service Fee Revenues

Schedule MHE - 1

Proposed New Fees	Type of Order	2 Yr Avg. Service Orders (All Classes)	2 Yr Avg. Service Orders (Rate Sch. 210)	Current Unit Rate	Proposed Unit Rate	Current Revenue	Attrition Year est. Revenue	Increased Revenue
Activation Fee, new meter sets	MSET	1,801	1,476	$ 40.00	$ 40.00	$ 59,040	$ 72,020	12,980
Activation Fee, new meter sets	TOSI	9,161	8,052	$ 40.00	$ 40.00	$ 322,080	$ 366,440	44,360
Activation Fee, reconnect from delinquency (Rate 210)	RDEL	4,117	3,672	$ 40.00	$ 40.00	$ 146,860	$ 164,660	17,800
Activation Fee, reconnect from delinquency (Other rates)	RDEL	445	445	$ 35.00	$ 40.00	$ 15,575		
Activation Fee, reconnect from seasonal	RSEA	389	194	$ 40.00	$ 40.00	$ 7,760	$ 15,540	7,780
Activation Fee, reconnect from Customer off-request	RCUS	62	43	$ 40.00	$ 40.00	$ 1,720	$ 2,480	760
						$ 553,035	**$ 621,140**	**83,680**

CY2005 Service Orders

Office	MSET	TOSI	RDEL	RSEA	RCUS
Blountville	107	699	412	36	13
Columbia	381	1448	854	19	5
Franklin	284	805	307	12	13
Greenville	13	142	66	27	2
Johnson City	275	1541	892	142	12
Maryville	86	1182	446	22	8
Morristown	126	902	232	44	2
Murfreesboro	381	1640	437	48	2
Shelbyville-Tn	92	347	187	17	
Union City	106	513	414	20	2
Grand Total	1,851	9,219	4,247	387	59
no. of orders for Residential	1,517	8,103	3,788	193	41

CY2006 Service Orders

Office	MSET	TOSI	RDEL	RSEA	RCUS
Blountville	96	682	314	37	7
Columbia	404	1449	826	30	1
Franklin	258	863	319	21	14
Greenville	28	145	40	25	3
Johnson City	247	1458	544	137	20
Maryville	120	1087	396	24	8
Morristown	111	841	196	41	4
Murfreesboro	259	1718	720	41	5
Shelbyville-Tn	123	389	296	12	
Union City	104	471	335	22	3
Grand Total	1,750	9,103	3,986	390	65
no. of orders for Residential	1,435	8,001	3,555	195	45

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REFISED TARIFF	)	**DOCKET NO. 07-_____**

RONALD B. EDELSTEIN

I. INTRODUCTION OF WITNESS

Q. Please state your name and business address.

A. My name is Ronald Edelstein. My business address is 1700 South Mount Prospect Road, Chicago, IL 60618.

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

A. I am employed by the Gas Technology Institute ("GTI") as Director, State Regulatory Programs.

II. SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. I will testify in three areas:

- I will summarize the history of the Gas Technology Institute ("GTI") and its predecessor, GRI;
- I will describe the benefits that natural gas consumers receive from GTI and its Gas Consumer Benefits Research and Development; and
- I will request that the Tennessee Regulatory Authority ("Authority") give Atmos Energy Corporation ("Atmos Energy") the authority to collect a surcharge from its customers to fund Gas Consumer Benefits R&D.

III. WITNESS QUALIFICATIONS

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Florida with a BS in Aerospace Engineering (1969), Rensselaer Polytechnic Institute (RPI) with an MS in Engineering Science: Solid Mechanics (1972), and another MS from RPI in Engineering Science: Environmental Science & Technology (1977). I began my employment with Pratt & Whitney, working as a structural engineer on gas turbines for 8 years, then Planning Research Company as an engineering consultant to the U.S. Department of Energy for three years, then the Solar Energy Research Institute as an R&D planner for three years. I joined the Gas Research Institute ("GRI") (now Gas Technology Institute) in 1983 as an R&D planner. I have also held positions as Director of Planning and Director of Sales. My current position is Director of State Regulatory Programs.

Q. Have you previously filed testimony before any regulatory commission?

A. Yes. I have filed testimony before regulatory commissions in the states of Georgia, Kansas, Massachusetts, Tennessee, Missouri, Oklahoma, Virginia, and Michigan.

IV. OVERVIEW OF GTI R&D

Q. What is "gas consumer benefits R&D"?

A. This is a specific type of R&D, in which the applicable technologies result in benefits that primarily accrue to gas consumers. These benefits include lower energy use and energy bills (through increased-efficiency appliances and equipment), increased safety, enhanced deliverability, and contained costs for distribution operations and maintenance (O&M).

Q. What is the GTI?

A. Natural gas local distribution companies ("LDCs") and pipeline companies, in agreement with the Federal Energy Regulatory Commission ("FERC"), formed GRI in 1977 in the midst of natural gas curtailments and a predicted gas supply shortage. That organization, now known as GTI, directed 75% of its initial research efforts toward increasing supply and lowering the cost of acquiring natural gas. This emphasis decreased in the 1980s to about one-third of our budget as a "bubble" developed in natural gas supply.

Q. What were the results of this effort?

A. The primary focus of the R&D has been on unconventional gas (coalbed methane, tight gas sands, and Devonian shale). First portrayed as a "gas bubble", the supply shortage turned into a surplus, eventually resulting in substantial savings to gas consumers. Production of coalbed methane, called "moonbeam gas" by its detractors, jumped from under 50 billion cubic feet (Bcf) /year in the 1980s to over 1,700 Bcf /year by 2006. During the same period, production of tight sands gas went from 300 Bcf /year to over 4,500 Bcf /year. Devonian shale production went from a negligible level in the 1980s to 800 Bcf in 2006. R&D performed by GTI (amongst other initiatives) reduced the technical risks inherent in finding and recovering these unconventional gas resources and aided in bringing them into mainstream production.

In the area of conventional supply, GTI developed an imaging technology to produce high-resolution seismic "pictures" of subsurface features. This enables producers to find natural gas that had been overlooked between existing wells.

Q. What is GTI's emphasis on end-use R&D?

A. Initially, end-use R&D was about 20% of GTI's budget; then shifted to about half

of our budget in the 1980's and 1990's, and is now about 25% of our budget. The focus has been on increased-efficiency, lower-emissions equipment (for traditional end uses) like residential/commercial space heating and water heating equipment and industrial process heating, steam production, and combined heat and power applications

Q. What results has GTI had with its research into residential space heating?

A. Prior to GTI, typical home furnace efficiency was in the range of 60% to 70%. With the introduction of the 96%+ efficiency fully condensing pulse combustion furnace, GTI raised the bar and encouraged manufacturers to develop options for the fully condensing furnace. Today, condensing furnaces with over 90% efficiency account for about 25% of residential furnace sales; the pulse combustion furnace and its derivatives are still the most efficient furnaces on the market.

Q. Can you give a Tennessee-specific example?

A. In Tennessee, over 65,000 fully condensing furnaces were sold to residential consumers between 1995 and 2000 (according to Gas Appliance Manufacturers Association data) alone. These have benefited Tennessee consumers who purchased the devices by net present value of savings of $331 per furnace, even taking into account the higher capital cost of the more-efficient furnaces, compared to a 78% efficient gas furnace. This has saved Tennessee residential consumer over $21.7 million dollars, net present value. Additionally, in 2002 alone over 0.5 Bcf of reduction in gas load was achieved, resulting in savings to all Tennessee consumers because of reduction in gas demand.

Q. How do these savings compare to the cost of the GTI FERC R&D program?

A. Over the same time period, 1995 – 2000, the ***entire*** GTI FERC R&D program cost

all Tennessee residential gas customers $11.71 per customer for the six years indicated, or about $12.8 million. The benefit-to-cost ratio of just one GTI-developed technology, then, compared to the entire cost of the R&D program, was 1.7 to 1. The benefit-to-cost ratio for all 500 technologies that GTI developed and brought to the marketplace is substantially higher.

Q. Do you have any idea what this total benefit-to-cost ratio might be?

A. Yes we do. From Exhibit No. 1, a national analysis of the benefit-to-cost ratio of GTI's FERC R&D program, reviewed by FERC in May, 2004, our overall consumer benefit-to-cost ratio is 8 to 1.

Q. Are there any projects explicitly designed for the low-income gas customer?

A. Yes, GTI is working on two projects that could directly benefit the low-income gas customer. First, we have under development a combination water heater/ space heater system for residential homes that uses a low-cost, fully condensing, high-efficiency (greater than 93%) water heater to provide both water heating and space heating needs for the home. It would eliminate the need for a space heater in smaller homes and apartments. This project has only been tested in the laboratory, and needs additional field testing in a real-world environment to validate proof of feasibility. Second, we are working on a heating-only absorption gas heat pump that has a heating efficiency of 120-140%. If the capital cost of the unit could be significantly reduced through R&D, this unit could provide substantial energy savings to the low-income gas customer.

Q. What about commercial applications of GTI's R&D?

A. GTI funding has produced a new generation of natural gas engine-driven, absorption, and desiccant-based cooling systems. First-generation single-effect

absorption cooling systems had coefficients of performance (COPs) of 0.6; the efficiencies of these new systems (developed as a result of GTI and other R&D) are verified for COPs ranging from 0.8 to 1.2, producing gas savings as well as lowering peak electric loads.

Q. What about industrial applications of GTI's R&D?

A. GTI-funded advancements in industrial combustion equipment helped increase the efficiency and lower the emissions from process heating and boiler steam production markets. For instance, in 2001, GTI demonstrated oscillating combustion on a forging furnace with a 49% decrease in NOx emissions and a 3% decrease in fuel usage, while keeping the average CO emissions below 100 ppm; this technology has applications to a wide range of high-temperature industrial furnaces.

Q. Would the private sector have invested in this R&D without the existence of GTI?

A. Not likely. Current laws and regulations in general allow far lower efficiencies and allow higher NOx emissions. Manufacturers generally have no incentive – cost or otherwise -- to produce such efficient or environmentally friendly equipment above and beyond regulatory requirements. Unfortunately, energy efficiency in and of itself does not sell well in the U.S. market, and so is not invested in by manufacturers.

V. GTI'S CONTRIBUTIONS TO SAFETY

Q. How does GTI contribute to safety?

A. Typically, as new equipment is developed, systemic gaps can cause problems in the areas of safety and reliability. For example, gas furnace corrosion is dependent on

vent system design and installation but, typically, the meter and upstream service is handled by the LDC, the furnace by the manufacturer, and the vent system by the installers. As manufacturers began to offer partially condensing furnace designs with 80% to 90% efficiencies, the heat exchanger and vent system began to experience corrosion problems which did not exist in the lower-efficiency furnaces sold before 1981. GRI designed improved heat exchangers and by developed vent installation guidelines that minimized the amount of condensation. GRI also developed furnace installation instructions that are included in every mid-efficiency residential furnace sold in the U.S. and its vent design procedures have been incorporated into the National Fuel Gas Code.

Q. Do you have other examples of safety-related R&D?

A. Yes. Other safety-related research resulted in the elimination of "false positives" from CO monitors and developed scientific data for acceptable NOx levels for indoor air quality. In 1998, GTI introduced a test methodology to evaluate new water heater designs that could reduce or prevent flammable vapor incidents when flammable liquids are improperly stored adjacent to the heater.

Q. Would the private sector have invested in this R&D without the existence of GTI?

A. That is unlikely. The problems fell "between sectors"; that is, an ultimate problem resulted from perfectly acceptable and safe technologies not being able to co-exist in the same environment. GTI was uniquely placed to bridge that gap and provide successful solutions.

Q. What have been the results of GTI's R&D efforts to increase the safety and reduce the cost of gas transmission and distribution systems?

A. GTI research focused on the fundamentals of polyethylene (PE) pipe, especially fracture mechanics, failure analysis, and joining integrity in an effort to lower the technical risks and increase the confidence in PE pipe. When GTI was created, plastic pipe comprised about 20% of all new distribution mains; today, non-corroding PE, with a cost of about half that of coated steel pipe, comprises over 90% of all new main installations.

Q. Are there other examples of operations-related R&D?

A. Yes. Most gas mains and services installed in the 1970s used trenching tools which tore up the surface and subsurface, increasing restoration costs and risked penetrating near-surface utility lines. Six years of GTI research yielded the first set of guided horizontal boring tools which are now in general use throughout the gas industry, providing substantial O&M cost savings.

Q. Has GTI R&D improved operational safety?

A. Yes. For instance, GTI developed the optical methane detector (OMD). This device works by directing a laser beam from a vehicle to quickly and reliably scan streets for methane leakage. Many LDCs conduct required leak inspections by a walking survey; the OMD will allow LDCs to convert to driving surveys with a significant reduction in response time and reduction in labor cost. Also, GTI's gas transmission R&D introduced low-NOx controls for reciprocating engines and gas turbines used at large compressor stations.

VI. GTI'S REMAINING CHALLENGES

Q. What R&D issues and challenges remain for GTI?

A. I believe there are substantial remaining issues for gas supply, delivery, and use that have major impacts on gas consumers, dollarized benefits, environmental benefits,

and safety benefits. There are many vital reasons for continuing the work GTI has begun. I will describe a few of the challenges that are ahead of us.

Advanced laser-based drilling and fracturing technologies are in the basic research stage and require a substantial amount of funding to carry them forward.

Totally new sources of natural gas supply may be required to ensure domestic gas supply security. A vast supply resource may be in natural gas hydrates but DOE's basic research has not yet lowered the technical unknowns and risks to permit even exploratory production.

Substantial research is needed to enhance the confidence in current nondestructive evaluation (NDE) techniques used to inspect natural gas pipelines. A substantial portion of the national pipeline system is not "piggable"; that is, valves, bends, turns, reduced-diameter pipe sections, or other obstructions prohibit internal inspection by moving a mechanical device, or "pig", through the pipe. Further, current NDE tools and technologies can detect pipe wall thinning and circumferential flaws but other types of flaws, such as stress corrosion cracking and axial flaws, are very difficult to detect. Only additional R&D can ameliorate these and other issues such as pipeline coatings lifetime determination and microbiologically influenced corrosion.

Despite 20 years of research, we are still unable to reliably locate buried plastic pipe under all types of soil and moisture conditions. Tracer wire laid above the pipe is helpful but, since it can corrode or break, locating plastic pipe by tracer wire is not always reliable.

The guided horizontal boring tools described earlier are guidable from point to point as well as steerable; however, they still cannot "see" in front of themselves

underground. The ability to locate sewer pipes, utilities and other obstacles is still an important and unresolved safety issue.

Infrastructure Security is at the forefront of national attention following the events of 9/11. R&D in this area is still uncharted; yet the "cyber" and physical security of our natural gas infrastructure is critical to gas consumers and the national interests.

Environmental issues surrounding old manufactured gas plant sites will cost millions of dollars to clean up. The ability to rapidly detect PCB's that may be in gas systems is another environmental challenge.

End-use programs that are under development but which will not be able to proceed without continued funding include a low-cost, fully condensing residential water heater which is over 92% efficient, a residential heating-only absorption-based gas heat pump with a heating COP of 1.4, and an industrial super-boiler with efficiencies over 96% currently being funded by DOE as a laboratory sub-scale pilot project. The super boiler has entered limited field testing.

A low-cost residential/commercial fuel cell is still not on the horizon. The private sector and DOE are developing a host of technologies for distributed generation, including larger fuel cells, reciprocating engines, and microturbines. However, their successful integration into the gas distribution system and electric grid is still not assured, emissions and costs (compared to central station generation and electric T&D system upgrades) need to be analyzed, and their impact on the reliability of the gas and electric infrastructure has not yet been documented.

VII. GTI'S ONGOING EFFORTS TO SUPPORT THE COMPANY'S CUSTOMERS

Q. What specific types of research projects is GTI expecting to research on behalf of Atmos Energy and its customers?

A. There are at least fourteen R&D projects GTI is planning that support Atmos Energy's natural gas customers. Ten of these projects are in the operations area and four in the end-use area. The objectives of the operations projects are to increase safety and reduce operating and maintenance costs. The objectives of the end-use projects are to increase the efficiency and enhance the safety of gas use equipment.

Q. What are the Operations Projects Atmos Energy is planning to fund?

A. These projects are: (1) Miniature Methane/Ethane Detector for Leak Surveys: Previous gas-industry-sponsored work has resulted in the development of optical methods of finding gas leaks by detecting methane and, more recently, ethane. The presence of ethane in gas leak positively confirms that the leak is related to natural gas, and not "swamp gas" or other sources of methane. This confirmation eliminates the cost of gas sampling and analysis, minimizes multi-party discussions and time for the gas industry, thus reducing the cost of operations. However, detection of very low levels of ethane in natural gas leaks is very challenging. Initial experiments conducted with the previously developed proof-of-concept system for ethane have demonstrated the viability of detection of ethane content in natural gas plumes under realistic leak conditions. The proof-of-concept tests were successful in detection of ethane presence in low concentration (30 ppm methane) natural gas plumes. The best sensitivity of these tests showed the detection capability of ethane to 200 ppb. These Concept Evaluation Unit tests used an

optical modulator for ethane detection which was too large to be integrated into a Portable Methane Detector (PMD) being developed under a separate project.

It was decided that the first step towards a practical ethane instrument would be to develop a miniaturized ethane modulator, the main component of the PMD. This miniaturized Ethane/Methane Detector (EMD) project is now coming to a successful conclusion. Although the work is not yet fully complete, an ethane capable modulator (approximately one cubic inch in size) has been developed. Thermal testing under controlled, laboratory conditions showed that ethane detection would be much more difficult (approximately three times more demanding than methane-only detection). Preliminary tests have shown that the miniature EMD modulator is capable of operating at or near the same sensitivity level as the much larger unit used in the concept evaluation tests.

The next logical step in the EMD development is to miniaturize other components of ethane detection and integrate the ethane system into the PMD unit.

(2) Hand-Held Acoustic System for Plastic Pipe Location: Past GTI-sponsored research has successfully demonstrated that active pulsed-echo sonic technology can detect and locate small-diameter pipes, including polyethylene (PE) pipes, to the depth of 5 feet in a laboratory environment. In addition, attenuation measurement data sets collected by a third party from soils around the United States were applied to the current system to perform mathematical analysis on the applicability of the system. This analysis showed that a laboratory-grade acoustic system has the potential for detecting 1.5 and 4-inch diameter pipes at a depth of 3 ft for 50% and 100% of soils in the United States, respectively.

In this project, the laboratory-grade pulse-echo pipe location system will be designed into a hand-held system for application to buried pipe detection. The system will include data acquisition and processing boards powered by a battery, transducer and receiver arrays in a cane-like setup, and data display system. The system will be tested with participating utilities for detecting buried pipes, 1 to 6 inches in diameter at depths from 6 inches to 10 feet. The data collected at each location will require less than two minutes and the analyzed data will be displayed to the system operator.

(3) Remote Laser Leak Surveys: Current leak surveys of natural gas distribution systems involve use of "flame packs" and the mobile Optical Methane Detector (OMD). Both of these leak location technologies require that the detector be brought in contact with the gas leakage plume, a very labor-intensive effort. The Laser Line-scan Camera (LLC) technology being developed under the on-going GTI-managed, utility-sponsored project with Laser Imaging Systems, Inc. (LIS) and AVISYS, Inc. allows "stand-off" inspection of both mains and service lines out to distances of 30 meters from a moving vehicle. The initial results of the on-going project are very encouraging. However, the detection limit, inspection speed, operator interface and packaging of the system will require further evaluations/improvements to make the LLC an attractive alternative to the current leak survey practices.

The primary objective of the proposed project is to evaluate/improve the detection limit and inspection speed of the LLC, and to make the system more user-friendly. This will be accomplished by conducting additional testing in laboratory, in field, and upgrading various components of the current LLC design.

In the current, on-going project, a prototype LLC was designed and built. This system used two semi-conductor lasers, one at a wavelength strongly absorbed by methane and the other at a wavelength for which the gas is essentially transparent. These two lasers are scanned across the field-of-view of a 32-element detector array that is projected from a turret atop a van.

The line scan field-of-view of the detector array is displayed on a conventional video image of the area being inspected. The operator controls the direction of the LLC field-of-view. When the line scan passes over an area on the surface where there is methane gas, an upward deflection of the line occurs. The higher the gas concentration, the higher is the line-scan deflection. By orienting the viewing direction of the LLC to maximize the line scan deflection, the operator is able to pinpoint the location of the leakage plume.

The specific technical issues to be resolved in the proposed project are: (1) Evaluation of detection limit and improvements: Studies involving the effect of laser pulse width and signal processing sample rates on the leak detection limit will be conducted. Improvements to the detection limit will be implemented, (2) Range limitations: Various designs of the collection optics will be investigated to increase the detection range of the LLC system, (3) Establish maximum survey speed: Trade-offs between line-scan frequency and detection sensitivity will be performed to determine the maximum survey speed for the LLC, (4) Packaging/operator interface improvements: Special attention will be directed towards reducing the size and power requirements of the LLC system. The system package will be hardened for routine field application, and the operator interface will be simplified.

(4) Integration of Electromagnetic and Acoustic Obstacle Detection Systems for Utility Construction Operations: This project focuses on integrating the drill-head mounted electromagnetic (EM) obstacle detection sensors under development at Maurer Technology, Inc. (MTI) with the surface deployed acoustic sensors being developed by Folsom Research, Inc. (FRI). The objective of these projects is to provide real-time detection of underground utilities during horizontal directional drilling (HDD) operations during installation of pipes. The current technology development is funded by GTI with cofunding from several utilities. Together, these technologies have the potential to prevent striking and damaging buried utilities during creation of the pilot hole or during back reaming operations. The warning and detection circuitry would be electronically tied to the drill string rotation and forward advance controls so the drill string can be automatically stopped before a strike can occur. By combining these two technologies into a single, integrated display it would be possible to successfully detect buried, energized cables, as well as steel, plastic, clay and concrete pipes.

The specific objectives of this project will be to: (1) Improve the noise generation capability for acoustic technology, (2) Design a wireless radio link between the matrix of acoustic sensors and their processor to simplify field operation, (3) Reduce the size of the EM electronics and sensors mounted in the jet head for use in smaller utility directional drilling rigs (4) Integrate the data acquisition, processing and display of the acoustic and EM sensors, (5) Work with leading drill rig manufacturers to incorporate automatic stoppage of drill string rotation and advance when obstacles are detected within a few feet of the boring head, and (6) Conduct field trials of the integrated obstacle detection system.

(5) Product Development of an Obstacle Detection System Using Ground Penetrating Radar (GPR): Currently there are no commercial instruments available to sense the presence of obstacles in the vicinity of a horizontal directional drilling (HDD) bore used for installation of pipes. In the on-going project with Vermeer Manufacturing Company under the sponsorship of GTI, a new advanced GPR system, mounted on the drill head of an HDD that is capable of detecting obstacles in the proximity of the bore is being developed. It is expected that this initial on-going project will provide a pre-production system suitable for only one size HDD machine. This new GPR offers a step forward in the detection of obstacles in the HDD operations. However, this system will require further enhancements to be suitable as a commercially acceptable product from it current pre-production status.

The objective of the proposed work is to produce a fully commercial version of the drill head mounted GPR applying the results of the past developments.

(6) Inspection Platforms for Unpiggable Lines: In response to a number of significant pipeline incidents in recent years, the federal government has imposed new requirements on gas transmission pipeline operators to assess the condition of their facilities. One of the methods used to examine a trans-mission pipeline is in-line inspection (ILI), also known as "smart pigging." Many transmission pipelines are designed to accommodate pigs. Similar requirements are expected within the next few years for LDC-owned transmission pipelines. Unfortunately, the majority of LDC-owned transmission or higher pressure lines contain short-radius bends, plug valves and other obstacles that render them unpiggable with traditional pigging devices.

The following system requirements were identified:

- 12" to 24" diameter; up to 0/5" wall thickness
- Five mile run length
- Self-powered
- Operate in gas flow velocities of 25 feet per second to 150 feet per second
- Able to negotiate plug valves, mitered bends, compound 90 degree bends, and diameter reductions of at least two sizes
- Detect defects resulting from both internal and external corrosion through the use of MFL sensors
- Minimize the number of hot taps
- Minimize extent of excavations needed for launching

In 2002, a preliminary investigation was conducted into the feasibility of developing integrated locomotor/sensor robotic system for the inspection of presently unpiggable LDC-owned pipelines. Two proposals were funded, from Foster-Miller/PII and Automatika/Maurer Engineering. Each of these teams produced preliminary designs. Additional R&D is required to further develop the systems.

This R&D will involve a Phase II effort to develop and test the following:

- Foster-Miller/PII System
  - Locomotor and inspection sensor application
  - Performance testing
- Automatika/Maurer Engineering System
  - Test critical technologies
  - Wireless

- Locomotor
- In-pipe battery recharge
- Inspections sensor application

(7) Safe Reliable Operation and Maintenance of Aldyl A Plastic Gas Pipe Systems: Plastic pipe was introduced to the natural gas industry in the early 1960's. With its many advantages over steel pipe (including lower cost, lighter weight, easier handling, speedier installation and joining, no corrosion problems, and no welding), it quickly became the material of choice for gas distribution systems. Some of these early materials have, and continue to, perform well. However, significant technology improvements since the 1960's have made the current generation of plastic piping materials highly rugged and reliable, with many types of plastic piping having estimated life expectancies in excess of fifty years. While new plastic pipe materials perform very well, some of the early materials could be problematic under certain applications.

This project has as its intent the identification of specific problems and issues associated with the use of Aldyl-A pipe systems (pipe and fittings). The objectives of this project are to:

- Determine the performance characteristics of Aldyl-A materials, by year of manufacture, through laboratory testing of samples and feedback provided by participants
- Determine the estimated remaining useful life of the product materials by year of manufacture, including the influence of such factors as operating pressure, temperature, surface scratches, defects, type of backfill, and other conditions that may impact on life expectancy.

(8) Alternative Methods for Pavement Cutting: Most of the current pavement cutting and restoration procedures use jackhammers, pavement saws, and backhoes for cutting and moving the asphalt and concrete layers. These methods are noisy, restricted to daylight operation, produce a risk of injury, and can cause damage to adjacent uncut pavement.

This project focuses on evaluating alternatives to these methods with the objectives of eliminating the drawbacks of existing methods and presenting improvements in efficiency and cost-effectiveness. The proposed work consists of two phases:

- Phase I: Evaluate several alternative technologies. These technologies will include laser cutting devices, thermal cutting methods, microwave devices, water jets, and the latest developments in mechanical cutters such as pavement breakers and diamond saws. These methods have varying degrees of efficiency and operating costs. The work of this phase will also include laboratory evaluation and specification development for the most promising technology.
- Phase II: Acquire, design, and implement engineering modifications to produce a prototype of the selected method which meets the specifications and requirements of Phase I. Coordinate field tests with the participating utilities for evaluating the performance of the device under realistic operating conditions.

(9) Micro-Excavation System Applications: This project has as its intent the development of equipment, tools, sensors, materials, and procedures to access, examine, and maintain buried pipe through two, two-inch diameter excavations. The objectives of this project are to:

- Develop a prototype articulating device to hold sensors, toos, and light sources, and to successfully deliver them through a two-inch opening down to a buried pipe.
- Evaluate prototype sensors to examine a section of pipe through a micro-excavation opening to inspect for corrosion, coating conditions, and wall thinning.
- Evaluate the effects of creating small voids around the pipe during micro-excavation, and determine methods to sufficiently backfill and compact micro-excavation openings.
- Evaluate existing anaerobic sealing tools and procedures for use in micro-excavations.
- Develop methods to install anodes on pipes for cathodic protection through micro-excavations.
- Evaluate methods to abandon gas services through micro-excavations.

(10) Service Applied Main Stopper: This project focuses on lowering the costs associated with emergency gas shut-off due to third-party damage, through the development of an innovative tool and method of use. Current field practices to isolate the damaged section of pipe involve multiple excavations to set stopping or squeeze-off equipment as well as multiple customer shut-offs. The Service Applied Main Stopper (SAMS) project objectives are to: (1) Develop technology and the necessary tools that will utilize existing customer service lines and meter sets to isolate pipe ruptures and stop the flow of gas, (2) Reduce costs by minimizing excavations through the use of the SAMS "no-dig" technology, and (3)

Decrease the isolation area, which will reduce customer outages and impact due to third-party main damage

Service lines allow safe entry to the gas main. By inserting a stopping device through the customer's meter valve, crews can isolate the damaged section between neighboring customer service lines and stop the flow of gas.

Developing this technology will resolve two major issues: (1.) the costs associated with third-party damage repairs and (2.) the ability to isolate and stop a ruptured gas main. The costs involved with third-party damages are high due to the labor associated with the number of excavations required to isolate the damaged area. Addressing the ruptured main, without having to make any excavations, would allow crews to decrease the time required to stop the blowing gas, decrease total repair allocations and substantially minimize the costs in restoration of pavement and landscaping. All of this will be performed remotely, at the customer's meter, which also increases crew safety.

Q What are the end-use projects being proposed?

A. These projects are: (11) Codes and Standards Program: The gas industry recognizes the importance of ensuring that gas technologies comply with appropriate codes and standards. Maintaining the option for cost-effective gas technologies is a critical, but often unseen, element of the broader product R&D process. Working closely with the gas industry and research partners, this program will develop and present in-depth technical information needed by codes and standards organizations and regulatory bodies. Further, this program will proactively investigate systemic issues, like mid-efficiency furnace venting, that

arise unanticipated from the use of advanced gas technology to ensure that gas continues to remain the safe, reliable, and environmentally benign energy option.

(12) Reduced-Cost Residential Desiccant Unit Development: GTI initiated a residential desiccant dehumidifier project with the intention of characterizing and field testing a reduced-cost unit. Preliminary design has been completed to accommodate the burner system as developed by the manufacturer and to better integrate and simplify the concept to create a cost-effective unit for the general residential home market, including Tennessee. The proposed program would have two phases. The first phase would encompass design finalization, including DFMA (design for manufacturing and assembly) analysis, control application and refinement (including a staged or modulated combustion system), integration of a heat recovery option, full ASHRAE/ARI (American Society of Heating, Refrigeration and Air-Conditioning Engineers/American Refrigeration Institute) characterization of the unit, and ANSI (American National Standards Institute) certification testing. The second phase of this program would be a field testing phase that would validate the various model configurations in field applications.

(13) Unitary Natural Gas Engine-Driven Combination Heat Pump and Standby Generator: The objective of this project is to develop a low-emission natural gas engine-driven generator set that provides high-efficiency heating and cooling for the residential customer and supplies electricity to meet standby electrical loads. The space conditioning system could thus continue to operate even during periods of electrical power outages or brownouts. Both laboratory development to verify proof-of-concept and field testing to validate (efficiency, emissions, durability) performance under actual field conditions are required.

(14) Superboiler Development: The objective of this project is to field test the Superboiler which has up to 94% energy efficiency, NOx and CO emissions less than 5 ppm, and reduced footprint and weight specifications. This technology has direct applications not only to the industrial market but as the forerunner of low-income ratepayer residential multifamily dwelling boiler applications

Q How will the projects be chosen?

A. Atmos Energy will provide the authorization as to where their research-funding dollars are applied from the list of candidate projects. In future years, the selected projects will be funded to their conclusion.

VIII. FUNDING GTI

Q. How is GTI currently funded?

A. Since it was established in 1977, GTI has been funded through a FERC-authorized surcharge on gas transported over the interstate pipelines. Atmos Energy customers have supported GTI R&D through upstream suppliers prices which were in turn charged under Atmos Energy's retail cost of gas. The FERC has discontinued that charge in mid-2004 and has transferred the funding authority to the state jurisdiction. Thus, GTI no longer collects FERC-approved funds, but relies instead on state-based approval of R&D surcharges for gas-consumer-interest R&D

Q. What level of funding is GTI seeking from local distribution companies that are coming before their state jurisdictions in request of general base rate changes?

A. GTI is recommending that revenues equivalent to 1.74 cents per MMBtu be collected from Atmos Energy's natural gas customers in its Tennessee service area.

The 1.74 cents is also consistent with the Federal Energy Regulatory Commission (FERC) approved charge from the GTI R&D program up until 1998, when parties agreed to reduce and then eliminate the FERC-approved charge. This is also the rate GTI has recommended in cases before other state commissions. Atmos Energy would thus choose from amongst the list of projects just described. As these are multiyear projects and new projects will be proposed in following years, this amount of funding would be required each year.

Q. What other states are already participating in GTI's state funding program?

A. There are 22 states currently authorizing research funding for gas-consumer-interest R&D for at one or more of the LDCs in their state. These are Alabama, Arizona, California, Delaware, Florida, Idaho, Illinois, Kentucky, Mississippi, Minnesota, New York, New Hampshire, New Jersey, New Mexico, New York, North Carolina, Oklahoma, Oregon, Pennsylvania, Virginia, Washington, and Wyoming.

Q. Would you expect the dollars collected to be earmarked for GTI?

A. Not necessarily. Atmos Energy will have the ability to (1) choose specific R&D projects that will benefit its customers and (2) place these R&D dollars with GTI or other research organizations for gas-consumer-interest R&D purposes.

IX. CONCLUSION

Q. What do you have to say in conclusion?

A. Over the past twenty-five years, gas consumers have realized billions of dollars of benefits from GTI's R&D. Our overall consumer benefit-to-cost ratio is 8:1 (see the Benefits exhibit), including all R&D costs and benefits from commercialized products and services. Based on our over twenty-year track record of maintaining

benefit-cost ratios of over 8:1, I believe that in the future GTI can sustain this benefit-to-cost ratio for Tennessee gas consumers.

The guidance from public utility commissions and LDCs as well as others (such as consumer advocates and environmental groups) will ensure the selection of specific R&D projects that are appropriate to and offer benefits for Tennessee gas consumers.

Continuation of GTI's R&D programs is absolutely critical for the continued supply, transport, and use of natural gas as a current and future environmentally benign, domestically produced energy source for Tennessee and for the United States.

Q. Does this conclude your prefiled testimony?

A. Yes it does.

BEFORE THE
Tennessee Regulatory Authority

In the matter of Atmos Energy Corporation)
of Dallas, Texas, for authority to file tariffs)
reflecting an increase in rates for gas service)
provided to customers in the Tennessee service)
area of the Company)

AFFIDAVIT

STATE OF ILLINOIS)
) ss
COUNTY OF COOKE)

RONALD B. EDELSTEIN, first being duly sworn, deposes and says that he is Ronald B. Edelstein referred to in the document entitled "Direct Testimony of Ronald B. Edelstein" before the Tennessee Regulatory Authority of the State of Tennessee, and that the statements therein were prepared by him or under his direction and are true and correct to the best of his information, knowledge and belief.

Ronald B. Edelstein
Director, State Regulatory Programs
Gas Technology Institute

Subscribed and sworn to before me, this 1st day of May, 2007.

Notary Public

My commission expires 08-01-08

OFFICIAL SEAL
DOLORES CLARK
NOTARY PUBLIC - STATE OF ILLINOIS
MY COMMISSION EXPIRES:08/01/08

EXHIBIT
No.1

GRI-04/0061

Benefits of GRI RD&D Results That Have Been Placed in Commercial Use in 1999 Through 2003

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Abstract

This report provides brief descriptions for sixteen new GRI RD&D products commercialized in 2003 and two enhancements of previously introduced products. The economic benefits are quantified for eighty-one items commercialized between 1999 and 2003 that are known to have produced significant economic benefits for their users. The calculated ratio of the benefits to gas customers to total GRI costs incurred in 1999 through the end of 2003 was 8.0 to 1.

Acknowledgments

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Introduction

Between January 1, 2003 and December 31, 2003, sixteen GRI RD&D results were placed in commercial service. In addition, enhanced versions of two previously commercialized items were placed in use*. Those items are listed in Table 1, and brief descriptions of the eighteen items are included in Appendix A. With these new additions, some 133 GRI RD&D results have entered the commercial marketplace during the 5-year period between January 1999 and December 2003. The full list of the 133 items is included in Appendix B. As one measure of the value of the GRI RD&D program, the economic benefits accruing to users of 81 out of the 133 products can be compared to the total outlays of GRI during the past five years. This paper highlights the new GRI products that have entered the market during the past year and presents the results of the benefit-to-cost analysis of GRI's RD&D results during the past five years.

Notable additions to the list of GRI RD&D results placed in commercial service in 2003 include:

- Upgrades to the National Fuel Gas Code relating to the requirements for combustion air supply and corrugated gas vent connectors.
- A software tool to estimate critical information such as annual or monthly loads and costs associated with air-conditioning, heating, and on-site power generation for commercial buildings.
- A low-NO_x, high-heat-transfer industrial burner that provides significantly higher heat transfer to furnace loads, higher furnace efficiency, and lower flame and combustion products temperature.
- Paralleling switchgear for distributed generation systems that reduces the barriers to installing gas-fired DG equipment.
- A report on the safety of vacuum excavation equipment used to remove soil from holes that are being dug by distribution companies.
- Evaluation of alternate methods for removing cyanide wastes from former manufactured gas plant sites.
- A chemical fingerprinting methodology for enhanced environmental forensic analysis to characterize complex manufactured gas plant wastes.
- A software package to evaluate potential adverse environmental effects of pipeline crossings of streams.
- Technology to improve the quality of the cement used to seal the annulus between the casing and surrounding rock in gas wells.
- Development of produced water atlases for 10 major gas-producing states and a handbook on actual produced water management practices and disposal economics for 26 basins.
- A comprehensive report on the gas potential of the Lewis shale formation of the San Juan Basin in Colorado and New Mexico.

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* For tangible products (hardware, software) we interpret "commercialized" to mean that the product is commercially available, economically viable without subsidies, and has been sold in meaningful quantities. For the less tangible reports and other information products, we require that the products have been used in a commercial enterprise and have generated demonstrable economic benefits to the users. "Enhanced" products have been augmented in a commercially significant way, with or without GRI support. The augmentation may be a technical improvement in a product line, expansion of a product catalog, or expansion of the product market into new areas not available to the original product at its time of introduction.

Table 1. GRI RD&D Results That Have Been Placed in Commercial Use in 2003

RESIDENTIAL
1. Upgrades to the National Fuel Gas Code

COMMERCIAL
2. Building Energy Analyzer™

INDUSTRIAL
3. Low-NO_x Combustion System for Glass Furnaces *
4. Low-NO_x, High-Heat-Transfer Burner
5. LNG Interchangeability in Burners

POWER GENERATION
6. Distributed Generation Switchgear
7. Guidebook to Gas-Fired Distributed Energy Technologies

DISTRIBUTION
8. Safety of Vacuum Excavation Operations
9. Gas Distribution Construction Guide
10. Removing Cyanide Wastes from MGP Sites
11. Chemical Fingerprinting for Enhanced Environmental Forensic Analysis

PIPELINE
12. Gas Leak Measurement Device (Hi-Flow® Sampler) *
13. Environmental Effects of Pipeline Crossings of Streams
14. Standard for Coriolis Meters

EXPLORATION AND PRODUCTION
15. Cement Pulsation Technology
16. Analysis for Radium in Marine Sediments
17. Produced Water Atlases and Handbook
18. Gas Resource and Production Potential of the Lewis Shales

* Enhancement to a previous product.

Benefits Results

Between January 1999 and December 2003, one hundred and thirty-three GRI RD&D results were placed in commercial service. The full list of the 133 items placed in commercial use is included in Appendix B. This report focuses on evaluating the benefits of 81 of the 133 GRI RD&D items that are known to have produced significant *quantifiable economic* benefits for their users. The 81 items are listed in Table 2. Benefits to product users in typical applications were calculated by comparing the economics of the GRI-sponsored products with the economics of products that would have been used in the absence of the GRI product. Product cost and performance data were obtained from product vendors, from field test results, or from product users. The measure of product benefit is the net present value of the incremental cash flow to the user (cost savings minus incremental cost) over the product lifetime using a real discount rate of 5% (above inflation). The GRI Baseline[1] national average projections of energy prices were used, when appropriate, to estimate cost savings. Total benefits were calculated by multiplying the unit benefits by the sales projected by product vendors from the first year in which the product was sold through 2008. The results are shown in Table 2. A range of product sales is shown to protect proprietary vendor sales projections.

As shown in Table 2, calculated economic benefits for the 81 items are estimated to be between $3.4 and $5.9 billion. Table 3 shows the expected value of benefits, at about $4.9 billion, and the breakdown of the economic benefits by sector. We estimate that the 81 items account for most of the economic benefits that would be calculated for the entire set of 133 products. Omitted items often offer significant benefits to their users, but have not achieved widespread use as have the 81 high impact items. In addition, some of the omitted items are designed to produce benefits that are not easily expressed in economic terms. For example, RD&D results provide test methods for new gas equipment, technologies to meet existing or anticipated air emissions requirements, and information that is useful to the gas industry in developing gas resources and delivering the gas to consumers.

[1] P.D. Holtberg, J.C. Cochener, "Baseline Projection Data Book: 2001 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2020," GRI-01/0002.1 and GRI-01/0002.2, GRI, March 2001.

Table 2. Summary of Benefits of GRI RD&D Results That Have Been Placed in Commercial Use in 1999 Through 2003

	Sales or Applications Projected Through 2008 (in units)			Year of First Sale	Net Present Value of Benefits** (Million 2003$)		
RESIDENTIAL							
Upgrades to the National Gas Fuel Code	***			2003	$62.5	to	$109.3
COMMERCIAL							
kitchenCOST™ Software	545	to	1,000	1998/99	$37.3	to	$68.5
Modulating Indirect-Fired Make-Up Air Unit with Clean Modulation	1,800	to	3,300	1999	$6.4	to	$11.8
GATC: AERCO Benchmark Boiler	1,350	to	2,700	1999	$26.5	to	$53.0
PITCO Gas Fryers	75,000	to	138,000	1999	$45.7	to	$86.6
AUTOFRY™ Deep Fat Fryer	2,130	to	4,260	1999	$8.1	to	$16.2
York 600 RT 134a Chiller	60	to	95	2000	$32.7	to	$51.3
Tecogen 150 RT 134a Chiller	65	to	105	2000	$2.2	to	$3.6
INDUSTRIAL							
Process Application of Composite Radiant Tubes	39,600	to	68,600	1994/99	$66.6	to	$115.4
High Performance Infrared Burners	125	to	190	1995/00	$612.27	to	$918.40
Natural Gas Cofiring in Biomass-Fueled Stoker Boilers	13	to	20	1999	$103.9	to	$163.3
Ultra-Low-NOx Boiler Burner	120	to	180	1999	$62.1	to	$93.1
METHANE de-NOX® Reburn Technology	6	to	11	1999	$136.2	to	$233.5
Forced Convection Heater (FCH) Systems – Automotive	11	to	19	2000	$14.2	to	$23.6
Oscillating Combustion Burner	125	to	225	2001	$17.0	to	$30.4
Low-NO_x Combustion System for Glass Furnaces	11	to	21	1995/03	$69.7	to	$127.9
Low-NOx, High-Heat-Transfer Burner	170	to	300	2003	$31.6	to	$56.5
POWER GENERATION							
IR PowerWorks Microturbine Cogeneration Systems	2,600	to	4,000	2000	$50.2	to	$78.9
Advanced High-Output Gas Engine-Generator (Caterpillar 3500® Series)	40	to	60	2001	$12.6	to	$21.6
Distributed Generation Switchgear	***			2003	$3.0	to	$4.7
TRANSPORTATION							
NGV Cylinders Types 1 and 2	28,500	to	69,700	1999	$5.5	to	$13.4
Advanced NGV Fueling Dispenser	80	to	170	2002	$1.2	to	$2.6
DISTRIBUTION							
Plastic Pipe Across (and on) Bridges	4,125	to	8,660	1995/99	$63.2	to	$132.8
DrillPath™ Software for Directional Drilling Operations	110	to	160	1996/99	$2.4	to	$3.6

	Sales or Applications Projected Through 2008 (in units)			Year of First Sale	Net Present Value of Benefits** (Million 2003$)		
Starline® 2000 Renewal Technology	135,300	to	248,000	1999	$1.9	to	$3.5
Guided Mole	20	to	40	1999	$4.6	to	$8.0
Gas Holder Manual of Practice	7	to	12	1999	$6.3	to	$11.5
One-Step Paving	230	to	430	2000	$3.4	to	$6.7
Soil Compaction Supervisor	470	to	820	2000	$19.4	to	$33.9
Self-Loading, High-Efficiency Trailer for Coiled PE Pipe	22	to	43	2001	$70.8	to	$141.7
Cold-Mix Restoration of Pavement Cuts	130	to	330	2001	$9.4	to	$24.4
Imaging Underground Utility Structures	900	to	1,650	2001	$6.4	to	$11.7
Comparative Evaluation of PE Pipe Materials	55	to	110	2001	$50.1	to	$100.3
Directional Drilling for Plastic Pipe under Railroad Crossings	46	to	100	2001	$12.6	to	$27.2
PE LIFESPAN FORECASTING™	135	to	250	1994/01	$83.7	to	$154.9
Pipe Splitting Tool	15	to	30	1998/02	$9.5	to	$19.0
Gas Distribution Cost Database	450	to	800	2002	$11.8	to	$21.0
Assessment of PVC Pipe	4,300	to	9,500	2002	$20.0	to	$44.1
Plastic Pipe Informational Web Site		***		2002	$4.3	to	$7.9
Worker Exposure to Hazardous Substances		***		2002	$5.4	to	$16.2
Safety of Vacuum Excavation Operations	50	to	160	2003	$2.6	to	$8.3
Gas Distribution Construction Guide	22,500	to	54,000	2003	$2.9	to	$6.9
Removing Cyanide Wastes from MGP Sites	6	to	14	2003	$4.6	to	$11.9
Chemical Fingerprinting for Enhanced Environmental Forensic Analysis	185	to	290	2003	$49.5	to	$77.8
PIPELINE							
Breeze Haz™ Environment and Safety Offsite Consequence Modeling Software	3,000	to	5,300	1999	$14.0	to	$24.4
Emeritus Report B31.8 Code, Federal Pipeline Safety Regulations		***		2000	$19.2	to	$57.7
Elastic Wave Vehicle Tool		***		2000	$67.6	to	$146.5
API 14.1 Gas Sampling Standard.	5	to	11	2001	$5.0	to	$10.9
Ultrasonic Meter Installation Effects	2,500	to	5,000	2001	$65.4	to	$130.7
Orifice Meter Operational Effects	20	to	40	2001	$38.0	to	$70.7
DamageExpert™ Software	35	to	75	2001	$61.4	to	$133.0
Satellite Radar Interferometry Measurement of Slope Movement	20	to	45	2001	$48.8	to	$105.8
AIRCalc™ Software	145	to	265	2001	$79.4	to	$145.5
Predicting the Integrity of Storage Caverns in Thin Salt Beds	3	to	9	2002	$0.4	to	$1.2
ASME Standard for Pipeline Integrity Management		***		2002	$5.0	to	$10.8
NACE Standard for Direct Assessment of Pipeline Corrosion		***		2002	$0.7	to	$1.7
Reference Manuals of Best Practices for Horizontal Directional Drilling and its Effect in Wetlands	75	to	250	2002	$2.0	to	$6.5
Best Environmental Practices for Pipeline Construction	600	to	1,200	2002	$2.6	to	$5.2

	Sales or Applications Projected Through 2008 (in units)			Year of First Sale	Net Present Value of Benefits** (Million 2003$)		
Gas Leak Measurement Device (Hi-Flow® Sampler)	30	to	120	2000/03	$4.6	to	$18.4
Environmental Effects of Pipeline Crossings of Streams	745	to	1,150	2003	$45.4	to	$71.3
Standard for Coriolis Meters	115	to	230	2003	$6.2	to	$12.4
EXPLORATION AND PRODUCTION							
Unconventional Natural Gas Database	110	to	190	1999/01	$10.4	to	$18.3
Downhole Gas/Water Separation CD-ROM	75	to	130	1999	$8.8	to	$15.2
Advanced Crosswell Seismic Source	200	to	400	1999	$33.7	to	$66.8
High Power VSP Mechanical Seismic Source	520	to	750	1999	$25.4	to	$37.0
Advanced Stimulation Technologies CD-ROM	45	to	80	1999	$5.5	to	$10.0
Coiled Tubing Standards	3	to	5	1999	$15.7	to	$30.3
GRI–MSTR™ Software and Report to Predict Toxicity of Produced Water Discharged to the Marine Environment	280	to	440	1999	$12.5	to	$19.7
Glycol Dehydrator Emissions Calculation Program - GLYCalc™ 4.0	720	to	1,330	1992/00	$76.0	to	$140.7
ProTreat™ Software for Amine Gas Treating Applications	45	to	75	2000	$136.1	to	$226.9
Cased Hole Resistivity Tool	800	to	1,300	2000	$12.3	to	$20.0
Cased Hole Pressure Tool	725	to	1,245	2000	$106.5	to	$182.6
Well Siting in Carbonates – EGI Report	90	to	140	2000	$72.2	to	$108.3
Portfolio of Emerging Natural Gas Resources – Rocky Mountain Basins	480	to	720	2000	$110.6	to	$165.9
Mercury Contamination Training Workshop	300	to	500	2000	$3.0	to	$5.1
New Gas Exploration Concepts	65	to	100	2001	$280.8	to	$441.2
StreamAnalyzer™ Software	370	to	820	2001	$80.3	to	$176.6
Enhanced Seismic Spectral Processor	200	to	330	2002	$35.0	to	$56.8
Cement Pulsation Technology	670	to	1,340	2003	$23.9	to	$47.9
Analysis for Radium in Marine Sediments	12	to	24	2003	$3.3	to	$6.6
Gas Resource and Production Potential of the Lewis Shales	45	to	70	2003	$32.1	to	$48.2
TOTAL (million of 2003 dollars, 5% discount rate)					$3,402		$5,934

* Enhancement to a previous product for a new market application.

** Net present value calculations based on a real discount rate of 5% (excluding inflation), stated in 2003 dollars.

*** Benefits are based on user feedback about technical and market influence of the RD&D items.

Table 3. Total Expected Benefits by Sector

	Quantified GRI RD&D Results	Net Present Value of Benefits (Million 2003$)
• Residential	1	$104
• Commercial	7	$256
• Industrial	9	$1,360
• Power Generation	3	$94
• Transportation	2	$15
• Distribution	22	$760
• Pipeline	17	$772
• Exploration and Production	20	$1,582
TOTAL	81	$4,943

GRI RD&D Costs

Between January 1999 and December 2003, GRI outlays totaled $530 million. For comparison to the RD&D benefits calculated above, the cost cash flow stream was converted to an equivalent net present value lump sum expenditure at the beginning of 2003. As with the benefits calculation, a 5% real discount rate was used in the net present value calculation. The calculated equivalent cost was $619 million. These costs include all outlays made by GRI during the past 5-year period, not just the costs incurred to produce the 133 RD&D products. Consequently, a portion of the calculated cost will yet generate benefits as additional products are commercialized in the future.

Benefit-to-Cost Ratio

Dividing the calculated benefits by the costs results in a calculated benefit-to-cost ratio range of 5.5 : 1 to 9.6 : 1 (benefits of $3.4 to $5.9 billion divided by outlays of $619 million) with an expected value of 8.0 : 1 ($4.94 billion divided by $619 million). In a similar analysis carried out in 2003 for RD&D items placed in commercial use between 1998 and 2002, the calculated ratio of the benefits to gas customers to total GRI costs incurred during the same period was 8 to 1[2].

Conclusions

GRI's planning and budget allocation process strives to put in place a program with the maximum ratio of benefits to RD&D costs for the mutual benefit of the gas customer and the gas industry. The economic evaluation of GRI's commercially successful RD&D results have consistently shown that benefits far exceed the costs of the RD&D program.

Analysis of the benefits of approximately 81 of the 133 GRI RD&D items placed in commercial service between January 1999 and December 2003 shows that GRI RD&D will return about $8.0 for every dollar invested in GRI during the same period. In addition to the fact that only a portion of GRI's commercialized

[2] A.D. Bournakis, " Benefits of GRI RD&D Results That Have Been Placed in Commercial Use in 1998 Through 2002," Gas Research Institute, May 2003, GRI-03/0106.

RD&D items are included in the benefits calculation, all of the costs of GRI's operations during the 1999 to 2003 period have been included in the calculation of the benefit-to-cost ratio.

Appendix A
GRI RD&D Results That Have Been Placed in Commercial Use in 2003

RESIDENTIAL

Upgrades to the National Fuel Gas Code: GRI research led to recommendations for the 2002 National Fuel Gas Code (NFGC), published by the National Fire Protection Association in 2003, relating to the requirements for combustion air supply and corrugated gas vent connectors. These recommendations were intended to improve installation practices and energy efficiency. GRI's recommendations for appliance air requirements were to: 1) remove the designation of "unusually tight construction," because all new homes have what was previously considered unusually tight construction; 2) increase the required volume of rooms containing natural-draft gas appliances from at least 50 cubic feet per thousand Btu per hour of gas input to at least 52.5; and 3) specify a required volume of at least 37.5 cubic feet per thousand Btu per hour of gas input for rooms containing fan-vented appliances. GRI's recommendations for corrugated vent connectors were: 1) corrugated connectors to be equivalent to normal vent connectors and should both be oversized and have long-radius bends; 2) oversized corrugated connectors should be designed to avoid sudden expansions or contractions at the connections; and 3) flexible chimney reliners should have a design capacity 15% less than comparable Type B gas vents. The adoption of GRI's recommendations will allow greater flexibility in placing appliances in homes and will help reduce construction costs. Many installations that formerly required outdoor air to be ducted to the appliance will no longer require that expensive ducting.

COMMERCIAL

Building Energy Analyzer™: The Building Energy Analyzer™, developed by GRI, is a software tool that aids heating, ventilation, and air-conditioning (HVAC) professionals in tailoring economic analyses for several types of facilities. The program allows users to estimate critical information such as annual or monthly loads and costs associated with air-conditioning, heating, and on-site power generation for commercial buildings. The Building Energy Analyzer compares the performance of a wide variety of HVAC technologies, such as standard- and high-efficiency electric chillers, variable-speed electric chillers, absorption chillers, engine-driven chillers, on-site power generators, thermal storage, heat recovery, and desiccant systems. It estimates annual or monthly loads and costs associated with air-conditioning, heating, power generation, thermal storage and cogeneration systems for a given building and location. It performs quick-to-use economic analysis for the customer's utility rates, location, and building type. Additional features include: templates for each of the 15 most typical commercial building types; capability to handle complex utility rates; weather data for 233 cities; ability to perform life-cycle cost analysis on building cooling, heating, and power generation (BCHP) equipment. The software program is compatible with Windows® 95, 98, 2000, and XP and ME systems. Version 2.0 of BEA was released in 2003. The program with a complete manual in PDF format is distributed by GTI, with user support, maintenance, and upgrades provided through GTI's InterEnergy Software Project.

INDUSTRIAL

*** Low-NO_x Combustion System for Glass Furnaces:** Regenerative glass furnaces use extremely high air-preheat temperatures, which result in very high uncontrolled emissions of NOx. These furnaces are being placed under stringent regional and state regulations. GRI developed a furnace system that cost-effectively reduce NOx emissions from regenerative glass melters to less than 2.5 pounds per ton of glass. The new combustion technology, called oxygen-enriched air staging (OEAS), uses a unique method of introducing combustion air to control NOx formation. In a first combustion stage, the amount of combustion air through the firing ports is limited to decrease the oxygen available in the flame's high-temperature zone. This reduces NOx formation but leads to high concentrations of carbon monoxide and unburned hydrocarbons. Oxygen-enriched air is injected into the furnace in a second stage near the exit ports to complete the combustion. OEAS has been successfully retrofitted to endport container-glass

furnaces with flint and amber glass production capacities of 135 to 320 tons per day. NOx levels were reduced by 50-70%. The OEAS technology has now been adapted to operate similarly on sideport furnaces, which are used for nearly 65% of U.S. glass production. Endport and sideport furnaces are similar in concept, but significantly different in physical design and flame characteristics. OEAS has been successfully retrofitted to seven endport container-glass furnaces and three sideport container-glass furnaces. NOx was reduced by 50 to 70% on endport furnaces, with no adverse impacts on other emissions, furnace performance, or glass quality. OEAS technology applied to three sideport furnaces reduced NOx by 40% to as much as 70%. GRI licensed OEAS technology to Combustion Tec, the glass division of Eclipse Combustion. In 2003, Combustion Tec began marketing OEAS for endport and sideport glass furnaces.

Low-NO_x, High-Heat-Transfer Burner: Two serious problems with high-temperature combustion processes, such as glass melting, are their intrinsically low efficiency and high emissions of NO_x. Efficiency is low because of the high energy content of the combustion products leaving the process. NO_x emissions are high because NO_x yield increases as combustion temperature increases. The use of recuperative heat exchangers to increase efficiency and the use of post-process NO_x emissions control equipment are costly solutions to the problems. Both problems could be mitigated by using oxygen instead of air to support the combustion. However, although oxy-gas firing has been implemented commercially to some extent, oxy-gas flames emit less thermal radiation than is desired for high process productivity. GRI developed a new oxy-gas burner that increases flame radiation by forming soot in the flame and then consuming the soot before it leaves the furnace. The High-Luminosity burner provides a preheating zone at the burner inlet to form soot, a fuel-rich flame zone to radiate heat to the furnace load, and a fuel-lean zone to burn out the soot. The soot radiation increases the effectiveness of heat transfer within the furnace and cools the flame, thereby reducing NO_x formation. The new burner provides significantly higher heat transfer to furnace loads, higher furnace efficiency, lower flame temperature, lower combustion products exit temperature, and significantly lower NO_x emissions. The high-luminosity burner can be used in conjunction with other NO_x reduction techniques, including combustion modifications and oxygen-enriched air staging. The burner is an easily installed, low-cost process modification that can, in oxy-fuel applications, increase process and energy efficiency by up to 10 percent while emitting 50 percent less NO_x than conventional oxy-gas burners. Test results showed a 4.5 percent increase in total heat transfer, which corresponds to a 10 percent decrease in fuel use. Combustion Tec Division of Eclipse™, Inc. licensed the technology and began marketing the burner to the glass industry in 2003 under the brand name Primefire® 400.

LNG Interchangeability in Burners: GRI evaluated the sensitivity of selected burners to compositions typical of LNG that is rich in heavier hydrocarbons. With LNG poised to play an increasingly important role in U.S. natural gas supplies, one of the issues of interest to the gas industry is the degree to which natural gas from LNG is interchangeable with pipeline quality gas in terms of its performance in combustion equipment, especially if heavier hydrocarbon components become more concentrated during handling. The heavier hydrocarbons would increase the density, heating value, and flame speed of the gas. If these increases are large enough, they may adversely affect the performance of some gas burners. The selected burners represent a variety of U.S. residential appliances. This study replicated previous methods that were used to study interchangeability to demonstrate their applicability to LNG, identified a set of indices that can be used to predict combustion behavior, investigated several ways to reduce the heating value of LNG, and related the performance of a specially designed test burner to the performance of a variety of residential appliances. The R&D determined interchangeability indices for natural gases used in the U.S. and for a range of anticipated world LNG imports to the U.S. It determined that, for the residential burners studied, expected LNG compositions are adequately interchangeable with U.S. pipeline gases if their heating value and density are suitably adjusted by dilution with air or nitrogen.

POWER GENERATION

Distributed Generation Switchgear: GRI developed paralleling switchgear for distributed generation (DG) systems that offer lower capital costs; plug-and-play simplicity; integration with leading natural gas engine-generator set manufacturers; conformity with basic electric utility interconnection requirements; conformity with existing or projected industry standards; and remote monitoring, communications, and control functions. Consolidating system functions reduced the number of components, and this reduction in components led to a smaller footprint, lower material costs, and less engineering. In addition to cost reduction, the new switchgear has more features, and this makes gas-fueled DG systems more attractive. The switchgear offers the widest array of communication capabilities found in DG systems today. The cost of switchgear was reduced from $75-$100 per kilowatt to $40-$60 per kilowatt. This was accomplished by reducing the number of components in the generator control section by 40-60%, reducing the space required for mounting the generator controls by 50%, reducing the engineering time by 30%, and reducing sheet metal and bus bar by 40-70%. The results of this R&D have significantly reduced the barriers to installing gas-fired DG equipment. The switchgear became commercially available from GE Zenith Controls in 2003 under the name Entellysis®.

Guidebook to Gas-Fired Distributed Energy Technologies: There has been an increase in interest in on-site generation of electric power systems, also known as distributed energy (DE) systems. DE systems that recover and use exhaust heat from the engines to provide other thermal needs at the site are called cogeneration systems or combined heat and power (CHP) systems. CHP systems offer users high energy efficiency (up to 80%) because they make heat available that would be wasted if the electric power were generated at a central power station. Although DE and CHP systems offer very high energy efficiencies, they have not had high market penetration. Potential DE and CHP users are not familiar with DE and CHP equipment performance and cost. To help overcome the lack of familiarity, GRI cooperated with the National Renewable Energy Laboratory (NREL) to publish a definitive guidebook on the performance and cost of the various prime mover technologies that can be used to generate power in DE and CHP applications. These technologies are reciprocating engines, small gas turbines, microturbines, steam turbines, fuel cells, and Stirling engines. The guide was published in 2003 and is available from NREL. It describes each of the six technologies, their power generation performance, cost, and emissions characteristics. Because some of the technologies have not yet been fully commercialized, the guide also predicts the performance and cost that the prime mover technologies will achieve in the future (2010, 2020, and 2030).

DISTRIBUTION

Safety of Vacuum Excavation Operations: Vacuum excavation involves the use of equipment to remove soil from holes that are being dug by distribution companies. Interest in using it has expanded greatly with the introduction of keyhole repair technologies, which depend on vacuum excavation. Keyhole repairs often encounter leaking gas in small spaces, and this has raised the question of whether vacuum excavation will pose unexpected hazards from ignition of gas-air mixtures in the vacuum hoses or the soil collection tank. Vacuum hoses are often made of plastic materials that are inexpensive and lightweight. Flow of air and solids through plastic pipes can create static electricity, which could be an ignition source. Flying rocks hitting the steel wall of the soil collection tank could also create sparks. GRI performed experiments designed with the deliberate goal of causing ignition. The experiments demonstrated that both high static electricity voltages and flammable gas-air mixtures can co-exist in the hoses and soil collection tanks without ignition occurring. A report, GRI-03/0128, "Vacuum Excavation of Potentially Flammable Gases," was released in September 2003. It gives gas companies confidence that vacuum excavation can be accomplished at least as safely as more traditional mechanical excavation. It is impossible to prove that ignition cannot occur under any condition that may occur during vacuum excavation. If gas company supervisors believe that there is an unacceptably high likelihood of gas ignition during a specific vacuum excavation operation, they can use aluminum-coated or other highly conductive vacuum hoses and ground both the soil collection tank and the hose. Small amounts of water

can also be used to prevent static charge accumulation. The report also contains recommendations for maintaining safety during the use of suction techniques to remove water from flooded gas mains.

Gas Distribution Construction Guide: To help LDCs appropriately adopt new construction and repair technologies, GRI developed a Web site that describes many commercially available technologies that have been developed. It is called the Utility Construction Methods Selection Guide. The site covers many trenching and boring technologies for replacing deteriorating gas pipes, pipe lining technologies for pipe rehabilitation without replacement, and pipe bursting and splitting technologies for situations where lining is not feasible. In general, for each technology, the Guide contains the following sections: introduction, general description, advantages, limitations, technical application data, special considerations, application trends, U.S. utility experience, and contact information. The Guide describes six case studies in which trenchless or "no-dig" methods have been used for rehabilitating or replacing old and deteriorating gas mains and service lines. The six case studies cover the following six technologies: Amex® 2000, horizontal directional drilling, RENU™, starline®, Swagelining™, and U-Liner. Information on each case study is organized into the following sections: introduction, method applied, participating utility, application location, technical data, cost and savings data, economic analysis, and contact information. The Web site also contains an on-line economic calculator that compares various utility construction methods. Based on user inputs, the calculator selects appropriate rehabilitation or replacement methods for comparison. The analysis of the selected methods includes total installed cost, annual cost over the life of the project, net present value, and life-cycle cost. The Web site was put into operation in 2003 at www.gtiservices.org.

Removing Cyanide Wastes from MGP Sites: Cyanide compounds are found in the groundwater at many former manufactured gas plant (MGP) sites in the U.S. The cyanide compounds are residues of the manufactured gas purification process, which used iron-impregnated solid materials, such as wood chips, in purifier boxes to remove hydrogen sulfide from the manufactured gas. The iron compounds in the purifier box also removed some cyanide from the product gas. Spent iron compounds were often regenerated by spreading them on the ground. Some of the iron compounds remained in the soil and, upon contact with water, released cyanide compounds, which later entered the groundwater. Previous studies indicate that the dominant forms of cyanide compounds in purifier box wastes are iron cyanide complexes, which are highly stable in groundwater and resist natural decontamination by microorganisms. Current stringent limitations on allowable concentrations of cyanide in groundwater pose a compliance challenge. GRI evaluated alternate methods for removing iron cyanide complexes from the treatment plant effluent. The evaluation found that certain anion-exchange resins would adsorb the cyanide complexes, with a sorption capacity of up of up to 10% iron cyanide by weight. The resin functioned in the presence of high concentrations of sulfate ions, which interfere with the operation of most ion-exchange resins. GRI then developed a process based on the anion-exchange resins. The process was successfully demonstrated, at full scale, in an MGP waste treatment plant. It is recommended for treatment of water that contains up to 10,000 ppb of cyanide compounds. US Filter, in cooperation with GTI, is offering the process commercially.

Chemical Fingerprinting for Enhanced Environmental Forensic Analysis: Environmental forensic techniques are increasingly used to identify specific wastes, particularly at former MGP sites. However, currently, available analytical methods of environmental forensic techniques do not have enough conclusive discriminating power to insure scientific accuracy, reproducibility, and overall confidence in the use of chemical fingerprinting to characterize complex MGP wastes. These wastes, primarily dense non-aqueous phase liquid tars consisting of polynuclear aromatic hydrocarbon (PAH) compounds, are often aged, exceptionally dense, commingled with other wastes, and subjected to weathering over extended periods of time. With GRI support, the Gas Technology Institute has used chemical fingerprinting to successfully discern tar wastes from wholly different sources, and even to distinguish manufactured gas plant wastes from different plant operations. As a service to utility companies and

others, GTI is providing fingerprinting, forensic engineering, and technical support for the identification of pollutants at particular sites, as well as for the study of process mechanisms. GTI takes a two-tiered approach in its environmental forensic services: The first is to characterize the discrete organic pollutants (e.g., BTEX, PAHs, PCBs, and endocrine-disrupting compounds) in water, soil, or sediment samples. These organic compounds all possess distinct "chemical fingerprints" which often can provide sufficient information to determine the origin(s) or source(s) of the contamination. The second tier is to characterize or "chemically fingerprint" the complex macromolecular organic matter in the sample matrix itself for signatures of various sources (e.g., natural, agricultural, industrial, and anthropogenic). Specifically, natural organic matter (NOM) is characterized for water samples, soil organic matter (SOM) is characterized for soil samples, and sediment organic matter (SdOM) is characterized for sediment samples. This technique has proven to be a sufficient monitoring tool that quantitatively compares changes in the organic quality of NOM/SOM/SdOM due to seasonal influence, changes in inputs or discharges, as well as treatment. Furthermore, the chemical fragments that are the reflection of these influences can be identified, quantified, and compared with other chemical and biological data to establish relationships.

PIPELINE

*** Gas Leak Measurement Device (Hi-Flow® Sampler):** GRI has developed an improved version of the Hi-Flow® Sampler, an inexpensive instrument for field measurement of leak rates. The Hi-Flow Sampler can be used to measure the rate of gas leakage around various pipe fittings, valve packings, and compressor seals in natural gas transmission, storage, and compressor facilities. It also measures background methane concentration in the air and automatically corrects the leak rate measurement for this background methane. The instrument is based on straightforward principles of dynamic dilution and concentration measurement. A very large, measured flow of air sweeps the area of the leak, completely capturing any gas leaking from the component being tested. The rate of the gas leak is calculated from the concentration of methane in the sweep air. The instrument is intrinsically safe for use in Class I hazardous locations. It has been approved by the Canadian Standards Association (C22.2 No. 157, June 1992), American National Standards Institute (June 27, 2002), and Underwriters Laboratories (UL913-2002). It provides data logging and instantaneous leak-rate display, and only minimal operator training is needed. In 2003, Bacharach®, Inc. began marketing the Hi-Flow Sampler.

Environmental Effects of Pipeline Crossings of Streams: Regulatory agencies have expressed concern about the environmental impact of pipeline water crossing construction on stream and river ecosystems. The main issue is the entrainment of sediment during pipeline construction and the effects of the sediment on downstream aquatic organisms. Because there were limited data and no field-proven predictive tools to quantify the effects of sediment released during water-crossing construction, assessment of impacts has been based on professional judgment and consideration of worst-case scenarios. This has led to the use of construction methods that were unnecessarily costly and often did not actually improve the degree of environmental protection. Because of the large number of pipeline water crossings and the large differences in cost among crossing methods, there was a need for scientifically defensible planning tools that allow industry to construct cost-effective, environmentally acceptable watercourse crossings. To meet this need, GRI developed CROSSING™ software and released it in 1998. It estimates how much the release of sediment during in-stream construction affects downstream fish communities. In 2003, CROSSING™ version 2.0, a more robust software package, was released. CROSSING™ 2.0 helps gas companies and regulators evaluate potential adverse effects of water crossing construction. This enables the selection of least-cost construction methods that satisfy environmental goals. Gas consumers will benefit from lower cost of pipeline service and from the prompt availability of pipeline service without delays in construction caused by unnecessarily extended permitting procedures.

Standard for Coriolis Meters: As part of its continuing search for better gas meters, the gas industry has become interested in using Coriolis meters in certain applications. Coriolis meters are of interest because

they measure mass flow rate, which can be converted to a "standard" gas flow rate with only knowledge of the density of the gas at reference conditions. This is important because it avoids the need to predict the density of high-pressure gases with an equation of state and would avoid the errors associated with that prediction. Because of the mechanics involved in these meters, they are typically limited in size to pipe diameters less than 6 inches. Therefore, they would not be used for mainline meters, but would be used to measure gas flow to large customers or small municipalities. Manufacturers developed Coriolis meters for gas applications and reported the results of their development efforts, but no comprehensive, independent tests results were published. GRI evaluated the suitability of these meters for gas flow measurement, based on a test plan developed under the auspices of the American Gas Association. The tests verified that some of the meters that have been developed are accurate enough for gas custody transfer measurement. The results were incorporated into an American Gas Association report, issued in 2003. This report will serve as a standard for the gas industry. It provides a performance-based specification and test methods for Coriolis meters intended for natural gas flow measurement. It contains several appendices addressing theory, operation, accuracy, research, and test data.

EXPLORATION AND PRODUCTION

Cement Pulsation Technology: Cement is used to seal the annulus between gas well casings and surrounding rock, to insure that gas flows are taken from the intended formation, that the gas does not leak into shallower (lower pressure) formations, and that the gas is not contaminated with flows from other formations. It has been estimated that the cement in 20% of cemented wells on land fail within the first five years and as many as 65% of offshore wells fail within 15 years. Without remediation, the well may not reach its full gas production potential, and the annular leakage may present safety issues. GRI found that the quality of the cement structure can be improved significantly by vibrating the cement with pressure pulses transmitted from the surface immediately after cementing. Applying the pulses from the surface is less costly than the chemical additives that are now used to help reduce the occurrence of cement integrity problems. This low-cost technology will improve the ability of well cementing operations to seal gas zones. It will improve cement quality and decrease well repair costs. The pulsing technique was tested in 150 wells in gas fields that have been prone to gas leakage through the cement. An estimated $2 million in cement remediation costs was avoided. GRI's research included modeling to understand gas migration in cement and to study pulse propagation, technique effectiveness, and cement quality. In 2003 the technique was made commercially available in the U.S. by Reservoir Isolation Technical Services (RITS).

Analysis for Radium in Marine Sediments: Environmental concerns arose in regulatory agencies over the possible presence of naturally occurring radioactive materials in natural gas. Nuclear reactions of naturally occurring uranium and thorium in the rock of producing formations can form radium isotopes such as radium-226 and radium-228, which have long half-lives. In addition to long half-lives, these isotopes have long biological residence times because they incorporate into living skeletal material. They present health risks to gas industry workers because they may be deposited in gas processing equipment. To enable accurate assessment of possible risks, GRI investigated methods for determining the concentrations of these radium isotopes in produced water, fish, and sediments. The goal was to identify a reliable analysis method for measuring concentrations as low as 0.01 picoCuries per gram of material. Based on this information a method for inter-laboratory tests was developed. It was found that commercial radiochemical laboratories could obtain reliably accurate results with this method. In addition, a new, analytical method for seawater was evaluated and found to be accurate and sensitive to less than 0.01 picoCuries per gram. A report, GRI/01-0244, "Development, Evaluation, and Validation of Radioanalytical Methods for the Measurement of Radium 226 and 228 in Environmental Media Relevant to the Offshore Oil and Gas Industry," was made available in 2003 to gas production companies and service laboratories. The research results will help gas companies focus their remediation and control efforts on sites that pose true risks. This will enhance worker safety and reduce the overall cost of gas production.

Produced Water Atlases and Handbook: Changing environmental regulations and subsequent changes in permitting processes for produced water disposal are obliging oil and gas producers to modify their water treatment and disposal practices, often incurring higher costs. Surface discharge, which is the most economical strategy for produced water disposal, is no longer a viable option in many states where regulations have increasingly restricted the quality and quantity of water that can be disposed in that manner. When surface disposal is not a choice, beneficial use of recycled water becomes a favorable option. GRI compiled data to characterize the amount of water produced, production trends, and pertinent environmental regulations and analyzed localized produced water management strategies and costs. Annual oil, gas, and water production volumes were documented for key fields in each of the oil and gas basins in ten states. Producers reporting high volumes of water coupled with high hydrocarbon production were identified and interviewed to obtain specific information about their strategies for managing or disposing of produced water and the costs associated with those strategies. The data are contained in ten atlases, one for each of the following major gas-producing states: Wyoming, Colorado, Utah, New Mexico, Montana, Kansas, Oklahoma, Illinois, Michigan, and Louisiana. The research also produced a handbook that is a resource for gas producers and provides them with actual produced water management practices and disposal economics for 26 basins in ten states. The handbook also describes technologies that are used to treat or handle produced water. GRI published the atlases on a single compact disc in 2003. The Handbook is a separate GRI publication, also published in 2003.

Gas Resource and Production Potential of the Lewis Shale: The Lewis shale formation of the San Juan Basin in Colorado and New Mexico has an enormous gas-in-place volume. The properties of the reservoir and the mechanisms that control gas production from this formation are not well understood. GRI conducted formation evaluation research to quantify the gas-in-place volume stored by sorption, compression, and solution mechanisms; the depths of the most permeable rock; and the production mechanisms. The research collected and interpreted new data that were needed to improve the analysis of the wireline log data that are used to quantify the amount of gas in place and to determine the zones of greatest gas deliverability within the Lewis Shale. The research determined in situ gas permeabilities and estimated the amount of gas in place and how much of it should be recoverable. Shale gas reservoirs extend throughout the Western Cretaceous Basins from New Mexico to Canada. The amount of gas in place documented for the San Juan Basin are likely to be present in at least eight western basins. The formation evaluation approach implemented and documented during this research is applicable to all of these basins. The results of the research were published in a comprehensive report in 2003, GRI-03/0037, Final Report: "Lewis Shale Gas Resource and Production Potential". The information will help E&P companies understand this unconventional resource and will serve as a starting point for applying improved reservoir characterization technology to the development of the Lewis and other shale gas reservoirs. The enhanced understanding will lead to lower exploration costs and increased production of natural gas from shale formations.

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* Enhancement to a previous product.

Appendix B
GRI RD&D Results That Have Been Placed in Commercial Use in 1999 Through 2003

RESIDENTIAL

1. Combo Systems Sizing and Installation Guidelines – 1992/2000
2. NAECA Water Heater Assessment - 2000
3. Indoor Emissions from Cooking – 2001
4. Summary Report of GRI's Venting Research - 2002
5. Gas Venting Safety Assessment - 2002
6. Accurate Assessment of Heat Pump Efficiency – 2002
7. Upgrades to the National Fuel Gas Code - 2003

COMMERCIAL

8. GATC Quick Response Activities – 1995/1999
   (Life-Cycle Cost Model for Food Service Technologies)
9. BinMaker™ Pro: The Weather Summary Tool – 1997/2000
10. kitchenCOST™ Software- 1998/99
11. Modulating Indirect-Fired Make-Up Air Unit - 1999
12. GATC: AERCO Benchmark Boiler - 1999
13. Engine Rooftop Heat Pump (Goettl 15-20 ton) - 1999
14. PITCO Gas Fryers - 1999
15. AUTOFRY™ Deep Fat Fryer - 1999
16. Analysis of Commercial Sizing and Installation Guidelines - 2000
17. Gas Cooling Guide – Pro Version - 2000
18. York 600 RT 134a Chiller - 2000
19. Tecogen 150 RT 134a Chiller - 2000
20. Trane Single Effect Horizon Chiller - 2000
21. Chiller Application Briefs - 2000
22. Restaurant Kiosk Ventilation and High-Performance Gas Countertop – 2000
23. Comparison of Radiant and Convective Unit Heaters - 2002
24. Gas-Fired Commercial Steam Cooker – 2002
25. Building Energy Analyzer™ - 2003

INDUSTRIAL

26. Process Application of Composite Radiant Tubes (and Case Studies) and Advanced U-Shaped Radiant Tubes - 1994/99/2002
27. Low-NO_x Air Staging for Glass Melting/Low-NO_x Combustion System for Glass Furnaces 1995/2003
28. Industrial Boiler Gas Cofiring (including Biomass) - 1995/99
29. High Performance Infrared Burners (and Application Tools) – 1995/99
30. METHANE de-NOX® Controls for Stoker Boilers - 1999
31. Ultra-Low-NO_x Burner for Boiler Retrofit - 1999
32. Forced Convection Heater (FCH) Systems – Automotive – 2000
33. Oscillating Combustion Burner - 2001

34. Radiant Heater Characterization Facility - 2001
35. Low-NO_x Retrofit Burners for Fire-Tube Boilers – 2002
36. Low-Cost Multi-Gas Continuous Emissions Monitor – 2002
37. Low-NO_x, High-Heat-Transfer Burner 2003
38. LNG Interchangeability in Burners - 2003

POWER GENERATION

39. DGen Pro™ Software – 1998/99/2000
40. SOAPP™ Modules – 1998/99
41. Microturbines (Capstone and Honeywell) - 1999
42. Distributed Generation Guidebook for Municipal Utilities - 1999
43. IR PowerWorks Microturbine Cogeneration Systems – 2000
44. Advanced High-Output Gas Engine-Generator (Caterpillar 3500® Series) – 2001
45. Distributed Generation Switchgear – 2003
46. Guidebook to Gas-Fired Distributed Energy Technologies - 2003

TRANSPORTATION

47. Cummins C8.3G Engine – 1996/2001
48. John Deere 8.1L Engine – 1996/99/2002
49. MACK E7G Refuse Hauler – 1996/2002
50. John Deere 6.8L – 1998/99
51. NGV Cylinders (Types 1 and 2) - 1999
52. Glass-Fiber-Wrapped Fuel Tanks for NGVs - 2000
53. Advanced NGV Fueling Dispenser
54. Best Practices for Medium-and Heavy-Duty NGV Fuel System Design - 2002
55. Clean Cities Initiative to Evaluate NGV Technology - 2002
56. Resource Guide for Heavy-Duty LNG Vehicles - 2002
57. Regional Natural Gas Vehicle Fueling Infrastructure Standards - 2002

DISTRIBUTION

58. PE LIFESPAN FORECASTING™ – 1994/2001
59. Plastic Pipe Across Bridges – 1995/99
60. DrillPath™ Guided Boring Software – 1996/99
61. Pipe Splitting Tool - 1998/02
62. TUBIS™ Software for Repair/Replace Decisions - 1999
63. Pipe Ovality and Scratch Depth Measurement Device and Guidelines - 1999
64. Plastic Pipe Repair Techniques - 1999
65. Starline® 2000 Renewal Technology - 1999
66. Guided Mole - 1999
67. Gas Holder Manual of Practice - 1999
68. Precision Pipe Locator - 2000
69. One-Step Paving - 2000
70. Bare Steel Maintenance Optimization System (BASMOS) Software - 2000
71. Soil Compaction Supervisor - 2000

72. Self-Loading, High-Efficiency Trailer for Coiled PE Pipe - 2001
73. Cold-Mix Restoration of Pavement Cuts - 2001
74. Imaging Underground Utility Structures - 2001
75. Comparative Evaluation of PE Pipe Materials - 2001
76. Directional Drilling for Plastic Pipe under Railroad Crossings - 2001
77. Gas Distribution Cost Database - 2002
78. Effect of Bomb Blasts on Gas Distribution Equipment- 2002
79. Assessment of PVC Pipe - 2002
80. Effect of Utility Cuts on Pavement Quality - 2002
81. Plastic Pipe Informational Web Site - 2002
82. Evaluation of the Performance of Carbon Monoxide Alarms - 2002
83. Worker Exposure to Hazardous Substances – 2002
84. Safety of Vacuum Excavation Operations - 2003
85. Gas Distribution Construction Guide - 2003
86. Removing Cyanide Wastes from MGP Sites – 2003
87. Chemical Fingerprinting for Enhanced Environmental Forensic Analysis - 2003

PIPELINE

88. Clock Spring® Composite Pipeline Repair Material – 1995/99
89. Risk Assessment/Risk Management Guidelines – 1996/99
90. Breeze Haz™ Environment and Safety Offsite Consequence Modeling Software - 1999
91. Emeritus Report B31.8 Code, Federal Pipeline Safety Regulations - 2000
92. Elastic Wave Vehicle Tool - 2000
93. Gas Leak Measurement Device (Hi-Flow® Sampler) – 2000/03
94. API 14.1 Gas Sampling Standard - 2001
95. Ultrasonic Meter Installation Effects -2001
96. Orifice Meter Operational Effects - 2001
97. Orifice Plate Installation Effects - 2001
98. Gas Storage Well Rehabilitation and Damage Prevention - DamageExpert™ Software -2001
99. Satellite Radar Interferometry Measurement of Slope Movement - 2001
100. AIRCalc™ Software – 2001
101. Predicting the Integrity of Storage Caverns in Thin Salt Beds - 2002
102. ASME Standard for Pipeline Integrity Management - 2002
103. NACE Standard for Direct Assessment of Pipeline Corrosion - 2002
104. Revegetation of Rights-of-Way in Wetlands - 2002
105. Reference Manuals of Best Practices for Horizontal Directional Drilling and its Effects in Wetlands - 2002
106. Best Environmental Practices for Pipeline Construction - 2002
107. Integrated Vegetation Management – 2002
108. Environmental Effects of Pipeline Crossings of Streams - 2003
109. Standard for Coriolis Meters - 2003

EXPLORATION AND PRODUCTION

110. Glycol Dehydrator Emissions Calculation Program – GLYCalc™ - 1992/2000
111. Gas Composition Database – 1996/2001
112. Unconventional Natural Gas Database – 1999/2001

113.Nitrogen Removal Requirements Report - 1999
114.Downhole Gas/Water Separation CD-ROM - 1999
115.Advanced Crosswell Seismic Source - 1999
116.High Power VSP Mechanical Seismic Source - 1999
117.Advanced Stimulation Technologies CD-ROM - 1999
118.Coiled Tubing Standards - 1999
119.GRI–MSTR™ Software and Report to Predict Toxicity of Produced Water Discharged to the Marine Environment – 1999
120.ProTreat™ Software for Amine Gas Treating Applications - 2000
121.Cased Hole Resistivity Tool - 2000
122.Cased Hole Pressure Tool - 2000
123.Well Siting in Carbonates – EGI Report - 2000
124.Portfolio of Emerging Natural Gas Resources – Rocky Mountain Basins - 2000
125.Mercury Contamination Training Workshop – 2000
126.New Gas Exploration Concepts - 2001
127.StreamAnalyzer™ Software - 2001
128.Enhanced Seismic Spectral Processor - 2002
129.Evaluating Ecological Impacts at E&P Sites – 2002
130.Cement Pulsation Technology - 2003
131.Analysis for Radium in Marine Sediments - 2003
132.Produced Water Atlases and Handbook - 2003
133.Gas Resource and Production Potential of the Lewis Shales - 2003

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

PRE-FILED TESTIMONY OF CHRIS HUTZLER
ON BEHALF OF ATMOS ENERGY CORPORATION

I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Chris Hutzler. I am employed by the international management consulting firm of Towers Perrin. I am a Principal with the firm and I am responsible for assisting companies with the financial management of their retirement programs as well as plan design and benefit administration outsourcing. My business address is 12377 Merit Drive, Suite 1200, Dallas, Texas 75251.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND, AND CURRENT RESPONSIBILITIES.

A. I received a Bachelor of Arts degree from Kansas Wesleyan University in 1988. I have over 18 years of consulting experience, including 16 with Towers Perrin. I was elected Principal in 2001 and am currently the Senior Actuary for the Texas offices with responsibility for technical issues impacting pension plans. I am a Fellow in the Society of Actuaries, a Member of the American Academy of Actuaries, and an Enrolled Actuary under the Employment Retirement Income Security Act ("ERISA"). Additionally, I have the Chartered Financial Analyst® designation and am a member of the CFA Institute.

Q. WHAT ARE YOUR JOB RESPONSIBILITES?

A. I have specialized in retirement programs for my entire career. I consult with large corporations, including Atmos Energy Corporation ("Atmos or the "Company"), regarding retirement compensation matters.

Q. HAVE YOU EVER TESTIFIED BEFORE THE TENNESSEE REGULATORY AUTHORITY ("TRA") OR OTHER REGULATORY ENTITITES?

A. No, I have not formally testified before any regulatory commissions. However, I have previously assisted Atmos in rate case preparation and discussion with respect to this topic.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to sponsor the Company's inclusion of certain retirement plan costs in this rate proceeding and to explain why inclusion of such costs is reasonable and necessary.

II. OVERVIEW OF THE COMPANY'S PENSION ACCOUNT PLAN

Q. ARE YOU FAMILIAR WITH THE COMPANY'S PENSION ACCOUNT PLAN?

A. Yes, the Pension Account Plan, or "PAP," is a defined benefit plan to which the Company contributes for the financial security of its employees. The PAP is a cash balance plan that provides for annual pay credits and interest credits to a notional account for the employee. The pay credit amount is allocated based on the employee's age, number of service years, and annual salary. The interest credit amount is based on the 30-Year Treasury Securities Rate. The benefit payable from the plan is based on the notional account balance at commencement age. Atmos pays the full cost of the plan through payments to a trust funding the plan.

Q. WHAT COMPANY EMPLOYEES ARE ELIGIBLE TO PARTICIPATE IN THE PAP?

A. All employees in Tennessee are eligible to participate in the PAP on the first day of the month after they complete one year of Participation Service. Employees earn a year of Participation Service when they perform at least 1,000 hours of service during the first twelve months of their employment or during any calendar year thereafter.

Q. ARE YOU FAMILIAR WITH THE COMPANY'S COMPENSATION PHILOSOPHY?

A. Yes. My colleague, Atmos witness Mr. John Ellerman, fully explains the Company's compensation philosophy in his pre-filed direct testimony.

Q. HOW DOES THE PAP FIT INTO THE COMPANY'S COMPENSATION PHILOSOPHY?

A. As explained by Mr. Ellerman, the Company's compensation program is comprised of many components. One integral component is the PAP. A competitive pension plan improves the Company's ability to recruit and retain talented employees since pension plans are widely prevalent in the labor markets in which the Company competes for any key talent.

Q. ARE PENSION PLANS USED WIDELY IN THE UTILITY BUSINESS TODAY?

A. Yes, pension plans are widely prevalent in the utility sector.

III. PENSION PLAN COSTS

Q. HOW ARE PENSION PLAN COSTS TYPICALLY MEASURED?

A. There are various measures for pension plan cost. The two most prevalent are the Financial Accounting Standard (FAS) 87 pension cost (which was recently amended by FAS

158) and the actual cash contribution for the year based upon funding requirements established by the Employee Retirement Income Security Act (ERISA).

Q. HOW ARE THESE TWO METHODS DIFFERENT?

A. The FAS accounting and the ERISA funding requirements are separate calculations designed for different purposes. FAS 87, as amended by FAS 158, is designed as an objective way to represent the actual cost of the plan over the employee's service period, while the ERISA funding requirements simply ensure that the pension plan is sufficiently funded to pay the retirement benefits of the participants..

Q. HAS ATMOS ADOPTED FAS 87?

A. Yes. Atmos has adopted FAS 87. The rules under FAS 87 require companies to calculate their pension liabilities based on high quality corporate bond yields and use consistent methods and assumptions for purposes of calculating the cost of the pension plans for financial reporting purposes. These accounting rules were established to provide consistency in the way pension plan cost is calculated in the marketplace.

Q. HAS ATMOS ADOPTED FAS 158?

No. Atmos Energy will adopt FAS 158 on September 30, 2007.

Q. HOW DOES FAS 158 DIFFER FROM FAS 87?

FAS 158 carries forward the pension liability calculation and expense recognition rules of FAS 87. Therefore, FAS 158 **does not** change the amount of a company's liability or the level of cost recognized in its income statement. However, FAS 158 modifies the rules regarding the manner in which pension assets and liabilities are presented on the balance sheet and changes the disclosures required for the financial statements. Under FAS 87, companies were required to show the total pension plan liability as a footnote to the fi-

nancial statements rather than directly on the balance sheet. Under FAS 158, companies are now required to recognize in the balance sheet the overfunded or underfunded position of a pension plan, along with a corresponding noncash, after-tax adjustment to stockholders' equity.

Q. WHAT IS THE BEST MEASURE OF PENSION PLAN COST FOR RATEMAKING PURPOSES?

A. For the purposes of setting rates, the best measure of pension plan cost is one that achieves three objectives: i) that it is a reasonable measure ii) that it provides an objective way to represent the actual cost of a plan over the related employee service period and iii) that it can be consistently applied over time to different generations of ratepayers and over different jurisdictions. The FAS pension cost does a better job of satisfying the three objectives and is therefore a better measure of pension plan cost for ratemaking.

Q. WHY IS THE FAS PENSION COST A MORE REASONABLE MEASURE OF ACTUAL PENSION COSTS?

A. The FAS 87 pension cost is tied to the change in unfunded obligation over a year. Unlike the actual cash contribution made to the plan, the FAS pension cost is intended to reflect the cost of the pension plan over an employee's service period. Changes in a plan's unfunded obligations are recognized in an orderly fashion by amortizing the amount of the change over time. This measure of cost does a better job of tracking the expected change in the unfunded liability from year to year.

The FAS 87 pension cost is less subject to management discretion. The FAS pension cost is based on a single defined cost method and must be calculated based on a narrow range of assumptions, resulting in more consistency from year to year and across compa-

nies. In contrast, management has wide latitude to decide how much to contribute to the plan in a given year.

The FAS 87 pension cost better reflects the value of benefits earned during a year. As participants continue to receive pay and service in a pension plan, they earn benefits that cost the company money even though the actual cash contribution made for that particular year may differ significantly from the value of benefits earned during that year.

The FAS 87 pension cost is fairer to the different generations of ratepayers. Many of the cash funding rules have built-in thresholds. If these thresholds are met, the actual cash contribution may be $0; if these thresholds are not met, plan sponsors may make large contributions. In well funded plans, companies may not make a contribution for many years and then later make large contributions. Conversely, if management decides to contribute larger amounts now, contributions will be lower in future years, all other things being equal. If pension costs were recovered in the rates based on the actual cash contribution, costs would be recovered as the company contributed to the plan and not necessarily when benefits were earned by participants.

Q. HOW IS THE FAS PENSION COST DIFFERENT FROM THE ERISA FUNDING REQUIREMENTS?

A. The actual cash contribution is more subject to management discretion based on company-specific funding objectives. ERISA defines both minimum required and maximum tax deductible contribution amounts. Companies are free to contribute any amount between the minimum and the maximum. Thus, companies may make the minimum contribution to save cash for another business purpose or because they expect to earn a greater return in another business opportunity. Or, a company may make a larger contri-

bution to minimize the volatility of future contributions, avoid Pension Benefit Guaranty Corporation premiums, avoid quarterly contribution requirements, or to achieve a particular funding target.

ERISA cash funding methods and assumptions are not required to be consistent across companies. Companies have significant flexibility in the methods and assumptions used to calculate the funding requirements of a pension plan and also in the funding policy they adopt. Because of the variety of practices used to calculate the funding amounts, there is the potential for wide variation in contribution amounts for similar pension plans.

Q. IS THE USE OF THE FAS PENSION COST COMMONLY ACCEPTED FOR MEASURING PENSION COSTS?

A. Yes. It is my understanding that the FAS pension cost is the most common measure of pension cost used for ratemaking purposes in various states. In all the states where Atmos operates, recovery of the pension cost is based on the FAS pension cost measure. Using different measures of pension costs in different jurisdictions would, over time, advantage some states while disadvantaging others.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

VERIFICATION

STATE OF TEXAS)
)
COUNTY OF DALLAS)

I, Chris Hutzler, being first duly sworn, state that I am a Principal with the consulting firm of Towers Perrin, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Testimony of Chris Hutzler in support of Atmos Energy Corporation's Petition thereto pre-filed in this docket on the date of filing of this Petition are true and correct to the best of my knowledge, information and belief.

Chris Hutzler

Sworn and subscribed before me this 6 day of April, 2007.

TRACI L. USHER
Notary Public, State of Texas
My Commission Expires
October 28, 2007

Traci L Usher
Notary Public

My Commission Expires: Oct 28 2007

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

DANIEL M. MEZIERE

I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Daniel M. Meziere. My business address is 5430 LBJ Freeway, Suite 600, Dallas, Texas 75240.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Director of Accounting Services for Atmos Energy Corporation (hereinafter "Atmos" or the "Company").

Q. WHAT ARE YOUR JOB RESPONSIBILITIES?

A. I am primarily responsible for directing various accounting activities and policies within the Company. My primary duties include the oversight of general accounting, fixed assets accounting, accounts payable, payroll, and cost allocations. I also serve on an internal committee which is responsible for the oversight and monitoring of Sarbanes-Oxley (SOX) compliance. In addition, I work with both our internal and external auditors on implementing, testing, maintaining and modifying the Company's accounting controls, as well as interfacing between the auditors and the Company.

I am also responsible for ensuring effective financial and internal controls for the Company's accounting processes, system and procedures. I have knowledge of the Company's accounting activities, which include compiling, processing, reporting and analyzing financial information to satisfy the requirements of internal management, internal auditors, external independent auditors and regulatory agencies.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science degree in Accounting from East Central Oklahoma State University in 1983 and a Masters of Business Administration from the University of Dallas in 1997.

I have worked in the energy industry for almost 20 years in a variety of accounting and finance positions. I joined Atmos Energy Corporation in 2002 in my current position.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes. I am licensed by the State of Oklahoma as a Certified Public Accountant.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE TENNESSEE REGULATORY AUTHORITY OR OTHER REGULATORY ENTITIES?

A. Yes, I have testified before the Tennessee Regulatory Authority in Docket 05-00258. Additionally, I have testified before the Georgia Public Service Commission in Docket No. 20298-U, the Missouri Public Service Commission in Docket No. GR-2006-0387, the Railroad Commission of Texas in Docket No. 9676, and the Kentucky Public Service Commission in Case No. 2006-00464.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to authenticate the historic books and records of the Company and demonstrate the integrity of the financial information that has been filed in this case. I am also providing testimony concerning the Company's Cost Allocation Manual (CAM) which describes the methodology for shared services cost allocations.

Q. ARE YOU SPONSORING ANY SCHEDULES TO YOUR TESTIMONY?

A. Yes. I am sponsoring Schedule DMM-1. This exhibit is a true and correct copy of Atmos' current Cost Allocation Manual.

III. AUTHENTICATION OF BOOKS AND RECORDS

Q. ARE THE BOOKS AND RECORDS OF THE COMPANY PREPARED UNDER YOUR DIRECTION?

A. Yes, for the areas under my direction (which do not include gas accounting or taxation).

Q. HOW DOES ATMOS MAINTAIN AND UTILIZE ITS BOOKS AND RECORDS IN THE REGULAR COURSE OF BUSINESS?

A. Atmos maintains its books and records in accordance with the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts (USOA) and Generally Accepted Accounting Principles (GAAP). The USOA is the prescribed methodology for maintaining utility records in all of the state jurisdictions which regulate the Company's natural gas utility operations, which currently include

Colorado, Georgia, Illinois, Iowa, Kansas, Kentucky, Louisiana, Mississippi, Missouri, Tennessee, Texas and Virginia.

Atmos' accounting organization utilizes integrated computerized business systems to efficiently process, record and maintain transactions generated in the regular course of business. Financial transactions are created and entered into the system at or near the time of the transaction by the responsible personnel in various divisions having personal knowledge, or acting in reliance on information transmitted by persons having personal knowledge of the transactions, as well as of the applicable accounting procedures and requirements. Reports are generated by the system in the regular course of business to assist in management's review of the results of operations and to assist in the analysis of the cost data of gas operations.

Q. AS DIRECTOR OF ACCOUNTING SERVICES, HOW DO YOU ASSURE YOURSELF THAT TRANSACTIONS ARE RECORDED PROPERLY?

As Director of Accounting Services, I have personal knowledge of the organizational business processes and staffing in the Controllership function. The Controller's organization is staffed with highly qualified accounting managers and staff, with many accounting positions filled by CPAs. The managers in the organization are charged with the responsibility to inspect, review and revise, if appropriate, the work of the accountants they supervise. To fill certain management positions, an individual is required to have an accounting degree as well as significant accounting experience. We have established and maintained controls that ensure the accuracy of our books and records. These controls help identify any necessary adjustments to accounting entries which are then recorded to the original books and records in a timely manner.

Additionally, Atmos contracts with KPMG for internal audit services. This group periodically performs reviews of those controls.

Q. WHAT TYPES OF REGULAR AUDITS ARE CONDUCTED TO AUTHENTICATE ATMOS ENERGY'S BOOKS AND RECORDS?

A. Atmos' books and records are audited annually by the independent public accounting firm of Ernst & Young LLP. In addition, Ernst & Young LLP also performs reviews of Atmos' quarterly financial statements. These audits and reviews are conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States).

IV. COST ALLOCATION MANUAL

Q. WHAT IS THE COST ALLOCATION MANUAL?

A. The Cost Allocation Manual (CAM), contained in Schedule DMM-1, describes and documents the process whereby allocations are made within the books and records of the Company. These include allocations of various common expenses which are incurred for the benefit of two or more of the Company's rate divisions and are therefore allocable to those rate divisions. Additionally, the CAM describes and documents the processes whereby allocations are made between Atmos and its affiliates and between affiliates.

Q. ARE YOU RESPONSIBLE FOR OVERSIGHT OF THE CAM?

A. Yes. I coordinate and oversee the updating of the CAM.

Q. PLEASE DESCRIBE THE HISTORY OF THE CAM.

A. The CAM was first developed in response to Kentucky regulation 807 KAR 5:080 and was first filed with the Kentucky Public Service Commission in April of 2001.

The Company is required to update the CAM each year. Atmos has used the CAM to document its allocation processes in the regular course of business since it was first filed.

Q. ARE THE ALLOCATIONS DESCRIBED IN THE CAM USED IN EVERY JURISDICTION IN WHICH ATMOS OPERATES?

A. Yes. The CAM is uniformly applied in all twelve states in which Atmos has regulated utility operations for allocation of common costs among Atmos' various operating divisions, including Tennessee.

Q. DOES THE CAM DESCRIBE ALLOCATIONS OF BALANCE SHEET AMOUNTS?

A. No. The CAM describes how to allocate expense items from Atmos' income statement. Investment or balance sheet items are not allocated within Atmos Energy's books and records. Investment amounts are allocated only for ratemaking purposes in the context of a rate filing or certain regulatory reports. Company witness James C. Cagle is providing testimony in this filing, including Company's allocation of shared costs.

Q. IN YOUR OPINION, DOES THE COMPANY'S ALLOCATION PROCESS UNIFORMLY AND CONSISTENTLY ALLOCATE COMMON OR SHARED SERVICES COSTS?

A. Yes, the allocation process described in the CAM operates fairly and reasonably in allocating those costs on a uniform basis, both as between Atmos' various operating divisions and affiliates and between the various regulatory jurisdictions in which the Company operates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

VERIFICATION

STATE OF TEXAS)
)
COUNTY OF DALLAS)

I, Daniel M. Meziere, being first duly sworn, state that I am the Director of Accounting Services for Atmos Energy Corporation, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Testimony of Daniel M. Meziere in Support of Atmos Energy Corporation's Petition and the Exhibits thereto pre-filed in this docket on the date of filing of this Petition are true and correct to the best of my knowledge, information and belief.

Daniel M. Meziere

Sworn and subscribed before me this 18 day of April, 2007.

Easter Bunny Dixon
Notary Public
STATE OF TEXAS
My Commission Expires
March 05, 2011

Easter Bunny Dixon
Notary Public

My Commission Expires: March 5, 2011

Schedule
DMM-1

ATMOS ENERGY CORPORATION
COST ALLOCATION MANUAL
April 1, 2007

TABLE OF CONTENTS

Page No.	Description
2	Introduction
2	a. Corporate Structure
3	b. Accounting
4	c. Glossary of Terms
7	Capitalized overhead (general)
8	Stores overhead
9	Expenses in Shared Services – Customer Support cost centers
10	O&M Expenses in Shared Services – General Office cost centers
11	SSU – Customer Support depreciation and taxes, other than income taxes
12	SSU – General Office depreciation and taxes, other than income taxes
13	West Texas Division general office O&M, depreciation and taxes other than income taxes, to rate division level
14	Colorado-Kansas Division general office expenses to state regional office division level and rate division level
15	Colorado-Kansas Division state regional office division level expenses to rate division levels
16	Kentucky/Mid-States Division general office expenses to rate division level
17	Louisiana Division general office expenses to rate divisions.
18	Benefits cost allocation
19	Intercompany labor
20	Intercompany labor – Storage O&M Fee
21	Installing yard lines
22	Adjustments to uncollectible accounts expense
23	Intra-company labor allocation - other than operating division general office labor
24	Other income and interest expense
25	Gas Supply services between operating divisions and affiliate
26	Gas cost between state jurisdictions for contiguous systems
27	Gas storage services between an operating division and an affiliate
28	Allocation of lost & unaccounted (L&U) storage gas
29	Gas supply services
30	Facilities services
31	Working capital funds management
32	Gas sampling analysis
33	Gas storage services provided between affiliates
34	Storage Service to TLGP
35	Intrastate pipeline service
36	Salaries & benefits cost allocation
37	Property Insurance
38	Appendix A - Organizational Chart

1. Introduction:

a. Corporate Structure

Atmos Energy Corporation ("Atmos") operates its utility business in twelve states through seven operating divisions. The operating divisions are divisions of Atmos and are not subsidiaries or separate legal entities. The operating divisions are Mid-Tex and West Texas Divisions through which Atmos operates in Texas; Colorado-Kansas Division through which Atmos operates in Kansas, Colorado and a small portion of the Company's Missouri operations; Louisiana Division through which Atmos operates in Louisiana; Kentucky/Mid-States Division through which Atmos operates in Kentucky, Tennessee, Georgia, Missouri, Virginia, Illinois and Iowa; Mississippi Division through which Atmos operates in Mississippi and Atmos Pipeline-Texas Division through which Atmos operates its intrastate pipeline business in Texas. The operating divisions are not separate legal entities, and therefore, by definition, cannot be affiliates of Atmos.

Technical and support services are provided to the operating divisions by centralized shared services departments primarily located at the Atmos headquarters in Dallas. These centralized functions include, but are not limited to, Accounting, Gas Supply, Human Resources, Legal, Rates and the Customer Support. The costs for these shared services are allocated to the operating divisions. In addition, for operating divisions that operate in more than one rate jurisdiction, costs from the operating division general office are allocated to separate rate divisions within the operating division.

In addition to its utility business, Atmos also has non-utility operations. The non-utility business is operated through a number of subsidiaries which are separate legal entities and one division. A chart showing Atmos' current organizational structure is contained in Appendix A. As the organizational structure indicates, Atmos Energy Corporation owns 100% of Mississippi Energies, Inc, Blue Flame Insurance Services, LTD, PDH I Holding Company, Inc, and Atmos Energy Holdings, Inc. Atmos Energy Holdings, Inc. is the sole owner of Egasco, LLC, Atmos Pipeline and Storage, LLC, Atmos Energy Services, LLC, Atmos Power Systems, Inc., Atmos Energy Marketing, LLC, Enermart Energy Services Trust and United Cities Propane Gas, Inc. Atmos Pipeline and Storage, LLC is the sole owner of WKG Storage, Inc., Trans Louisiana Gas Storage, Inc., UCG Storage Inc., Atmos Exploration and Production, Inc., Trans Louisiana Gas Pipeline, Inc. and Atmos Gathering Company, LLC. Atmos Energy Services, LLC is the sole owner of Energas Energy Services Trust. Mississippi Energies, Inc. holds an equity interest in Legendary Lighting, LLC (50%) and Unitary GH&C Products, LLC (28%). Atmos Gathering Company, LLC is the sole owner of Straight Creek Gathering GP, LLC and the sole limited partner of Straight Creek Gathering, LP, holding a 99% interest. Straight Creek Gathering GP, LLC is the general partner holding a 1% interest in Straight Creek Gathering, LP.

Please note. The descriptions contained herein do not address tariffed services.

b. Accounting:

Atmos' account coding structure enables it to capture the costs for allocable activities. Expenses, Assets, and Liabilities for Atmos' shared services and other operating division general office divisions are coded to applicable location codes and cost centers which are then allocated to the appropriate rate divisions based upon the methodologies described herein. Allocations recorded in the books and records of the company, are primarily for management control purposes and may not be reflective of the allocation methodology used for rate making purposes.

Atmos account coding structure is as follows:

XXX.	XXXX.	XXXX.	XXXXX.	XXXXXX.	XXXX.
Company	Cost Center	FERC Account	Sub-Account	Service Area	Future Use
3 digit	4 digit	4 digits	5 digits	6 digits	4 digits

Within the above coding structure, "Company" and "Cost Center" are primarily utilized for management reporting purposes and reflects the internal management "cost responsibility" structure of Atmos Energy Corporation, exclusive of its subsidiaries. The term "Company" as utilized for account coding refers to a subsidiary or separate legal entity or to one of the Company's seven operating divisions under which Atmos conducts the vast majority of its utility business in twelve states. "Cost Center" addresses departmental cost responsibility and is primarily utilized for budget control purposes. Utilization of the "Company" or "Cost Center" fields is not suitable for financial or regulatory reporting purposes.

The field described by FERC account contains the three digit FERC USOA account plus one extension digit which in some cases is utilized by the FERC USOA.

The first three digits of the Service Area field are the primary coding utilized for cost allocations within Atmos and is generally referred to as "rate division number". This portion of the field denotes Atmos' various rate divisions as well as the Company's various shared services and operating division general office divisions. These codes are the primary source of information for regulatory reporting and rate activity. The remaining three digits represent "town" location which is utilized only for some accounts.

c. Glossary of Terms:

Affiliate - For purposes of this document, one or more of Atmos' subsidiaries.

Atmos Pipeline-Texas Division – The operating division within which Atmos Energy Corporation conducts its intrastate pipeline business within the State of Texas.

Below the Line - Amounts which are generally not included in an analysis of costs from which gas service rates are derived.

Colorado-Kansas Division - The operating division which Atmos Energy Corporation conducts business within the states of Colorado, Kansas and a portion of the Company's Missouri operation.

Composite Factor - The Company's general allocation factor which is derived for each applicable area based upon the simple average of gross plant in service, average number of customers and direct operation and maintenance expenses as a percentage of the total of each of these items.

Corporate Headquarters - The headquarters of Atmos Energy Corporation located in Dallas, Texas.

Cost Centers - Account coding which denotes cost responsibility primarily for management purposes.

Direct Charges - Those charges which may originate at a shared services department or operating division general office division which are booked directly to the applicable rate division.

FERC USOA - The Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission.

Kentucky/Mid-States Division - The operating division which Atmos Energy Corporation conducts business within the Commonwealth of Kentucky, the Commonwealth of Virginia, the states of Illinois, Iowa, Tennessee, Georgia and the majority of the Company's operations in Missouri.

Louisiana Division - The operating division which Atmos Energy Corporation does business within the State of Louisiana.

Mid-Tex Division - The operating division which Atmos Energy Corporation conducts business within the central part of the State of Texas.

Mississippi Division - The operating division which Atmos Energy Corporation does business in the State of Mississippi.

Municipal Jurisdiction - For Atmos' operations in Texas, each municipality which it serves has original jurisdiction over rates.

Operating Division - The Company's operations within each of its six utility regional divisions are typically referred to as "operating divisions" in more general discussions or "Company" within the context of Atmos account coding structure. Operating divisions are not subsidiaries or

separate legal entities. An operating division contains at least one rate division. Operating divisions with multiple rate divisions have one operating division general office rate division in addition to rate divisions corresponding to regulatory jurisdictional areas. There is also one non-utility operating division referred to as Atmos Pipeline – Texas Division.

Operating Division General Office - Administrative offices that are located outside of shared services offices and which serve as the base of operations and central office for each "operating division".

Rate Division - Denotes Atmos' regulatory jurisdictions that are defined by state boundaries, geographic boundaries within states or municipal boundaries within the State of Texas. The term also denotes Atmos' various shared services, and operating division general office divisions. These codes are the primary source for regulatory reporting and rate activity.

Service Area - The portion of the Company's account coding structure of which the first three digits denote rate division. The last three digits of this code denote "town" which is used only in certain instances.

Shared Services - The Company's functions that serve multiple rate divisions. These services include departments such as Legal, Billing, Call Center, Accounting, Gas Supply, Rates Administration among others. Shared Services is comprised of Shared Services – General Office and Shared Services – Customer Support

Shared Services – Customer Support – The Company's functions that serve multiple rate divisions. These services include billing, customer call center functions and customer support related services.

Shared Services – General Office – The Company's functions that serve multiple rate divisions. These services include all other functions not encompassed by Shared Services – Customer Support.

Subsidiaries - The Atmos Energy Corporation subsidiaries are:

Atmos Energy Holdings, Inc.
Atmos Energy Marketing, LLC
Atmos Exploration & Production, Inc.
Atmos Pipeline and Storage, LLC
Atmos Power Systems, Inc.
Atmos Energy Services, LLC
Blue Flame Insurance Services, LTD
Egasco, LLC
Energas Energy Services Trust
Enermart Energy Services Trust
Mississippi Energies, Inc.
Trans Louisiana Gas Pipeline, Inc.
Trans Louisiana Gas Storage, Inc.
UCG Storage, Inc.
WKG Storage, Inc.
Legendary Lighting, LLC (50%)
PDH I Holding Company, Inc.

Unitary GH&C Products, LLC (28%)
United Cities Propane Gas, Inc.
Atmos Gathering Company, LLC
Straight Creek Gathering GP, LLC
Straight Creek Gathering, LP

West Texas Division - The operating division which Atmos Energy Corporation conducts business within the western part of the State of Texas.

Service:	Capitalized overhead (general)
Description:	Overhead related to capital expenditures
Current Provider of Service	Shared Services Atmos Pipeline – Texas Louisiana Division general office Kentucky/Mid-States Division general office Colorado-Kansas Division general office Mid-Tex Division Mississippi Division West Texas Division
Current Use of Service	Rate divisions
Basis for allocation	Capitalized overhead costs are accumulated by operating division (and states level for multiple state divisions). Each operating division (and state) sets an application rate for the year based on projected expenditures. As expenditures for CWIP are booked, the overhead assigned is applied at the application rate. Periodically, the application rate is reviewed. Shared services overhead is allocated to operating divisions based on operating division capital expenditures. At the end of each quarter, the amount that has accumulated in the OH project is cleared to all eligible projects that incurred charges during that quarter.

Service:	Stores overhead
Description:	Overhead related to inventory warehousing is allocated to materials as issued.
Current Provider of Service	Shared Services Operating division general office
Current Use of Service	Atmos Pipeline – Texas West Texas Division rate divisions Louisiana Division rate divisions Kentucky/Mid-States Division rate divisions Mid-Tex Division rate division Colorado-Kansas Division rate divisions Mississippi Division rate division
Basis for allocation	Overhead costs for inventory items, including rent, labor, supervision and adjustments are accumulated by operating division. Each operating division sets an application rate for the year based on projected overhead and materials activity. As materials are issued from the warehouse, the overhead assigned is also allocated to the same account. Periodically, the balance in the undistributed stores overhead account is compared to the materials on hand balance and a new rate is determined. Shared Services stores overhead is allocated monthly to the operating divisions based on number of meters.

Service:	Expenses in Shared Services – Customer Support cost centers
Description:	Includes all expenses for Customer Support.
Current Provider Of Service	Shared Services
Current Use of Service	West Texas Rate Divisions Mid-Tex Division Louisiana Rate Divisions Kentucky/Mid-States Rate Divisions Colorado-Kansas Rate Divisions Mississippi Division
Basis for allocation	Costs are allocated to the applicable rate division level in total based on the average number of customers in each operating division as a percentage of the total number of customers in all of the operating divisions.

Service:	O&M Expenses in Shared Services – General Office cost centers
Description:	Includes O&M expenses in Shared Services – General Office.
Current Provider Of Service	Shared Services
Current Use of Service	Atmos Energy Marketing, LLC Atmos Power Systems, Inc Atmos Pipeline and Storage, LLC Atmos Energy Services, LLC West Texas Division Mid-Tex Division Atmos Pipeline - Texas Louisiana Division Kentucky/Mid-States Division Colorado-Kansas Division Mississippi Division
Basis for allocation	Costs are allocated to affiliates and operating divisions based on a composite factor applied to the Shared Services departments. Shared Services departments which provide services to the Company's affiliates, utilize a composite factor The computation includes the affiliates (if Mid-Tex and Atmos Pipeline-Texas are provided services by a department, the composite factor will include Mid-Tex and Atmos Pipeline-Texas at a 25%, 50%, 75% or 100% rate depending on how much service the department provides) . Shared Service departments that do not provide services to the Company's affiliates, utilize a composite factor that does not include the Company's affiliates (If Mid-Tex and Atmos Pipeline-Texas are provided services by a department, the composite factor will include Mid-Tex and Atmos Pipeline-Texas at a 25%, 50%, 75% or 100% rate depending on how much service the department provides) .

Service:	SSU – Customer Support depreciation and taxes other than income taxes
Description:	Includes all depreciation and taxes other than income tax charged in Shared Services – Customer Support.
Current Provider Of Services	Shared Services
Current Use of Service	West Texas Rate Divisions Louisiana Rate Divisions Kentucky/Mid-States Rate Divisions Mid-Tex Division Colorado-Kansas Rate Divisions Mississippi Division
Basis for allocation	Costs are allocated to the applicable rate division level in total based on the average number of customers in each operating division as a percentage of the total number of customers in all of the operating divisions.

Service:	SSU – General Office depreciation and taxes other than income taxes
Description:	Includes all depreciation and taxes other than income tax charged in Shared Services – General Office.
Current Provider Of Services	Shared Services
Current Use of Service	Atmos Energy Marketing, LLC Atmos Power Systems, Inc Atmos Pipeline and Storage, LLC Atmos Energy Services, LLC West Texas Division Mid-Tex Division Atmos Pipeline - Texas Louisiana Division Kentucky/Mid-States Division Colorado-Kansas Division Mississippi Division
Basis for allocation	Costs are allocated to the applicable operating divisions in total based on the Composite Factor. The Composite Factor is the simple average of three percentages: The percentage of Gross Direct Property Plant and Equipment in each operating division unit as a percentage of the total Direct Property Plant and Equipment in all of the operating divisions. The number of customers in each operating division as a percentage of the total number of customers in all of the operating divisions. The total direct O&M expense in each operating division as a percentage of the total direct O&M expense in all operating divisions.

Service:	West Texas Division general office O&M, depreciation and taxes other than income taxes to rate division levels.
Description:	Allocation of general office O&M, depreciation and taxes other than income tax costs to rate division levels
Current Provider of Service	West Texas Division general office
Current Use of Service	West Texas Division rate divisions
Basis for allocation	Costs are allocated to the applicable operating divisions in total based on the Composite Factor. The Composite Factor is the simple average of three percentages: The percentage of Gross Direct Property Plant and Equipment in each division as a percentage of the total Direct Property Plant and Equipment in the West Texas Division rate divisions. The number of customers in each rate division as a percentage of the total number of customers in the West Texas Division rate divisions. The total direct O&M expense in each municipal rate division as a percentage of the total direct O&M expense in the West Texas Division rate divisions.

Service:	Colorado-Kansas Division general office expenses to state regional office division level and rate division levels.
Description:	Allocation of division general office costs to state regional office division levels and rate division levels.
Current Provider of Service	Colorado-Kansas Division general office
Current Use of Service	Colorado-Kansas Operating Division state office divisions and rate divisions.
Basis for allocation	Costs are allocated to the applicable regional office and rate divisions in total based on the Composite Factor. The Composite Factor is the simple average of three percentages: The percentage of Gross Direct Property Plant and Equipment in each state as a percentage of the total Direct Property Plant and Equipment in Colorado-Kansas Division. The number of customers in each state as a percentage of the total number of customers in Colorado-Kansas Division. The total direct O&M expense in each state as a percentage of the total direct O&M expense in Colorado-Kansas Division.

Service:	Colorado-Kansas Division state regional office division level expenses to rate division levels.
Description:	Allocation of state regional office division level costs to rate division levels.
Current Provider of Service	Colorado-Kansas Division regional division office
Current Use of Service	Colorado-Kansas Division rate divisions
Basis for allocation	Costs are allocated to the applicable rate divisions in total based on the Composite Factor. The Composite Factor is the simple average of three percentages: The percentage of Gross Direct Property Plant and Equipment in each state as a percentage of the total Direct Property Plant and Equipment in Colorado-Kansas Division. The number of customers in each state as a percentage of the total number of customers in Colorado-Kansas Division. The total direct O&M expense in each state as a percentage of the total direct O&M expense in Colorado-Kansas Division.

Service:	Kentucky/Mid-States Division general office expenses to rate division level
Description:	Allocation of operating division general office costs to rate division levels
Current Provider Of Service	Kentucky/Mid-States Division general office
Current Use of Service	Kentucky/Mid-States Division rate divisions
Basis for allocation	Costs are allocated to the applicable rate divisions in total based on the Composite Factor. The Composite Factor is the simple average of three percentages: The percentage of Gross Direct Property Plant and Equipment in each state as a percentage of the total Direct Property Plant and Equipment in Kentucky/Mid-States Division. The number of customers in each state as a percentage of the total number of customers in Kentucky/Mid-States Division. The total direct O&M expense in each state as a percentage of the total direct O&M expense in Kentucky/Mid-States Division

Service:	Louisiana Division general office expenses to rate divisions.
Description:	Allocation of general office costs to rate division levels
Current Provider of Service	Louisiana Division general office
Current Use of Service	Louisiana Division rate divisions
Basis for allocation	Costs are allocated to the applicable rate divisions in total based on the Composite Factor. The Composite Factor is the simple average of three percentages: The percentage of Gross Direct Property Plant and Equipment in each state as a percentage of the total Direct Property Plant and Equipment in Louisiana Division. The number of customers in each state as a percentage of the total number of customers in Lousiana Division. The total direct O&M expense in each state as a percentage of the total direct O&M expense in Lousiana Division

Service:	Benefits cost allocation
Description:	Accumulates fringe benefits (workers compensation, basic life insurance, SFAS/106, medial/dental insurance, long term disability, ESOP, pension cost etc.) and allocates to the rate jurisdictions and/or subsidiaries.
Current Provider of Service	Shared Services
Current Use of Service	Atmos Pipeline – Texas Division Atmos Power Systems, Inc UCG Storage, Inc Atmos Energy Services, LLC Atmos Energy Marketing, LLC West Texas Division Louisiana Division Kentucky/Mid-States Division Mid-Tex Division Colorado-Kansas Division Mississippi Division
Basis for allocation	Fringe benefits components are accumulated by each operating division general office. Benefit expenses are allocated to rate jurisdictions by multiplying each rate jurisdiction's labor dollars by that particular operating division's benefits load percentage. The load percentage is calculated using total budgeted benefits divided by total labor. An allocation of fringe benefits from Shared Services to the subsidiaries is calculated based on the number of employees of each subsidiary that receive their benefits from Atmos Energy Corporation.

Service:	Intercompany labor
Description:	To the extent operating division employees provide labor services to another affiliate, the labor costs for the services will be charged to the appropriate affiliate.
Current Provider of Service	Atmos Pipeline - Texas Louisiana Division Colorado-Kansas Division Kentucky/Mid-States Division Mid-Tex Division Mississippi Division
Current Use of Service	UCG Storage, Inc. Atmos Energy Marketing, LLC WKG Storage, Inc Trans Louisiana Gas Pipeline, Inc. Trans Louisiana Gas Storage, Inc.
Basis for allocation	Labor charges are captured through direct time sheet entries and transferred to the appropriate subsidiary receiving the labor services.

Service:	Intercompany labor – Storage O&M Fee
Description:	To the extent operating division employees provide services to an affiliate a fee will be charged to the affiliate.
Current Provider of Service	Kentucky/Mid-States Division (Kentucky operations only)
Current Use of Service	WKG Storage, Inc UCG Storage, Inc
Basis for allocation	For the operation and maintenance of the East Diamond Storage Facilities, WKG Storage, Inc. shall pay Atmos Energy Corporation a monthly fee as set forth in the Natural Gas Storage Field and Pipeline Operations Agreement dated August 1, 2004. For the operation and maintenance of the Barnsley Storage Facilities, UCG Storage, Inc. shall pay Atmos Energy Corporation a monthly fee as set forth in the Natural Gas Storage Field and Pipeline Operations Agreement dated July 10, 2006.

Service:	Installing yard lines
Description:	Includes all costs incurred by the operations within Kentucky of the Kentucky/Mid-States Division to install customer-owned yard line. In Kentucky, Atmos does not own the yard line and the work it conducts on such yard lines is not regulated for ratemaking purposes.
Current Provider of Service	Kentucky/Mid-States Division
Current Use of Service	Kentucky/Mid-States Division (Kentucky operations only)
Basis for allocation	Materials and labor are charged to other expense below the line. Use of transportation or work equipment is recorded in the same account by journal entry based on actual usage. Revenue generated for these yard line billings are booked directly to other income below the line.

Service:	Adjustments to Uncollectible Accounts Expense
Description:	Allocation of additional expense amounts booked to adjust the Provision for Uncollectibles (Account 144)
Current Provider of Service	West Texas Division rate divisions Louisiana Division rate divisions Kentucky/Mid-States Division rate divisions Colorado-Kansas Division rate divisions Mid-Tex Division rate division Mississippi Division rate division
Current Use of Service	West Texas Division rate divisions Louisiana Division rate divisions Kentucky/Mid-States Division rate divisions Colorado-Kansas Division rate divisions Mid-Tex Division rate division Mississippi Division rate division
Basis of Intra-company Allocations	Costs are allocated to the rate divisions in total based on Sales Revenue.

Service:	Intra-company labor allocation – other than operating division general office labor
Description:	Certain employee activities cross multiple rate divisions within an operating division. The costs associated with such activities include labor, benefits and associated taxes.
Current Provider of Service	Atmos Pipeline – Texas Division West Texas Division Louisiana Division Kentucky/Mid-States Division Mid-Tex Division Colorado-Kansas Division Mississippi Division
Current Use of Service	Atmos Pipeline – Texas Division West Texas Division Louisiana Division Kentucky/Mid-States Division Mid-Tex Division Colorado-Kansas Division Mississippi Division
Basis of Intra-company Allocations	Labor associated with cross-jurisdictional activities is allocated to each jurisdiction based on the level of employee activity. The allocations are captured either through direct time sheet entries or fixed labor distribution percentages.

Service:	Other income and interest expense
Description:	Allocation of Shared Services' other income and interest expense
Current Provider of Service	Shared Services
Current Use of Service	West Texas Division Louisiana Division Kentucky/Mid-States Division Mid-Tex Division Colorado-Kansas Division Mississippi Division Atmos Pipeline – Texas
Basis for allocation	Interest Expense, Interest Income and Other Non Operating Income in shared services are allocated to each utility division based on the budget allocation percentages. The budget allocation is based on net investment by business unit as of the latest month available when the budget is prepared, with normalizing or averaging adjustments to working capital. Net investment is total assets less non-debt liabilities (excluding long-term debt, notes payable and current maturities.) The allocation factors are the same for the whole year

Service:	Gas supply services between the operating divisions and an affiliate
Description:	Atmos Energy Services provides gas supply administrative services to the operating divisions.
Current Provider of Service	Atmos Energy Services, LLC
Current Use of Service	West Texas Division Louisiana Division Mid-States Division Colorado-Kansas Division Mississippi Division
Basis for allocation	Costs are charged directly to a specific service area in Atmos Energy Services which is relative to each location of the operating divisions (i.e. Georgia costs accumulated in Atmos Energy Services are billed directly to the operating division for Georgia). These costs are billed to the operating divisions on a monthly basis. Administrative charges are allocated to each region based on total throughput volumes from the prior fiscal year.

Service:	Gas cost between state jurisdictions for contiguous systems.
Description:	Gas costs that apply to contiguous systems that cross state jurisdictional boundaries are allocated between those rate jurisdictions.
Current Provider of Service	West Texas Division Colorado-Kansas Division Kentucky/Mid-States Division
Current Use of Service	West Texas Division Colorado-Kansas Division Kentucky/Mid-States Division
Basis of Allocations	Allocations are based upon throughput for the West Texas Division and the Colorado-Kansas Division's Southeast Colorado/Southwest Kansas operations. For the Colorado-Kansas Division's Kansas/Missouri system and for the Kentucky/Mid-States Division, demand costs are allocated based on peak-day requirements. Commodity costs are allocated based upon throughput.

Service:	Gas storage services between an operating division and an affiliate
Description:	To the extent an operating division stores gas in a storage field owned by an affiliate, a rental fee for the use of the storage field shall be charged by the affiliate.
Current Provider of Service	UCG Storage, Inc. WKG Storage, Inc.
Current Use of Service	Kentucky/Mid-States Division
Basis for allocation	The annual demand charge between UCG Storage, Inc. and Atmos Energy Corporation (Tennessee operations only) is calculated based on fiscal year plant in service, gas inventory, actual operational costs incurred, and application of revenue and cost of capital conversion factors based on prior regulatory approval. In the calculation of the demand charge, costs not specifically related to a designated area are allocated to each affiliate based on percentage of total plant servicing that affiliate. The annual demand charge between WKG Storage, Inc. and Atmos Energy Corporation (Kentucky operation only) is based on services provided at actual cost, market rate, or as otherwise provided under tariff or contract.

Service:	Allocation of lost & unaccounted (L&U) storage gas
Description:	Lost & unaccounted (L&U) gas related to an affiliate's gas storage field is allocated to all affiliates and operating division that store gas in the field.
Current Provider of Service	UCG Storage, Inc.
Current Use of Service	UCG Storage, Inc. Kentucky/Mid-States Division (Tennessee Operations Only)
Basis for allocation	Lost & unaccounted (L&U) gas related to an affiliate's gas storage field is calculated by a third party on an annual basis and is allocated to all relevant subsidiaries and operating divisions that utilize the field for storage. The amount of L&U allocated is based on each subsidiary or operating division's average of the total volumes.

Service:	Gas supply services
Description:	Purchase, management and administration of gas supply arrangements
Current Provider of Service	Atmos Energy Marketing, L.L.C. Trans Louisiana Gas Pipeline, Inc
Current Use of Service	Kentucky/Mid-States Division Colorado-Kansas Division Louisiana Division Mississippi Division West Texas Division
Basis for allocation	Charges are a result of either an open market bid process or other market based rate.

Service:	Facilities services
Description:	System operating and maintenance services
Current Provider of Service	Louisiana Division
Current Use of Service	Atmos Energy Marketing, LLC
Basis for allocation	Rate per volumetric unit is cost based.

Service:	Working capital funds management
Description:	Funds are invested on behalf of or provided to affiliates based on operations.
Current Provider of Service	Atmos Energy Corporation
Current Use of Service	Atmos Energy Holdings, Inc. Atmos Energy Marketing, LLC Atmos Energy Services, LLC Atmos Power Systems, Inc. Atmos Pipeline and Storage, LLC UCG Storage, Inc. WKG Storage, Inc. Atmos Exploration & Production, Inc. Trans Louisiana Gas Storage, Inc. Trans Louisiana Gas Pipeline, Inc. Atmos Energy Services, LLC Egasco, LLC Enermart Energy Services Trust Energas Energy Services Trust Mississippi Energies, Inc. PDH I Holding Company, Inc United Cities Propane Gas, Inc Atmos Gathering Company, LLC. Straight Creek Gathering GP, LLC
Basis for allocation	Interest income or expense is recognized each month at the subsidiaries' level based on the average outstanding balance of each respective inter-company receivable/payable balance and Atmos' average effective rate of short term debt net of commitment fees plus 2.75 basis points.

Service:	Gas sampling analysis
Description:	To the extent an operating division provides gas-sampling analysis to an affiliate, the affiliate is charged a fee for the analysis and related services provided.
Current Provider of Service	Louisiana Division
Current Use of Service	Trans Louisiana Gas Storage, Inc. Trans Louisiana Gas Pipeline, Inc. Atmos Energy Marketing, LLC
Basis for allocation	The gas sampling analysis charge is based on the lesser of cost of service or market rate applicable to the affiliate's location for the services provided. Gas sampling analysis may also include other related services as required such as a moisture test, H2S, CO2, sample collection, and mileage.

Service:	Gas storage services provided between affiliates
Description:	To the extent an affiliate stores gas in a storage field owned by another affiliate, a fee for the use of the storage field shall be charged.
Current Provider of Service	WKG Storage, Inc. Trans Louisiana Gas Storage, Inc.
Current Use of Service	Atmos Energy Marketing, LLC Trans Louisiana Gas Pipeline, Inc.
Basis for allocation	The fee to the affiliate utilizing the storage service is based on services provided at actual cost, market rate, or as otherwise provided under tariff.

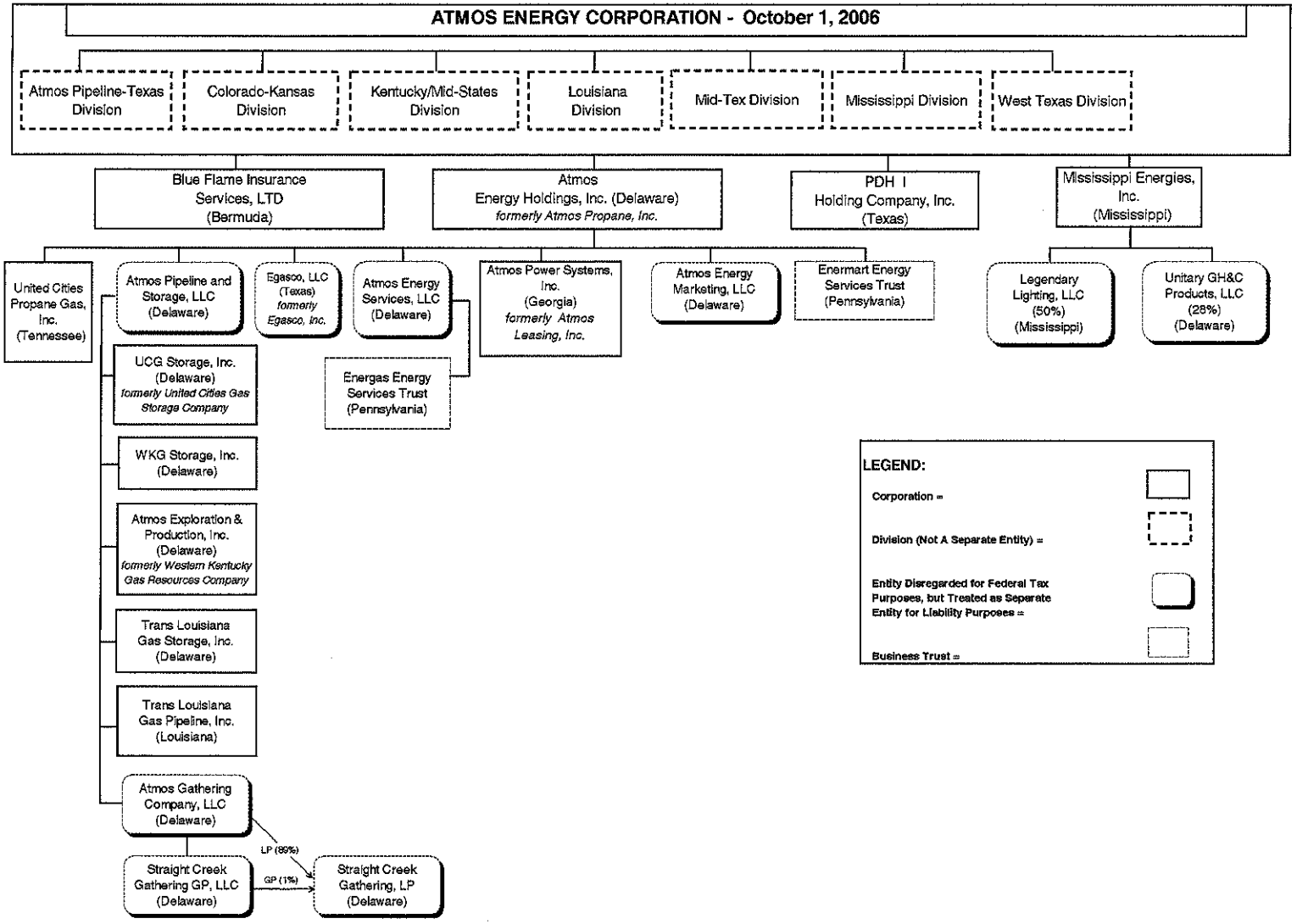
Service:	Storage service to TLGP
Description:	Storage Services
Current Provider of Service	Trans Louisiana Gas Storage, Inc.
Current Use of Service	Trans Louisiana Gas Pipeline, Inc.
Basis for allocation	Charges are based on a market rate.

Service:	Intrastate pipeline service
Description:	Intrastate pipeline service
Current Provider of Service	Trans Louisiana Gas Pipeline
Current Use of Service	Atmos Energy Marketing, LLC Louisiana Division
Basis for allocation	Charges are market based.

Service:	Salaries & benefits cost allocation
Description:	Salaries and benefits (medical insurance, profit sharing plan) cost allocations between affiliates.
Current Provider of Service	Atmos Energy Marketing, L.L.C
Current Use of Service	Trans Louisiana Gas Storage, Inc. Trans Louisiana Gas Pipeline, Inc. Atmos Energy Marketing. LLC Atmos Power Systems, Inc.
Basis for allocation	Costs are allocated based on each individual employee's calculated allocation rate between companies.

Service:	Property Insurance
Description:	Blue Flame Insurance Services, LTD. provides a direct property insurance policy. The policy covers the property against all risks of direct physical loss or damage.
Current Provider of Service	Blue Flame Insurance Services, LTD
Current Use of Service	Kentucky/Mid-States Division Colorado-Kansas Division Louisiana Division Mississippi Division Mid-Tex Division West Texas Division Atmos Pipeline – Texas Division Atmos Energy Marketing, LLC Atmos Exploration & Production, Inc. Atmos Pipeline and Storage, LLC Atmos Power Systems, Inc. Trans Louisiana Gas Pipeline, Inc. Trans Louisiana Gas Storage, Inc. UCG Storage, Inc. WKG Storage, Inc.
Basis for allocation	Atmos Energy Corp. is invoiced by Blue Flame Insurance Services. Costs are then further allocated based on property value of each affiliate.

Appendix A


ATMOS ENERGY CORPORATION - October 1, 2006
Atmos Pipeline-Texas Division
Colorado-Kansas Division
Kentucky/Mid-States Division
Louisiana Division
Mid-Tex Division
Mississippi Division
West Texas Division
Blue Flame Insurance Services, LTD (Bermuda)
Atmos Energy Holdings, Inc. (Delaware) formerly Atmos Propane, Inc.
PDH I Holding Company, Inc. (Texas)
Mississippi Energies, Inc. (Mississippi)
United Cities Propane Gas, Inc. (Tennessee)
Atmos Pipeline and Storage, LLC (Delaware)
Egasco, LLC (Texas) formerly Egasco, Inc.
Atmos Energy Services, LLC (Delaware)
Atmos Power Systems, Inc. (Georgia) formerly Atmos Leasing, Inc.
Atmos Energy Marketing, LLC (Delaware)
Enermart Energy Services Trust (Pennsylvania)
Legendary Lighting, LLC (50%) (Mississippi)
Unitary GH&C Products, LLC (28%) (Delaware)
UCG Storage, Inc. (Delaware) formerly United Cities Gas Storage Company
Energas Energy Services Trust (Pennsylvania)
WKG Storage, Inc. (Delaware)
Atmos Exploration & Production, Inc. (Delaware) formerly Western Kentucky Gas Resources Company
Trans Louisiana Gas Storage, Inc. (Delaware)
Trans Louisiana Gas Pipeline, Inc. (Louisiana)
Atmos Gathering Company, LLC (Delaware)
LP (99%)
GP (1%)
Straight Creek Gathering GP, LLC (Delaware)
Straight Creek Gathering, LP (Delaware)
LEGEND:
Corporation =
Division (Not A Separate Entity) =
Entity Disregarded for Federal Tax Purposes, but Treated as Separate Entity for Liability Purposes =
Business Trust =

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	**Docket No. 07-**
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	

DR. DONALD A. MURRY

I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME.

A. My name is Donald A. Murry.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a Vice President and economist with C. H. Guernsey & Company. I work out of the Oklahoma City, Oklahoma office at 5555 North Grand Boulevard, 73112, and the Tallahassee, Florida office. I am also a Professor Emeritus of Economics on the faculty of the University of Oklahoma.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

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

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. From 1964 to 1974, I was an Assistant and Associate Professor and Director of Research on the faculty of the University of Missouri - St. Louis. For the period 1974-98, I was a Professor of Economics at the University of Oklahoma, and

since 1998, I have been Professor Emeritus at the University of Oklahoma. Until 1978, I also served as Director of the University of Oklahoma's Center for Economic and Management Research. In each of these positions, I directed and performed academic and applied research projects related to energy and regulatory policy. During this time, I also served on several state and national committees associated with energy policy and regulatory matters, published, and presented a number of papers in the field of regulatory economics in the energy industries.

Q. WHAT IS YOUR EXPERIENCE IN REGULATORY MATTERS?

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

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE OR BEEN AN EXPERT WITNESS IN PROCEEDINGS BEFORE REGULATORY BODIES?

A. Yes, I have appeared before the U.S. District Court-Western District of Louisiana, U.S. District Court-Western District of Oklahoma, District Court-Fourth Judicial District of Texas, U.S. Senate Select Committee on Small Business, Federal Power Commission, Federal Energy Regulatory Commission, Interstate Commerce Commission, Alabama Public Service Commission, Alaska Public Utilities Commission, Arkansas Public Service Commission, Colorado Public Utilities Commission, Florida Public Service Commission, Georgia Public Service Commission, Illinois Commerce Commission, Iowa Commerce Commission, Kansas Corporation Commission, Kentucky Public Service Commission, Louisiana Public Service Commission, Maryland Public Service Commission, Mississippi Public Service Commission, Missouri Public Service Commission, Nebraska Public Service Commission, New Mexico Public Service Commission, New York Public Service Commission, Power Authority of the State of New York, Nevada Public Service Commission, North Carolina Utilities Commission, Oklahoma Corporation Commission, South Carolina Public Service Commission, Tennessee Public Service Commission, Tennessee Regulatory Authority, The Public Utility Commission of Texas, the Railroad Commission of Texas, the State Corporation Commission of Virginia, and the Public Service Commission of Wyoming.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A. Atmos Energy Corporation ("Atmos Energy") retained me to analyze the current cost of capital and to recommend a rate of return and capital structure that are appropriate for the Tennessee operating division in this proceeding. In this

testimony, I refer to the Tennessee operating division of Atmos Energy as "Atmos" or the "Company."

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am sponsoring an exhibit that I have attached to my testimony which includes Schedules DAM-1 through DAM-31.

Q. WAS THIS EXHIBIT PREPARED EITHER BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

III. SUMMARY

Q. WHAT SUBJECT AREAS DO YOU INTEND TO COVER IN YOUR TESTIMONY?

A. I will testify concerning the following subject areas:

1. Utility Regulation and Fair Rate of Return.
2. The Economic Environment.
3. Selection and Analysis of Comparable Companies to Atmos Energy.
4. The Capital Structure of Atmos Energy.
5. Cost of Long-Term Debt for Atmos Energy.
6. Financial risks to Atmos Energy's common equity investors.
7. Business risks to Atmos Energy's common equity investors.
8. Financial Statistics for Atmos Energy and Comparable Gas Distribution Companies.
9. Cost of Common Stock for Atmos Energy.

10. The Discounted Cash Flow ("DCF") Method and its Strengths, its Weaknesses, Methodology and Results.

11. The Capital Asset Pricing Model ("CAPM") and its Strengths, Weaknesses, Methodology and Results.

12. Interpretation of the DCF and CAPM results.

13. Recommended Allowed Return on Common Stock for Atmos Energy.

14. Financial integrity test--Comparison of After-Tax Interest Coverage Ratio for Atmos Energy with Comparable Gas Distribution Companies.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony addresses the following issues:

- I was retained by Atmos Energy to analyze the current cost of capital and to recommend a rate of return and capital structure appropriate for the Tennessee operating division in this proceeding.
- I studied the current economic environment and, in particular, the current and forecasted level of interest rates.
- I studied Atmos Energy's capital structure, cost of debt, and cost of common stock appropriate for setting rates in this case.
- Atmos Energy's current capital structure reflects a relatively high amount of leverage and low common equity ratio when compared to its historical capital structure.
- The common equity ratio of Atmos Energy is lower than the common equity ratios of other typical gas distribution utilities.

- Atmos Energy's current common equity ratio has been influenced by a large debt issue used to finance an acquisition. Therefore, one can view it as a transitional common equity ratio.
- Consistent with the management of Atmos Energy's announced intention for a recent common stock issuance, the Company's common equity ratio has been increasing.
- In this rate case, I am recommending a projected capital structure for Atmos Energy of 51.50 percent long-term debt and 48.50 percent common equity.
- Atmos Energy's appropriate cost of debt for this proceeding is the embedded weighted average cost of long-term debt of 6.10 percent.
- To assess the cost of Atmos Energy's common stock equity, I reviewed indicators of financial and business risks for Atmos Energy and compared them to a group of comparable natural gas distribution utilities.
- Although the business risk of Atmos Energy appears to be similar to the business risk faced by a typical natural gas distribution utility in today's markets, Atmos Energy's financial risk is decidedly greater, due to its relatively low common stock equity.
- My review of applicable financial statistics showed that *Value Line* forecasts a return on common stock for a group of comparable local gas distribution companies ("LDCs") of 12.3 percent in 2007. At the same time, *Value Line* predicts only a 9.0 percent return for Atmos

Energy. Even with a relatively low common equity ratio, Atmos Energy's common stock earnings are significantly lower than the average of the group of comparable LDCs.

- The combination of a low common equity ratio and a low realized equity return means that Atmos Energy has a relatively low weighted average cost of capital. A comparison of Atmos Energy's total capital costs to a group of comparable utilities shows this to be the case.
- I used two methods, the Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM") for my market analysis of the costs of common equity for Atmos Energy and for each of the comparable natural gas distribution utilities.
- From this analysis, the relevant common equity results for Atmos Energy for the CAPM method ranged from 11.46 percent to 12.22 percent and the DCF method range for a group of comparable companies with bond ratings similar to Atmos was 11.40 percent to 12.00 percent.
- These results centered on a range of 11.5 percent to 12.0 percent, and I am therefore recommending a return to common equity for Atmos Energy of 11.75 percent. My recommended total cost of capital for Atmos Energy is 8.84 percent.
- To verify the adequacy of my recommended return for Atmos Energy, I compared the After-Tax Interest Coverage for Atmos Energy, at this return, to the current After-Tax Interest Coverage for the comparable

LDCs. My recommended allowed return for Atmos Energy will result in an After-Tax Interest Coverage of just 2.81 times. This compares to an average coverage for the comparable companies of 3.80 times. It further confirms that my recommended allowed return is a very conservative recommendation.

IV. UTILITY REGULATION

Q. HOW DID THE POLICIES AND PROCEDURES OF UTILITY REGULATION AFFECT YOUR OPINION IN REGARD TO COST OF CAPITAL?

A. I based my analysis and recommendations on the role of regulation in the natural gas distribution industry. Economies of scale at the distribution level of utility service indicate that the duplication of facilities by more than one firm may be economically inefficient. For this reason, analysts have long recognized the likely presence of market power in a franchised utility market. This is the principal economic rationale for utility regulation.

Recognizing this market structure, the objective of my analysis was to determine an allowed return for the Company which would be sufficient to recover the costs of providing service. Furthermore, the allowed return should not be higher than necessary to attract and maintain invested capital that provides utility service. From my perception as an economist, I also believe that these analytical objectives are consistent with the legal standard of a "fair rate of return" in regulation.

Q. WHAT DID YOU MEAN BY USING THE TERM "LEGAL STANDARD" WHEN YOU REFERRED TO THE CONCEPT OF A "FAIR RATE OF RETURN?"

A. The term "fair rate of return," as I use it, is consistent with the return that meets the standards set by the United States Supreme Court decision in *Bluefield Water Works and Improvement Company vs. Public Service Commission, 262 U.S. 679 (1923) ("Bluefield")*, and as further modified in *Federal Power Commission vs. Hope Natural Gas Company, 320 U.S. 591 (1944) ("Hope")*. My understanding of these decisions is that they characterize a "fair rate of return" as one that provides earnings to investors which are similar to returns on alternative investments in companies of equivalent risk.

Q. IS THE TERM A "FAIR RATE OF RETURN" IMPORTANT TO YOUR ANALYSIS?

A. Yes. The term "fair rate of return" is important in ratemaking because it sets a standard for the rate of return, and this was the objective of my analysis and recommendation. Generally, a return is sufficient if it enables the company to operate successfully and provide utility services, attract capital, maintain its financial integrity, and compensate investors for the associated risks of investment. This interpretation, I believe, is consistent with the regulatory standard I discussed previously.

V. ECONOMIC ENVIRONMENT

Q. WHAT ECONOMIC FACTORS WERE IMPORTANT TO YOUR ANALYSIS OF ATMOS' COST OF CAPITAL IN THIS PROCEEDING?

A. Major factors in the current economic environment that affect investors' decisions are their expectations regarding inflation and interest rates. Inflationary pressures are a cause of tighter federal monetary policy, which leads generally to higher interest rates. Higher interest rates, in turn, lead to higher costs of capital for regulated utilities. In the case of a regulated utility such as Atmos, the regulatory environment is also a critical component of the business environment. Anticipated regulatory actions, as well as forecasts of inflation and interest rates, affect investors' expectations of utility returns and their evaluations of the risks and returns on alternative investments.

Q. CAN YOU SUMMARIZE THE CURRENT ECONOMIC ENVIRONMENT?

A. Yes. Through the first quarter of 2007, economic activity is expanding at a moderate pace and *Blue Chip Financial Forecasts (Blue Chip)* predicts real Gross Domestic Product (GDP) will increase to 3.0 percent by the fourth quarter and grow at an approximately 2.6 percent rate in 2007. (See Schedule DAM-1) Manufacturing activity is increasing nationwide causing labor markets to remain tight with some businesses having a difficult time finding skilled and professional workers. Factory production rose 0.7 percent in March, up from 0.1 percent in February. The Federal Open Market Committee predicts unemployment will

average 4.5 percent to 4.75 percent in the fourth quarter of 2007 as compared to 4.6 percent in December 2006.

The housing market remains soft, with some recent signs of improvement, and analysts expect high inventories of new homes to keep residential construction in check. In contrast, commercial real estate markets are strong. Lending activity is up in the commercial and industrial sectors, while residential lending and refinancing continues to weaken.

Q. WHAT ARE SOME OF THE CONSEQUENCES OF THIS ECONOMIC GROWTH?

A. Strong manufacturing activity, spurred by economic growth abroad and increasing exports, should keep labor markets tight. Many forecasters predict low unemployment will offset negative consumer confidence associated with the housing slump and any decline in home prices. Significantly, the jobless rate fell to 4.4 percent in March—matching the lowest rate in five years.

Housing starts rose a stronger-than-expected 0.8 percent in March to an annual rate of 1.52 million units. Building permits also rose 0.8 percent in March, indicating good expected future construction activity. Generally, many forecasters anticipate that real GDP growth will improve into 2008 as the drag from slow residential investment ebbs and capital spending improves.

Q. YOU MENTIONED THAT YOU USED INFORMATION AND FORECASTS FROM *BLUE CHIP FINANCIAL FORECASTS* IN YOUR ANALYSIS. CAN YOU EXPLAIN WHY YOU USED *BLUE CHIP?*

A. *Blue Chip Financial Forecasts* is a very respected publication that reports the consensus forecasts of financial forecasters. These consensus forecasts, and the predictions of the individual forecasters embodied in them, are available to knowledgeable investors. Consequently, these forecasts, which are from reliable sources, are very likely to affect investors' decisions.

Q. YOU MENTIONED THE INFLATION RATE AS AN IMPORTANT FACTOR TO EXAMINE. WHAT ARE THE CURRENT INFLATION CONSIDERATIONS?

A. The economy currently shows definite signs of increasing inflation after several years of relatively stable prices. In the first quarter 2007, overall consumer prices increased at a 4.7 percent seasonally adjusted annual rate. Significantly, this rate is nearly twice the 2.5 percent rate for all of 2006. Additionally, the Federal Reserve's preferred measure of inflation, the Commerce Department's Personal Consumption Expenditures Price Index, was up 2.4 percent in February from a year earlier. This is above the Fed "comfort zone" of 1 percent to 2 percent. As though in confirmation of the relative importance of this development, the minutes from the March 20-21 Open Market Committee meeting of the Federal Reserve state, "Further policy firming might prove necessary to foster lower inflation." Inflation pressures that lead to tighter money imply a rising cost of capital generally. As Schedule DAM-2 illustrates, increasing inflationary pressures are troubling to the financial markets and have the full attention of federal policymakers.

Q. HOW HAVE THE GENERAL LEVEL OF ECONOMIC ACTIVITY AND INFLATION EXPECTATION AFFECTED INTEREST RATES?

A. The state of the economy and economic expectations provide an important background for my cost of capital analysis because inflationary pressures almost certainly lead to actions by the Federal Reserve to increase interest rates. For example, the Federal Open Market Committee ("FOMC") raised interest rates 17 times between June 2004 and June 2006. Although the FOMC recently has forgone raising short-term rates further, it has indicated it will remain vigilant regarding inflation concerns. For example, in a speech at Rutgers University on April 17, Philadelphia Federal Reserve Bank President Charles Plosser said inflation remains too high for the central bank's comfort.

Q. YOU DISCUSSED SOME FACTORS CURRENTLY AFFECTING INTEREST RATES. WHAT ARE THE RECENT AND CURRENT LEVELS OF BOND RATES?

A. As shown on Schedule DAM-3, according to the Federal Reserve, the yields on 10-year Treasury Notes bottomed out in 2003 but have been increasing ever since. Currently, the 10-year Treasury notes and Baa-corporate rate are about 4.56 percent and 6.27 percent, respectively.

Q. WHAT IS THE FORECASTED LEVEL OF BOND INTEREST RATES?

A. Generally, analysts expect long-term bond rates to continue rising. The *Blue Chip* forecasts for the Baa-corporate rate and the 30-year Treasury rate are for continued increases to 6.7 percent and 5.0 percent respectively into 2008. (See Schedules DAM-4.1 and DAM-4.2.) *Value Line* provides a longer-term forecast

for the 2010-12 period and also shows interest rate increases out to that period. I have shown this continued forecasted growth in interest rates in Schedules DAM-5.1 and 5.2.

Q. CAN YOU SUMMARIZE HOW THE ECONOMIC ENVIRONMENT WAS IMPORTANT TO YOUR RECOMMENDATION IN THIS PROCEEDING?

A. The rates set in this proceeding will be in effect during a period of rising inflation and interest rates, and I considered that background for my analysis. Rising inflation and interest rates erode earnings and adversely affect the cost of a utility's debt and equity. Utilities such as Atmos are particularly sensitive to the effects of inflation and increasing interest rates because they are capital intensive with large interest payment obligations. The rising costs erode utility margins. That is, rising inflation and interest rates increase the risk that common stockholders will not achieve their anticipated returns on investment.

VI. SELECTION OF COMPARABLE COMPANIES

Q. YOU STATED THAT YOU COMPARED YOUR ANALYTICAL RESULTS FOR ATMOS ENERGY TO THE RESULTS FROM SIMILAR CALCULATIONS FOR A GROUP OF COMPARABLE NATURAL GAS DISTRIBUTION COMPANIES. WHAT CRITERIA DID YOU USE TO SELECT THE UTILITIES THAT YOU IDENTIFIED AS COMPARABLE TO ATMOS ENERGY FOR YOUR ANALYSIS?

A. I identified criteria that were similar to the characteristics of Atmos Energy. Using these criteria, I selected a group of local gas distribution utilities for comparative analysis. I first selected the comparable companies from a group of gas distribution companies reported on by *Value Line.* These companies are all publicly traded utilities. Second, because of the importance of size in determining the cost of capital of a utility, I limited the group of distribution companies to firms with a market capitalization of at least $1 billion. Third, as a measure of financial health and similar investor expectations, I excluded companies that do not pay a dividend. Finally, I limited this group to companies that are primarily gas distributors.

Q. YOU USED SELECTION CRITERIA SIMILAR TO ATMOS ENERGY WHEN SELECTING A GROUP OF COMPANIES TO STUDY. WHAT WAS THE REASON FOR THIS?

A. I selected a group of companies for analysis that were comparable to Atmos Energy in many respects, so their financial risks and the associated costs of common stock equity would be similar. In this way, I could use the results from analysis of the comparable group as a surrogate for Atmos Energy analytically.

Q. BASED ON YOUR SELECTION CRITERIA, WHAT COMPANIES DID YOU SELECT AS COMPARABLE TO ATMOS ENERGY FOR YOUR ANALYSIS?

A. I selected eight natural gas distribution utilities that are similar in many respects to Atmos Energy. These are AGL Resources, New Jersey Resources, NICOR,

Inc., Northwest Natural Gas, Piedmont Natural Gas, South Jersey Industries, Southwest Gas, and WGL Holdings, Inc.

VII. CAPITAL STRUCTURE

Q. WHAT IS THE CAPITAL STRUCTURE THAT YOU ARE RECOMMENDING FOR ATMOS IN THIS PROCEEDING?

A. Atmos Energy raises and provides the capital to the Tennessee operating division. I believe that the capital structure of the parent company is appropriate for calculating the cost of capital in this proceeding. I have illustrated this capital structure in Schedule DAM-6. Long-Term Debt is 51.50 percent of total capital, and Common Equity is 48.50 percent of total capital.

Q. HOW DOES YOUR RECOMMENDED CAPITAL STRUCTURE FOR ATMOS COMPARE TO THE HISTORICAL CAPITAL STRUCTURE OF ATMOS ENERGY?

A. I am recommending a common equity ratio for ratemaking for Atmos in this proceeding that is within the range of Atmos Energy's recent, historical common equity ratios. For example, in 2004, which was just prior to issuing debt to finance a significant acquisition, the common stock equity level was 56.8 percent. Then following that acquisition, the common equity ratio of Atmos Energy was exceptionally low, but it appears to be increasing to more typical levels. *Value Line* data forecast the average common stock equity of the comparable gas distribution utilities in 2007 at 55.4 percent. This comparison further demonstrates that the common equity ratio estimated by Atmos and proposed in this proceeding

is a reasonable one for setting rates which will be in effect during the next several years. I have illustrated these equity comparisons in Schedule DAM-7.

Q. IS THE CAPITAL STRUCTURE THAT YOU PROPOSE FOR RATEMAKING IN THIS PROCEEDING CONSISTENT WITH YOUR UNDERSTANDING OF ATMOS ENERGY'S PLANNED FINANCING?

A. Yes. For example, Atmos Energy's 10-K Report for the Fiscal Year 2006, at page 52, describes the planned future capitalization levels, as follows:

> Within three to five years, we intend to reduce our capitalization ratio to a target range of 50 to 55 percent through cash flow generated from operations, continued issuance of new common stock under our Direct Stock Purchase Plan and Retirement Savings Plan, and access to the equity capital markets.

This stated objective is consistent with the capital structure that I am recommending for the purpose of setting rates in this proceeding.

Q. ARE YOU AWARE OF EVIDENCE THAT ATMOS ENERGY WILL ISSUE AN AMOUNT OF COMMON STOCK SUFFICIENT TO RETURN TO ITS PRIOR COMMON EQUITY LEVELS?

A. Following other acquisitions, Atmos Energy has issued common stock over time and brought its common equity ratio back to a level which is close to my recommended level in this proceeding. As Schedule DAM-8 shows, *Value Line* predicts that Atmos Energy's common stock outstanding will grow at a rate which is many times faster than any of the comparable LDCs. In fact, a recent common stock issuance yielding net proceeds of approximately $192 million by Atmos Energy is consistent with these *Value Line* forecasts. Therefore, financing to date by Atmos Energy supports these forecasts. At the time of this issue, Atmos

Energy's management stated that the purpose of this offering was to pay down outstanding debt.

Q. YOU RECOMMENDED A CAPITAL STRUCTURE FOR RATEMAKING IN THIS PROCEEDING THAT DID NOT INCLUDE ANY SHORT-TERM DEBT. WHAT WAS YOUR REASON FOR NOT INCLUDING ANY SHORT-TERM DEBT IN THIS CAPITAL STRUCTURE?

A. I did not include short-term debt because it is not part of Atmos Energy's permanent capital structure. Atmos Energy does not use short-term debt to support its long-term assets which provide utility service to its customers. Atmos Energy's short-term debt fluctuates greatly and even disappears for months at a time. It is obvious that Atmos Energy uses its short-term debt to support such variable operating expenses as the cost of purchased gas.

Q. DID YOU INVESTIGATE WHETHER ATMOS ENERGY'S SHORT-TERM DEBT SUPPORTS LONG-TERM ASSETS WHICH PROVIDE UTILITY SERVICE TO ITS CUSTOMERS?

A. Yes. I reviewed the historical end of month short-term debt balances of Atmos Energy. As Schedule DAM-9 clearly illustrates, Atmos Energy uses short-term debt to meet the fluctuating costs of gas and other operating expenses. Because the short-term debt of Atmos Energy frequently falls to zero and remains at that level for months at a time, it cannot be supporting the long-term assets of the utility.

VIII. COST OF LONG-TERM DEBT

Q. YOU SAID THAT YOU DETERMINED THE COST OF LONG-TERM DEBT OF ATMOS ENERGY. WHAT DID YOU DETERMINE IS THE WEIGHTED AVERAGE COST OF LONG-TERM DEBT APPROPRIATE FOR SETTING RATES IN THIS PROCEEDING?

A. Atmos Energy's embedded weighted average cost of long-term debt as of October 31, 2008, is 6.10 percent. I have illustrated this calculation in Schedule DAM-10.

IX. FINANCIAL RISK

Q. YOU MENTIONED THAT YOU INVESTIGATED ATMOS ENERGY'S "FINANCIAL RISK" TO ITS COMMON EQUITY INVESTORS. WHAT IS FINANCIAL RISK?

A. Financial risk is the risk to a company's common stockholders that is a consequence of its use of financial leverage. This risk results from using fixed income securities to finance the firm. Because the return to common stockholders is the income available after a company pays its debt holders, it is a residual return. This means it is less certain than the contracted return to debt holders.

Q. CAN YOU READILY DETERMINE THE LEVELS OF FINANCIAL RISK FACED BY COMMON STOCKHOLDERS FROM THE FINANCIAL INFORMATION THAT YOU STUDIED?

A. In general, the lower the common stock equity ratio, the greater the relative prior obligation owed to debt holders. Consequently, all things being equal, the risk faced by common stockholders is greater if the common equity ratio is smaller.

Q. DO YOU BELIEVE FINANCIAL RISK IS IMPORTANT FOR AN ANALYST TO CONSIDER WHEN ESTIMATING THE COST OF CAPITAL IN A RATE PROCEEDING?

A. Yes. Of course, in order to attract and maintain capital, firms must compensate common stock investors for this risk. Financial risk is a very basic determinant of the cost of capital, and consequently, it affects the required return necessary and sufficient in a rate proceeding.

Q. HOW DID FINANCIAL RISK ENTER INTO YOUR DETERMINATION OF THE COST OF COMMON EQUITY OF ATMOS IN THIS PROCEEDING?

A. As I noted previously, the common equity of Atmos Energy, which is appropriate for this proceeding, is 48.50 percent. Also, as I noted earlier, the estimated average common equity ratio for the comparable companies is 55.4 percent. The capital structures of the comparable utilities are less risky than the capital structure of Atmos Energy as indicated by the respective equity ratios. Consequently, even at my recommended capital structure, financial risk is a very significant factor for setting an allowed return in this proceeding. As a corollary to this high risk common equity ratio, for ratemaking purposes, this is also relevant because common equity is the highest cost component of permanent capital.

Q. DID YOU REVIEW ANY OTHER MEASURES OF FINANCIAL RISK REPORTED BY THIRD PARTIES?

A. Yes, I reviewed some widely recognized measures of financial health that are largely influenced by the level of financial risk. For example, I specifically

compared *Value Line's* measure of "Financial Strength," Standard & Poor's ("S&P's") Credit Ratings, and S&P's "Business Position" ratings for Atmos Energy with those of the comparable companies. These measures by independent financial analysts are consistent with my conclusions about financial risks when I compared Atmos Energy's common equity ratio to the common equity ratios of the comparable companies.

Q. PLEASE EXPLAIN YOUR FINDINGS WHEN YOU COMPARED THE VALUE LINE AND THE S&P FINANCIAL RISK MEASURES.

A. Atmos Energy's "Financial Strength," according to *Value Line,* is "B+". By comparison, the median rating for the group of comparable companies is "B++". Only Southwest Gas, a LDC with recent financial difficulties, and a "B" rating, has a lower rating than Atmos Energy. Similarly, Standard & Poor's credit rating for Atmos Energy is "BBB", but for the comparable companies, the median rating is "A". Likewise, Standard & Poor's "Business Position" measures Atmos Energy as one of only two of these LDCs with a rating as low as "4"; the median for the comparable LDCs is a "3". Consequently, each one of these measures by *Value Line* and S&P shows Atmos Energy's securities to be more risky than those of the group. In fact, when reviewing these risk measures, including the bond rates, a clear distinction is obvious among these LDCs. South Jersey Industries, Southwest Gas and Atmos Energy have the lowest risk profiles of this group. I have illustrated these comparisons in Schedule DAM-11.

X. BUSINESS RISK

Q. YOU ALSO STATED THAT YOU INVESTIGATED THE "BUSINESS RISK" OF ATMOS. WHAT IS BUSINESS RISK?

A. Business risk is the exposure of the returns to common stockholders that results from business operations. LDCs experience heightened business risk because declining sales threaten margins, and generally, LDCs' sales have fallen recently because of rising gas costs and keener competition from other fuels. Additionally, recent increasing operating costs as a result of inflation and rising interest rates narrow margins available to investors.

Q. CAN YOU EXPLAIN MORE FULLY HOW HIGH GAS COSTS INCREASE THE BUSINESS RISK OF INVESTORS?

A. High gas costs lead to increases in working capital and short-term debt required to pay suppliers. Since high gas costs lead to lower consumption and rising bad debt expenses, a LDC's accounts receivables and short-term debt levels also increase.

Q. DID YOU CONSIDER BUSINESS RISK IN YOUR ANALYSIS IN THIS PROCEEDING?

A. Yes. As is the case for all LDCs, Atmos Energy's division in Tennessee has similar business risks to those LDCs operating in the U. S. To the holders of common equities of a LDC, the business risk associated with the current high gas costs is whether the company will recover these costs in a timely manner.

Q. DID YOU ALSO REVIEW ANY FINANCIAL MEASURES SHOWING THE RELATIVE BUSINESS RISKS OF ATMOS ENERGY AND THE COMPARABLE COMPANIES?

A. I compared some *Value Line* measures for Atmos Energy and the comparable LDCs that incorporate the analysts' assessments of business risks of the companies. *Value Line* ranks the "Safety" of an investment in Atmos Energy as a "2". The average for the comparable LDCs is virtually the same at "1.9." By this ranking, a "1" is the highest and a "5" is the lowest. *Value Line* determined that Atmos Energy is only a slightly more "timely" investment than the average of the comparable LDCs. I illustrate these rankings in Schedule DAM-12.

XI. FINANCIAL STATISTICS

Q. PREVIOUSLY YOU MENTIONED THAT YOU REVIEWED KEY FINANCIAL STATISTICS OF ATMOS ENERGY. WHAT FINANCIAL STATISTICS DID YOU REVIEW THAT WERE RELEVANT TO YOUR RECOMMENDATION?

A. I compared earnings, dividend histories and forecasted dividends for Atmos Energy and the comparable LDCs. From these comparisons, I was able to discern the relative financial performance of Atmos Energy in recent markets relative to these comparable LDCs.

Q. EARLIER YOU STATED THAT ATMOS ENERGY'S LOW COMMON EQUITY RATIO INDICATED A RELATIVELY HIGH LEVEL OF FINANCIAL RISK. DID ATMOS ENERGY'S FINANCIAL PERFORMANCE SHOW THAT THE COMPANY EARNED HIGHER RETURNS ON ITS COMMON EQUITY BECAUSE OF THIS HIGHER FINANCIAL RISK?

A. No. Paradoxically, although the common equity ratio of Atmos Energy is low relative to the comparable LDCs, its return to common stock is lower than the average return for the group. In fact, in each of the last five years, Atmos Energy's return to common stock has been lower than the average for the comparable group. Moreover, *Value Line* is predicting that Atmos Energy will earn only 9.0 percent on common stock equity in 2007 as compared to the estimated average for the comparable LDCs in 2007 of 12.3 percent. In fact, despite its relatively low common equity ratio, *Value Line* predicts that Atmos Energy's return to common equity in 2007 will be lower than every one of the LDCs in this comparable group. I show these comparisons in Schedule DAM-13.

Q. DID YOU VERIFY THAT THE LOW COMMON EQUITY RATIO AND LOW RETURN TO COMMON EQUITY RESULT IN A LOW RETURN TO TOTAL CAPITAL FOR ATMOS ENERGY?

A. Yes. Atmos Energy's low common equity ratio and low return on common stock together result in a low total cost of capital. Atmos Energy's cost of total capital of 6.0 percent for 2007, as estimated by *Value Line,* is much lower than the 8.3 percent average cost of total capital of the comparable LDCs. I illustrated this comparison of the cost of total capital in Schedule DAM-14.

Q. DID YOU DETERMINE WHETHER ATMOS ENERGY'S LOW COMMON STOCK EARNINGS HAVE HAMPERED ITS ABILITY TO MAINTAIN ITS DIVIDEND?

A. I cannot determine the direct cause and effect relationship between Atmos Energy's common stock earnings and dividends. However, I did compare Atmos

Energy's dividend growth rate to that of the comparable companies. Atmos Energy's dividend growth was only 1.63 percent over the past five years. By comparison, the average for the comparable gas distribution utilities is more than twice the rate of Atmos Energy, or 4.23 percent. I have shown these dividend changes in Schedule DAM-15.

Q. ATMOS ENERGY HAS A RELATIVELY LOW RETURN ON COMMON STOCK. HOW DOES ATMOS ENERGY'S DIVIDEND PAYOUT RATIO COMPARE TO THE PAYOUT RATIOS OF THE COMPARABLE COMPANIES?

A. Atmos Energy's dividend payout has averaged 69.4 percent over the most recent five-year period, which is higher than the 60.3 percent average for the comparable companies. Notably, the average dividend payout ratio for the comparable LDCs has been relatively flat in recent years. Schedule DAM-16 shows these relative payout ratios of Atmos Energy and the comparable LDCs.

Q. IN YOUR COMPARATIVE ANALYSIS OF DIVIDENDS AND EARNINGS, DID YOU EVALUATE THE RELATIVE MARKET ACCEPTANCE OF THE COMMON STOCK OF ATMOS ENERGY AND THE OTHER GAS DISTRIBUTION COMPANIES?

A. Yes, I reviewed the common stock price earnings ("P/E") ratios of Atmos Energy and the comparable companies. This comparison showed that, at present, Atmos Energy's market price earnings ratio of 15.6 times is similar to the average P/E ratios for the comparable LDCs. I have shown these comparisons in Schedule DAM-17.

XII. COST OF COMMON STOCK

Q. YOU ALSO STATED PREVIOUSLY THAT YOU CALCULATED THE COST OF COMMON STOCK EQUITY FOR ATMOS. PLEASE EXPLAIN THE METHODOLOGIES THAT YOU USED IN THIS ANALYSIS.

A. For my cost of capital analysis, as I stated previously, I used the two more common and accepted market-based methods for estimating the cost of common stock in regulatory proceedings, namely the Discounted Cash Flow method and the Capital Asset Pricing Model. I applied each of these methods to a group of comparable companies to estimate the cost of common stock for Atmos. I used these methods to calculate the cost of common equity as a comparison to the results of the analysis for Atmos Energy. Interpreting the results in these calculations is obviously a critical step in the analysis. Consequently, I investigated the underlying assumptions of each of these methods to determine if they were satisfied and to assess the likely results if circumstances prevented them from being satisfied in this instance. To put my analysis into perspective, I also reviewed academic literature related to the use of these two techniques. In this way, I interpreted the results while taking into account the relative strengths and weaknesses of these methods. Finally, to put the results of these calculations into perspective, I evaluated them in the context of current market conditions.

XIII. DISCOUNTED CASH FLOW METHOD

Q. YOU MENTIONED THAT YOU USED THE DCF METHOD FOR DETERMINING THE COST OF COMMON STOCK. CAN YOU DEFINE

THE DCF METHODOLOGY FOR MEASURING THE COST OF COMMON EQUITY?

A. Yes. The DCF calculation of the investor's required rate of return can be expressed by the following formula:

$$K = D/P + g$$

Where:
K = cost of common equity
D = dividend per share
P = price per share and
g = rate of growth of dividends, or alternatively, common stock earnings.

In this expression, K is the capitalization rate required to convert the stream of future returns into a current value.

Q. YOU MENTIONED THE UNDERLYING ASSUMPTIONS OF THE COST OF CAPITAL MODELS. WHAT ASSUMPTIONS UNDERLYING THE DCF METHOD ARE IMPORTANT WHEN ESTIMATING THE COST OF COMMON STOCK EQUITY IN PRACTICE?

A. I believe one can identify the following important underlying assumptions associated with the basic annually compounded DCF model:

1. Investors are risk averse. That is, for a given return, investors will seek the alternative with the lowest amount of risk. In other words, the greater the risk that investors assume with a given investment, the greater the return that they will require from that investment.

2. The discount rate must exceed the growth rate, i.e. K in the stated expression must exceed g. The mathematics associated with the derivation of the basic annually compounded DCF model requires this assumption.

3. The payout and the price earnings ratios remain constant.

4. Expected cash flows consist of dividends and the future sale price of the stock. The sales price in any period will equal the present value of the dividends and the sales price expected after that period

including any liquidating dividend. Consequently, the sales price in any period is equal to the present value of all expected future dividends.

5. Dividends are paid annually.

6. There is no external financing.

As noted in these assumptions, expected cash flows consist of dividends and the future sale price of the stock, but actually, earnings drive both.

XIV. STRENGTHS OF THE DCF

Q. WHAT ARE THE STRENGTHS OF THE DCF THAT YOU THINK ARE IMPORTANT TO YOUR ANALYSIS?

A. The DCF's principal strength is that it is theoretically sound; it relates an investor's expected return in the form of dividends and capital gains to the value that the investor is willing to pay for those returns. The DCF implies that an investor is willing to pay a market price that is equal to the present value of an anticipated stream of earnings. In this way, one can estimate the opportunity cost of investors' funds. The DCF relates known market price information and the company's dividend and earnings performance to determine the value that investors place on anticipated returns. Other advantages in using the DCF to measure the cost of capital for ratemaking, is that regulatory analysts commonly use it, and participants in proceedings generally understand it.

Q. IN YOUR OPINION, IS THIS ESTIMATE OF THE COST OF COMMON EQUITY CONSISTENT WITH THE REGULATORY OBJECTIVE OF

SETTING AN ALLOWED RETURN EQUAL TO THE RETURNS OF EQUIVALENT RISK?

A. Yes. The DCF develops an estimate of the marginal cost of investing in a given utility. This is consistent with the principle of setting a return equal to returns of equivalent risk. This cost of capital, however, is not necessarily sufficient to assure that a return at this level attract and maintain capital even in the very near term.

XV. WEAKNESSES OF THE DCF

Q. DOES THE DCF METHOD POSSESS ANY WEAKNESSES THAT MAY BE IMPORTANT IN THIS APPLICATION?

A. Yes. The DCF can have conceptual and data problems. In either instance, they may lead to misinterpretation of the calculated results.

Q. YOU MENTIONED CONCEPTUAL PROBLEMS. IN YOUR EXPERIENCE, WHAT CONCEPTUAL PROBLEMS MAY BE IMPORTANT WHEN YOU USE THE DCF TO ESTIMATE THE COST OF CAPITAL IN A RATE PROCEEDING?

A. When using the DCF method in a rate proceeding, there is a danger that participants will misinterpret and misapply its results. For example, results from using dividend growth rates in the DCF will be misleading if investors are purchasing and selling a stock because of anticipated changes in earnings and potential capital gains rather than just near-term dividend growth. That is, if an assumption (such as dividends being the sole source of value expectations of an

investor) is not accurate, then analysts will error if they do not recognize this distinction.

Also, as I stated previously, the DCF method calculates the marginal, or incremental, cost of common stock equity of a company. If analysts do not recognize the theoretical significance of this calculation, they may misapply the results of their calculations. As a marginal cost estimate, the DCF produces an estimate of the minimal return necessary to attract or maintain investment funds in a company's common stock equity. Stated differently, this means that the DCF method does not account for any other factors that may affect the ability of the company to earn that return. This practical recognition is obviously critically important in a regulatory setting.

Q. FROM A PRACTICAL STANDPOINT, WHY IS THE MARGINAL COST NATURE OF THE DCF SIGNIFICANT IN A REGULATORY SETTING?

A. If a DCF-based cost of common equity, even if realistically developed, becomes the allowed return for a regulated utility, this will not provide enough cushion so the realized return will be sufficient to attract and maintain capital. Analysts, interpreting the results of the DCF calculations, may not recognize this. Consequently, the DCF-based calculations may be misleading. In fact, this misunderstanding of the DCF results can virtually assure that a regulated company will not have the opportunity to earn its allowed return.

Q. ARE YOU AWARE IF REGULATORY COMMISSIONS RECOGNIZE THESE LIMITATIONS OF THE DCF?

A. Yes. Regulatory commissions have recognized the difficulties of relying on the raw, unadjusted DCF calculations. In one such example, a regulatory commission recognized that the assumptions underlying the DCF model rarely, if ever, hold true.[1] This commission stated that an "...unadjusted DCF result is almost always well below what any informed financial analyst would regard as defensible and therefore requires an upward adjustment based largely on the expert witness' judgment."[2]

Q. IN ADDITION TO AN ADJUSTMENT BASED ON "EXPERT" JUDGEMENT, IN YOUR EXPERIENCE, ARE YOU AWARE OF REGULATORS AND ANALYSTS ATTEMPTING TO COMPENSATE FOR THE MARGINAL COST NATURE OF THE DCF?

A. Yes. Both regulators and analysts have often applied compensating adjustments for the marginal cost nature of the DCF adjustment, and they do so in a variety of ways. Although these various adjustments may differ greatly in their approaches, each addresses the inadequacy of the marginal cost estimates of the cost of capital in some manner. For example, I have observed such practices as applying a "flotation" adjustment, a "market pressure" adjustment or an adjustment to common equity to reflect the market values of debt and equity.

Q. YOU MENTIONED THAT A FLOTATION ADJUSTMENT IS ONE WAY THAT ANALYSTS ADDRESS THE MARGINAL COST NATURE OF THE DCF. EXPLAIN WHY THIS IS THE CASE.

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[1] Phillips, Charles F., Jr. and Robert G. Brown, *Chapter 9: The Rate of Return,* The Regulation of Public Utilities: Theory and Practice, (1993: Public Utility Reports, Arlington, VA) p. 423.
[2] Ibid, *In re Indiana Michigan Power Company,* 116 PUR4th 1, 17 (Ind. 1990).

A. The reason analysts apply a flotation adjustment is because the market-based DCF estimate of the cost of capital does not account for the costs of issuing common stock. That is, the market-based DCF does not incorporate the costs incurred when issuing securities, like legal fees, investment banker fees and the publication costs of a prospectus. The flotation adjustment attempts to raise the market-measured cost of capital, which is the return required to attract the marginal investor, to the same level as the true cost of capital of the utility.

Q. RECOGNIZING THE MARGINAL COST NATURE OF THE DCF AND THE NEED OF A REGULATED UTILITY TO BE ACTIVE IN THE FINANCIAL MARKETS, DO YOU RECOMMEND CALCULATING A FLOTATION ADJUSTMENT?

A. No, I do not. Instead, I believe it is an adequate recognition of the marginal cost nature of the DCF for an analyst to focus on the higher end of the DCF results. In my opinion, this will provide adequate compensation to attract and maintain investment in a utility's common stock.

Q. WHAT IS THE RATIONALE OF A "MARKET PRESSURE" ADJUSTMENT TO THE MARGINAL COST NATURE OF THE DCF?

A. Market pressure is the measured impact of an issuance of common stock on the prices of that common stock. The DCF measured cost of common stock does not account for the price impact of additional, newly issued shares placed on the market. Consequently, the marginal cost of common stock measured prior to this issuance, if set as the allowed return, will fail to capture the true cost of capital necessary to attract investors.

Q. DO YOU RECOMMEND APPLYING A MARKET PRESSURE ADJUSTMENT TO THE DCF RESULTS IN SELECTING A RECOMMENDED ALLOWED RETURN IN RATEMAKING?

A. No. Again, in most circumstances, I believe looking to the higher end of the DCF market-based results will supply a reasonable return on common stock for a regulated utility. This should also provide an adequate return to compensate for the impact of newly issued securities and to attract investors to newly issued common stock.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO THE COST OF EQUITY TO REFLECT MARKET VALUES FOR DEBT AND EQUITY?

A. Regulatory convention dictates that an analyst should use the book values of securities, when establishing the capital structure of a utility for ratemaking. Some analysts adjust the cost of equity for ratemaking to compensate for the difference between market value and book value. Theoretically, market values should be used to calculate the cost of capital because they values reflect investors' perceptions of risks and returns and form the basis for determining the marginal cost of capital, or in other words, the cost of attracting the next dollar of investment. An analyst should recognize the difference between market valuation and book valuation in a recommended allowed return.

XVI. DATA FOR THE DCF ANALYSIS

Q. ARE YOU AWARE OF STUDIES REGARDING DATA USED IN A DCF ANALYSIS THAT ARE MORE LIKELY TO PRODUCE RELIABLE ESTIMATES OF THE COST OF CAPITAL?

A. Yes. Academic studies have shown that, at least at certain times, analysts' forecasts are superior to historically trended growth rates as predictors of growth rates for DCF analyses.

Q. CAN YOU CITE SOME OF THE STUDIES THAT DEMONSTRATED THAT INVESTORS LOOK TO ANALYSTS' FORECASTS WHEN MAKING INVESTMENT DECISIONS?

A. Yes. A number of authors have addressed the merits of analysts' forecasts in a DCF analysis of the cost of capital. For example, a well-known financial textbook, by Brigham and Gapenski, argues that financial analysts' growth rate forecasts are the best source for growth measures in a DCF analysis. They state:

> Analysts' growth rate forecasts are usually for five years into the future, and the rates provided represent the average growth rate over the five-year horizon. Studies have shown that analysts' forecasts represent the best source for growth for DCF cost of capital estimates.[3]

Some other research reported in the academic literature supports this position. For example, Vander Weide and Carleton found:

> ...overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically oriented growth measures in predicting the firm's stock price....Our results are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions.[4]

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[3] Brigham, Eugene F., Louis C. Gapenski, and Michael C. Ehrhardt, "Chapter 10: The Cost of Capital," Financial Management Theory and Practice, Ninth Edition (1999: Harcourt Asia, Singapore), p. 381.

[4] Vander Weide, James H. and Willard T. Carleton, "Investor Growth Expectations: Analysts vs. History," *The Journal of Portfolio Management,* Spring 1988, pp. 78-82.

As to the use of the DCF in utility regulatory proceedings, Timme and Eisemann examined the effectiveness of using analysts' forecasts rather than historical growth rates. They concluded:

> The results show that all financial analysts' forecasts contain a significant amount of information used by investors in the determination of share prices not found in the historical growth rate....The results provide additional evidence that the historical growth rates are poor proxies for investor expectations; hence they should not be used to estimate utilities' cost of capital.[5]

Q. ARE YOU AWARE OF ANY OTHER EMPIRICAL INFORMATION THAT FOCUSES ON THE IMPORTANCE OF COMMON STOCK EARNINGS?

A. Yes. In an "event analysis," a colleague and I compared the market reactions to dividend announcements and common stock earnings announcements for a group of electric utilities. Specifically, we looked at announcements that were likely to be a surprise to the market. We looked at the price impact of both earnings announcements and dividend announcements that exceeded *Value Line's* projected levels. Among these companies, there were 8 dividend announcements and 19 earnings announcements that exceeded analysts' expectations from September 2001 to December 2003. By developing ratios of a utility's common stock price to the Dow Jones Utility Index, we statistically isolated the impact of these announcements and linked them to contemporaneous price changes. As Schedule DAM-18 shows, the impact on market prices of the unexpected earnings per share announcements in these cases is obvious and of unexpected dividend announcements seemingly less so.

[5] Timme, Stephen G. and Peter C. Eisemann, "On the Use of Consensus Forecasts of Growth in the Constant Growth Model: The Case of Electric Utilities," *Financial Management*, Winter 1989, pp. 23-35.

Q. WHAT HAS BEEN THE RECENT RELATIONSHIP BETWEEN COMMON STOCK EARNINGS AND DIVIDEND GROWTH FOR LDCS?

A. In recent years, dividends generally have grown more slowly than earnings per share for both Atmos Energy and the comparable utilities. I have illustrated these recent growth figures in Schedule DAM-19; they also show that *Value Line* expects this lower dividend growth rate to continue for the next few years.

Q. CAN YOU EXPLAIN WHY THE RECENT DIVIDEND GROWTH HAS TRAILED EARNINGS PER SHARE GROWTH FOR THESE LDCS?

A. Of course, I cannot be certain as to why boards of directors have not raised dividends at the same rate that earnings per share have increased. However, industry developments provide a clue. The LDCs have faced increasing competitive pressures in the last few years because of restructuring in the industry and competition for alternative fuels. Boards of directors are likely to be more conservative in this environment. This is likely to lead to conserving cash and refraining from very large dividend increases. This is a form of investment in the company even when earnings may appear to warrant increasing dividends to common stockholders.

Q. HOW DID YOU DETERMINE COMMON STOCK PRICES FOR YOUR DCF ANALYSIS?

A. I was interested in current market valuations, and I studied recent prices for Atmos Energy as well as the comparable LDCs. In addition, because utility rates set in this proceeding will be in effect for a number of years, I also took a longer view regarding market prices. I developed price information from *YAHOO!*

Finance for the past year and also for a recent two-week period. As a consequence, I developed DCF results using these different price estimates.

XVII. DCF CALCULATIONS

Q. WHAT WERE THE RESULTS OF YOUR DCF ANALYSES?

A. I combined historical and forecasted dividend growth rates to take into account the influence of recent financial results and forecasts. Using these growth rates and the common stock prices for the past year produced very low estimates for both Atmos Energy and the comparable LDCs. These resulting DCF calculations are, in fact, so low that they are not useful for setting an allowed return for Atmos Energy in this proceeding. I illustrate these DCF results in Schedule DAM-20. For the comparable companies, the average higher DCF cost of common return is only 7.57 percent. For Atmos Energy, despite its lower common equity ratio and relatively higher financial risk, the high-end DCF common equity estimate is only 6.52 percent. To illustrate that this is not a credible DCF result, as a comparison, the current forecasted Baa bond rate, which is a lower risk instrument than the common equities of Atmos Energy and the LDCs, is 6.4 percent. So, these DCF results are not reasonable standards for setting rates for an LDC such as Atmos. Current prices result in even lower, less credible estimates of the cost of common equity. For Atmos Energy, the current prices result in a high–end estimate of only 5.58 percent. I have illustrated these results in Schedule DAM-21.

Q. WHAT RESULTS DID YOUR DCF ANALYSIS PRODUCE WHEN YOU USED EARNINGS GROWTH RATES?

A. Combining the historical and forecasted earnings per share growth rates produced more credible DCF results. For Atmos Energy, using prices over the past year, the high end of the cost of common equity estimates is 10.52 percent. As previously noted, the group of comparable LDCs had distinctively different financial risk measures such as bond ratings. For example, the comparable LDCs with bond ratings below A+, like Atmos Energy, had DCF results of 12.00 percent. I have shown the results of these calculations in Schedule DAM-22. Using current price levels, the corresponding DCF estimates for Atmos Energy are 9.58 percent and 11.20 percent for the comparable A or lower rated utilities. I show these calculations in Schedule DAM-23. Using only the forecasted earnings per share growth rate, the high-end DCF estimates for Atmos Energy are 10.01 percent using prices over the past year and 10.44 percent for the comparable LDCs. I illustrate this calculation in Schedule DAM-24. As I illustrate in DAM-25, using more recent prices, the similar DCF result is 9.07 percent for Atmos Energy and 9.65 percent for the comparable LDCs.

Q. THE FINANCIAL RISK DIFFERENCE OF ATMOS ENERGY AND THE COMPARABLE COMPANIES IS OBVIOUSLY IMPORTANT. DID YOU IDENTIFY WHETHER THE FINANCIAL RISK DIFFERENCES APPEARED TO AFFECT THE DCF RESULTS?

A. Yes. Among the comparable LDCs, I noted that the lower bond rated companies had distinctly higher DCF results. I have illustrated this difference in Schedule DAM-26.

XVIII. CAPITAL ASSET PRICING MODEL

Q. YOU STATED THAT YOU USED THE CAPITAL ASSET PRICING MODEL IN YOUR ANALYSIS. WHAT IS THE CAPITAL ASSET PRICING MODEL?

A. The Capital Asset Pricing Model is a risk premium method that measures the cost of capital based on an investor's ability to diversify by combining securities of various risks into an investment portfolio. It measures the risk differential, or premium, between a given portfolio and the market as a whole. The diversification of investments reduces the investor's total risk. However, some risk is non-diversifiable, e.g., market risk, and investors remain exposed to that risk. The theoretical expression of the CAPM model is:

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

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

In this expression, the value of market risk is the differential between the market rate and the "risk-free" rate. Beta is the measure of the volatility, as a measure of risk, of a given security relative to the risk of the market as a whole. By estimating the risk differential between an individual security and the market as a whole, an analyst can measure the relative cost of that security compared to the market as a whole.

XIX. STRENGTHS OF THE CAPM

Q. WHAT, IN YOUR OPINION, ARE THE STRENGTHS OF THE CAPM METHOD?

A. As a risk premium method, the CAPM provides a relatively long-term perspective. It takes current debt costs as a basis for measuring the cost of common stock. It links the incremental cost of capital of an individual company with the risk differential between that company and the market as a whole. Although it is a less refined calculation, it is a good tool for assessing the general level of the cost of a security. As a comparison to DCF methods, which are more sensitive to changes in market prices and earnings, the CAPM produces much more stable results over short time periods. Also, the CAPM will typically produce relatively similar results for companies in the same industry, whereas, the DCF method may produce wide-ranging calculations among companies in the same industry.

XX. WEAKNESSES OF THE CAPM

Q. WHAT PROBLEMS DO YOU PERCEIVE TO BE IMPORTANT WHEN ONE USES THE CAPM TO MEASURE THE COST OF CAPITAL IN A RATEMAKING PROCEEDING?

A. The CAPM results for a company are very sensitive to the company's beta used in the analysis. Commonly, the beta differential is the determining factor regarding whether a cost of capital estimate is high or low. However, since beta is a single measure of risk, the CAPM cannot account for any risks not included as measures

of market volatility. Consequently, on occasion, the CAPM has failed to identify significant market risks to investors. This is one important problem when interpreting the CAPM results.

Q. ARE YOU AWARE OF PROBLEMS WITH THE CAPM THAT HAVE SPECIAL IMPLICATIONS FOR SETTING THE COST OF CAPITAL IN RATEMAKING?

A. Yes. Most utilities have betas less than one, and a number of analysts have shown that the CAPM underestimates the cost of capital of companies with betas less than one. For example, Atmos Energy's *Value Line* beta is 0.80. All of the comparable LDCs except NICOR also have betas less than one, ranging from 0.70 to 0.95. NICOR's beta is 1.30. The same analysis has also shown that the CAPM overestimates the cost of capital of companies with betas greater than one, but this is a less important finding as far as ratemaking is concerned. In addition, the academic literature has shown overwhelmingly that the standard CAPM method will underestimate the cost of capital of smaller companies, and this underestimation of capital costs may require an adjustment.

Q. YOU STATED THAT THE FINANCIAL LITERATURE RECOGNIZES THAT THE CAPM METHOD MAY REQUIRE AN ADJUSTMENT FOR A COMPANY'S SIZE. WHAT IS THE NATURE OF THIS RECOGNIZED BIAS?

A. R. W. Banz[6] and M. R. Reinganum[7] in the 1980's, for example, is a good reference which points out a size bias in the CAPM. Reinganum examined the relationship between the size of the firm and its price-earnings ratio. He found that small firms experienced average returns greater than those of large firms which had equivalent risk as measured by the beta. Of course, the beta is the distinguishing measure of risk in the CAPM. Banz confirmed that beta does not explain all of the returns associated with smaller companies; hence, the CAPM would understate their cost of common equity. In the same time frame, Fama and French confirmed that the Banz analysis consistently rejected the central CAPM hypothesis that beta sufficed to explain the expected return of investors.[8]

Q. WHAT DID YOU MEAN WHEN YOU SAID THAT THE CAPM METHOD REQUIRES AN ADJUSTMENT?

A. Although repeated studies showed that the CAPM method possesses a bias that understates the expected returns of small companies, this remained only an empirical observation without a clear remedy. However, Ibbotson Associates, which is the common source of data for the risk premium used in CAPM analyses, has now developed an adjustment for this bias. Ibbotson Associates discusses the problem as follows:

> One of the most remarkable discoveries of modern finance is that of the relationship between firm size and return. The relationship cuts across the entire size spectrum but is most evident among smaller companies, which

[6] Banz, R.W., "The Relationship Between Return and Market Value of Common Stock," *Journal of Financial Economics*, March 1981, pp. 3-18.
[7] Reinganum, M. R., "Misspecification of Capital Asset Pricing: Empirical Anomalies Based on Earnings, Yields, and Market Values," *Journal of Financial Economics*, March 1981, pp. 19-46.
[8] Fama, Eugene F., and Kenneth R. French, "The CAPM is Wanted, Dead or Alive," *The Journal of Finance*, Vol. LI, No. 5, pp. 1947-1958.

have higher returns on average than larger ones. Many studies have looked at the effect of firm size on return.[9]

Q. HAVE ANY REGULATORY COMMISSIONS ACCEPTED THIS SIZE ADJUSTMENT TO THE CAPM IN RATE PROCEEDINGS WHEN DETERMINING THE COST OF COMMON EQUITY?

A. Yes. The Minnesota Public Utilities Commission has done so in an Interstate Power and Light Company case. The Commission observed:

> The Administrative Law Judge takes comfort from the fact that Ibbotson Associates is a widely-recognized statistical reporting firm that has a national reputation. He considers it to be in the same general category as Standard & Poor's or Moody's. There is no indication that the report in question was prepared for IPL, or the utility industry, to bolster arguments in rate cases. Instead, it appears that the report in question is part of an almanac-type yearbook that Ibbotson prepares without any particular focus on the utility industry. The Administrative Law Judge understands and shares the concerns of the Staff concerning the methodology used, and thinks the issue is worthy of pursuit in some other forum. But for purposes of this case, the Administrative Law Judge accepts the principal conclusion of the study – that size of a firm is a factor in determining risk and return.[10]

XXI. CAPM METHODOLOGY

Q. PLEASE EXPLAIN THE CAPM METHODOLOGY THAT YOU USED IN YOUR ANALYSIS.

A. I applied two different, but complementary, approaches to estimate a CAPM cost of capital. One of these methods examines the historical risk premium of common stock over high grade corporate bonds. The other integrates the risk premium of common stocks to long-term government bonds in recent markets. This second

[9] Chapter 7: Firm Size and Return, "Ibbotson Associates' Stocks, Bonds, Bills, and Inflation: 2006 Yearbook Valuation Edition," edited by James Harrington and Michael Barad, p. 129.
[10] *In the Matter of the Petition of Interstate Power and Light Company for Authority to Increase its Electric Rates in Minnesota,* Docket No. E-001/GR-03-767, p. 7.

method requires an adjustment for the bias because of company size as I mentioned previously. For some time the financial literature has recognized this bias as an empirical problem, but a method for compensating for this bias is a recent analytical development. To account for this empirical bias against smaller companies, Ibbotson Associates has prescribed quantitative adjustments to the CAPM. Ibbotson publishes this in the same data source, which many analysts use to estimate the risk premium in their CAPM analyses.

Q. DID YOU APPLY THE ADJUSTMENT RECOMMENDED BY IBBOTSON ASSOCIATES IN YOUR ANALYSIS?

A. Yes. In my CAPM analysis, I followed the method recommended by Ibbotson Associates to compensate for this inherent data bias.

XXII. CAPM RESULTS

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSES?

A. The results of my two CAPM analyses for Atmos are 11.46 percent and 12.22 percent. For the comparable companies, these results average 12.59 percent and 12.87 percent. I illustrate these calculations in Schedules DAM-27 and DAM-28. As I discussed, the CAPM identifies the single risk component embodied in market volatility, and this comparison reveals the failure of the CAPM to isolate the higher financial risk of Atmos Energy than the comparable LDCs. Only Northwest Natural Gas and South Jersey Industries currently have *Value Line* betas less than Atmos Energy's 0.80.

XXIII. INTERPRETING THE DCF AND CAPM RESULTS

Q. HOW DID YOU INTEGRATE YOUR DCF AND CAPM CALCULATIONS INTO YOUR OVERALL ANALYSIS?

A. The recent and forecasted interest rates and returns on alternative investments provide a perspective for interpreting the DCF and CAPM calculations.

Q. HOW ARE INTEREST RATES IMPORTANT TO YOUR INTERPRETATION OF THE DCF AND CAPM RESULTS?

A. Significantly, the levels of interest rates are a measure of the return that investors in utility equities might expect from alternative investments. Consequently, forecasted rising interest rates mean that investors will require higher returns from their common stock investments in the near-term. Relatively speaking, if the risk premium between common stock and debt remains relatively constant, the returns to common stock investments must increase in order to attract and maintain capital. This is an important consideration when establishing an allowed return.

Q. DID YOU CONSIDER HOW ANY TARIFF PROVISIONS, SUCH AS A WEATHER NORMALIZATION ADJUSTMENT (WNA) OR A CUSTOMER UTILIZATION (CUA) OF YOUR COMPARABLE COMPANIES, SHOULD AFFECT YOUR RECOMMENDED ALLOWED RETURN?

A. Yes, I did. I reviewed the some tariff provisions of the group of comparable LDCs that I studied. For example, Atlanta Gas Light, AGL Resources' distribution subsidiary, has a provision that it calls the Dedicated Design Day Capacity (DDDC) charge. This assigns capacity charges based on the peak day

consumption.[11] New Jersey Natural Gas has what it calls the weather normalization clause in its tariff.[12] Northwest Natural Gas has a WNA that started in October 2006 in Oregon.[13] In North Carolina, Piedmont's tariff has a "Customer Utilization Tracker" which adjusts for actual weather.[14] Southwest Gas' California Division has the "Core Fixed Cost Adjustment Mechanism," to stabilize the recovery of authorized margins.[15] In Maryland, WGL's Washington Gas Light has a Revenue Normalization Adjustment that accounts for actual temperatures and promotes conservation.[16] Because these companies have these tariff provisions, this further confirms that they represent good companies for a benchmark analysis of Atmos in this proceeding.

Q. YOU STATED THAT YOU LOOKED AT ALTERNATIVE RETURNS. WHAT DID THIS REVIEW SHOW?

A. Notably, the recent economic expansion, which I discussed previously, has resulted in sizable returns to a number of industries in the non-regulated sectors. Of course, industrial firms are alternatives available to potential utility investors, and, in that sense, their earnings are relevant to this analysis. In addition to experiencing returns greater than in the gas distribution sector, many of these non-regulated industries' earnings have also grown during this economic expansion. I show this comparison in Schedule DAM-29.

[11] www.atlantagaslight.com/RatesRegulations/CustomerCharges.aspx
[12] New Jersey Resources, Form 10-K, November 29, 2005, p. 4.
[13] Northwest Natural Gas Company, Form 10-Q, November2, 2006, p. 23..
[14] Piedmont Natural Gas Company: North Carolina Service Regulations, Appendix C.
[15] Southwest Gas Tariff: California Division, Cal. PUC Sheet No. 6001-G and Sheet No. 6390-G
[16] WGL Holdings, Form 10-Q, August 9, 2006, pp. 19 & 25.

XXIV. RECOMMENDED RETURN

Q. HOW DID YOU GO ABOUT DETERMINING A RECOMMENDED ALLOWED RETURN ON COMMON STOCK FOR ATMOS ENERGY?

A. First, as a predicate for determining the cost of capital, I determined the appropriate capital structure for ratemaking. I determined that Atmos Energy's projected common equity ratio of 48.50 percent and long-term debt ratio of 51.50 percent is the appropriate capital structure for ratemaking for the Tennessee operating division in this proceeding. I took special note of the relatively low common stock equity, and, by inference, the relatively high financial risk of Atmos Energy. Based on the history and stated plans of Atmos, my recommended capital structure is the capital structure that investors are likely to anticipate when investing in the company. Consequently, I based my recommended allowed return on equity on the assumption of this capital structure. Other background assumptions for my recommendation are persistent inflationary pressures and forecasted rising interest rates. I also observed the current common stock earnings of comparable LDCs in current markets and Atmos Energy's relatively low common equity returns in comparison. Despite Atmos Energy's relatively high financial risk, *Value Line* predicts that the company can expect relatively low common equity earnings in 2007. For example, *Value Line* predicts a common equity return for the eight comparable LDCs ranging from 9.5 percent to 17.0 percent and averaging 12.3 percent. Its estimate for Atmos Energy is below that range, or just 9.0 percent. Also, I noted that Atmos Energy had a relatively high dividend payout ratio as compared to the eight gas distribution companies.

The relevant DCF results for Atmos Energy were in the broad range of 10.01 percent to 10.52 percent. The relevant results were 9.95 percent and 10.44 percent for all comparable LDCs, with lower financial risk. The LDCs with lower bond ratings had DCF results of 12.00 percent and 11.40 percent. The two CAPM analyses provided return on common equity estimates of 11.46 to 12.22 percent for Atmos Energy. Despite the higher financial risk, the comparable LDCs have higher betas, and consequently they had higher CAPM estimates at 12.59 percent and 12.87 percent.

Q. WHAT IS YOUR RECOMMENDED RETURN ON COMMON STOCK EQUITY FOR ATMOS IN THIS PROCEEDING?

A. Based on the analysis of Atmos and assuming that the Authority adopts my recommended capital structure, I am recommending an allowed return for Atmos in this proceeding of 11.75 percent. This is lower than the current estimated common equity returns of the comparable LDCs. Because these LDCs have lower financial risk than Atmos Energy, this is further confirmation of my recommended allowed return.

Q. USING YOUR RECOMMENDED CAPITAL STRUCTURE, COST OF DEBT AND COST OF COMMON STOCK EQUITY, WHAT TOTAL COST OF CAPITAL ARE YOU RECOMMENDING FOR ATMOS IN THE PROCEEDING?

A. My recommended allowed return on common equity of 11.75 percent and a cost of debt of 6.10 percent at my recommended capital structure will result in a total cost of capital of 8.84 percent. I illustrate this calculation in Schedule DAM-30.

XXV. FINANCIAL INTEGRITY TEST

Q. YOU STATED THAT YOU TESTED YOUR RECOMMENDED RETURN TO VERIFY ITS ADEQUACY AND APPROPRIATENESS FOR THIS PROCEEDING. HOW DID YOU TEST FOR ITS ADEQUACY AND APPROPRIATENESS?

A. I compared Atmos' After-Tax Interest Coverage ratio, at various recommended allowed returns, to the After-Tax Interest Coverage ratios of the comparable LDCs that I studied. The After-Tax Interest Coverage is a meaningful measure for this purpose because it shows whether funds from operations will be sufficient to meet a company's fixed interest obligations. For example, the higher the coverage ratio, the greater the likelihood that the returns from operations will be sufficient to meet the fixed interest obligations. Using the existing coverage ratios of the comparable LDCs as a standard, and by calculating the coverage ratio for Atmos at alternative recommended return levels, I can determine whether they will produce coverages higher than, less than or in line with this standard.

Q. WHAT DID YOUR CALCULATION OF THE AFTER-TAX INTEREST COVERAGE OF ATMOS REVEAL?

A. As a standard for my recommended allowed return, the After-Tax Interest Coverage ratio for the comparable LDCs currently averages 3.80 times. At my recommended allowed return of 11.75 percent, the After-Tax Interest Coverage of Atmos Energy would be only 2.81 times. By this comparison, my recommended allowed return would produce an After-Tax Interest Coverage that is much lower than the current level among comparable LDCs. Using the After-Tax Interest

Coverage average of the comparable LDCs as a standard, my recommendation is very conservative and low-cost.

Q. WHAT DID YOU CONCLUDE FROM THIS COMPARISON OF INTEREST COVERAGES OF THE COMPARABLE LDCS AND ATMOS?

A. I show this comparison in Schedule DAM-31. This test of financial integrity verifies the reasonableness under current market conditions of my recommended capital structure of 48.5 percent common stock equity and 51.5 percent long-term debt and an allowed return on common equity of 11.75 percent.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

VERIFICATION

STATE OF OKLAHOMA)
)
COUNTY OF OKLAHOMA)

I, Dr. Donald A. Murry, being first duly sworn, state that I am a Vice President and economist with C.H. Guernsey & Company, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Testimony of Dr. Donald A. Murry in support of Atmos Energy's Petition and the Exhibits thereto pre-filed in this docket on the date of filing of this Petition are true and correct to the best of my knowledge, information and belief.

Donald A. Murry

Sworn and subscribed before me this 17th day of April, 2007.

CAROLYN S. HANES NOTARY #01019787 EXP. 12/04/09 PUBLIC STATE OF OKLAHOMA

Carolyn S. Hanes
Notary Public

My Commission Expires: 12-4-09

Atmos Energy Corporation

List of Schedules

Schedule DAM - 1: Real GDP Consensus Forecasts

Schedule DAM - 2: Historical Economic Statistics

Schedule DAM - 3: History of Long-Term Bond Yields

Schedule DAM - 4.1: Forecast Bond Yield Rates Chart

Schedule DAM - 4.2: Forecast Bond Yield Rates Table

Schedule DAM - 5.1: Value Line's Interest Rates Chart

Schedule DAM - 5.2: Value Line's Interest Rates Table

Schedule DAM - 6: Projected Capital Structure

Schedule DAM - 7: Comparison of Common Equity Ratios

Schedule DAM - 8: Comparison of Common Stock Shares Outstanding

Schedule DAM - 9: Short-Term Debt Balances

Schedule DAM - 10: Embedded Cost of Long-Term Debt

Schedule DAM - 11: Comparison of Standard & Poor's and Value Line's Financial Ratings

Schedule DAM - 12: Comparison of Value Line's Safety and Timeliness Ranks

Schedule DAM - 13: Comparison of Returns on Common Equity

Schedule DAM - 14: Comparison of Returns on Capital

Schedule DAM - 15: Comparison of Dividends per Share

Schedule DAM - 16: Comparison of Dividend Payout Ratios

Schedule DAM - 17: Comparison of Average Annual P/E Ratio

Schedule DAM - 18: Stock Price Responses to Dividend and Earnings Announcements

Schedule DAM - 19: DCF Growth Rate Summary

Schedule DAM - 20: Dividend Growth Rate DCF Using 52-Week Share Prices

Schedule DAM - 21: Dividend Growth Rate DCF Using Current Share Prices

Schedule DAM - 22: Earnings Growth Rate DCF Using 52-Week Share Prices

Schedule DAM - 23: Earnings Growth Rate DCF Using Current Share Prices

Schedule DAM - 24: Projected Growth Rate DCF Using 52-Week Share Prices

Schedule DAM - 25: Projected Growth Rate DCF Using Current Share Prices

Schedule DAM - 26: Discounted Cash Flow Analysis by Bond Rating

Schedule DAM - 27: Size Adjusted Capital Asset Pricing Model

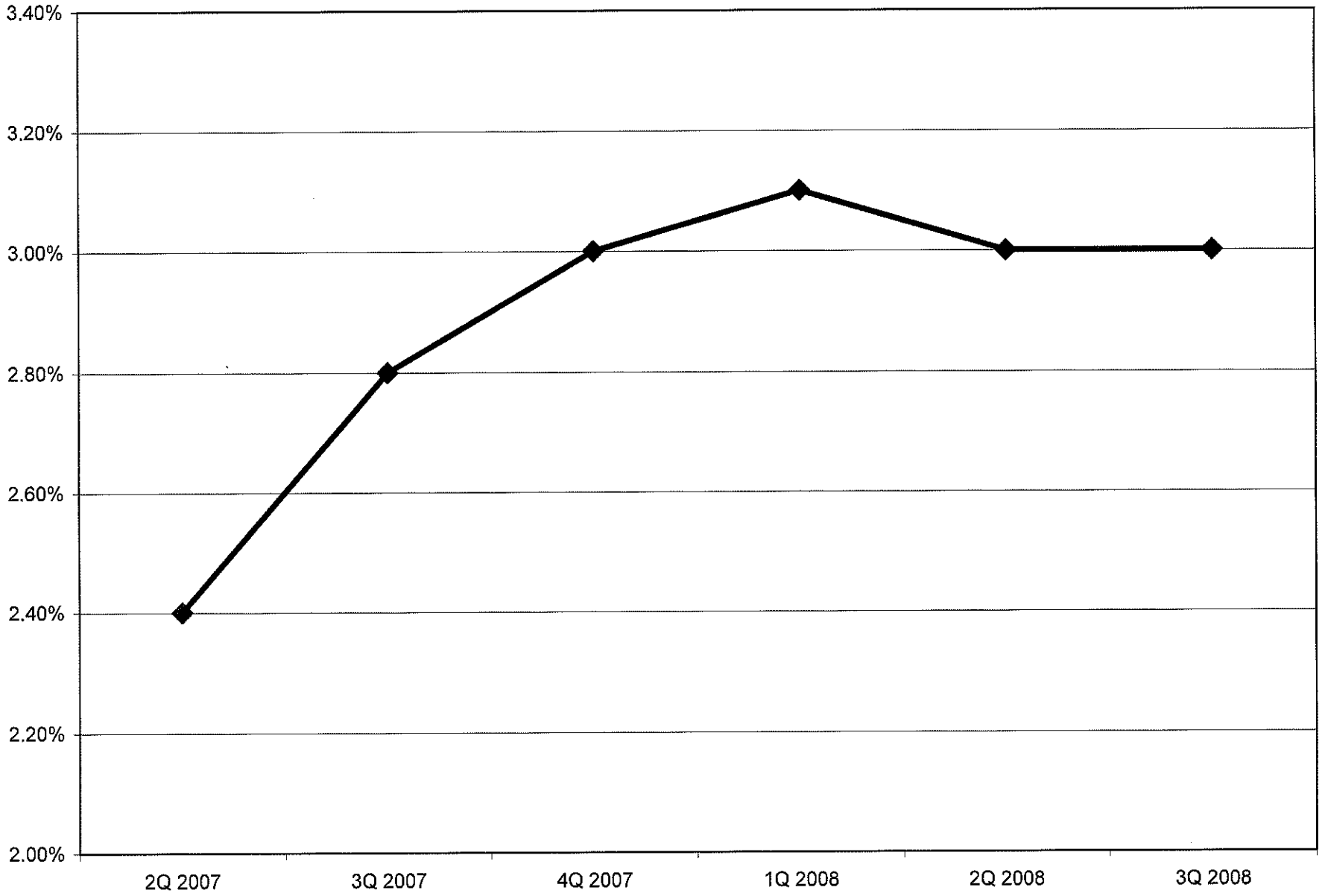
Schedule DAM - 28: Historical Capital Asset Pricing Model

Schedule DAM - 29: Recent Returns on Common Equity

Schedule DAM - 30: Projected Capital Structure and Cost of Capital

Schedule DAM - 31: Comparison of After-Tax Times Interest Earned Ratios

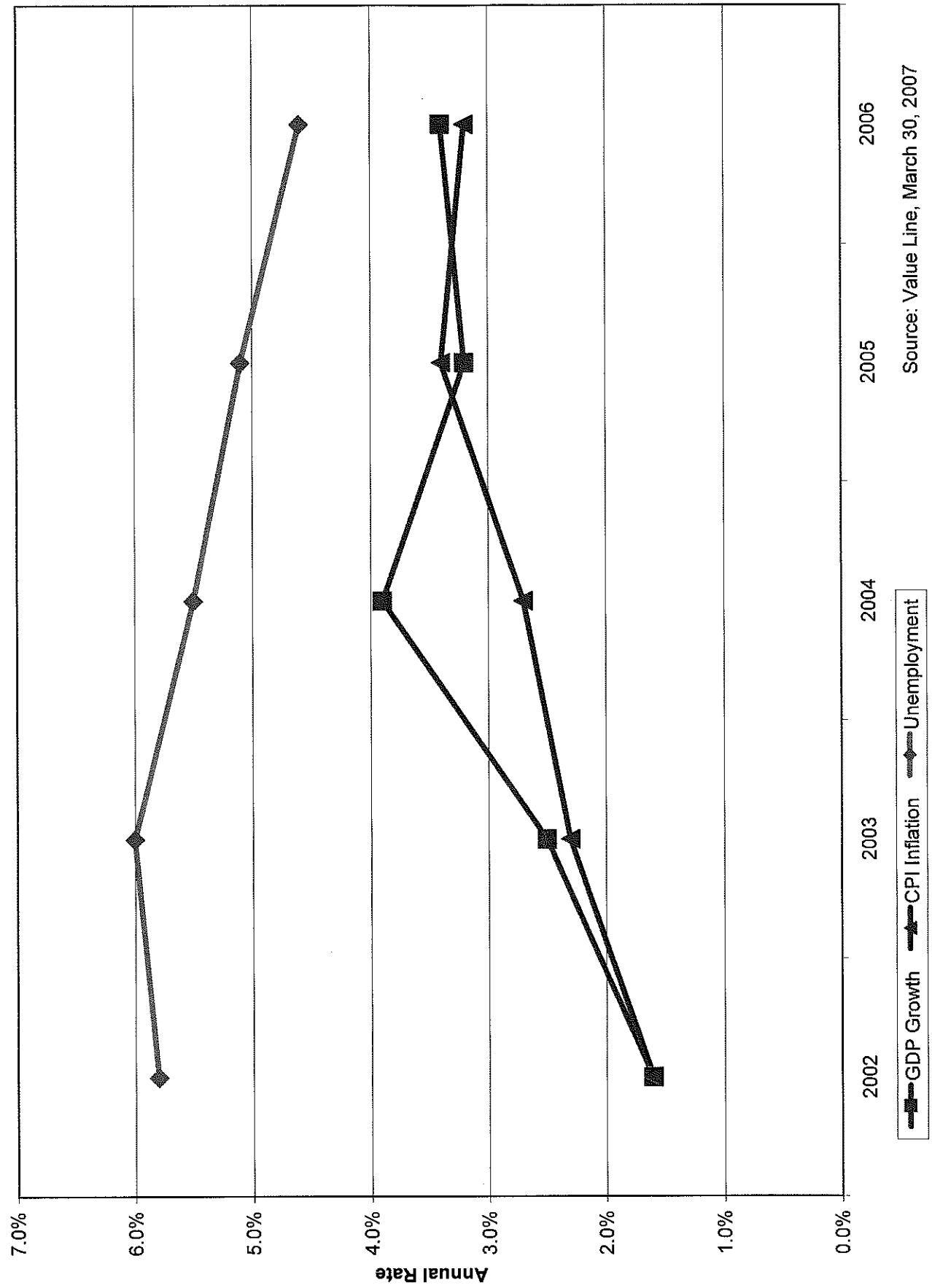
Atmos Energy Corporation
Real GDP Consensus Forecast



Source: Blue Chip Financial Forecasts, April 1, 2007

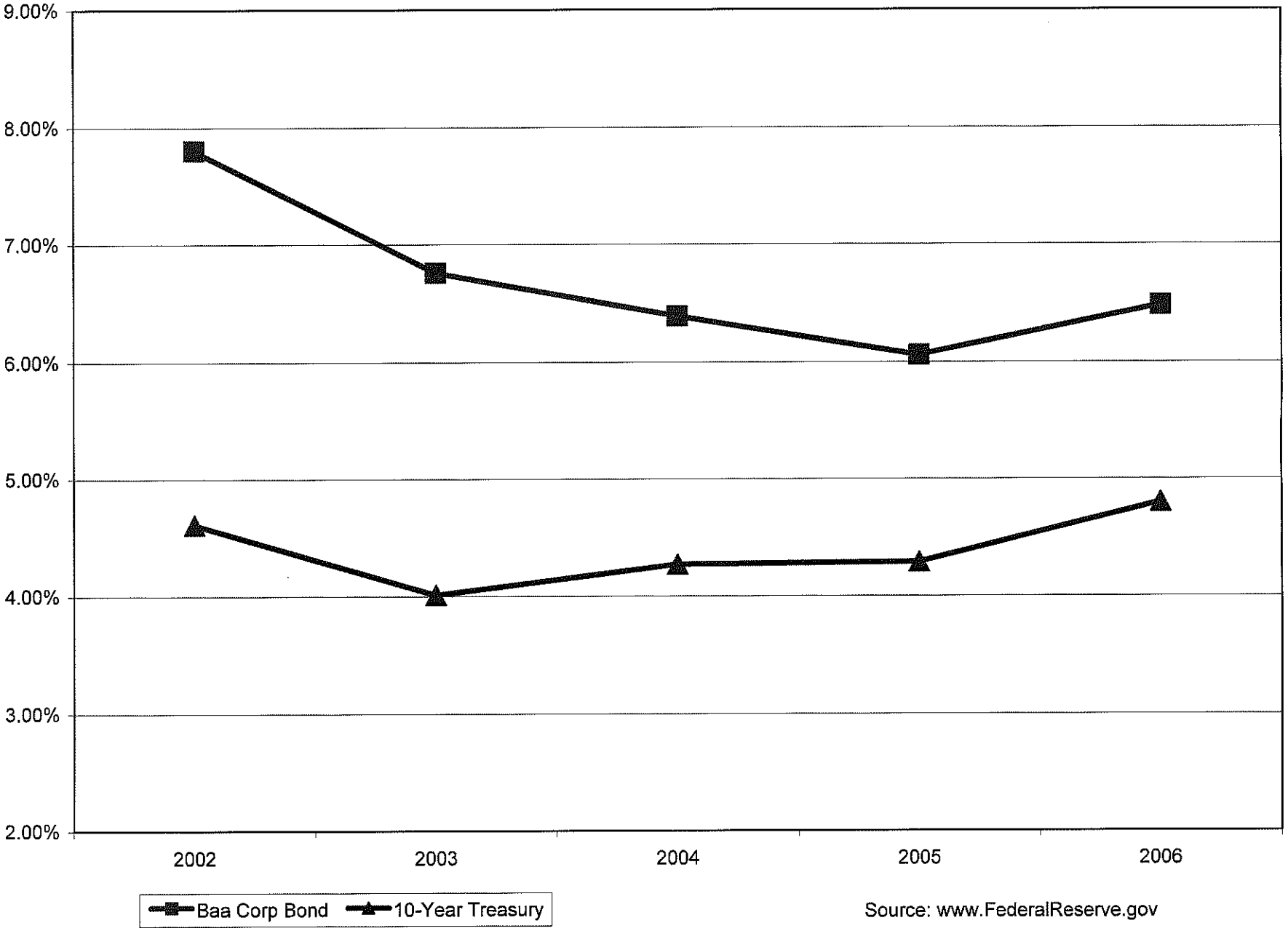
Schedule DAM - 1

Atmos Energy Corporation
Historical Economic Statistics
2002 to 2006



Source: Value Line, March 30, 2007

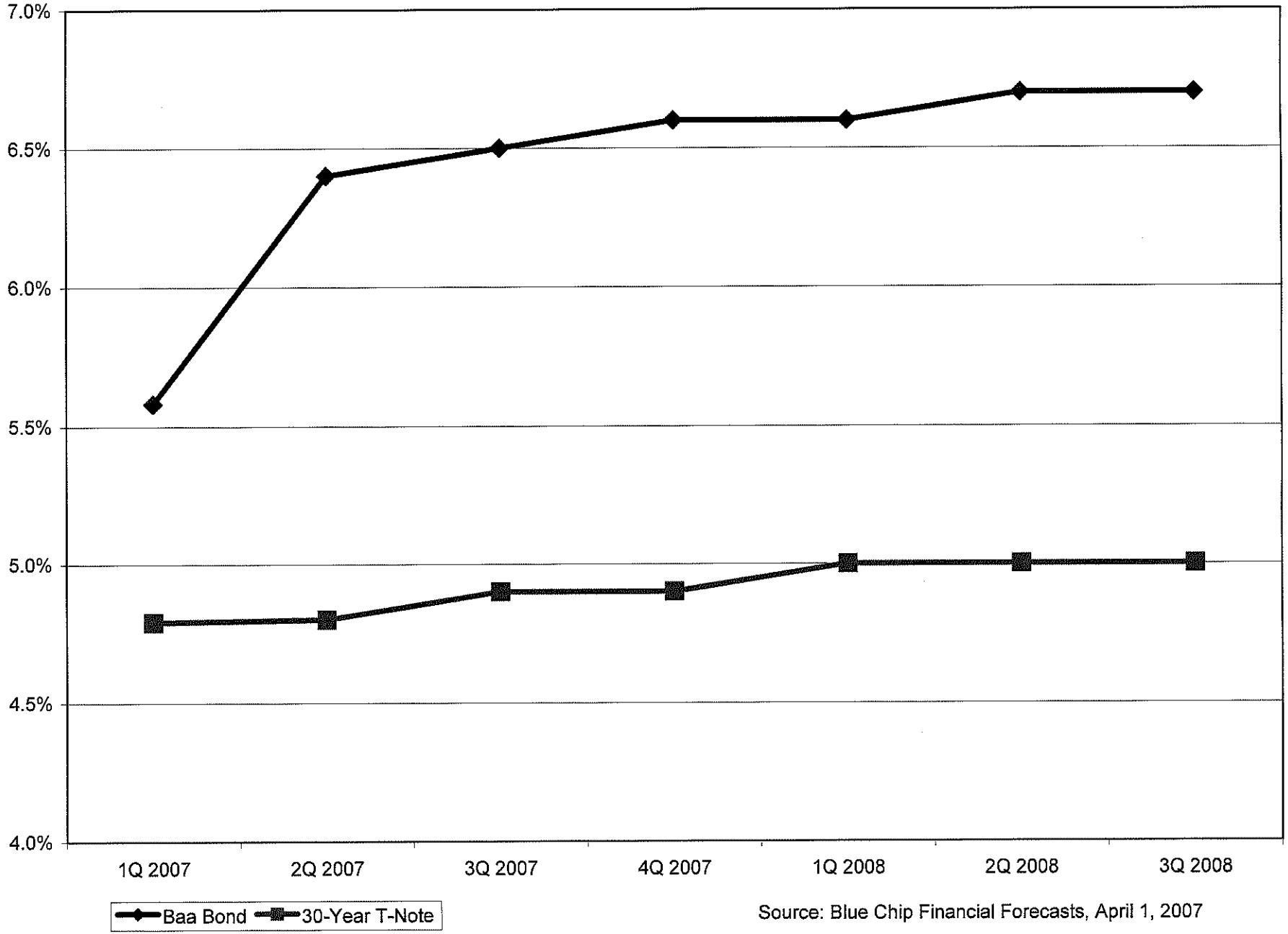
Atmos Energy Corporation
History of Long-Term Bond Interest Rates



Source: www.FederalReserve.gov

Schedule DAM - 3

Atmos Energy Corporation
Bond Interest Rate Forecasts



Source: Blue Chip Financial Forecasts, April 1, 2007

Schedule DAM - 4.1

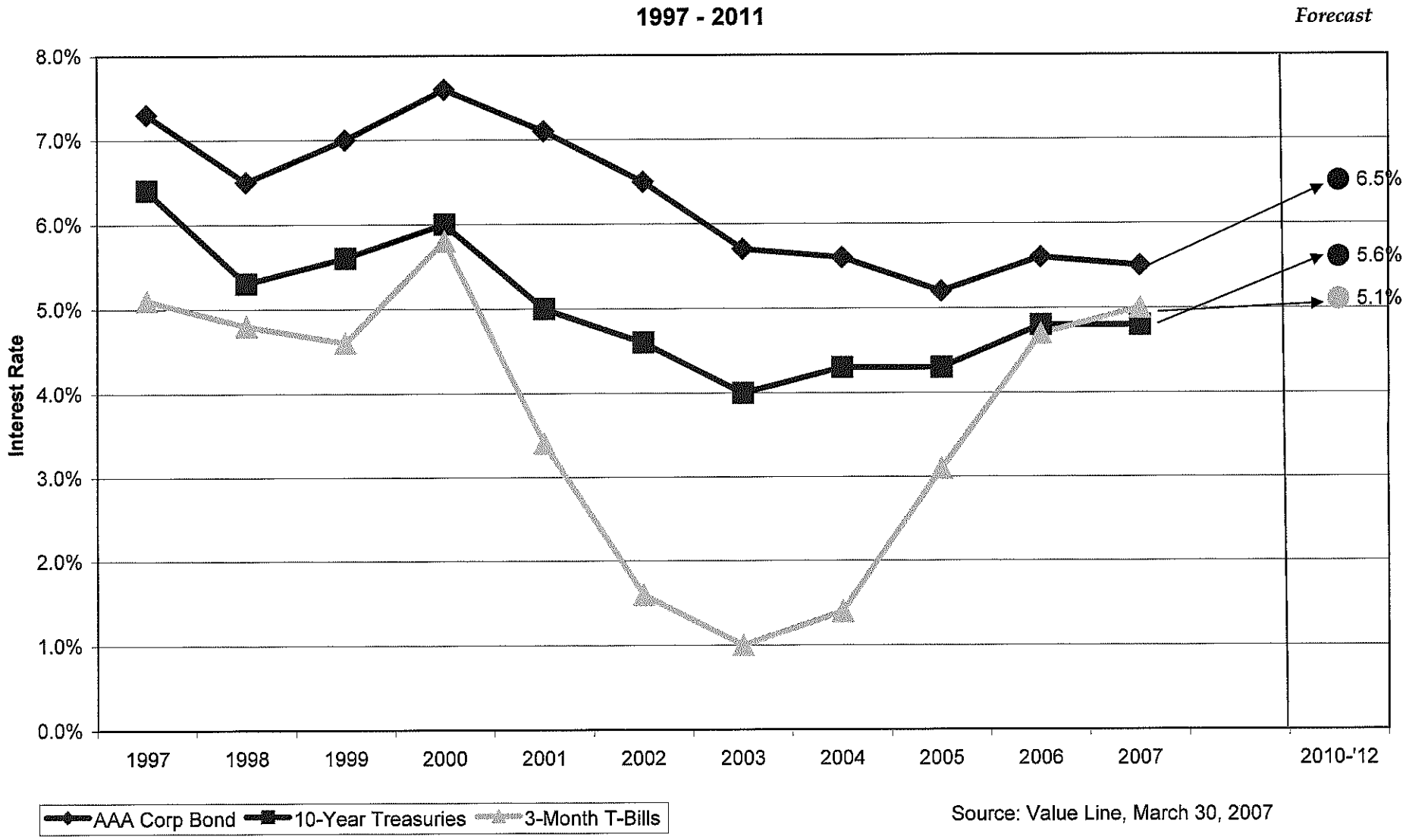
Atmos Energy Corporation

Bond Interest Rate Forecasts

Quarter	Baa Bond	30-Year T-Note
1Q 2007	5.6%	4.8%
2Q 2007	6.4%	4.8%
3Q 2007	6.5%	4.9%
4Q 2007	6.6%	4.9%
1Q 2008	6.6%	5.0%
2Q 2008	6.7%	5.0%
3Q 2008	6.7%	5.0%

Source: Blue Chip Financial Forecasts, April 1, 2007

Atmos Energy Corporation
Value Line Interest Rates and Forecasts
1997 - 2011



Source: Value Line, March 30, 2007

Schedule DAM - 5.1

Atmos Energy Corporation

Comparison of Value Line's Interest Rates

Year	AAA Corp Bond	10-Year Treasuries	3-Month T-Bills
1997	7.3%	6.4%	5.1%
1998	6.5%	5.3%	4.8%
1999	7.0%	5.6%	4.6%
2000	7.6%	6.0%	5.8%
2001	7.1%	5.0%	3.4%
2002	6.5%	4.6%	1.6%
2003	5.7%	4.0%	1.0%
2004	5.6%	4.3%	1.4%
2005	5.2%	4.3%	3.1%
2006	5.6%	4.8%	4.7%
2007	5.5%	4.8%	5.0%
2010-'12	6.5%	5.6%	5.1%

Source: Value Line Investment Survey

Atmos Energy Corporation

Projected Capital Structure

Thirteen Month Average as of October 31, 2008

	Percent of Total
Long Term Debt	51.50%
Common Equity	48.50%
Total	100.00%

Source :
Atmos Energy Corporation Work Papers

Atmos Energy Corporation

Comparable Gas Companies

Comparison of Common Equity Ratios

Company	2003	2004	2005	2006	2007E	Forecast '10-'12
Atmos Energy Corp.	49.8%	56.8%	42.3%	43.0%	51.0%	49.0%
AGL Resources	49.7%	46.0%	48.1%	49.8%	50.0%	50.8%
New Jersey Resources	61.9%	59.7%	58.0%	65.2%	65.5%	68.5%
NICOR, Inc.	60.3%	60.1%	62.5%	66.0%	67.0%	71.0%
Northwest Natural Gas	50.3%	54.0%	53.0%	53.6%	53.0%	52.0%
Piedmont Natural Gas	57.8%	56.4%	58.6%	51.7%	51.0%	51.0%
South Jersey Industries	49.0%	51.0%	55.1%	55.3%	55.6%	57.5%
Southwest Gas	34.0%	35.8%	36.2%	39.4%	40.0%	43.0%
WGL Holdings, Inc.	54.3%	57.2%	58.6%	61.5%	61.0%	64.0%
Comparable Companies' Averages	52.2%	52.5%	53.8%	55.3%	55.4%	57.2%

Source: Value Line Investment Survey

Atmos Energy Corporation

Comparable Gas Companies

Comparison of Common Shares Outstanding

Company	2003	2004	2005	2006	2007E	Forecast '10-'12	Growth 08-'12
Atmos Energy Corp.	51.48	62.80	80.54	81.74	89.50	107.00	19.55%
AGL Resources	64.50	76.70	77.70	77.75	78.00	80.00	2.56%
New Jersey Resources	27.23	27.74	27.55	27.63	28.00	29.50	5.36%
NICOR, Inc.	44.04	44.10	44.18	44.70	44.60	45.00	0.90%
Northwest Natural Gas	25.94	27.55	27.58	27.28	27.50	29.00	5.45%
Piedmont Natural Gas	67.31	76.67	76.70	74.61	73.80	71.80	-2.71%
South Jersey Industries	26.46	27.76	28.98	29.30	29.60	31.00	4.73%
Southwest Gas	34.23	36.79	39.33	41.77	43.00	47.50	10.47%
WGL Holdings, Inc.	48.63	48.67	48.65	48.89	48.91	49.00	0.18%

Source: Value Line Investment Survey

Schedule DAM - 8

Atmos Energy Corporation

History of Short - Term Debt

End of Month Balances

Month	Outstanding Balance
January, 2003	$102,240,000
February, 2003	$98,700,000
March, 2003	$29,700,000
April, 2003	$33,400,000
May, 2003	$32,650,000
June, 2003	$700,000
July, 2003	$53,850,000
August, 2003	$75,350,000
September, 2003	$118,600,000
October, 2003	$153,325,000
November, 2003	$195,450,000
December, 2003	$191,850,000
January, 2004	$148,800,000
February, 2004	$29,900,000
March, 2004	$0
April, 2004	$0
May, 2004	$0
June, 2004	$0
July, 2004	$0
August, 2004	$0
September, 2004	$0
October, 2004	$16,575,000
November, 2004	$29,700,000
December, 2004	$28,800,000
January, 2005	$58,875,000
February, 2005	$0
March, 2005	$0
April, 2005	$0
May, 2005	$0
June, 2005	$0
July, 2005	$34,725,000
August, 2005	$39,775,000
September, 2005	$144,875,000
October, 2005	$292,500,000
November, 2005	$346,255,000
December, 2005	$399,450,000
January, 2006	$407,275,000
February, 2006	$346,900,000
March, 2006	$262,475,000
April, 2006	$238,875,000
May, 2006	$222,350,000
June, 2006	$297,550,000
July, 2006	$298,225,000
August, 2006	$292,086,000
September, 2006	$383,386,000
October, 2006	$406,125,000
November, 2006	$393,475,000
December, 2006	$154,650,000

Source: Atmos Energy Work Papers

Atmos Energy Corporation

Schedule DAM - 10

Embedded Costs of Long - Term Debt

Thirteen Month Average as of October 31, 2008

Debt Series	13 Month Average Amount Outstanding	Interest Rate	Effective Interest Cost
10.43% First Mortgage Bond P due 2017 (eff 2012)	$6,346,154	10.430%	$661,904
10% Senior Notes due Dec 2011	$1,151,654	10.000%	$115,165
10% Senior Notes due Dec 2011	$1,151,654	10.000%	$115,165
6.75% Debentures Unsecured due July 2028	$150,000,000	6.750%	$10,125,000
7.38% Senior Notes due May 2011	$350,000,000	7.375%	$25,812,500
5.125% Senior Notes due Feb 2013	$250,000,000	5.125%	$12,812,500
6.67% MTN A1 due Dec 2025	$10,000,000	6.670%	$667,000
6.27% MTN A2 due Dec 2010	$10,000,000	6.270%	$627,000
Projected 6.00% Refinancing Issuance	$300,000,000	6.000%	$18,000,000
4.00% Sr Note due 10/15/2009	$400,000,000	4.000%	$16,000,000
4.95% Sr Note due 10/15/2014	$500,000,000	4.950%	$24,750,000
5.95% Sr Note due 10/15/2034	$200,000,000	5.950%	$11,900,000
Industrial Develop Revenue Bond 07/13	$715,200	7.900%	$56,501
Atmos Power Sys - Wells Fargo 05/08	$558,950	5.650%	$31,581
US Bancorp - 04/09	$1,105,513	5.290%	$58,482
Pulaski -- Ingas, Ingram & Carvell 06/08	$38,462	8.000%	$3,077
Total Long-Term Debt Outstanding	$2,181,067,586		$121,735,875
Less Unamortized Debt Discount	$2,627,285		
Amortization of Debt Discount			$11,103,566
Total	$2,178,440,301		$132,839,441
Embedded Cost of Long-Term Debt			6.10%

Source: Atmos Energy Work Papers

Atmos Energy Corporation

Comparable Gas Companies

Comparison of Standard and Poor's and Value Line Financial Ratings

Company	Value Line Financial Strength	S&P Rating	S&P Business Position
Atmos Energy Corp.	B+	BBB	4
AGL Resources	B++	A-	4
New Jersey Resources	A	A+	2
NICOR, Inc.	A	AA	3
Northwest Natural Gas	A	AA-	1
Piedmont Natural Gas	B++	A	2
South Jersey Industries	B++	BBB+	3
Southwest Gas	B	BBB-	3
WGL Holdings, Inc.	A	AA-	3
Comparable Companies' Median	B++	A	3.0

Sources: Value Line Investment Survey
www.standardandpoors.com

Atmos Energy Corporation

Comparable Gas Companies

Comparison of Value Line's Safety and Timeliness Rank

	Safety Rank	Timeliness Rank
Atmos Energy Corp.	2	3
AGL Resources	2	4
New Jersey Resources	1	5
NICOR, Inc.	3	3
Northwest Natural Gas	1	3
Piedmont Natural Gas	2	4
South Jersey Industries	2	3
Southwest Gas	3	3
WGL Holdings, Inc.	1	4
Comparable Companies' Average	1.9	3.6

Source: Value Line Investment Survey

Atmos Energy Corporation

Comparable Gas Companies

Comparison of Returns on Common Equity

	2003	2004	2005	2006	2007E	Five Year Average
Atmos Energy Corp.	9.3%	7.6%	8.5%	9.9%	9.0%	8.9%
AGL Resources	14.0%	11.0%	12.9%	13.0%	13.5%	12.9%
New Jersey Resources	15.6%	15.3%	17.0%	12.6%	12.5%	14.6%
NICOR, Inc.	12.3%	13.1%	12.5%	14.0%	13.0%	13.0%
Northwest Natural Gas	9.0%	8.9%	9.9%	10.6%	10.5%	9.8%
Piedmont Natural Gas	11.8%	11.1%	11.5%	11.0%	11.5%	11.4%
South Jersey Industries	11.6%	12.5%	12.4%	16.3%	17.0%	14.0%
Southwest Gas	6.1%	8.3%	6.4%	9.0%	9.5%	7.9%
WGL Holdings, Inc.	14.0%	11.7%	12.0%	10.2%	10.5%	11.7%
Comparable Companies' Averages	11.8%	11.5%	11.8%	12.1%	12.3%	11.9%

Source: Value Line Investment Survey

Atmos Energy Corporation

Comparable Gas Companies

Comparison of Returns on Total Capital

Company	2003	2004	2005	2006	2007E
Atmos Energy Corp.	6.2%	5.8%	5.3%	6.1%	6.0%
AGL Resources	8.9%	6.3%	7.9%	8.0%	8.0%
New Jersey Resources	10.7%	10.1%	11.2%	9.6%	9.5%
NICOR, Inc.	8.3%	8.8%	9.4%	10.9%	10.5%
Northwest Natural Gas	5.7%	5.9%	6.5%	7.5%	7.0%
Piedmont Natural Gas	8.6%	7.8%	8.2%	7.1%	7.0%
South Jersey Industries	7.3%	7.9%	8.3%	10.2%	10.5%
Southwest Gas	4.2%	5.0%	4.3%	5.5%	6.0%
WGL Holdings, Inc.	9.1%	8.2%	8.5%	7.7%	7.5%
Comparable Companies Averages	7.9%	7.5%	8.0%	8.3%	8.3%

Source: Value Line Investment Survey

Atmos Energy Corporation

Comparable Gas Companies

Comparison of Dividends per Share

Company	2003	2004	2005	2006	2007E	Growth '03-'07
Atmos Energy Corp.	1.20	1.22	1.24	1.26	1.28	1.63%
AGL Resources	1.11	1.15	1.30	1.48	1.64	11.35%
New Jersey Resources	1.24	1.30	1.36	1.44	1.52	5.23%
NICOR, Inc.	1.86	1.86	1.86	1.86	1.90	0.36%
Northwest Natural Gas	1.27	1.30	1.32	1.39	1.44	3.26%
Piedmont Natural Gas	0.82	0.85	0.91	0.95	0.99	5.12%
South Jersey Industries	0.78	0.82	0.86	0.92	0.98	5.90%
Southwest Gas	0.82	0.82	0.82	0.82	0.86	0.81%
WGL Holdings, Inc.	1.28	1.30	1.32	1.34	1.38	1.78%
Comparable Companies' Averages	1.15	1.18	1.22	1.28	1.34	4.23%

Source: Value Line Investment Survey

Atmos Energy Corporation

Comparable Gas Companies

Comparison of Dividend Payout Ratios

Company	2003	2004	2005	2006	2007E	Five Year Average
Atmos Energy Corp.	70%	77%	73%	63%	64%	69.4%
AGL Resources	53%	49%	52%	57%	58%	53.8%
New Jersey Resources	51%	49%	50%	50%	49%	49.8%
NICOR, Inc.	88%	84%	81%	68%	71%	78.4%
Northwest Natural Gas	72%	69%	63%	61%	60%	65.0%
Piedmont Natural Gas	74%	66%	68%	75%	72%	70.9%
South Jersey Industries	57%	52%	50%	37%	36%	46.4%
Southwest Gas	72%	49%	65%	41%	41%	53.6%
WGL Holdings, Inc.	56%	65%	62%	70%	68%	64.2%
Comparable Companies' Averages	65.4%	60.4%	61.4%	57.3%	56.9%	60.3%

Source: Value Line Investment Survey

Atmos Energy Corporation

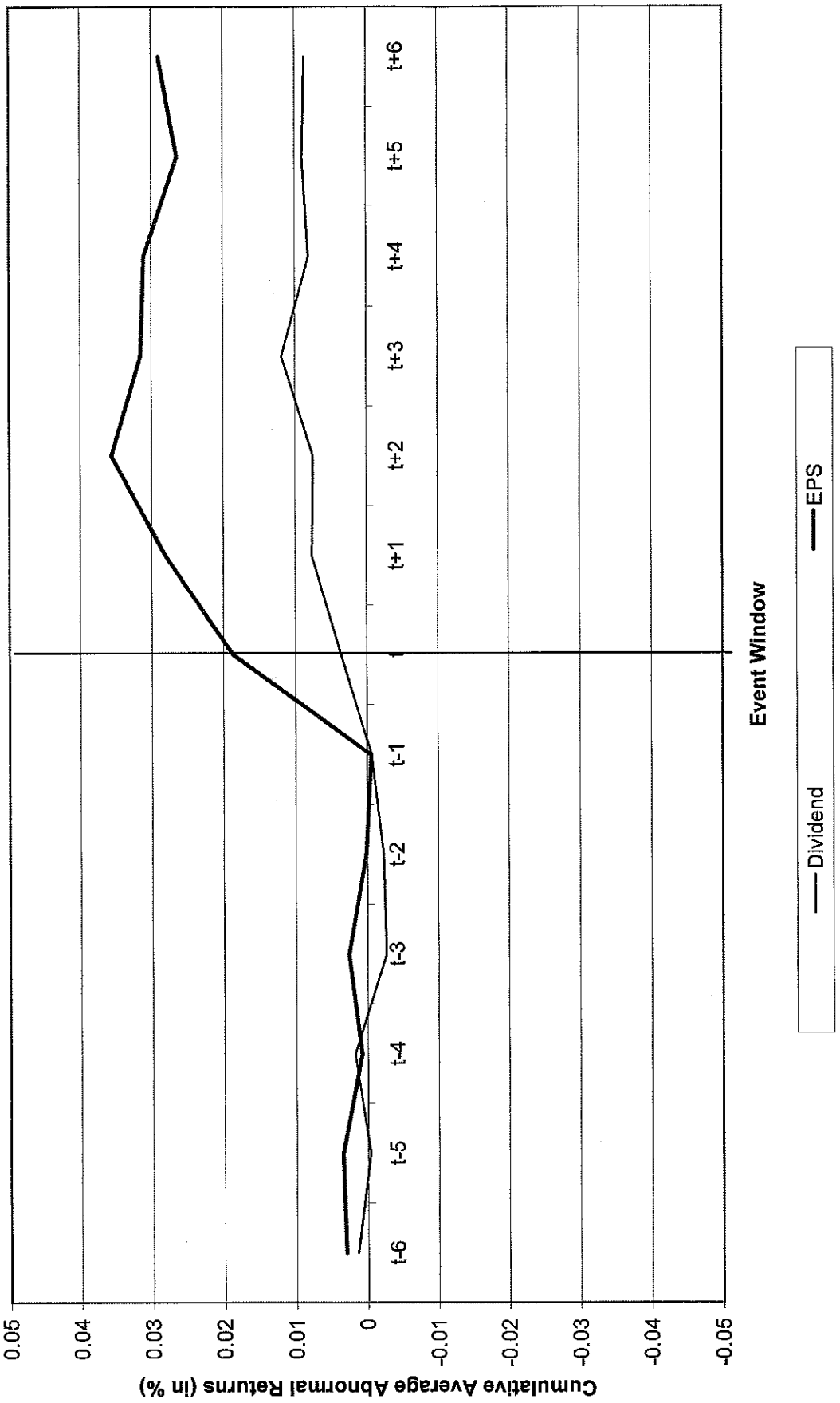
Comparable Gas Companies

Comparison of Average Annual P/E Ratio

Company	2002	2003	2004	2005	2006	Current
Atmos Energy Corp.	15.2	13.4	15.9	16.1	13.5	15.6
AGL Resources	12.5	12.5	13.1	14.3	13.5	14.6
New Jersey Resources	14.7	14.0	15.3	16.8	16.1	17.1
NICOR, Inc.	13.1	15.8	15.9	17.3	13.3	15.4
Northwest Natural Gas	17.2	15.8	16.7	17.0	16.3	18.1
Piedmont Natural Gas	18.4	16.7	16.6	17.9	19.4	18.0
South Jersey Industries	13.5	13.3	14.1	16.6	14.9	12.7
Southwest Gas	19.9	19.2	14.3	20.6	15.9	17.3
WGL Holdings, Inc.	23.1	11.1	14.2	14.7	15.5	15.7
Comparable Companies' Averages	16.6	14.8	15.0	16.9	15.6	16.1

Source: Value Line Investment Survey

Stock Price Responses to Positive Dividend and EPS Announcements Greater than Expected
(Cumulative Average Abnormal Returns)



Atmos Energy Corporation

Comparable Gas Companies

Discounted Cash Flow Growth Rate Summary

	Value Line 2002 TO 2011 Estimate			Value Line Five Year Historical			Projections Value Line		S & P
	EPS	DPS	Book Value	EPS	DPS	Book Value	EPS	DPS	EPS
Atmos Energy Corp.	5.51%	1.51%	6.01%	10.0%	2.0%	8.5%	5.0%	1.5%	6.0%
AGL Resources	6.23%	5.73%	6.17%	13.5%	2.0%	8.5%	3.5%	5.5%	4.0%
New Jersey Resources	4.39%	3.78%	8.32%	8.0%	3.5%	8.5%	2.5%	3.0%	5.0%
NICOR, Inc.	0.94%	1.05%	4.17%	-3.5%	3.5%	1.5%	4.0%	1.0%	4.0%
Northwest Natural Gas	5.95%	4.04%	3.49%	5.0%	1.0%	3.5%	7.0%	4.0%	5.0%
Piedmont Natural Gas	4.72%	4.21%	4.56%	5.0%	5.0%	6.5%	3.0%	4.0%	4.0%
South Jersey Industries	11.42%	5.26%	7.62%	11.5%	2.5%	13.0%	9.5%	5.5%	7.0%
Southwest Gas	9.52%	1.04%	3.92%	-0.5%	0.0%	3.0%	8.0%	1.5%	12.0%
WGL Holdings, Inc.	2.42%	1.48%	3.54%	6.0%	1.5%	3.0%	1.0%	1.5%	4.0%
Comparable Companies' Averages	5.70%	3.32%	5.22%	5.63%	2.38%	5.94%	4.81%	3.25%	5.63%

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

Atmos Energy Corporation

Comparable Gas Companies

Dividend Growth Rate DCF Using 52-Week Share Prices

	Share Prices Low	Share Prices High	2007 Dividend	52 Week Yields Low	52 Week Yields High	2001-03 DPS	2010-12E DPS	Growth Rate	Cost of Capital Low	Cost of Capital High
Atmos Energy Corp.	25.55	33.09	1.28	3.87%	5.01%	1.18	1.35	1.51%	5.37%	6.52%
AGL Resources	34.43	42.90	1.64	3.82%	4.76%	1.09	1.80	5.73%	9.55%	10.49%
New Jersey Resources	42.85	53.16	1.52	2.86%	3.55%	1.20	1.68	3.78%	6.64%	7.32%
NICOR, Inc.	38.72	49.92	1.90	3.81%	4.91%	1.82	2.00	1.05%	4.86%	5.96%
Northwest Natural Gas	33.30	46.30	1.44	3.11%	4.32%	1.26	1.80	4.04%	7.15%	8.37%
Piedmont Natural Gas	23.21	28.44	0.99	3.48%	4.27%	0.79	1.15	4.21%	7.69%	8.48%
South Jersey Industries	25.63	38.56	0.98	2.54%	3.82%	0.76	1.20	5.26%	7.80%	9.08%
Southwest Gas	26.46	39.95	0.86	2.15%	3.25%	0.82	0.90	1.04%	3.19%	4.29%
WGL Holdings, Inc.	27.04	33.55	1.38	4.11%	5.10%	1.27	1.45	1.48%	5.60%	6.59%
Comparable Companies' Averages	31.46	41.60	1.34	3.24%	4.25%	1.13	1.50	3.32%	6.56%	7.57%
Comparable Companies' Averages for Bond Ratings of A+ and Above									6.06%	7.06%
Comparable Companies' Averages for Bond Ratings Below A+									7.06%	8.09%

Sources:
Value Line Investment Survey
Yahoo! FINANCE

Schedule DAM - 20

Atmos Energy Corporation

Comparable Gas Companies

Dividend Growth Rate DCF Using Current Share Prices

	Share Prices Low	Share Prices High	Current Dividend	Current Yields Low	Current Yields High	2001-03 DPS	2010-12E DPS	Growth Rate	Cost of Capital Low	Cost of Capital High
Atmos Energy Corp.	31.44	31.93	1.28	4.01%	4.07%	1.18	1.35	1.51%	5.52%	5.58%
AGL Resources	40.50	41.12	1.64	3.99%	4.05%	1.09	1.80	5.73%	9.72%	9.78%
New Jersey Resources	49.02	49.75	1.52	3.06%	3.10%	1.20	1.68	3.78%	6.83%	6.88%
NICOR, Inc.	47.13	47.97	1.90	3.96%	4.03%	1.82	2.00	1.05%	5.01%	5.08%
Northwest Natural Gas	44.25	44.99	1.44	3.20%	3.25%	1.26	1.80	4.04%	7.24%	7.30%
Piedmont Natural Gas	26.06	26.72	0.99	3.71%	3.80%	0.79	1.15	4.21%	7.92%	8.01%
South Jersey Industries	35.58	36.72	0.98	2.67%	2.75%	0.76	1.20	5.26%	7.93%	8.01%
Southwest Gas	37.64	38.42	0.86	2.24%	2.28%	0.82	0.90	1.04%	3.28%	3.32%
WGL Holdings, Inc.	31.29	31.75	1.38	4.35%	4.41%	1.27	1.45	1.48%	5.83%	5.89%
Comparable Companies' Averages	38.93	39.68	1.34	3.40%	3.46%	1.13	1.50	3.32%	6.72%	6.79%
Comparable Companies' Averages for Bond Ratings of A+ and Above									6.23%	6.29%
Comparable Companies' Averages for Bond Ratings Below A+									7.21%	7.28%

Sources:
Value Line Investment Survey
Yahoo! FINANCE

Atmos Energy Corporation

Comparable Gas Companies

Earnings Growth Rate DCF Using 52-Week Share Prices

	Share Prices Low	Share Prices High	2007 Dividend	52 Week Yields Low	52 Week Yields High	2001-03 EPS	2010-12E EPS	Growth Rate	Cost of Capital Low	Cost of Capital High
Atmos Energy Corp.	25.55	33.09	1.28	3.87%	5.01%	1.54	2.50	5.51%	9.37%	10.52%
AGL Resources	34.43	42.90	1.64	3.82%	4.76%	1.80	3.10	6.23%	10.05%	10.99%
New Jersey Resources	42.85	53.16	1.52	2.86%	3.55%	2.14	3.15	4.39%	7.25%	7.94%
NICOR, Inc.	38.72	49.92	1.90	3.81%	4.91%	2.67	2.90	0.94%	4.74%	5.84%
Northwest Natural Gas	33.30	46.30	1.44	3.11%	4.32%	1.75	2.95	5.95%	9.06%	10.28%
Piedmont Natural Gas	23.21	28.44	0.99	3.48%	4.27%	1.02	1.55	4.72%	8.20%	8.99%
South Jersey Industries	25.63	38.56	0.98	2.54%	3.82%	1.25	3.30	11.42%	13.96%	15.25%
Southwest Gas	26.46	39.95	0.86	2.15%	3.25%	1.15	2.60	9.52%	11.68%	12.77%
WGL Holdings, Inc.	27.04	33.55	1.38	4.11%	5.10%	1.77	2.20	2.42%	6.54%	7.53%
Comparable Companies' Averages	31.46	41.60	1.34	3.24%	4.25%	1.69	2.72	5.70%	8.94%	9.95%
Comparable Companies' Averages for Bond Ratings of A+ and Above									6.90%	7.90%
Comparable Companies' Averages for Bond Ratings Below A+									10.97%	12.00%

Sources:
Value Line Investment Survey
Yahoo! FINANCE

Atmos Energy Corporation

Comparable Gas Companies

Earnings Growth Rate DCF Using Current Share Prices

	Share Prices Low	Share Prices High	Current Dividend	Current Yields Low	Current Yields High	2001-03 EPS	2010-12E EPS	Growth Rate	Cost of Capital Low	Cost of Capital High
Atmos Energy Corp.	31.44	31.93	1.28	4.01%	4.07%	1.54	2.50	5.51%	9.51%	9.58%
AGL Resources	40.50	41.12	1.64	3.99%	4.05%	1.80	3.10	6.23%	10.21%	10.28%
New Jersey Resources	49.02	49.75	1.52	3.06%	3.10%	2.14	3.15	4.39%	7.44%	7.49%
NICOR, Inc.	47.13	47.97	1.90	3.96%	4.03%	2.67	2.90	0.94%	4.90%	4.97%
Northwest Natural Gas	44.25	44.99	1.44	3.20%	3.25%	1.75	2.95	5.95%	9.15%	9.21%
Piedmont Natural Gas	26.06	26.72	0.99	3.71%	3.80%	1.02	1.55	4.72%	8.43%	8.52%
South Jersey Industries	35.58	36.72	0.98	2.67%	2.75%	1.25	3.30	11.42%	14.09%	14.18%
Southwest Gas	37.64	38.42	0.86	2.24%	2.28%	1.15	2.60	9.52%	11.76%	11.81%
WGL Holdings, Inc.	31.29	31.75	1.38	4.35%	4.41%	1.77	2.20	2.42%	6.77%	6.83%
Comparable Companies' Averages	38.93	39.68	1.34	3.40%	3.46%	1.69	2.72	5.70%	9.09%	9.16%
Comparable Companies' Averages for Bond Ratings of A+ and Above									7.07%	7.12%
Comparable Companies' Averages for Bond Ratings Below A+									11.12%	11.20%

Sources:
Value Line Investment Survey
Yahoo! FINANCE

Schedule DAM - 23

Atmos Energy Corporation

Comparable Gas Companies

Projected Growth Rate DCF Using 52-Week Share Prices

	Share Prices		2007	52 Week Yields		EPS Estimates		Cost of Capital	
	Low	High	Dividend	Low	High	Value Line	S&P	Low	High
Atmos Energy Corp.	25.55	33.09	1.28	3.87%	5.01%	5.00%	6.00%	8.87%	10.01%
AGL Resources	34.43	42.90	1.64	3.82%	4.76%	3.50%	4.00%	7.32%	8.76%
New Jersey Resources	42.85	53.16	1.52	2.86%	3.55%	2.50%	5.00%	5.36%	8.55%
NICOR, Inc.	38.72	49.92	1.90	3.81%	4.91%	4.00%	4.00%	7.81%	8.91%
Northwest Natural Gas	33.30	46.30	1.44	3.11%	4.32%	7.00%	5.00%	8.11%	11.32%
Piedmont Natural Gas	23.21	28.44	0.99	3.48%	4.27%	3.00%	4.00%	6.48%	8.27%
South Jersey Industries	25.63	38.56	0.98	2.54%	3.82%	9.50%	7.00%	9.54%	13.32%
Southwest Gas	26.46	39.95	0.86	2.15%	3.25%	8.00%	12.00%	10.15%	15.25%
WGL Holdings, Inc.	27.04	33.55	1.38	4.11%	5.10%	1.00%	4.00%	5.11%	9.10%
Comparable Companies' Averages	31.46	41.60	1.34	3.24%	4.25%	4.81%	5.63%	7.49%	10.44%
Comparable Companies' Averages for Bond Ratings of A+ and Above								6.60%	9.47%
Comparable Companies' Averages for Bond Ratings Below A+								8.37%	11.40%

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

Atmos Energy Corporation

Comparable Gas Companies

Projected Growth Rate DCF Using Current Share Prices

	Share Prices		Current	Current Yields		EPS Estimates		Cost of Capital	
	Low	High	Dividend	Low	High	Value Line	S&P	Low	High
Atmos Energy Corp.	31.44	31.93	1.28	4.01%	4.07%	5.00%	6.00%	9.01%	9.07%
AGL Resources	40.50	41.12	1.64	3.99%	4.05%	3.50%	4.00%	7.49%	8.05%
New Jersey Resources	49.02	49.75	1.52	3.06%	3.10%	2.50%	5.00%	5.56%	8.10%
NICOR, Inc.	47.13	47.97	1.90	3.96%	4.03%	4.00%	4.00%	7.96%	8.03%
Northwest Natural Gas	44.25	44.99	1.44	3.20%	3.25%	7.00%	5.00%	8.20%	10.25%
Piedmont Natural Gas	26.06	26.72	0.99	3.71%	3.80%	3.00%	4.00%	6.71%	7.80%
South Jersey Industries	35.58	36.72	0.98	2.67%	2.75%	9.50%	7.00%	9.67%	12.25%
Southwest Gas	37.64	38.42	0.86	2.24%	2.28%	8.00%	12.00%	10.24%	14.28%
WGL Holdings, Inc.	31.29	31.75	1.38	4.35%	4.41%	1.00%	4.00%	5.35%	8.41%
Comparable Companies' Averages	38.93	39.68	1.34	3.40%	3.46%	4.81%	5.63%	7.65%	9.65%
Comparable Companies' Averages for Bond Ratings of A+ and Above								6.77%	8.70%
Comparable Companies' Averages for Bond Ratings Below A+								8.53%	10.60%

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

Atmos Energy Corporation

Comparable Gas Companies

Discounted Cash Flow Analysis By Bond Rating

	Standard & Poor's A+ Rating or Higher		Below Standard & Poor's A+ Rating	
	Low	High	Low	High
Dividend Growth DCF Analysis	6.06%	7.06%	7.06%	8.09%
Earnings Growth DCF Analysis	6.90%	7.90%	10.97%	12.00%
Projected Growth DCF Analysis	6.60%	9.47%	8.37%	11.40%

Sources: Schedules DAM-20 through DAM-25

Atmos Energy Corporation

Comparable Gas Companies

Size Adjusted Capital Asset Pricing Model

	Risk Free Return	Beta	Equity Risk Premium	Adjusted Equity Risk Premium	Size Premium	Cost of Equity
Atmos Energy Corp.	4.81%	0.80	7.10%	5.68%	0.97%	11.46%
AGL Resources	4.81%	0.95	7.10%	6.75%	0.97%	12.53%
New Jersey Resources	4.81%	0.80	7.10%	5.68%	1.76%	12.25%
NICOR, Inc.	4.81%	1.30	7.10%	9.23%	0.97%	15.01%
Northwest Natural Gas	4.81%	0.75	7.10%	5.33%	1.76%	11.90%
Piedmont Natural Gas	4.81%	0.80	7.10%	5.68%	1.76%	12.25%
South Jersey Industries	4.81%	0.70	7.10%	4.97%	1.76%	11.54%
Southwest Gas	4.81%	0.85	7.10%	6.04%	1.76%	12.61%
WGL Holdings, Inc.	4.81%	0.85	7.10%	6.04%	1.76%	12.61%
Comparable Companies' Average	4.81%	0.88	7.10%	6.21%	1.56%	12.59%

Sources :
Value Line Investment Survey
Ibbotson Associates 2007 SBBI Yearbook: Valuation Edition
Federal Reserve Statistical Release

Atmos Energy Corporation

Comparable Gas Companies

Historical Capital Asset Pricing Model

	Market Total Returns	Long-Term Corporate Bonds Return	Risk Premium	Beta	Adjusted Risk Premium	Aaa Corporate Bonds Return	Cost of Equity
Atmos Energy Corp.	14.85%	6.20%	8.65%	0.80	6.92%	5.30%	12.22%
AGL Resources	14.85%	6.20%	8.65%	0.95	8.22%	5.30%	13.52%
New Jersey Resources	14.85%	6.20%	8.65%	0.80	6.92%	5.30%	12.22%
NICOR, Inc.	14.85%	6.20%	8.65%	1.30	11.25%	5.30%	16.55%
Northwest Natural Gas	14.85%	6.20%	8.65%	0.75	6.49%	5.30%	11.79%
Piedmont Natural Gas	14.85%	6.20%	8.65%	0.80	6.92%	5.30%	12.22%
South Jersey Industries	14.85%	6.20%	8.65%	0.70	6.06%	5.30%	11.36%
Southwest Gas	14.85%	6.20%	8.65%	0.85	7.35%	5.30%	12.65%
WGL Holdings, Inc.	14.85%	6.20%	8.65%	0.85	7.35%	5.30%	12.65%
Comparable Companies' Average	14.85%	6.20%	8.65%	0.88	7.57%	5.30%	12.87%

Sources :
Value Line Investment Survey
Ibbotson Associates 2007 SBBI Yearbook: Valuation Edition
Federal Reserve Statistical Release

Atmos Energy Corporation

Recent Increase in Returns on Common Equity

By Industry Group

Industry	Earnings 2003	2004	2005	2006	Percent Increase 2003-2006
Atmos	9.30%	7.60%	8.50%	9.90%	0.60%
Building Materials	13.50%	15.30%	16.00%	16.00%	2.50%
Cement & Aggregates	9.40%	14.50%	19.50%	22.50%	13.10%
Chemical/Diversified	15.20%	16.20%	19.70%	19.50%	4.30%
Healthcare Information	11.70%	14.40%	14.40%	15.50%	3.80%
Household Products	33.50%	34.60%	39.80%	18.50%	-15.00%
Insurance (Life)	9.30%	9.60%	10.80%	11.00%	1.70%
Machinery	12.10%	16.50%	19.20%	20.50%	8.40%
Railroad	8.60%	9.30%	11.60%	10.50%	1.90%
Three Month Treasury Security	1.01%	1.37%	3.15%	4.73%	3.72%

Sources: Value Line Investment Survey
Federal Reserve

Atmos Energy Corporation

Projected Cost of Capital

Thirteen Month Average as of October 31, 2008

	Percent of Total	Embedded Cost			Weighted Cost of Capital		
		Low	Middle	High	Low	Middle	High
Long Term Debt	51.50%	6.10%	6.10%	6.10%	3.14%	3.14%	3.14%
Common Equity	48.50%	11.50%	11.75%	12.00%	5.58%	5.70%	5.82%
Total Capital	100.00%				8.72%	8.84%	8.96%

Source:
Atmos Energy Corporation Work Papers

Atmos Energy Corporation

Comparable Gas Companies

Comparison of After-Tax Times Interest Earned Ratios

Atmos Energy Corp.	@11.50% ROE	2.78
	@11.75% ROE	2.81
	@12.00% ROE	2.85
AGL Resources		2.68
New Jersey Resources		4.20
NICOR, Inc.		7.57
Northwest Natural Gas		2.97
Piedmont Natural Gas		2.97
South Jersey Industries		4.63
Southwest Gas		1.90
WGL Holdings, Inc.		3.45
Comparable Companies' Average		3.80

Source : Value Line Investment Survey

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

THOMAS H. PETERSEN

I. INTRODUCTION OF WITNESS

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

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

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE THE TESTIMONY THAT YOU INTEND TO GIVE IN THIS PROCEEDING.

A. My testimony will cover four areas:

1. Calculation of the Company's projected revenue deficiency for the attrition year that ends October 31, 2008. The total projected revenue deficiency for that year is $11,055,188.

2. Calculation of an average rate base for that same period. The projected attrition year rate base is approximately $182 million as shown in Schedule THP-7.

3. I will explain the lead-lag analysis that I performed. Cash working capital is the capital investment in addition to other rate base items that is required to bridge the gap between when cash is paid for the expenses necessary to provide service and when cash is received from customers for that service. That amount should be included in the rate base that is used to set rates in this proceeding. Based upon my lead-lag study, the Company has a cash work capital requirement of approximately $5,614,251.

4. Based upon these calculations, the resulting rate of return on rate base is 5.21% and the rate of return on the equity-financed portion of rate base is 4.42%.

Q. WHAT CALCULATIONS HAVE YOU PERFORMED FOR YOUR TESTIMONY IN THIS PROCEEDING?

A. I have calculated the Company's projected revenue deficiency for the attrition year ended October 31, 2008. I also have calculated an average rate base for the period. My calculations incorporate the capital structure presented by Ms. Laurie Sherwood, the rate of return presented by Dr. Don Murry, depreciation rates presented by Mr. Donald Roff, cost allocations and revenues presented by Mr. James Cagle, and the expense projections presented by Mr. Greg Waller. The deficiency and rate base calculations are shown in attached Schedules THP-1 through THP-10 and related work papers. I also have performed a lead-lag analysis to calculate the cash working capital used to provide utility services.

The calculation of cash working capital to be included in rate base is shown in attached Schedules THP-CWC1 through THP-CWC9.

III. WITNESS QUALIFICATIONS

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

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

IV. REVENUE DEFICIENCY

Q. PLEASE EXPLAIN SCHEDULE THP-1.

A. Schedule THP-1 summarizes the elements of the cost of service, including gas cost expense, operation and maintenance expense, depreciation expense, taxes other than income taxes, return on rate base income tax, allowance for funds used during construction ("AFUDC") and interest on customer deposits. Schedule THP-1 compares the total cost of service to revenues at present rates in order to calculate a net revenue

deficiency. The resulting total projected revenue deficiency for the attrition year ended October 31, 2008 is approximately $11,055,188.

Q. PLEASE EXPLAIN SCHEDULES THP-2 AND THP-3.

A. Schedule THP-2 shows per book revenues for the test year ended December 31, 2006, and the projected attrition year revenues from Mr. Waller's testimony. Schedule THP-3 shows the test year per books gas cost and the projected cost of gas, also from Mr. Waller's testimony. The attrition year cost of gas is adjusted to remove rent for inter-company leased storage property that is booked to gas cost.

Q. PLEASE EXPLAIN SCHEDULE THP-4.

A. Schedule THP-4 shows the test year per books operation and maintenance expense, and the projected attrition year operation and maintenance expense from Mr. Waller's testimony. I have adjusted the attrition year operation and maintenance expense to remove rent on inter-company leased property, deducted amortization of gain on the sale of the Maryland Way property, annualized the amortization of rate case expenses from the 2006 contested case, included a two year amortization of rate case expenses related to this case and removed certain expense report amounts.

Q. PLEASE EXPLAIN SCHEDULE THP-5.

A. Schedule THP-5 shows the test year per books taxes other than income taxes expense, and the projected attrition year taxes other than income taxes expense from Mr. Waller's testimony.

Q. PLEASE EXPLAIN SCHEDULE THP-6.

A. Schedule THP-6 shows the test year per books depreciation and amortization expense, and the projected attrition year depreciation and amortization expense. The attrition year

depreciation expense is adjusted to reflect the proposed depreciation rates discussed in Mr. Roff's testimony on assets located in Tennessee as well as shared services assets, and to reflect the net elimination of inter-company leased property.

Q. PLEASE EXPLAIN SCHEDULE THP-7.

A. Schedule THP-7 shows the calculation of the test year per books rate base, and projected attrition year rate base. The rate base includes the projected thirteen month averages of the original cost of plant, accumulated depreciation, construction work in progress, storage gas investment, materials and supplies, cash working capital, accumulated deferred income tax, customer advances, customer deposits, accumulated interest on customer deposits and deferred rate case expenses. The items included are generally consistent with the items included in the rate base in the company's monthly 3.03 reports to the TRA. However, there are some differences between Schedule THP-7 and the 3.03 filings. Schedule THP-7 includes amounts for cash working capital and deferred rate case expenses while a credit for the unpaid portion of material and supplies is included in the 3.03 filings. The company's general ledger does not separately identify accounts payable related to materials and supplies. The company has performed a new lead-lag study to identify its cash working capital requirements.

Q. PLEASE EXPLAIN SCHEDULE THP-8.

A. Schedule THP-8 shows the calculation of state excise taxes and income taxes on the required return on rate base for both the test year ended December 31, 2006, and the attrition year ended October 31, 2008.

Q. PLEASE EXPLAIN SCHEDULE THP-9.

A. Schedule THP-9 shows the calculation of the overall cost of capital based on the projected capital structure from Ms. Sherwood's testimony of 48.5% equity and 51.5% debt, a debt cost rate based on the annualized cost rate on long tern debt as of April 30, 2006, of 6.10%, and the required rate of return on equity from Dr. Murry's testimony of 11.75%. The resulting weighted average cost of capital is 8.84%.

Q. PLEASE EXPLAIN SCHEDULE THP-10.

A. Schedule THP-10 shows the calculation of a rate of return on rate base and a rate of return on the equity financed portion of rate base for the test period and the attrition period, with costs and revenues as presented in schedules THP-2 through THP-9. The resulting rate of return on rate base is 7.54% for the test year and 5.21% for the attrition year, and the rate of return on the equity-financed portion of rate base is 9.24% for the test year and 4.42% for the attrition year.

V. CASH WORKING CAPITAL

Q. WHAT IS THE PURPOSE OF THE LEAD-LAG ANALYSIS?

A. Rate base is the value of invested capital, including all items used to provide utility service. Cash working capital is the capital investment in addition to other rate base items that is required to bridge the gap between when cash is paid for expenses necessary to provide service and when cash is received from customers for that service. As stated above, this amount is included in rate base. A lead-lag analysis is a method of measuring the amount of cash working capital used to provide utility service. This analysis compares two different lags. The lag between (1) the provision of service to customers

and the collection of cash from customers is compared to the lag between (2) the recording of expenses and the payment of cash by the company for those expenses.

Q. DO YOU HAVE ANY PAST EXPERIENCE PERFORMING LEAD-LAG STUDIES?

A. Yes. I have prepared several lead lag studies for the Company over the years.

Q. DID YOU PREPARE THE LEAD-LAG STUDY USING A METHODOLOGY THAT IS COMMONLY ACCEPTED IN REGULATED GAS UTILITY RATE PROCEEDINGS?

A. Yes. The lead lag study was prepared in accordance with accepted methodology for such studies.

Q. PLEASE DESCRIBE SCHEDULE THP-CWC1.

A. This Schedule actually consists of two parts – Schedule THP-CWC1 A and THP-CWC1 B. Schedule THP-CWC1 A summarizes the results of the lead-lag analysis for the attrition year that ends October 31, 2008. It shows the calculation of the cash working capital requirement based on revenue and expense lag days and projected expense amounts in the proposed revenue requirement.

Schedule THP-CWC1 B summarizes the results of the lead-lag analysis for the test year ended December 31, 2006. It shows the calculation of the cash working capital requirement based on revenue and expense lag days and actual expenses for the test year.

The individual expense categories analyzed are listed in column (a) of Schedules THP-CWC1 A and THP-CWC1 B. These include gas cost, operating and maintenance expenses, taxes other than income taxes, federal income tax, state excise tax, depreciation, interest on customer deposits, interest expense on long term debt, and return

on equity. Operating and maintenance ("O&M") expenses are divided into labor and other O&M costs. Taxes other than income taxes include payroll taxes – FICA and unemployment, ad valorem taxes, gross receipts taxes, TRA inspection fee, DOT fees, franchise taxes and allocated taxes.

The amounts shown in column (b) of Schedule THP-CWC1 A are for the attrition year ended October 2008 with adjustments. The amounts shown in column (b) of Schedule THP-CWC1 B are for the test year ended December 2006. The amounts in column (c) of each Schedule are calculated by dividing column (b) by 365 days. The revenue and expense lag days in columns (d) and (e) of both Schedules are calculated on Schedules THP-CWC2 through CWC9. Net lead-lag days in column (f) of each Schedule are calculated by subtracting column (e) from column (d). The cash working capital requirement in column (g) of each Schedule is calculated by multiplying the average daily amount in column (c) times the net lead-lag days in column (f). The net result, which is $5,614,251 of cash working capital for the attrition year, appears at the bottom of column (g) of Schedule THP-CWC1 A.

Q. PLEASE DESCRIBE SCHEDULE THP-CWC2.

A. The average revenue lag is calculated on Schedule THP-CWC2. The revenue lag is the average number of days from the time service is provided by the company until revenue related to that service is available to pay bills. It consists of four subparts:

- the service lag,
- the billing lag,
- the collection lag, and
- the bank lag.

Q. WHAT IS THE SERVICE LAG?

A. The service lag is the average number of days from the time service is provided until the meter is read. Since service is provided daily and meters are read monthly, the service lag is one-half month or 15.21 days.

Q. WHAT IS THE BILLING LAG?

A. The billing lag is the time lag from meter reading to bill issuance. The billing lag was calculated separately for those customers on the company's regular billing system and for those customers whose bills are too complicated to be calculated on the company's regular billing system. The average billing lag for customers on the regular billing system calculated, based on all bills issued in a heating season month (January) and a non-heating season month (September) was 3.09 days. Those customers' bills account for approximately 97% of annual revenues. The average billing lag for the complicated bills in the test year was 12.35 days. Those bills account for approximately 3% of annual revenues. The overall weighted average billing lag was 3.37 days.

Q. WHAT IS THE COLLECTION LAG?

A. The collection lag is the average number of days between issuing a bill and receiving payment. This was calculated by dividing the average daily accounts receivable balance by the average daily revenue. The collection lag was calculated for the year ended December 2006. It resulted in a lag period of 25.81 days.

Q. WHAT IS THE BANK LAG?

A. The bank lag is the one-day lag between receiving payment and having funds available to draw at the bank. Customer accounts receivable balances are credited when payment is received.

Q. WHAT IS THE TOTAL AVERAGE REVENUE LAG?

A. The resulting total average revenue lag is 45.39 days, as shown on the last line of Schedule THP-CWC2.

Q. PLEASE DESCRIBE SCHEDULE THP-CWC3.

A. Schedule THP-CWC3 shows the calculation of the average purchased gas cost payment lag of 40.51 days from the delivery of the gas to the payment for the gas. The schedule shows the service dates, the invoice date, and the payment date for all gas invoices in the test year.

Q. PLEASE DESCRIBE SCHEDULE THP-CWC4.

A. Schedule THP-CWC4 shows the calculation of the average payroll lag, which is the average number of days from the time service is provided until payroll related to that service is paid. The payroll lag days consists of three subparts:

- the service lag,
- the payment lag, and
- the check-clearing lag.

Q. WHAT IS THE SERVICE LAG?

A. The service lag is the average number of days from the time service is provided until the end of the pay period. With the Company's two-week pay period, the service lag is seven days

Q. WHAT IS THE PAYMENT LAG?

A. Payment lag is the average number of days between the end of the pay period and payment date. With the Company's practice of paying on Friday for a pay period that ended the previous Friday, the payment lag is seven days. Most employees use direct

deposit, and therefore have no check-clearing lag. However, the few employees that are paid by check result in an average check-clearing lag of 0.23 days.

Q. WHAT IS THE TOTAL AVERAGE PAYROLL LAG?

A. The total average payroll lag is 14.23 days.

Q. PLEASE DESCRIBE SCHEDULE THP-CWC5.

A. Schedule THP-CWC5 shows the calculation of the average number of lag days for other O&M expenses. The calculation is based on an analysis of payments for the twelve months ended December 31, 2006. A sample of 5,987 invoices was used to determine the lag between the date services were provided to the Company and the date the Company paid the bill for those services. If no information was available regarding the date service was provided, then the date of the invoice was used. The resulting weighted average lag from service to payment is 19.58 days. A sample of 4,414 checks was used to determine the lag between the date that checks were written and the date that the checks cleared. The resulting weighted average check-clearing lag is 2.23 days. Therefore, the total average lag for the other O&M expenses is 21.81 days.

Q. PLEASE DESCRIBE SCHEDULE THP-CWC6.

A. Schedule THP-CWC6 shows the calculation of the average payment lag days for other taxes. The calculation of the lag is shown separately for each type of tax (payroll taxes – FICA and unemployment, ad valorem taxes, gross receipts taxes, TRA inspection fee, DOT fees, and franchise taxes).

Q. PLEASE DISCUSS THE LAG RELATING TO PAYROLL TAXES.

A. Payroll taxes consist of FICA taxes and unemployment taxes. FICA taxes are paid by wire on the third banking day after each payday. On average, FICA lag days are equal to

the payroll lag days for direct deposit employees plus 2.6 days, for a total lag of 16.6 days. Unemployment taxes are paid quarterly at the end of the month following each quarter. Therefore, for unemployment taxes, the lag, as calculated from the mid-point of the quarter to the payment date at the end of the following month, is 76 days.

Q. PLEASE DISCUSS THE LAG RELATING TO AD VALOREM TAXES.

A. Ad valorem taxes for a calendar year are paid on February 28 of the following year. Therefore, the ad valorem tax lag, as calculated from the mid-point of the calendar year to the payment date, is 241.50 days.

Q. PLEASE DISCUSS THE LAG RELATING TO GROSS RECEIPTS TAXES.

A. Gross receipts taxes are paid annually on August 1, for the period of July 1 of the current year through June 30 of the following year. Therefore, gross receipts taxes are paid on a (151.50) day lead, as opposed to a lag.

Q. PLEASE DISCUSS THE LAG RELATING TO THE TRA INSPECTION FEE.

A. The annual TRA Inspection Fee is paid on or before April 1 of each year, for the revenue period January 1 through December 31 of the prior year. Therefore, the TRA Inspection Fee lag, as calculated from the mid-point of the calendar year to the payment date, is 272.50 days.

Q. PLEASE DISCUSS THE LAG RELATING TO THE DOT FEE.

A. The annual DOT fee lag of 241.5 days is calculated from the midpoint of the calendar year to the payment date on February 28th of the following calendar year.

Q. PLEASE DISCUSS THE LAG RELATING TO THE STAE FRANCHISE TAX.

A. The franchise tax is paid in four quarterly payments during the year similar to the state excise tax. The resulting lag is 29.5 days.

Q. PLEASE DESCRIBE SCHEDULE THP-CWC7.

A. Schedule THP-CWC7 shows the calculation of the federal income tax lag. Income taxes for a fiscal year are paid in four quarterly payments during the year. Two payments are before the mid-point of the tax year and two are after the midpoint. The average lag from the midpoint of the tax year to the payment dates is 29.5 days. This is the lag for paying current taxes. Taxes that are deferred are recorded as a rate base credit and thus have an expense lag of zero days.

Q. PLEASE DESCRIBE SCHEDULE THP-CWC8.

A. Schedule THP-CWC8 shows the calculation of the state excise tax lag. State excise taxes for a fiscal year are paid on the same schedule as federal income taxes. Therefore, the average lag from the midpoint of the tax year to the payment dates is also 29.5 days for paying current taxes, and zero days for deferred taxes.

Q. PLEASE DESCRIBE SCHEDULE THP-CWC9.

A. Schedule THP-CWC9 shows the calculation of the long-term debt lag. Long-term debt interest expense includes monthly payments, quarterly payments, and semi-annual payments. Interest is recorded on an accrual basis and paid in the period it is due. The long-term debt lag, as calculated from the mid-point of the accrual period to the payment date, averages 84.18 days.

Q. HOW IS THE RATE BASE TREATMENT OF PREPAYMENTS CONSISTENT WITH THE CALCULATION OF CASH WORKING CAPITAL?

A. Prepayments relate to expenses that are paid before they are recorded as expenses. They can be included in a cash working capital study in one of two ways. First, they can be included with a negative lag to reflect the gap from the payment to the recording of the

expense. This way both the lag from the payment to the recording of the expense and the subsequent revenue lag from the provision of service to the receipt of cash are recognized in rate base. Second, they can be included as prepayments in rate base and then treated in the lead-lag study at a zero lag as if the payment was made at the time that the expense was recorded. This way the inclusion as prepayments recognizes the lag from payment to recording of expense and the lead-lag study recognizes only the revenue lag. In this filing I have used the first approach, calculating rate base by including prepaid items in the lead-lag study with a negative lag and not separately including prepayments.

Q. DISCUSS THE TREATMENT OF DEPRECIATION EXPENSE IN THE LEAD-LAG STUDY.

A. Depreciation expense is treated similar to a prepayment. When a plant asset is purchased, the expense is recognized over time as depreciation expense. The payment for the asset precedes the receipt of service from the asset and the recording of expense. The lag between payment for the asset and the recording of depreciation expense is recognized by the inclusion in rate base of plant in service.

Q. DOES INCLUSION OF PLANT IN SERVICE IN RATE BASE SUFFICE TO PROPERLY ACCOUNT FOR ALL OF THE LAG RELATING TO DEPRECIATION?

A. No. The inclusion in rate base of plant in service does not recognize the subsequent lag from the provision of service to the receipt of cash for that service. By including depreciation expense in the lead-lag study with a zero expense lag, the lead-lag study properly recognizes the subsequent revenue lag on recovering cash related to investment in plant assets. In other words, the investment in an asset is included in rate base as net

plant in service until depreciation is recorded on that asset. Recording depreciation removes the asset from rate base, even though cash has not been received to pay for the service provided by the asset, unless the revenue lag on depreciation expense is included in cash working capital through the lead-lag study.

Q. HOW MUCH IS THE COMPANY'S CASH WORKING CAPITAL REQUIREMENT?

A. Based upon all of the components of the lead-lag study, the Company has a cash working capital requirement for the attrition year of $5,614,251. That amount should be included in the rate base that is used to set rates in this proceeding.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF IT'S RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

VERIFICATION

STATE OF TEXAS)

COUNTY OF DALLAS)

I, Thomas H. Petersen, being first duly sworn, state that I am Director of Rate Department, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Testimony of Thomas H. Petersen in support of Atmos Energy Corporation's Petition and the Exhibits thereto pre-filed in this docket on the date of filing of this Petition are true and correct to the best of my knowledge, information and belief.

Thomas H. Petersen

Thomas H. Petersen

Sworn and subscribed before me this 1st day of May, 2007.

Ethel Z. Taylor

Notary Public

My Commission Expires: August 13, 2010

ETHEL Z TAYLOR
My Commission Expires
August 13, 2010

Schedule THP-1

Tennessee Distribution System
Cost of Service
Twelve Months Ended October 31, 2008

Line No.	Description	Reference	Amount
	(a)	(b)	(c)
1	Cost of Gas	Schedule 3	$135,046,808
2			
3	Operation & Maintenance Expense	Schedule 4	15,556,774
4			
5	Taxes Other Than Income Taxes	Schedule 5	7,010,933
6			
7	Depreciation & Amortization Expense	Schedule 6	10,890,872
8			
9	Return	Schedule 7	16,700,533
10			
11	Federal Income and State Excise Tax	Schedule 8	6,950,083
12			
13	AFUDC	Wp 1-2	(131,911)
14			
15	Interest on Customer Deposits	Wp 1-1	423,512
16			
17	Total Cost of Service		192,447,604
18			
19			
20	Revenue at Present Rates	Schedule 2	181,392,416
21			
22	Net Revenue Deficiency		11,055,188

Tennessee Distribution System
Interest on Customer Deposits
Twelve Months Ended October 31, 2008

Line No.	Description	Amount
	(a)	(b)
1	Average Customer Deposit Balance	$7,058,536
2		
3	Interest Rate on Customer Deposits	6.00%
4		
5	Adjusted Customer Deposit Interest	$423,512

Tennessee Distribution System
Allowance for Funds Used During Construction
Twelve Months Ended October 31, 2008

Line No.	Description	Amount
	(a)	(b)
1	Test Year AFUDC per books - Div 093 [1]	$217,049
2		
3	Less State Excise Tax Effect	14,108
4		
5		$202,941
6		
7	Less Federal Tax Effect	71,030
8		
9	Net AFUDC - Test Year	131,911
10		
11	Change from Test Year to Attrition Year	0
12		
13	Projected Attrition Year Net AFUDC	131,911

[1] Twelve months ended December 31, 2006 - Account 432

Schedule THP-2

Tennessee Distribution System
Summary of Revenue at Present Rates
Twelve Months Ended October 31, 2008

Line No.	Description		Amount
	(a)		(b)
1	Test year per books revenue [1]		184,574,748
2			
3	Change from Test Year to Attrition Year		(3,182,332)
4			
5	Projected Attrition Year Revenue		
	Margin at current WNA	46,390,701	
	Change in Margin due to updating WNA	(45,093)	
	Margin at proposed WNA	46,345,608	
	Gas cost	135,046,808	
	Total		181,392,416

[1] Twelve months ended December 31, 2006

Schedule THP-3

Tennessee Distribution System
Cost of Gas
Twelve Months Ended October 31, 2008

Line No.	Description	Amount
	(a)	(b)
1	Test year per books cost of gas [1]	$136,629,859
2		
3	Adjustments	
4	Net Elimination of Intercompany Leased Storage Property	(1,583,051)
5		
6	Total Adjusted Gas Cost	135,046,808
7		
8	Change from Test Year to Attrition Year	-
9		
10	Projected Attrition Year Gas Cost	135,046,808

[1] Twelve months ended December 31, 2006

Tennessee Distribution System
ELIMINATION OF LEASED PROPERTY-RENT
Twelve Months Ended October 31, 2008

Month	ENERGY (F82) O&M	STORAGE (D128) Gas Cost
Per Books:		
October-05	44,333	130,108
November-05	44,333	99,472
December-05	44,333	127,132
January-06	44,333	130,945
February-06	44,333	128,601
March-06	44,333	131,540
April-06	44,333	122,235
May-06	44,333	120,934
June-06	44,333	158,888
July-06	44,333	125,666
August-06	44,333	124,519
September-06	44,333	139,278
October-06	44,333	133,932
November-06	44,333	131,724
December-06	44,333	134,789
Calendar 2006	531,996	1,583,052

Schedule THP-4

Tennessee Distribution System
Operation and Maintenance Expenses
Twelve Months Ended October 31, 2008

Line No.	Description	Amount ($)
	(b)	(c)
1	Test year per books O&M Expense [1]	14,789,621
2		
3	Change from Test Year to Attrition Year	1,051,821
4		
5	Attrition Year O&M Expenses - Unadjusted	15,841,442
6		
7	Adjustments to O&M	
8	Net Elimination of Intercompany Leased Property - Rent	(531,996)
9	Gain on sale of Maryland Way Property	(16,899)
10	Amortization of rate case expense	330,000
11	Expense report elimination	(65,773)
12		
13	Total Adjustments	(284,668)
14		
15	Total Adjusted Operation and Maintenance Expenses	15,556,774

[1] Twelve months ended December 31, 2006

Tennessee Distribution System
Rate Case Expense
Twelve Months Ended October 31, 2008

Line No.	Description	Total	Balance	Amortization
	(a)	(b)	(c)	(d)
1	Contested Case Expense - Docket No. 05-00258	$165,000		
2				
3	Three year amortization (December 2006 through November 2009)			$55,000
4				
5	Attrition Year Average Balance		$32,083	
6				
7				
8				
9	Proposed Rate Case Expenses	550,000		
10				
11	Two year amortization (November 2008 through October 2010)			275,000
12				
13	Attrition Year Average Balance		412,500	
14				
15	Total	$715,000	$444,583	$330,000

Schedule THP-5

Tennessee\ Distribution System
Taxes Other Than Income Taxes
Twelve Months Ended October 31, 2008

Line No.	Description		Total
	(a)		(b)
1	Test year per books Other Taxes Expense [1]	$	5,851,994
2			
3	Change from Test Year to Attrition Year		1,158,939
4			
5	Attrition Year Taxes Other Than Income Taxes	$	7,010,933

[1] Twelve months ended December 31, 2006

Schedule THP-6

Tennessee Distribution System
Depreciation and Amortization Expense
Twelve Months Ended October 31, 2008

Line No.	Description	Amount	Source
	(a)	(b)	
1	Test year per books Depreciation Expense [1]	$ 11,498,043	
2			
3	Change from Test Year to Attrition Year	1,251,899	
4			
5	Attrition Year Depreciation Expense at current Depreciation Rates	$ 12,749,942	Wp 6-2
6			
7	Adjustment to reflect Proposed Depreciation Rates	(2,097,654)	
8			
9	Attrition Year Depreciation Expense at proposed Depreciation Rates	10,652,288	Wp 6-1
10			
11	Net Elimination of Intercompany Leased Property	238,584	Wp 6-3
12			
13	Total Depreciation and Amortization Expense, As Adjusted	$ 10,890,872	

[1] Twelve months ended December 31, 2006

Tennessee Distribution System
Depreciation Expense Adjustment
Proforma SSU Depreciation @ Proposed Depreciation Rates
Twelve Months Ended October 31, 2008

Line No.	Description	Amount	Alloc Pct	Allocated
1	Proforma Depreciation			
2	Tennessee Operations	$ 9,516,217	100.00%	$ 9,516,217
3	Mid-States General Office	366,610	27.17%	99,608
4	SSU Div 12 - Customer Service	15,733,629	4.03%	634,065
5	SSU Div 02 - General Office	9,743,285	4.13%	402,398
6				
7	Proforma Depreciation Adjustment			$ 10,652,288

Tennessee Distribution System
Depreciation Expense Adjustment
Proforma SSU Depreciation @ Current Depreciation Rates
Twelve Months Ended October 31, 2008

Line No.	Description	Amount	Alloc Pct	Allocated
1	Proforma Depreciation			
2	Tennessee Operations	$ 11,753,033	100.00%	$ 11,753,033
3	Mid-States General Office	366,610	27.17%	99,608
4	SSU Div 12 - Customer Service	12,526,967	4.03%	504,837
5	SSU Div 02 - General Office	9,502,768	4.13%	392,464
6				
7				
8	Proforma Depreciation Expense			$ 12,749,942

Tennessee Distribution System
Net elimination of Intercompany leased Property
Depreciation Expense
Twelve Months Ended October 31, 2008

Line No.	Description	Source	Amount
	(a)		(b)
1	Intercompany Leased Property - October 31 2007	Wp7-1	$7,063,897
2			
3	Intercompany Leased Property - October 31 2008	Wp7-1	6,825,313
4			
5	Decrease - Depreciation		$238,584

Schedule THP-7

Tennessee Distribution System
Rate Base & Return
Twelve Months Ended October 31, 2008
Thirteen Month Average

Line No.	Description	Test Year [1]	Change	Attrition Year	Source or Description	
	(a)	(b)	(c)	(d)	(e)	
1	Original Cost of Plant	307,235,302	37,504,378	344,739,680	Wp 7-1	Wp7-2
2						
3	Accumulated Depreciation and Amortization	(132,372,710)	(16,534,602)	(148,907,313)	Wp 7-1	Wp7-2
4						
5	Construction Work in Progress per Books	5,670,631	(28,141)	5,642,491	Wp 7-1	Wp7-2
6						
7	Storage Gas Investment	15,435,630	1,586,713	17,022,343	Wp 7-1	Wp7-2
8						
9	Cash Working Capital	4,321,563	1,292,688	5,614,251	Sch THP CWC1	
10						
11	Material & Supplies	58,752	(23,312)	35,441	Wp 7-1	Wp7-2
12						
13	Deferred Rate Case Expenses	110,000	334,583	444,583	3yr amort	
14						
15	Accumulated Deferred Income Tax	(34,830,861)	(23,720)	(34,854,581)	Wp 7-1	
16						
17	Customer Advances for Construction	(33,862)	(3,623)	(37,485)	Wp 7-1	Wp7-2
18						
19	Customer Deposits	(6,283,250)	(775,285)	(7,058,536)	Wp 7-1	Wp7-2
20						
21	Accumulated Interest on Customer Deposits	(563,662)	(94,600)	(658,262)	Wp 7-1	Wp7-2
22						
23	Unadjusted Rate Base	158,747,533	23,235,080	181,982,612		
24						
25	Adjustments:					
26	Net Elimination of Intercompany Leased Property	7,377,614	(433,009)	6,944,605	Wp 7-1	Wp7-2
27	Unamortized Maryland Way Gain	(43,891)	36,729	(7,162)	Wp 7-1	Wp7-2
28						
29	Total Rate Base	166,081,256	22,838,799	188,920,055		
30						
31	Return @ Overall Cost of Capital on Rate Base	14,681,583	2,018,950	16,700,533		

[1] Twelve months ended December 31, 2006

Tennessee Distribution System WP THP 7-1

Reallocation of Rate Base Items at Proforma Allocation Factors

Twelve Months Ended October 31, 2008

Row #	a	b	c	d	e	f	g	h	i	j

Gas Plant in Service (Account 101) 13 month average Balances.

		Service Area 093	Service Area 091	Service Area 012	Service Area 002	Service Area 093	Service Area 091	Service Area 012	Service Area 002	Total
	Month	Tennessee	MSBU	SSU Customer	SSU General	100%	27.17%	4.03%	4.13%	Tennessee
1	Oct-07	324,263,579	6,967,795	148,598,112	100,110,617	324,263,579	1,893,150	5,988,504	4,131,688	311,425,463
2	Nov-07	325,983,269	6,983,420	148,556,446	101,160,034	325,983,269	1,897,395	5,986,825	4,174,999	338,042,488
3	Dec-07	327,313,354	7,027,567	148,597,854	103,325,352	327,313,354	1,909,390	5,988,494	4,264,364	339,475,602
4	Jan-08	328,467,524	7,072,355	148,556,187	104,030,991	328,467,524	1,921,559	5,986,814	4,293,487	340,669,384
5	Feb-08	329,592,302	7,098,890	148,514,521	105,190,868	329,592,302	1,928,768	5,985,135	4,341,356	341,847,562
6	Mar-08	330,885,429	7,096,902	148,472,854	107,277,288	330,885,429	1,928,228	5,983,456	4,427,466	343,224,579
7	Apr-08	332,293,146	7,094,914	148,431,187	108,029,916	332,293,146	1,927,688	5,981,777	4,458,528	344,661,139
8	May-08	333,599,038	7,092,926	148,389,521	109,722,405	333,599,038	1,927,148	5,980,098	4,528,379	346,034,663
9	Jun-08	335,056,157	7,090,939	148,347,854	110,024,361	335,056,157	1,926,608	5,978,419	4,540,841	347,502,025
10	Jul-08	336,447,798	7,088,951	148,306,187	111,663,066	336,447,798	1,926,068	5,976,739	4,608,472	348,959,078
11	Aug-08	337,683,719	7,086,963	148,264,521	111,729,034	337,683,719	1,925,528	5,975,060	4,611,195	350,195,502
12	Sep-08	338,114,338	7,084,975	148,222,854	111,781,233	338,114,338	1,924,988	5,973,381	4,613,349	350,626,056
13	Oct-08	341,400,597	7,090,924	148,630,793	115,911,663	341,400,597	1,926,604	5,989,821	4,783,817	354,100,839
14	Average	332,392,327	7,067,502	148,452,992	107,688,987	332,392,327	1,920,240	5,982,656	4,444,457	344,739,680
15										
16										

17 Construction Work in Process (Account 1070).

18

19		Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	
20		093	091	012	002	093	091	012	002	Total
21	Month	Tennessee	MSBU	SSU Customer	SSU General	100%	27.17%	4.03%	4.13%	Tennessee
22	Oct-07	5,218,856	194,768	(62,147)	9,043,123	5,218,856	52,919	(2,505)	373,221	4,333,489
23	Nov-07	5,218,856	194,768	(62,147)	9,043,123	5,218,856	52,919	(2,505)	373,221	5,642,491
24	Dec-07	5,218,856	194,768	(62,147)	9,043,123	5,218,856	52,919	(2,505)	373,221	5,642,491
25	Jan-08	5,218,856	194,768	(62,147)	9,043,123	5,218,856	52,919	(2,505)	373,221	5,642,491
26	Feb-08	5,218,856	194,768	(62,147)	9,043,123	5,218,856	52,919	(2,505)	373,221	5,642,491
27	Mar-08	5,218,856	194,768	(62,147)	9,043,123	5,218,856	52,919	(2,505)	373,221	5,642,491
28	Apr-08	5,218,856	194,768	(62,147)	9,043,123	5,218,856	52,919	(2,505)	373,221	5,642,491
29	May-08	5,218,856	194,768	(62,147)	9,043,123	5,218,856	52,919	(2,505)	373,221	5,642,491
30	Jun-08	5,218,856	194,768	(62,147)	9,043,123	5,218,856	52,919	(2,505)	373,221	5,642,491
31	Jul-08	5,218,856	194,768	(62,147)	9,043,123	5,218,856	52,919	(2,505)	373,221	5,642,491
32	Aug-08	5,218,856	194,768	(62,147)	9,043,123	5,218,856	52,919	(2,505)	373,221	5,642,491
33	Sep-08	5,218,856	194,768	(62,147)	9,043,123	5,218,856	52,919	(2,505)	373,221	5,642,491
34	Oct-08	5,218,856	194,768	(62,147)	9,043,123	5,218,856	52,919	(2,505)	373,221	5,642,491
35	Average	5,218,856	194,768	(62,147)	9,043,123	5,218,856	52,919	(2,505)	373,221	5,642,491

Tennessee Distribution System WP THP 7-1
Reallocation of Rate Base Items at Proforma Allocation Factors
Twelve Months Ended October 31, 2008

Row #	a	b	c	d	e	f	g	h	i	j

Inventories- Plant Materials (Account 1540).

		Service Area 093	Service Area 091	Service Area 012	Service Area 002	Service Area 093	Service Area 091	Service Area 012	Service Area 002	Total
	Month	Tennessee	MSBU	SSU Customer	SSU General	100%	27.17%	4.03%	4.13%	Tennessee
1	Oct-07	0	130,440		0	0	35,441	-	0	35,441
2	Nov-07	0	130,440		0	0	35,441	-	0	35,441
3	Dec-07	0	130,440		0	0	35,441	-	0	35,441
4	Jan-08	0	130,440		0	0	35,441	-	0	35,441
5	Feb-08	0	130,440		0	0	35,441	-	0	35,441
6	Mar-08	0	130,440		0	0	35,441	-	0	35,441
7	Apr-08	0	130,440		0	0	35,441	-	0	35,441
8	May-08	0	130,440		0	0	35,441	-	0	35,441
9	Jun-08	0	130,440		0	0	35,441	-	0	35,441
10	Jul-08	0	130,440		0	0	35,441	-	0	35,441
11	Aug-08	0	130,440		0	0	35,441	-	0	35,441
12	Sep-08	0	130,440		0	0	35,441	-	0	35,441
13	Oct-08	0	130,440		0	0	35,441	-	0	35,441
14	Average	0	130,440		0	0	35,441		0	35,441
15										
16										

17 Inventories- Gas Stored (Account 1641).

18 *Includes Tennessee stored gas in Dvivision 93 and an allocated portion of Tennessee stored gas in Division 96*

		Service Area 093	Service Area 091	Service Area 012	Service Area 002	Service Area 093	Service Area 091	Service Area 012	Service Area 002	Total
	Month	Tennessee	MSBU	SSU Customer	SSU General	100%	27.17%	4.03%	4.13%	Tennessee
22	Oct-07	26,804,531	0		0	26,804,531	0	-	0	26,804,531
23	Nov-07	28,531,584	0		0	28,531,584	0	-	0	28,531,584
24	Dec-07	25,779,708	0		0	25,779,708	0	-	0	25,779,708
25	Jan-08	19,525,991	0		0	19,525,991	0	-	0	19,525,991
26	Feb-08	14,530,589	0		0	14,530,589	0	-	0	14,530,589
27	Mar-08	7,101,163	0		0	7,101,163	0	-	0	7,101,163
28	Apr-08	2,480,848	0		0	2,480,848	0	-	0	2,480,848
29	May-08	5,240,628	0		0	5,240,628	0	-	0	5,240,628
30	Jun-08	8,527,625	0		0	8,527,625	0	-	0	8,527,625
31	Jul-08	13,489,293	0		0	13,489,293	0	-	0	13,489,293
32	Aug-08	18,664,785	0		0	18,664,785	0	-	0	18,664,785
33	Sep-08	23,670,555	0		0	23,670,555	0	-	0	23,670,555
34	Oct-08	26,943,162	0		0	26,943,162	0	-	0	26,943,162
35	Average	17,022,343	0		0	17,022,343	0		0	17,022,343

Tennessee Distribution System WP THP 7-1
Reallocation of Rate Base Items at Proforma Allocation Factors
Twelve Months Ended October 31, 2008

Row #	a	b	c	d	e	f	g	h	i	j

Customers Deposits (Account 2350).

		Service Area 093	Service Area 091	Service Area 012	Service Area 002	Service Area 093	Service Area 091	Service Area 012	Service Area 002	Total
	Month	Tennessee	MSBU	SSU Customer	SSU General	100%	27.17%	4.03%	4.13%	Tennessee
1	Oct-07	-6,988,224	0		0	-6,988,224	0	-	0	-6,988,224
2	Nov-07	-6,999,871	0		0	-6,999,871	0	-	0	-6,999,871
3	Dec-07	-7,011,538	0		0	-7,011,538	0	-	0	-7,011,538
4	Jan-08	-7,023,224	0		0	-7,023,224	0	-	0	-7,023,224
5	Feb-08	-7,034,929	0		0	-7,034,929	0	-	0	-7,034,929
6	Mar-08	-7,046,654	0		0	-7,046,654	0	-	0	-7,046,654
7	Apr-08	-7,058,399	0		0	-7,058,399	0	-	0	-7,058,399
8	May-08	-7,070,163	0		0	-7,070,163	0	-	0	-7,070,163
9	Jun-08	-7,081,946	0		0	-7,081,946	0	-	0	-7,081,946
10	Jul-08	-7,093,749	0		0	-7,093,749	0	-	0	-7,093,749
11	Aug-08	-7,105,572	0		0	-7,105,572	0	-	0	-7,105,572
12	Sep-08	-7,117,415	0		0	-7,117,415	0	-	0	-7,117,415
13	Oct-08	-7,129,277	0		0	-7,129,277	0	-	0	-7,129,277
14	Average	-7,058,536	0		0	-7,058,536	0		0	-7,058,536
15										
16										

17 Accumulated Deferred FIT (Total Accounts 1900, 2820, 2813 month average balances.

		Service Area 093	Service Area 091	Service Area 012	Service Area 002	Service Area 093	Service Area 091	Service Area 012	Service Area 002	Total
	Month	Tennessee	MSBU	SSU Customer	SSU General	100%	27.17%	4.03%	4.13%	Tennessee
22	Aug-07	-32,531,292	1,739,323		-47,204,382	-32,531,292	472,574	-	-1,948,183	-34,006,901
23	Sep-07	-32,687,702	1,795,776		-46,520,108	-32,687,702	487,912	-	-1,919,942	-34,119,732
24	Oct-07	-32,728,372	1,949,850		-45,987,140	-32,728,372	529,774	-	-1,897,946	-34,096,543
25	Nov-07	-32,792,705	2,097,491		-45,159,715	-32,792,705	569,888	-	-1,863,797	-34,086,614
26	Dec-07	-32,925,199	2,141,858		-44,195,139	-32,925,199	581,943	-	-1,823,988	-34,167,244
27	Jan-08	-33,239,023	1,776,599		-48,091,039	-33,239,023	482,702	-	-1,984,776	-34,741,098
28	Feb-08	-33,363,313	1,414,419		-52,019,280	-33,363,313	384,298	-	-2,146,900	-35,125,915
29	Mar-08	-33,549,232	1,463,943		-51,428,652	-33,549,232	397,753	-	-2,122,524	-35,274,003
30	Apr-08	-33,667,908	1,625,268		-50,863,573	-33,667,908	441,585	-	-2,099,202	-35,325,525
31	May-08	-33,786,525	1,675,323		-50,207,917	-33,786,525	455,185	-	-2,072,143	-35,403,482
32	Jun-08	-33,964,118	1,718,138		-49,454,714	-33,964,118	466,818	-	-2,041,057	-35,538,356
33	Jul-08	-34,056,075	1,767,773		-48,662,377	-34,056,075	480,304	-	-2,008,356	-35,584,127
34	Aug-08	-34,172,230	1,871,853		-47,887,342	-34,172,230	508,582	-	-1,976,370	-35,640,017
35	Average	-33,343,361	1,772,124		-48,283,183	-33,343,361	481,486		-1,992,706	-34,854,581

Tennessee Distribution System
Reallocation of Rate Base Items at Proforma Allocation Factors
Twelve Months Ended October 31, 2008

WP THP 7-1

Row #	a	b	c	d	e	f	g	h	i	j

Accumulated Depreciation (Account 1080).

		Service Area 093	Service Area 091	Service Area 012	Service Area 002	Service Area 093	Service Area 091	Service Area 012	Service Area 002	Total
	Month	Tennessee	MSBU	SSU Customer	SSU General	100%	27.17%	4.03%	4.13%	Tennessee
1	Oct-07	-137,319,839	-4,907,532	-85,531,556	-47,408,760	-137,319,839	-1,333,376	(3,446,922)	-1,956,618	-144,056,755
2	Nov-07	-138,027,239	-4,937,957	-86,802,460	-48,132,957	-138,027,239	-1,341,643	(3,498,139)	-1,986,506	-144,853,527
3	Dec-07	-138,737,407	-4,968,997	-88,073,903	-48,875,385	-138,737,407	-1,350,076	(3,549,378)	-2,017,147	-145,654,009
4	Jan-08	-139,450,124	-4,997,922	-89,344,856	-49,623,229	-139,450,124	-1,357,935	(3,600,598)	-2,048,012	-146,456,669
5	Feb-08	-140,165,485	-5,026,831	-90,615,319	-50,380,476	-140,165,485	-1,365,790	(3,651,797)	-2,079,264	-147,262,336
6	Mar-08	-140,883,675	-5,055,725	-91,885,292	-51,155,263	-140,883,675	-1,373,641	(3,702,977)	-2,111,241	-148,071,534
7	Apr-08	-141,605,437	-5,084,603	-93,154,775	-51,935,878	-141,605,437	-1,381,487	(3,754,137)	-2,143,458	-148,884,519
8	May-08	-142,330,020	-5,112,248	-94,423,768	-52,730,574	-142,330,020	-1,388,998	(3,805,278)	-2,176,256	-149,700,551
9	Jun-08	-143,057,695	-5,139,878	-95,692,271	-53,527,141	-143,057,695	-1,396,505	(3,856,399)	-2,209,131	-150,519,730
10	Jul-08	-143,788,359	-5,167,491	-96,960,285	-54,337,316	-143,788,359	-1,404,007	(3,907,499)	-2,242,568	-151,342,434
11	Aug-08	-144,521,657	-5,195,090	-98,227,808	-55,147,290	-144,521,657	-1,411,506	(3,958,581)	-2,275,996	-152,167,740
12	Sep-08	-145,256,023	-5,222,672	-99,494,842	-55,956,942	-145,256,023	-1,419,000	(4,009,642)	-2,309,412	-152,994,077
13	Oct-08	-145,999,556	-5,250,289	-100,765,185	-56,802,045	-145,999,556	-1,426,503	(4,060,837)	-2,344,290	-153,831,187
14	Average	-141,626,347	-5,082,095	-93,151,717	-52,001,020	-141,626,347	-1,380,805	-3,754,014	-2,146,146	-148,907,313
15										
16										

17 Customers Advances (Account 2520).

18

19		Service Area 093	Service Area 091	Service Area 012	Service Area 002	Service Area 093	Service Area 091	Service Area 012	Service Area 002	Total
20										
21	Month	Tennessee	MSBU	SSU Customer	SSU General	100%	27.17%	4.03%	4.13%	Tennessee
22	Oct-07	-47,141	35,541		0	-47,141	9,656	-	0	-37,485
23	Nov-07	-47,141	35,541		0	-47,141	9,656	-	0	-37,485
24	Dec-07	-47,141	35,541		0	-47,141	9,656	-	0	-37,485
25	Jan-08	-47,141	35,541		0	-47,141	9,656	-	0	-37,485
26	Feb-08	-47,141	35,541		0	-47,141	9,656	-	0	-37,485
27	Mar-08	-47,141	35,541		0	-47,141	9,656	-	0	-37,485
28	Apr-08	-47,141	35,541		0	-47,141	9,656	-	0	-37,485
29	May-08	-47,141	35,541		0	-47,141	9,656	-	0	-37,485
30	Jun-08	-47,141	35,541		0	-47,141	9,656	-	0	-37,485
31	Jul-08	-47,141	35,541		0	-47,141	9,656	-	0	-37,485
32	Aug-08	-47,141	35,541		0	-47,141	9,656	-	0	-37,485
33	Sep-08	-47,141	35,541		0	-47,141	9,656	-	0	-37,485
34	Oct-08	-47,141	35,541		0	-47,141	9,656	-	0	-37,485
35	Average	-47,141	35,541		0	-47,141	9,656		0	-37,485

Tennessee Distribution System WP THP 7-1
Reallocation of Rate Base Items at Proforma Allocation Factors
Twelve Months Ended October 31, 2008

Row #	a	b	c	d	e	f	g	h	i	j

Interest on Customer Deposits (Account 2370-26919).

		Service Area 093	Service Area 091	Service Area 012	Service Area 002	Service Area 093	Service Area 091	Service Area 012	Service Area 002	Total
	Month	Tennessee	MSBU	SSU Customer	SSU General	100%	27.17%	4.03%	4.13%	Tennessee
1	Oct-07	-651,705	0	0	0	-651,705	0	-	0	-651,705
2	Nov-07	-652,791	0	0	0	-652,791	0	-	0	-652,791
3	Dec-07	-653,879	0	0	0	-653,879	0	-	0	-653,879
4	Jan-08	-654,969	0	0	0	-654,969	0	-	0	-654,969
5	Feb-08	-656,061	0	0	0	-656,061	0	-	0	-656,061
6	Mar-08	-657,154	0	0	0	-657,154	0	-	0	-657,154
7	Apr-08	-658,249	0	0	0	-658,249	0	-	0	-658,249
8	May-08	-659,347	0	0	0	-659,347	0	-	0	-659,347
9	Jun-08	-660,445	0	0	0	-660,445	0	-	0	-660,445
10	Jul-08	-661,546	0	0	0	-661,546	0	-	0	-661,546
11	Aug-08	-662,649	0	0	0	-662,649	0	-	0	-662,649
12	Sep-08	-663,753	0	0	0	-663,753	0	-	0	-663,753
13	Oct-08	-664,859	0	0	0	-664,859	0	-	0	-664,859
14	Average	-658,262	0	0	0	-658,262	0	0	0	-658,262
15										
16										

17 Net elimination of intercompany leased property

18										
19		Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	
20		093	091	012	002	093	091	012	002	Total
21	Month	Tennessee	MSBU	SSU Customer	SSU General	100%	27.17%	4.03%	4.13%	Tennessee
22	Oct-07	7,063,897	0		0	7,063,897	0	-	0	7,063,897
23	Nov-07	7,044,015	0		0	7,044,015	0	-	0	7,044,015
24	Dec-07	7,024,133	0		0	7,024,133	0	-	0	7,024,133
25	Jan-08	7,004,251	0		0	7,004,251	0	-	0	7,004,251
26	Feb-08	6,984,369	0		0	6,984,369	0	-	0	6,984,369
27	Mar-08	6,964,487	0		0	6,964,487	0	-	0	6,964,487
28	Apr-08	6,944,605	0		0	6,944,605	0	-	0	6,944,605
29	May-08	6,924,723	0		0	6,924,723	0	-	0	6,924,723
30	Jun-08	6,904,841	0		0	6,904,841	0	-	0	6,904,841
31	Jul-08	6,884,959	0		0	6,884,959	0	-	0	6,884,959
32	Aug-08	6,865,077	0		0	6,865,077	0	-	0	6,865,077
33	Sep-08	6,845,195	0		0	6,845,195	0	-	0	6,845,195
34	Oct-08	6,825,313	0		0	6,825,313	0	-	0	6,825,313
35	Average	6,944,605	0		0	6,944,605	0		0	6,944,605

Tennessee Distribution System WP THP 7-1

Reallocation of Rate Base Items at Proforma Allocation Factors

Twelve Months Ended October 31, 2008

Row #	a	b	c	d	e	f	g	h	i	j
	Unamortized Maryland Way Gain									
	- per amortization schedule									
		Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	
		093	091	012	002	093	091	012	002	Total
	Month	Tennessee	MSBU	SSU Customer	SSU General	100%	27.17%	4.03%	4.13%	Tennessee
1	Oct-07	-16,899	0		0	-16,899	0	-	0	-16,899
2	Nov-07	-15,212	0		0	-15,212	0	-	0	-15,212
3	Dec-07	-13,525	0		0	-13,525	0	-	0	-13,525
4	Jan-08	-11,838	0		0	-11,838	0	-	0	-11,838
5	Feb-08	-10,151	0		0	-10,151	0	-	0	-10,151
6	Mar-08	-8,464	0		0	-8,464	0	-	0	-8,464
7	Apr-08	-6,777	0		0	-6,777	0	-	0	-6,777
8	May-08	-5,090	0		0	-5,090	0	-	0	-5,090
9	Jun-08	-3,403	0		0	-3,403	0	-	0	-3,403
10	Jul-08	-1,716	0		0	-1,716	0	-	0	-1,716
11	Aug-08	-29	0		0	-29	0	-	0	-29
12	Sep-08	0	0		0	0	0	-	0	0
13	Oct-08	0	0		0	0	0	-	0	0
14	Average	-7,162	0		0	-7,162	0		0	-7,162

Tennessee Distribution System
Reallocation of Rate Base Items at Proforma Allocation Factors
Twelve Months Ended December 31, 2006

WP THP 7-2

Row #	a	b	c	d	e	f	g		h	i	j	k	l	m	n
		Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	Alloc.	Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	
		093	088	090	091	012	002	Factors	093	088	090	091	012	002	
			Central	Eastern				FY06	100%	54.58%	39.96%	47.68%	4.59%	4.90%	Total
	Month	Tennessee	Region	Region	MSBU	SSU Customer	SSU General	FY07	100%	0.00%	0.00%	27.17%	4.03%	4.13%	Tennessee
1	Gas Plant in Service (Account 101) 13 month average Balances.														
2															
3	Dec-05	288,148,202	316,368	45,773	5,962,466	0	204,441,638		288,148,202	172,674	18,291	2,842,904	0	10,020,715	301,202,786
4	Jan-06	288,645,714	316,368	45,773	5,962,466	0	204,920,454		288,645,714	172,674	18,291	2,842,904	0	10,044,184	301,723,767
5	Feb-06	289,706,747	316,368	45,773	5,962,466	0	211,993,301		289,706,747	172,674	18,291	2,842,904	0	10,390,860	303,131,476
6	Mar-06	290,842,485	316,368	45,773	5,964,275	0	213,299,883		290,842,485	172,674	18,291	2,843,766	0	10,454,902	304,332,118
7	Apr-06	291,106,317	316,368	45,773	5,964,275	0	219,576,355		291,106,317	172,674	18,291	2,843,766	0	10,762,544	304,903,592
8	May-06	291,221,119	150,952	30,292	5,833,144	142,557,168	81,386,999		291,221,119	82,390	12,105	2,781,243	6,545,632	3,989,187	304,631,675
9	Jun-06	292,605,109	205,726	33,077	5,851,089	142,527,016	81,797,220		292,605,109	112,287	13,218	2,789,799	6,544,248	4,009,294	306,073,954
10	Jul-06	293,704,495	210,547	33,077	5,883,255	142,576,132	82,191,730		293,704,495	114,917	13,218	2,805,136	6,546,503	4,028,631	307,212,899
11	Aug-06	295,395,741	210,547	33,077	5,883,255	148,985,859	76,391,967		295,395,741	114,917	13,218	2,805,136	6,840,811	3,744,355	308,914,178
12	Sep-06	299,907,054	213,021	33,077	6,671,374	148,996,816	76,599,090		299,907,054	116,267	13,218	3,180,911	6,841,314	3,754,507	313,813,270
13	Oct-06	300,387,946			6,935,773	148,996,816	86,948,228		300,387,946	0	0	1,884,450	6,004,572	3,588,460	311,865,428
14	Nov-06	301,298,273			6,943,362	148,586,583	87,201,783		301,298,273	0	0	1,886,512	5,988,039	3,598,925	312,771,749
15	Dec-06	301,979,433			6,908,401	148,586,583	88,137,543		301,979,433	0	0	1,877,013	5,988,039	3,637,545	313,462,029
16	average	294,226,818	257,264	39,147	6,209,662	90,139,459	131,914,322		294,226,818	108,011	12,033	2,632,803	3,946,089	6,309,547	307,235,302
17															
18															
19	Construction Work in Process (Account 1070).														
20															
21	Dec-05	2,239,833	33,573	5,816	4,962,262	-	27,034,742		2,239,833	18,324	2,324	2,366,007	0	1,325,109	4,333,489
22	Jan-06	2,617,276	34,684	2,599	5,516,690	-	28,397,836		2,617,276	18,930	1,039	2,630,358	0	1,391,921	6,659,524
23	Feb-06	2,383,029	34,086	2,623	6,166,802	-	26,368,669		2,383,029	18,604	1,048	2,940,331	0	1,292,461	6,635,474
24	Mar-06	4,661,683	61,036	2,814	1,232,698	-	26,586,897		4,661,683	33,313	1,125	587,750	0	1,303,158	6,587,029
25	Apr-06	5,357,343	60,113	2,625	1,528,796	-	22,573,786		5,357,343	32,810	1,049	728,930	0	1,106,455	7,226,587
26	May-06	4,166,938	52,155	-6,377	1,567,824	-	16,934,425		4,166,938	28,466	-2,548	747,539	0	830,042	5,770,436
27	Jun-06	4,152,664	5,094	89	1,177,580	30,152	15,889,954		4,152,664	2,781	36	561,470	1,384	778,847	5,497,181
28	Jul-06	4,280,995	293	265	1,381,912	(18,965)	17,222,848		4,280,995	160	106	658,896	-871	844,179	5,783,464
29	Aug-06	4,345,332	596	441	1,601,700	(62,147)	17,807,572		4,345,332	325	176	763,690	-2,854	872,839	5,979,510
30	Sep-06	2,486,219	453	146	183,457	(62,147)	19,570,952		2,486,219	247	58	87,472	-2,854	959,271	3,530,414
31	Oct-06	3,451,795	0	0	312,904	(62,147)	10,456,162		3,451,795	0	0	85,016	-2,505	431,539	3,965,845
32	Nov-06	4,037,155			246,799	(62,147)	9,375,780		4,037,155	0	0	67,055	-2,505	386,950	4,488,655
33	Dec-06	5,218,856			194,768	(62,147)	9,043,123		5,218,856	0	0	52,919	-2,505	373,221	5,642,491
34	average	3,799,932	25,644	1,004	2,005,707	(23,042)	19,020,211		3,799,932	11,843	339	944,418	(977)	915,076	5,670,631

Tennessee Distribution System
Reallocation of Rate Base Items at Proforma Allocation Factors
Twelve Months Ended December 31, 2006

WP THP 7-2

Row #	a	b	c	d	e	f	g		h	i	j	k	l	m	n
		Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	Alloc.	Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	
		093	088	090	091	012	002	Factors	093	088	090	091	012	002	
			Central	Eastern				FY06	100%	54.58%	39.96%	47.68%	4.59%	4.90%	Total
	Month	Tennessee	Region	Region	MSBU	SSU Customer	SSU General	FY07	100%	0.00%	0.00%	27.17%	4.03%	4.13%	Tennessee
	Inventories- Plant Materials (Account 1540).														
1	Dec-05	0			139,061		0		0	0	0	66,304	0	0	66,304
2	Jan-06	0			139,006		0		0	0	0	66,278	0	0	66,278
3	Feb-06	0			138,933		0		0	0	0	66,243	0	0	66,243
4	Mar-06	0			138,933		0		0	0	0	66,243	0	0	66,243
5	Apr-06	0			138,933		0		0	0	0	66,243	0	0	66,243
6	May-06	0			138,933		0		0	0	0	66,243	0	0	66,243
7	Jun-06	0			138,925		0		0	0	0	66,239	0	0	66,239
8	Jul-06	0			138,836		0		0	0	0	66,197	0	0	66,197
9	Aug-06	0			138,836		0		0	0	0	66,197	0	0	66,197
10	Sep-06	0			129,202		0		0	0	0	61,604	0	0	61,604
11	Oct-06	0			129,202		0		0	0	0	35,104	0	0	35,104
12	Nov-06	0			130,440		0		0	0	0	35,441	0	0	35,441
13	Dec-06	0			130,440		0		0	0	0	35,441	0	0	35,441
14	average	0			136,129		0		0	0	0	58,752	0	0	58,752
15															
16															
17	Inventories- Gas Stored (Account 1641).														
18		***Includes Tennessee stored gas in Dvivision 93 and an allocated portion of Tennessee stored gas in Division 96***													
19	Dec-05	26,533,862			0		0		26,533,862			0	-	0	26,533,862
20	Jan-06	20,378,566			0		0		20,378,566			0	-	0	20,378,566
21	Feb-06	18,912,361			0		0		18,912,361			0	-	0	18,912,361
22	Mar-06	8,506,160			0		0		8,506,160			0	-	0	8,506,160
23	Apr-06	1,480,901			0		0		1,480,901			0	-	0	1,480,901
24	May-06	4,128,814			0		0		4,128,814			0	-	0	4,128,814
25	Jun-06	7,356,001			0		0		7,356,001			0	-	0	7,356,001
26	Jul-06	11,343,708			0		0		11,343,708			0	-	0	11,343,708
27	Aug-06	15,340,363			0		0		15,340,363			0	-	0	15,340,363
28	Sep-06	19,375,610			0		0		19,375,610			0	-	0	19,375,610
29	Oct-06	23,027,019			0		0		23,027,019			0	-	0	23,027,019
30	Nov-06	23,594,850			0		0		23,594,850			0	-	0	23,594,850
31	Dec-06	20,684,979			0		0		20,684,979			0	-	0	20,684,979
32	average	15,435,630			0		0		15,435,630			0		0	15,435,630

Tennessee Distribution System
Reallocation of Rate Base Items at Proforma Allocation Factors
Twelve Months Ended December 31, 2006

WP THP 7-2

Row #	a	b	c	d	e	f	g		h	i	j	k	l	m	n
		Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	Alloc.	Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	
		093	088	090	091	012	002	Factors	093	088	090	091	012	002	
			Central	Eastern				FY06	100%	54.58%	39.96%	47.68%	4.59%	4.90%	Total
	Month	Tennessee	Region	Region	MSBU	SSU Customer	SSU General	FY07	100%	0.00%	0.00%	27.17%	4.03%	4.13%	Tennessee
	Customers Deposits (Account 2350).														
1	Dec-05	-6,126,797			0		0		-6,126,797			0	-	0	-6,126,797
2	Jan-06	-6,139,322			0		0		-6,139,322			0	-	0	-6,139,322
3	Feb-06	-6,185,465			0		0		-6,185,465			0	-	0	-6,185,465
4	Mar-06	-6,182,408			0		0		-6,182,408			0	-	0	-6,182,408
5	Apr-06	-6,086,070			0		0		-6,086,070			0	-	0	-6,086,070
6	May-06	-6,069,832			0		0		-6,069,832			0	-	0	-6,069,832
7	Jun-06	-6,053,600			0		0		-6,053,600			0	-	0	-6,053,600
8	Jul-06	-6,084,791			0		0		-6,084,791			0	-	0	-6,084,791
9	Aug-06	-6,140,498			0		0		-6,140,498			0	-	0	-6,140,498
10	Sep-06	-6,281,285			0		0		-6,281,285			0	-	0	-6,281,285
11	Oct-06	-6,653,596			0		0		-6,653,596			0	-	0	-6,653,596
12	Nov-06	-6,805,774			0		0		-6,805,774			0	-	0	-6,805,774
13	Dec-06	-6,872,815			0		0		-6,872,815			0	-	0	-6,872,815
14	average	-6,283,250			0		0		-6,283,250			0		0	-6,283,250
15															
16															
17	Accumulated Deferred FIT (Total Accounts 1900, 2820, 2830).				13 month average balances.										
18															
19	Dec-05	-34,541,515	-74,005	-15,764	-4,636,379	0	-54,187,730		-34,541,515	-40,392	-6,299	-2,210,626	0	-2,656,014	-39,454,845
20	Jan-06	-34,541,515	-74,005	-15,764	-4,636,379	0	-54,449,058		-34,541,515	-40,392	-6,299	-2,210,626	0	-2,668,823	-39,467,655
21	Feb-06	-34,541,515	-74,005	-15,764	-4,636,379	0	-54,884,471		-34,541,515	-40,392	-6,299	-2,210,626	0	-2,690,165	-39,488,996
22	Mar-06	-34,541,515	-74,005	-15,764	162,532	0	-54,981,465		-34,541,515	-40,392	-6,299	77,495	0	-2,694,919	-37,205,630
23	Apr-06	-34,541,515	-74,005	-15,764	162,532	0	-55,283,423		-34,541,515	-40,392	-6,299	77,495	0	-2,709,719	-37,220,430
24	May-06	-34,541,515	-74,005	-15,764	162,532	0	-55,665,215		-34,541,515	-40,392	-6,299	77,495	0	-2,728,433	-37,239,144
25	Jun-06	-34,541,515	-74,005	-15,764	9,446,548	0	-55,552,146		-34,541,515	-40,392	-6,299	4,504,114	0	-2,722,891	-32,806,983
26	Jul-06	-34,541,515	-74,005	-15,764	9,446,548	0	-55,681,460		-34,541,515	-40,392	-6,299	4,504,114	0	-2,729,229	-32,813,321
27	Aug-06	-34,541,515	-74,005	-15,764	9,446,548	0	-55,831,790		-34,541,515	-40,392	-6,299	4,504,114	0	-2,736,597	-32,820,690
28	Sep-06	-29,743,862	-76,228	-14,833	2,172,972	0	-44,643,302		-29,743,862	-41,605	-5,927	1,036,073	0	-2,188,193	-30,943,515
29	Oct-06	-29,743,862			2,081,911	0	-44,997,445		-29,743,862	0	0	565,655	0	-1,857,100	-31,035,307
30	Nov-06	-29,743,862			2,081,911	0	-45,537,060		-29,743,862	0	0	565,655	0	-1,879,370	-31,057,577
31	Dec-06	-29,914,116			2,081,911	0	-46,003,886		-29,914,116	0	0	565,655	0	-1,898,637	-31,247,098
32	average	-33,078,411	-74,227	-15,671	1,795,139	0	-52,130,650		-33,078,411	-31,164	-4,817	757,384	0	-2,473,853	-34,830,861

Tennessee Distribution System
Reallocation of Rate Base Items at Proforma Allocation Factors
Twelve Months Ended December 31, 2006

WP THP 7-2

Row #	a	b	c	d	e	f	g		h	i	j	k	l	m	n
		Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	Alloc.	Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	
		093	088	090	091	012	002	Factors	093	088	090	091	012	002	
			Central	Eastern				FY06	100%	54.58%	39.96%	47.68%	4.59%	4.90%	Total
	Month	Tennessee	Region	Region	MSBU	SSU Customer	SSU General	FY07	100%	0.00%	0.00%	27.17%	4.03%	4.13%	Tennessee
	Accumulated Depreciation (Account 1080).														
1	Dec-05	-122,139,049	-285,349	-29,791	-4,251,647	0	-102,093,947		-122,139,049	-155,743	-11,905	-2,027,185	0	-5,004,139	-129,338,021
2	Jan-06	-122,810,891	-287,174	-29,808	-4,276,434	0	-103,584,004		-122,810,891	-156,739	-11,911	-2,039,003	0	-5,077,174	-130,095,719
3	Feb-06	-123,617,811	-288,062	-29,824	-4,301,704	0	-105,117,130		-123,617,811	-157,224	-11,918	-2,051,053	0	-5,152,320	-130,990,326
4	Mar-06	-124,417,832	-288,959	-29,840	-4,326,730	0	-106,612,074		-124,417,832	-157,714	-11,924	-2,062,985	0	-5,225,595	-131,876,050
5	Apr-06	-125,281,406	-289,856	-29,857	-4,349,856	0	-108,160,219		-125,281,406	-158,203	-11,931	-2,074,011	0	-5,301,477	-132,827,029
6	May-06	-123,729,671	-124,719	-14,376	-4,242,049	-66,440,919	-41,139,547		-123,729,671	-68,071	-5,745	-2,022,609	-3,050,691	-2,016,457	-130,893,244
7	Jun-06	-124,518,993	-125,599	-14,567	-4,267,814	-67,543,413	-41,662,965		-124,518,993	-68,552	-5,821	-2,034,894	-3,101,313	-2,042,112	-131,771,684
8	Jul-06	-125,318,208	-126,490	-14,757	-4,293,342	-68,646,619	-42,192,685		-125,318,208	-69,038	-5,897	-2,047,065	-3,151,967	-2,068,076	-132,660,252
9	Aug-06	-126,146,488	-127,382	-14,948	-4,318,870	-70,267,421	-42,471,696		-126,146,488	-69,525	-5,973	-2,059,237	-3,226,388	-2,081,752	-133,589,364
10	Sep-06	-126,719,924	-128,366	-15,139	-4,392,476	-71,522,383	-43,007,260		-126,719,924	-70,062	-6,049	-2,094,332	-3,284,010	-2,108,003	-134,282,380
11	Oct-06	-127,516,647			-4,575,523	-72,771,113	-43,651,088		-127,516,647	0	0	-1,243,170	-2,932,676	-1,801,534	-133,494,026
12	Nov-06	-128,345,986			-4,615,085	-73,602,162	-40,322,843		-128,345,986	0	0	-1,253,919	-2,966,187	-1,664,173	-134,230,245
13	Dec-06	-128,841,321			-4,596,372	-74,842,309	-40,963,013		-128,841,321	0	0	-1,248,834	-3,016,145	-1,690,594	-134,796,895
14	average	-125,338,787	-207,196	-22,291	-4,369,839	-43,510,488	-66,229,113		-125,338,787	-86,990	-6,852	-1,866,023	-1,902,258	-3,171,800	-132,372,710
15															
16															
17	Customers Advances (Account 2520).														
18															
19	Dec-05	-56,691			35,541	0			-56,691	0	0	16,946	0	0	-39,745
20	Jan-06	-56,691			35,541	0			-56,691	0	0	16,946	0	0	-39,745
21	Feb-06	-56,691			35,541	0			-56,691	0	0	16,946	0	0	-39,745
22	Mar-06	-46,191			35,541	0			-46,191	0	0	16,946	0	0	-29,245
23	Apr-06	-46,191			35,541	0			-46,191	0	0	16,946	0	0	-29,245
24	May-06	-46,191			35,541	0			-46,191	0	0	16,946	0	0	-29,245
25	Jun-06	-47,141			35,541	0			-47,141	0	0	16,946	0	0	-30,195
26	Jul-06	-47,141			35,541	0			-47,141	0	0	16,946	0	0	-30,195
27	Aug-06	-47,141			35,541	0			-47,141	0	0	16,946	0	0	-30,195
28	Sep-06	-47,141			35,541	0			-47,141	0	0	16,946	0	0	-30,195
29	Oct-06	-47,141			35,541	0			-47,141	0	0	9,656	0	0	-37,485
30	Nov-06	-47,141			35,541	0			-47,141	0	0	9,656	0	0	-37,485
31	Dec-06	-47,141			35,541	0			-47,141	0	0	9,656	0	0	-37,485
32	average	-49,126			35,541	0			-49,126	0	0	15,264	0	0	-33,862

Tennessee Distribution System
Reallocation of Rate Base Items at Proforma Allocation Factors
Twelve Months Ended December 31, 2006

WP THP 7-2

Row #	a	b	c	d	e	f	g		h	i	j	k	l	m	n
		Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	Alloc.	Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	
		093	088	090	091	012	002	Factors	093	088	090	091	012	002	
			Central	Eastern				FY06	100%	54.58%	39.96%	47.68%	4.59%	4.90%	Total
	Month	Tennessee	Region	Region	MSBU	SSU Customer	SSU General	FY07	100%	0.00%	0.00%	27.17%	4.03%	4.13%	Tennessee
1	Interest on Customer Deposits (Account 2370-26919).														
2															
3	Dec-05	-494,249			0	0	0		-494,249			0	-	0	-494,249
4	Jan-06	-511,765			0	0	0		-511,765			0	-	0	-511,765
5	Feb-06	-524,499			0	0	0		-524,499			0	-	0	-524,499
6	Mar-06	-537,339			0	0	0		-537,339			0	-	0	-537,339
7	Apr-06	-538,986			0	0	0		-538,986			0	-	0	-538,986
8	May-06	-545,853			0	0	0		-545,853			0	-	0	-545,853
9	Jun-06	-553,912			0	0	0		-553,912			0	-	0	-553,912
10	Jul-06	-565,499			0	0	0		-565,499			0	-	0	-565,499
11	Aug-06	-582,236			0	0	0		-582,236			0	-	0	-582,236
12	Sep-06	-596,221			0	0	0		-596,221			0	-	0	-596,221
13	Oct-06	-611,747			0	0	0		-611,747			0	-	0	-611,747
14	Nov-06	-624,364			0	0	0		-624,364			0	-	0	-624,364
15	Dec-06	-640,942			0	0	0		-640,942			0	-	0	-640,942
16	average	-563,662			0	0	0		-563,662			0	0	0	-563,662
17															
18															
19	Net elimination of intercompany leased property														
20															
21	Dec-05	7,513,987			0		0		7,513,987			0	-	0	7,513,987
22	Jan-06	7,481,427			0		0		7,481,427			0	-	0	7,481,427
23	Feb-06	7,461,546			0		0		7,461,546			0	-	0	7,461,546
24	Mar-06	7,364,663			0		0		7,364,663			0	-	0	7,364,663
25	Apr-06	7,421,780			0		0		7,421,780			0	-	0	7,421,780
26	May-06	7,401,897			0		0		7,401,897			0	-	0	7,401,897
27	Jun-06	7,382,015			0		0		7,382,015			0	-	0	7,382,015
28	Jul-06	7,362,131			0		0		7,362,131			0	-	0	7,362,131
29	Aug-06	7,342,249			0		0		7,342,249			0	-	0	7,342,249
30	Sep-06	7,322,365			0		0		7,322,365			0	-	0	7,322,365
31	Oct-06	7,302,483			0		0		7,302,483			0	-	0	7,302,483
32	Nov-06	7,282,601			0		0		7,282,601			0	-	0	7,282,601
33	Dec-06	7,269,844			0		0		7,269,844			0	-	0	7,269,844
34	average	7,377,614			0		0		7,377,614			0		0	7,377,614

Tennessee Distribution System
Reallocation of Rate Base Items at Proforma Allocation Factors
Twelve Months Ended December 31, 2006

Row #	a	b	c	d	e	f	g		h	i	j	k	l	m	n
		Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	Alloc.	Service Area	Service Area	Service Area	Service Area	Service Area	Service Area	
		093	088	090	091	012	002	Factors	093	088	090	091	012	002	
			Central	Eastern				FY06	100%	54.58%	39.96%	47.68%	4.59%	4.90%	Total
	Month	Tennessee	Region	Region	MSBU	SSU Customer	SSU General	FY07	100%	0.00%	0.00%	27.17%	4.03%	4.13%	Tennessee
1	Unamortized Maryland Way Gain														
2	- per amortization schedule														
3	Dec-05	-54,013			0		0		-54,013			0	-	0	-54,013
4	Jan-06	-52,326			0		0		-52,326			0	-	0	-52,326
5	Feb-06	-50,639			0		0		-50,639			0	-	0	-50,639
6	Mar-06	-48,952			0		0		-48,952			0	-	0	-48,952
7	Apr-06	-47,265			0		0		-47,265			0	-	0	-47,265
8	May-06	-45,578			0		0		-45,578			0	-	0	-45,578
9	Jun-06	-43,891			0		0		-43,891			0	-	0	-43,891
10	Jul-06	-42,204			0		0		-42,204			0	-	0	-42,204
11	Aug-06	-40,517			0		0		-40,517			0	-	0	-40,517
12	Sep-06	-38,830			0		0		-38,830			0	-	0	-38,830
13	Oct-06	-37,143			0		0		-37,143			0	-	0	-37,143
14	Nov-06	-35,456			0		0		-35,456			0	-	0	-35,456
15	Dec-06	-33,769			0		0		-33,769			0	-	0	-33,769
16	average	-43,891			0		0		-43,891			0		0	-43,891

Schedule THP-8

Tennessee Distribution System
Computation of State Excise & Federal Income Taxes
Twelve Months Ended October 31, 2008

Line No.	Description		Test Year [1]	Change	Attrition Year
	(a)		(b)	(c)	(d)
1	Required Return		$14,681,583	$2,018,950	$16,700,533
2					
3	Interest Deduction		5,214,951	$717,139	5,932,090
4					
5	Equity Portion of Return		9,466,632	$1,301,811	10,768,443
6					
7	Application of Tax Rate to Equity Return - Tennessee	6.5%	615,331	$84,618	699,949
8					
9	Application of Tax Rate to Equity Return - Federal	35%	$3,097,955	$426,018	$3,523,973
10					
11			$3,713,286	$510,636	$4,223,922
12					
13	Tax Expansion Factor		1.64541	1.64541	1.64541
14					
15	Total Income Tax Liability		$6,109,878	$840,206	$6,950,083

[1] Twelve months ended December 31, 2006

Schedule THP-9

Tennessee Distribution System
Overall Cost of Capital
Twelve Months Ended October 31, 2008

Line No.	Description	Percent	Cost Rate	Overall Cost of Capital
	(a)	(b)	(c)	(d)
1	Long Term Debt Capital	51.50%	6.10%	3.14%
2	Equity Capital	48.50%	11.75%	5.70%
3				
4	Total Capital	100.0%		8.84%

Schedule THP-10

Tennessee Distribution System
Rate of Return
Twelve Months Ended October 31, 2008

Line No.	Description	Reference	Test Year [1]	Change	Attrition Year	Ratemaking Adjustments	Adjusted Amount
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Total Reveunes	Sch. 2	$ 184,574,748	$ (3,182,332)	$181,392,416	-	$181,392,416
2							
3	Gas Cost	Sch. 3	135,046,808	-	135,046,808	-	135,046,808
4							
5	Operation & Maintenance Expense	Sch. 4	14,237,381	1,604,061	15,841,442	(284,668)	15,556,774
6							
7	Taxes Other Than Income Taxes	Sch. 5	5,851,994	1,158,939	7,010,933	-	7,010,933
8							
9	Depreciation & Amortization Expense	Sch. 6	11,736,627	1,013,315	12,749,942	(1,859,070)	10,890,872
10							
11	Federal Income and State Excise Tax	Wp 10-1	4,801,887	(2,943,628)	1,858,259	755,435	2,613,694
12							
13	Interest on Customer Deposits	Wp 1-1	376,995	46,517	423,512	0	423,512
14							
15	Return on Rate Base		$ 12,523,056	$ (4,061,537)	$ 8,461,519	$1,388,303	$ 9,849,823
16							
17	Total Rate Base	Sch. 7	166,081,256	15,901,356	181,982,612	6,937,443	188,920,055
18							
19	Rate of Return on Rate Base		7.54%	-2.89%	4.65%	20.01%	5.21%
20							
21	Interest Expense	Sch. 8	5,214,951	499,303	5,714,254	217,836	5,932,090
22							
23	AFUDC Interest credit	Wp 1-2	(131,911)	-	(131,911)	-	(131,911)
24							
25	Return on Equity		$ 7,440,017		$ 2,879,177		$ 4,049,644
26							
27	Rate of Return on Equity		9.24%		3.26%		4.42%

[1] Twelve months ended December 31, 2006

Tennessee Distribution System
Computation of State Excise and Federal Income Taxes for Sch 10
Twelve Months Ended October 31, 2008

Line No.	Description		Test Year [1]	Projected Amount	Adjusted Amount
	(a)			(b)	(c)
1	Net Operating Income Before Income Tax		$17,324,943	$10,319,778	$12,463,517
2					
3	Interest Deduction		5,083,040	5,582,343	5,800,179
4					
5	Equity Portion of Return		12,241,904	4,737,436	6,663,338
6					
7	Application of Tax Rate to Equity Return - Tennessee	6.5%	795,724	307,933	433,117
8					
9	Application of Tax Rate to Equity Return - Federal	35%	$4,006,163	$1,550,326	$2,180,577
10					
11	Income Tax Expense		$4,801,887	$1,858,259	$2,613,694

[1] Twelve months ended December 31, 2006

Atmos Energy Corporation-Tennessee
Cash Working Capital Lead/Lag Analysis
For Attrition Period Ended October 31, 2008

Line No.	Description	Test Year Expenses	Average Daily Expense (b) / 365 days		Revenue Lag		Expense Lag	Net Lag (d) - (e)	CWC Requirement (c) x (f)
	(a)	(b)	(c)		(d)		(e)	(f)	(g)
1	Gas Supply Expense								
2	Purchased Gas	135,046,808	369,991	*Sch 2*	45.39	*Sch 3*	40.51	4.88	1,805,556
3									
4	Operation and Maintenance Expense								
5	O&M, Labor	6,269,415	17,176	*Sch 2*	45.39	*Sch 4*	14.23	31.16	535,204
6	O&M, Non-Labor	9,287,359	25,445	*Sch 2*	45.39	*Sch 5*	21.81	23.58	599,993
7	Total O&M Expense	15,556,774	42,621						1,135,197
8									
9									
10	Taxes Other Than Income								
11	Ad Valorem	2,776,452	7,607	*Sch 2*	45.39	*Sch 6*	241.50	(196.11)	(1,491,809)
12	State Gross Receipts Tax	2,764,815	7,575	*Sch 2*	45.39	*Sch 6*	(151.50)	196.89	1,491,442
13	Payroll Taxes	313,105	858	*Sch 2*	45.39	*Sch 6*	18.55	26.84	23,025
14	State Franchise Tax	500,001	1,370	*Sch 2*	45.39	*Sch 6*	29.50	15.89	21,769
15	TRA Inspection Fee	388,000	1,063	*Sch 2*	45.39	*Sch 6*	272.50	(227.11)	(241,418)
16	DOT	13,000	36	*Sch 2*	45.39	*Sch 6*	241.50	(196.11)	(7,060)
17									
18	Allocated Taxes-Shared Services	*164,319*							
19	Ad Valorem	17,867	49	*Sch 2*	45.39	*Sch 6*	241.50	(196.11)	(9,609)
20	Payroll Taxes	146,452	401	*Sch 2*	45.39	*Sch 6*	18.55	26.84	10,761
21									
22	Allocated Taxes-Business Unit	*91,241*							
23	Ad Valorem	32,604	89	*Sch 2*	45.39	*Sch 6*	241.50	(196.11)	(17,454)
24	Payroll Taxes	58,637	161	*Sch 2*	45.39	*Sch 6*	18.55	26.84	4,321
25	Total Taxes Other Than Income	7,010,933	19,209						(216,032)
26									
27	Federal Income Tax	*5,798,380*							
28	Current Taxes	875,836	2,400	*Sch 2*	45.39	*Sch 7*	29.50	15.89	38,136
29	Deferred Taxes	4,922,544	13,486	*Sch 2*	45.39	*Sch 7*	0.00	45.39	612,130
30									
31	State Excise Tax	*1,151,703*							
32	Current Taxes	193,682	531	*Sch 2*	45.39	*Sch 8*	29.50	15.89	8,438
33	Deferred Taxes	958,021	2,625	*Sch 2*	45.39	*Sch 8*	0.00	45.39	119,149
34									
35	Depreciation	10,890,872	29,838	*Sch 2*	45.39		0	45.39	1,354,347
36									
37	Interest on Customer Deposits	423,512	1,160	*Sch 2*	45.39		15.5	29.89	34,672
38									
39	Interest Expense - LTD	5,800,179	15,891	*Sch 2*	45.39	*Sch 9*	84.18	(38.79)	(616,482)
40									
41	Return on Equity	10,768,443	29,503	*Sch 2*	45.39		0	45.39	1,339,141
42									
43									
44	TOTAL	192,447,604	527,255						5,614,251

Atmos Energy Corporation-Tennessee
Cash Working Capital Lead/Lag Analysis
For Test Year Ended December 30, 2006

Line No.	Description		Test Year Expenses	Average Daily Expense (b) / 365 days		Revenue Lag		Expense Lag	Net Lag (d) - (e)	CWC Requirement (c) x (f)
	(a)		(b)	(c)		(d)		(e)	(f)	(g)
1	Gas Supply Expense									
2	Purchased Gas		135,046,808	369,991	*Sch 2*	45.39	*Sch 3*	40.51	4.88	1,805,557
3										
4	Operation and Maintenance Expense									
5	O&M, Labor		5,631,342	15,428	*Sch 2*	45.39	*Sch 4*	14.23	31.16	480,747
6	O&M, Non-Labor		8,606,039	23,578	*Sch 2*	45.39	*Sch 5*	21.81	23.58	555,974
7	Total O&M Expense		14,237,381	39,007						1,036,721
8										
9										
10	Taxes Other Than Income									
11	Ad Valorem		2,659,524	7,286	*Sch 2*	45.39	*Sch 6*	241.50	(196.11)	(1,428,929)
12	State Gross Receipts Tax		1,757,625	4,815	*Sch 2*	45.39	*Sch 6*	(151.50)	196.89	948,106
13	Payroll Taxes		232,023	636	*Sch 2*	45.39	*Sch 6*	18.55	26.84	17,059
14	State Franchise Tax		486,903	1,334	*Sch 2*	45.39	*Sch 6*	29.50	15.89	21,197
15	TRA Inspection Fee		421,232	1,154	*Sch 2*	45.39	*Sch 6*	272.50	(227.11)	(262,099)
16	DOT		12,470	34	*Sch 2*	45.39	*Sch 6*	241.50	(196.11)	(6,700)
17										
18	Allocated Taxes-Shared Services									
19	Ad Valorem		37,396	102	*Sch 2*	45.39	*Sch 6*	241.50	(196.11)	(20,092)
20	Payroll Taxes		4,313	12	*Sch 2*	45.39	*Sch 6*	18.55	26.84	317
21										
22	Allocated Taxes-Business Unit									
23	Ad Valorem		70,745	194	*Sch 2*	45.39	*Sch 6*	241.50	(196.11)	(38,010)
24	Payroll Taxes		169,656	465	*Sch 2*	45.39	*Sch 6*	18.55	26.84	12,474
25	State Franchise Tax		106	0	*Sch 2*	45.39	*Sch 6*	29.50	15.89	5
26	Total Taxes Other Than Income		5,851,993	16,033						(756,678)
27										
28	Federal Income Tax		*4,006,163*							
29	Current Taxes	15.1%	605,124	1,658	*Sch 2*	45.39	*Sch 7*	29.50	15.89	26,344
30	Deferred Taxes	84.9%	3,401,039	9,318	*Sch 2*	45.39	*Sch 7*	0.00	45.39	422,940
31										
32	State Excise Tax		*795,724*							
33	Current Taxes	16.8%	133,817	367	*Sch 2*	45.39	*Sch 8*	29.50	15.89	5,826
34	Deferred Taxes	83.2%	661,907	1,813	*Sch 2*	45.39	*Sch 8*	0.00	45.39	82,312
35										
36	Depreciation		11,736,627	32,155	*Sch 2*	45.39		0	45.39	1,459,522
37										
38	Interest on Customer Deposits		376,995	594	*Sch 2*	45.39		15.5	29.89	17,745
39										
40	Interest Expense - LTD		5,083,040	8,005	*Sch 2*	45.39	*Sch 10*	84.18	(38.79)	(310,541)
41										
42	Return on Equity		7,440,017	11,717	*Sch 2*	45.39		0	45.39	531,815
43										
44										
45	TOTAL		184,574,748	490,656						4,321,563

Atmos Energy Corporation-Tennessee
Revenue Lag Study
For Test Year Ended December 30, 2006

Line No.	Description		Weighted Average Lag
	(a)	(b)	(c)
1	Average Banner Billing Lag	3.09	
2			
3	% of Banner Bill customers:	97%	
4			
5	Weighted Average of Banner Billed Billing Lag		3.00
6			
7	Average Handbill Billing Lag	12.35	
8			
9	Weighted Average of Handbill Billing Lag	3%	
10			
11	Weighted Average of Handbill Billing Lag		0.37
12			
13	**Total Average Billing Lag**		3.37
14			
15	**Service Lag**		15.21
16			
17	**Collection Lag:**		25.81
18	(Test Yr Average Daily Accounts Receivable / Test Yr Average Daily Revenue)		
19			
20	**Bank Lag =**		1
21			
22	Total Revenue Lag =		45.39

Atmos Energy Corporation-Tennessee
Per Books Purchase Gas Cost
For Test Year Ended December 30, 2006

THP-CWC3

Line No.	Supplier	Production Month Start Service	Production Month Finish Service	Service Lag	Date of Invoice	Invoice Lag	Date Paid	Payment Lag	Total Lag	Amount	$ Days (h) x (i)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Anadarko Energy Service	12/1/05	12/31/2005	15.5	1/7/06	7.0	01/25/06	18	40.50	6,549,465.48	265,253,351.94
2	Atmos Energy Marketing	12/1/05	12/31/2005	15.5	1/16/06	16.0	01/25/06	9	40.50	15,625.47	632,831.54
3	Atmos Energy Marketing	12/1/05	12/31/2005	15.5	1/16/06	16.0	01/25/06	9	40.50	233,872.32	9,471,828.96
4	Atmos Energy Marketing	12/1/05	12/31/2005	15.5	1/17/06	17.0	01/25/06	8	40.50	11,805,718.37	478,131,593.99
5	Atmos Energy Marketing	12/1/05	12/31/2005	15.5	1/13/06	13.0	01/25/06	12	40.50	16,917.68	685,166.04
6	Atmos Energy Marketing	12/1/05	12/31/2005	15.5	1/17/06	17.0	01/25/06	8	40.50	385,561.24	15,615,230.22
7	Columbia Gulf Transmission	12/1/05	12/31/2005	15.5	1/13/06	13.0	01/17/06	4	32.50	1,530.00	49,725.00
8	Heritage Propane [1]	12/20/05	12/20/2005	0.5	12/22/05	2.0	01/11/06	20	22.50	1,261.76	28,389.60
9	Heritage Propane [1]	12/19/05	12/19/2005	0.5	12/21/05	2.0	01/11/06	21	23.50	1,057.47	24,850.55
10	Heritage Propane [1]	12/19/05	12/19/2005	0.5	12/20/05	1.0	01/11/06	22	23.50	311.35	7,316.73
11	Heritage Propane [1]	12/21/05	12/21/2005	0.5	12/23/05	2.0	01/11/06	19	21.50	800.59	17,212.69
12	Heritage Propane [1]	11/28/05	11/28/2005	0.5	11/30/05	2.0	01/23/06	54	56.50	326.05	18,421.83
13	Heritage Propane [1]	12/20/05	12/20/2005	0.5	12/22/05	2.0	01/11/06	20	22.50	851.02	19,147.95
14	Heritage Propane [1]	1/2/06	1/2/2006	0.5	1/4/06	2.0	01/17/06	13	15.50	949.40	14,715.70
15	Heritage Propane [1]	12/20/05	12/20/2005	0.5	12/22/05	2.0	01/17/06	26	28.50	1,558.99	44,431.22
16	Heritage Propane [1]	12/20/05	12/20/2005	0.5	12/22/05	2.0	01/23/06	32	34.50	327.12	11,285.64
17	Heritage Propane [1]	1/2/06	1/2/2006	0.5	1/4/06	2.0	01/18/06	14	16.50	1,819.84	30,027.36
18	Heritage Propane [1]	12/16/05	12/16/2005	0.5	12/19/05	3.0	01/23/06	35	38.50	2,304.43	88,720.56
19	Heritage Propane [1]	11/18/05	11/18/2005	0.5	11/21/05	3.0	01/23/06	63	66.50	2,090.56	139,022.24
20	Heritage Propane [1]	11/21/05	11/21/2005	0.5	11/23/05	2.0	01/23/06	61	63.50	1,578.74	100,249.99
21	Heritage Propane [1]	1/3/06	1/3/2006	0.5	1/5/06	2.0	01/24/06	19	21.50	835.86	17,970.99
22	Heritage Propane [1]	1/3/06	1/3/2006	0.5	1/5/06	2.0	01/24/06	19	21.50	979.65	21,062.48
23	Heritage Propane [1]	1/10/06	1/10/2006	0.5	1/12/06	2.0	01/27/06	15	17.50	1,874.35	32,801.13
24	Heritage Propane [1]	1/18/06	1/18/2006	0.5	1/20/06	2.0	01/30/06	10	12.50	1,963.63	24,545.38
25	Nashville Gas	12/1/05	12/31/2005	15.5	1/5/06	5.0	01/17/06	12	32.50	3,294.59	107,074.18
26	Atmos Energy Marketing	12/1/05	12/31/2005	15.5	1/17/06	17.0	01/27/06	10	42.50	368,298.29	15,652,677.33
27	BP Energy Company	12/1/05	12/31/2005	15.5	1/6/06	6.0	01/25/06	19	40.50	346,559.05	14,035,641.53
28	Anadarko Energy Service	1/1/06	1/31/2006	15.5	2/10/06	10.0	02/27/06	17	42.50	14,426,184.77	613,112,852.73
29	Atmos Energy Marketing	1/1/06	1/31/2006	15.5	2/16/06	16.0	02/25/06	9	40.50	26,042.94	1,054,739.07
30	Atmos Energy Marketing	1/1/06	1/31/2006	15.5	2/16/06	16.0	02/25/06	9	40.50	210,377.28	8,520,279.84
31	Atmos Energy Marketing	1/1/06	1/31/2006	15.5	2/20/06	20.0	02/25/06	5	40.50	15,466,948.82	626,411,427.21
32	Atmos Energy Marketing	1/1/06	1/31/2006	15.5	2/16/06	16.0	02/25/06	9	40.50	16,917.68	685,166.04
33	Atmos Energy Marketing	1/1/06	1/31/2006	15.5	2/20/06	20.0	02/25/06	5	40.50	390,886.75	15,830,913.38
34	ChevronTexaco	10/1/05	10/31/2005	15.5	12/2/05	32.0	02/28/06	88	135.50	697.95	94,572.23
35	Columbia Gulf Transmission	1/1/06	1/31/2006	15.5	2/6/06	6.0	02/20/06	14	35.50	1,530.00	54,315.00
36	Equitable Energy LLC	8/1/05	8/30/2005	15.0	10/11/05	42.0	02/28/06	140	197.00	26,897.74	5,298,854.78
37	Heritage Propane [1]	12/28/05	12/28/2005	0.5	12/30/05	2.0	02/03/06	35	37.50	1,606.07	60,227.63
38	Heritage Propane [1]	10/19/05	10/19/2005	0.5	10/21/05	2.0	02/03/06	105	107.50	1,198.34	128,821.55
39	Heritage Propane [1]	11/2/05	11/2/2005	0.5	11/4/05	2.0	02/03/06	91	93.50	1,512.51	141,419.69
40	Heritage Propane [1]	1/17/06	1/17/2006	0.5	1/19/06	2.0	02/03/06	15	17.50	1,007.54	17,631.95
41	Heritage Propane [1]	1/17/06	1/17/2006	0.5	1/19/06	2.0	02/03/06	15	17.50	1,036.09	18,131.58
42	Heritage Propane [1]	1/17/06	1/17/2006	0.5	1/19/06	2.0	02/03/06	15	17.50	885.24	15,491.70
43	Heritage Propane [1]	1/13/06	1/13/2006	0.5	1/16/06	3.0	02/03/06	18	21.50	224.28	4,822.02
44	Heritage Propane [1]	1/30/06	1/30/2006	0.5	1/31/06	1.0	02/08/06	8	9.50	363.21	3,450.50
45	Heritage Propane [1]	1/30/06	1/30/2006	0.5	1/31/06	1.0	02/08/06	8	9.50	719.73	6,837.44
46	Heritage Propane [1]	1/30/06	1/30/2006	0.5	1/31/06	1.0	02/08/06	8	9.50	668.56	6,351.32
47	Heritage Propane [1]	1/30/06	1/30/2006	0.5	1/31/06	1.0	02/08/06	8	9.50	779.01	7,400.60
48	Heritage Propane [1]	2/7/06	2/7/2006	0.5	2/9/06	2.0	02/21/06	12	14.50	2,439.68	35,375.36
49	Heritage Propane [1]	2/1/06	2/1/2006	0.5	2/3/06	2.0	02/21/06	18	20.50	1,366.23	28,007.72
50	Heritage Propane [1]	11/28/05	11/28/2005	0.5	11/30/05	2.0	02/21/06	83	85.50	(19.15)	(1,637.33)
51	Heritage Propane [1]	2/6/06	2/6/2006	0.5	2/8/06	2.0	02/21/06	13	15.50	555.77	8,614.44

Atmos Energy Corporation-Tennessee
Per Books Purchase Gas Cost
For Test Year Ended December 30, 2006

Line No.	Supplier	Production Month Start Service	Production Month Finish Service	Service Lag	Date of Invoice	Invoice Lag	Date Paid	Payment Lag	Total Lag	Amount	$ Days (h) x (i)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
52	Heritage Propane [1]	2/6/06	2/6/2006	0.5	2/8/06	2.0	02/21/06	13	15.50	741.41	11,491.86
53	Heritage Propane [1]	2/10/06	2/10/2006	0.5	2/13/06	3.0	02/21/06	8	11.50	197.28	2,268.72
54	Heritage Propane [1]	2/6/06	2/6/2006	0.5	2/8/06	2.0	02/21/06	13	15.50	695.23	10,776.07
55	Heritage Propane [1]	2/6/06	2/6/2006	0.5	2/8/06	2.0	02/21/06	13	15.50	1,271.92	19,714.76
56	Nashville Gas	1/1/06	1/31/2006	15.5	2/3/06	3.0	02/20/06	17	35.50	2,395.10	85,026.05
57	Occidental Energy Marketing	1/1/06	1/31/2006	15.5	2/14/06	14.0	02/28/06	14	43.50	7,595.00	330,382.50
58	Atmos Energy Marketing	1/1/06	1/31/2006	15.5	2/16/06	16.0	02/28/06	12	43.50	27,427.02	1,193,075.37
59	BP Energy Company	1/1/06	1/31/2006	15.5	2/26/06	26.0	02/28/06	2	43.50	572,987.51	24,924,956.69
60	Anadarko Energy Service	2/1/06	2/28/2006	14.0	3/10/06	10.0	03/27/06	17	41.00	3,585,936.38	147,023,391.58
61	Atmos Energy Marketing	2/1/06	2/28/2006	14.0	3/16/06	16.0	03/27/06	11	41.00	26,274.21	1,077,242.61
62	Atmos Energy Marketing	2/1/06	2/28/2006	14.0	3/30/06	30.0	03/27/06	(3)	41.00	(8.38)	(343.58)
63	Atmos Energy Marketing	2/1/06	2/28/2006	14.0	3/16/06	16.0	03/27/06	11	41.00	215,910.56	8,852,332.96
64	Atmos Energy Marketing	2/1/06	2/28/2006	14.0	3/21/06	21.0	03/27/06	6	41.00	6,012,986.64	246,532,452.24
65	Atmos Energy Marketing	2/1/06	2/28/2006	14.0	3/15/06	15.0	03/27/06	12	41.00	16,917.66	693,624.06
66	Atmos Energy Marketing	2/1/06	2/28/2006	14.0	3/21/06	21.0	03/27/06	6	41.00	392,657.67	16,098,964.47
67	Cinergy Marketing & Trading, LP	2/1/06	2/28/2006	14.0	3/14/06	14.0	03/31/06	17	45.00	3,354.90	150,970.50
68	Cinergy Marketing & Trading, LP	2/1/06	2/28/2006	14.0	3/14/06	14.0	03/31/06	17	45.00	3,714.36	167,146.20
69	Columbia Gulf Transmission	2/1/06	2/28/2006	14.0	3/6/06	6.0	03/22/06	16	36.00	1,530.00	55,080.00
70	Heritage Propane [1]	2/24/06	2/24/2006	0.5	2/27/06	3.0	03/15/06	16	19.50	2,367.63	46,168.79
71	Heritage Propane [1]	2/20/06	2/20/2006	0.5	2/21/06	1.0	03/20/06	27	28.50	1,122.10	31,979.85
72	Heritage Propane [1]	2/20/06	2/20/2006	0.5	2/21/06	1.0	03/15/06	22	23.50	880.97	20,702.80
73	Heritage Propane [1]	2/20/06	2/20/2006	0.5	2/21/06	1.0	03/15/06	22	23.50	1,072.83	25,211.51
74	Heritage Propane [1]	2/15/06	2/15/2006	0.5	2/17/06	2.0	03/17/06	28	30.50	2,845.74	86,795.07
75	Heritage Propane [1]	2/24/06	2/24/2006	0.5	2/27/06	3.0	03/17/06	18	21.50	1,849.23	39,758.45
76	Heritage Propane [1]	2/24/06	2/24/2006	0.5	2/26/06	2.0	03/17/06	19	21.50	1,707.19	36,704.59
77	Heritage Propane [1]	3/3/06	3/3/2006	0.5	3/6/06	3.0	03/17/06	11	14.50	1,201.75	17,425.38
78	Heritage Propane [1]	2/27/06	2/27/2006	0.5	3/1/06	2.0	03/17/06	16	18.50	787.75	14,573.38
79	Heritage Propane [1]	3/8/06	3/8/2006	0.5	3/10/06	2.0	03/21/06	11	13.50	862.61	11,645.24
80	Heritage Propane [1]	3/3/06	3/3/2006	0.5	3/6/06	3.0	03/21/06	15	18.50	802.94	14,854.39
81	Heritage Propane [1]	3/3/06	3/3/2006	0.5	3/6/06	3.0	03/21/06	15	18.50	596.39	11,033.22
82	Heritage Propane [1]	3/13/06	3/13/2006	0.5	3/14/06	1.0	03/29/06	15	16.50	867.89	14,320.19
83	Heritage Propane [1]	3/21/06	3/21/2006	0.5	3/23/06	2.0	03/29/06	6	8.50	386.53	3,285.51
84	Heritage Propane [1]	3/17/06	3/17/2006	0.5	3/20/06	3.0	03/29/06	9	12.50	1,133.81	14,172.63
85	Heritage Propane [1]	3/17/06	3/17/2006	0.5	3/20/06	3.0	03/29/06	9	12.50	446.14	5,576.75
86	Heritage Propane [1]	3/17/06	3/17/2006	0.5	3/20/06	3.0	03/29/06	9	12.50	552.94	6,911.75
87	Heritage Propane [1]	3/17/06	3/17/2006	0.5	3/20/06	3.0	03/29/06	9	12.50	684.98	8,562.25
88	Heritage Propane [1]	3/17/06	3/17/2006	0.5	3/20/06	3.0	03/29/06	9	12.50	324.29	4,053.63
89	Heritage Propane [1]	3/3/06	3/3/2006	0.5	3/6/06	3.0	04/04/06	29	32.50	552.57	17,958.53
90	Heritage Propane [1]	2/6/06	2/6/2006	0.5	2/8/06	2.0	04/04/06	55	57.50	(83.03)	(4,774.23)
91	Nashville Gas	2/1/06	2/28/2006	14.0	3/6/06	6.0	03/20/06	14	34.00	1,973.22	67,089.48
92	Occidental Energy Marketing	2/1/06	2/28/2006	14.0	3/8/06	8.0	03/31/06	23	45.00	12,180.00	548,100.00
93	Atmos Energy Marketing	2/1/06	2/28/2006	14.0	3/16/06	16.0	03/31/06	15	45.00	33,771.82	1,519,731.90
94	BP Energy Company	2/1/06	2/28/2006	14.0	3/15/06	15.0	03/27/06	12	41.00	156,276.26	6,407,326.66
95	Anadarko Energy Service	3/1/06	3/31/2006	15.5	4/10/06	10.0	04/25/06	15	40.50	3,313,742.14	134,206,556.67
96	Atmos Energy Marketing	3/1/06	3/31/2006	15.5	4/18/06	18.0	04/25/06	7	40.50	25,666.09	1,039,476.65
97	Atmos Energy Marketing	3/1/06	3/31/2006	15.5	4/18/06	18.0	04/25/06	7	40.50	189,864.70	7,689,520.35
98	Atmos Energy Marketing	3/1/06	3/31/2006	15.5	4/20/06	20.0	04/25/06	5	40.50	5,405,385.24	218,918,102.22
99	Atmos Energy Marketing	3/1/06	3/31/2006	15.5	4/11/06	11.0	04/25/06	14	40.50	16,161.03	654,521.72
100	Atmos Energy Marketing	3/1/06	3/31/2006	15.5	4/20/06	20.0	04/25/06	5	40.50	388,909.27	15,750,825.44
101	Heritage Propane [1]	3/29/06	3/29/2006	0.5	3/31/06	2.0	04/17/06	17	19.50	2,437.91	47,539.25
102	Heritage Propane [1]	3/27/06	3/27/2006	0.5	3/29/06	2.0	04/17/06	19	21.50	610.37	13,122.96

Atmos Energy Corporation-Tennessee
Per Books Purchase Gas Cost
For Test Year Ended December 30, 2006

THP-CWC3

Line No.	Supplier	Production Month Start Service	Production Month Finish Service	Service Lag	Date of Invoice	Invoice Lag	Date Paid	Payment Lag	Total Lag	Amount	$ Days (h) x (i)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
103	Heritage Propane [1]	3/29/06	3/29/2006	0.5	3/31/06	2.0	04/17/06	17	19.50	593.98	11,582.61
104	Heritage Propane [1]	3/29/06	3/29/2006	0.5	3/31/06	2.0	04/17/06	17	19.50	474.78	9,258.21
105	Heritage Propane [1]	4/17/06	4/17/2006	0.5	4/18/06	1.0	05/01/06	13	14.50	594.70	8,623.15
106	Heritage Propane [1]	4/17/06	4/17/2006	0.5	4/18/06	1.0	05/01/06	13	14.50	433.44	6,284.88
107	Heritage Propane [1]	4/18/06	4/18/2006	0.5	4/20/06	2.0	05/01/06	11	13.50	397.79	5,370.17
108	Nashville Gas	3/1/06	3/31/2006	15.5	4/5/06	5.0	04/18/06	13	33.50	1,955.71	65,516.29
109	Columbia Gulf Transmission	3/1/06	3/31/2006	15.5	4/3/06	3.0	04/25/06	22	40.50	1,530.00	61,965.00
110	Atmos Energy Marketing	3/1/06	3/31/2006	15.5	4/18/06	18.0	04/28/06	10	43.50	(105,532.23)	(4,590,652.01)
111	BP Energy Company	3/1/06	3/31/2006	15.5	4/6/06	6.0	04/25/06	19	40.50	123,934.50	5,019,347.25
112	Anadarko Energy Service	4/1/06	4/30/2006	15.0	5/10/06	10.0	05/25/06	15	40.00	2,948,978.30	117,959,132.00
113	Anadarko Energy Service	4/1/06	4/30/2006	15.0	5/10/06	10.0	05/25/06	15	40.00	1,704,426.69	68,177,067.60
114	Atmos Energy Marketing	4/1/06	4/30/2006	15.0	5/16/06	16.0	05/25/06	9	40.00	90,561.17	3,622,446.80
115	Atmos Energy Marketing	4/1/06	4/30/2006	15.0	5/16/06	16.0	05/25/06	9	40.00	170,359.41	6,814,376.40
116	Atmos Energy Marketing	4/1/06	4/30/2006	15.0	5/18/06	18.0	05/25/06	7	40.00	2,446,664.22	97,866,568.80
117	Atmos Energy Marketing	4/1/06	4/30/2006	15.0	5/25/06	25.0	05/25/06	-	40.00	(187.58)	(7,503.20)
118	Atmos Energy Marketing	4/1/06	4/30/2006	15.0	5/16/06	16.0	05/25/06	9	40.00	15,724.16	628,966.40
119	Atmos Energy Marketing	4/1/06	4/30/2006	15.0	5/18/06	18.0	05/25/06	7	40.00	276,899.78	11,075,991.20
120	Columbia Gulf Transmission	4/1/06	4/30/2006	15.0	5/3/06	3.0	05/17/06	14	32.00	1,530.00	48,960.00
121	Coral Resources	4/1/06	4/30/2006	15.0	5/11/06	11.0	05/25/06	14	40.00	2,547,175.14	101,887,005.60
122	Heritage Propane [1]	4/24/06	4/24/2006	0.5	4/25/06	1.0	05/09/06	14	15.50	1,461.17	22,648.14
123	Heritage Propane [1]	5/15/06	5/15/2006	0.5	5/16/06	1.0	06/09/06	24	25.50	355.10	9,055.05
124	Heritage Propane [1]	5/15/06	5/15/2006	0.5	5/16/06	1.0	06/09/06	24	25.50	691.55	17,634.53
125	Heritage Propane [1]	5/15/06	5/15/2006	0.5	5/16/06	1.0	06/09/06	24	25.50	532.89	13,588.70
126	Nashville Gas	4/1/06	4/30/2006	15.0	5/4/06	4.0	05/17/06	13	32.00	1,955.71	62,582.72
127	Atmos Energy Marketing	4/1/06	4/30/2006	15.0	5/16/06	16.0	05/25/06	9	40.00	15,820.98	632,839.20
128	Atmos Energy Marketing	3/1/06	3/31/2006	15.5	4/20/06	20.0	04/28/06	8	43.50	(388,909.27)	(16,917,553.25)
129	Atmos Energy Marketing	3/1/06	3/31/2006	15.5	4/20/06	20.0	04/28/06	8	43.50	358,435.21	15,591,931.64
130	Anadarko Energy Service	5/1/06	5/31/2006	15.5	6/12/06	12.0	06/26/06	14	41.50	5,042,149.18	209,249,190.97
131	Atmos Energy Marketing	5/1/06	5/31/2006	15.5	6/16/06	16.0	06/26/06	10	41.50	37,397.88	1,552,012.02
132	Atmos Energy Marketing	5/1/06	5/31/2006	15.5	6/16/06	16.0	06/26/06	10	41.50	168,272.26	6,983,298.79
133	Atmos Energy Marketing	5/1/06	5/31/2006	15.5	6/23/06	23.0	06/26/06	3	41.50	1,838.40	76,293.60
134	Atmos Energy Marketing	5/1/06	5/31/2006	15.5	6/16/06	16.0	06/26/06	10	41.50	2,415,757.65	100,253,942.48
135	Atmos Energy Marketing	5/1/06	5/31/2006	15.5	6/21/06	21.0	06/26/06	5	41.50	225.85	9,372.78
136	Atmos Energy Marketing	5/1/06	5/31/2006	15.5	6/14/06	14.0	06/26/06	12	41.50	16,371.51	679,417.67
137	Atmos Energy Marketing	5/1/06	5/31/2006	15.5	6/28/06	28.0	06/26/06	(2)	41.50	17.32	718.78
138	Atmos Energy Marketing	5/1/06	5/31/2006	15.5	6/16/06	16.0	06/26/06	10	41.50	276,809.91	11,487,611.27
139	Columbia Gulf Transmission	5/1/06	5/31/2006	15.5	6/3/06	3.0	06/15/06	12	30.50	1,530.00	46,665.00
140	Coral Resources	5/1/06	5/31/2006	15.5	6/6/06	6.0	06/26/06	20	41.50	1,017,005.14	42,205,713.31
141	Nashville Gas	5/1/06	5/31/2006	15.5	6/5/06	5.0	06/15/06	10	30.50	2,453.28	74,825.04
142	Anadarko Energy Service	5/1/06	5/31/2006	15.5	6/12/06	12.0	06/26/06	14	41.50	295,664.43	12,270,073.85
143	Atmos Energy Marketing	5/1/06	5/31/2006	15.5	6/14/06	14.0	06/26/06	12	41.50	23,830.28	988,956.62
144	Atmos Energy Marketing	6/1/06	6/30/2006	15.0	7/21/06	21.0	07/31/06	10	46.00	33,688.71	1,549,680.66
145	Anadarko Energy Service	6/1/06	6/30/2006	15.0	7/16/06	16.0	07/25/06	9	40.00	4,479,338.19	179,173,527.60
146	Atmos Energy Marketing	6/1/06	6/30/2006	15.0	7/21/06	21.0	07/25/06	4	40.00	161,077.33	6,443,093.20
147	Atmos Energy Marketing	6/1/06	6/30/2006	15.0	7/21/06	21.0	07/25/06	4	40.00	2,127,507.94	85,100,317.60
148	Atmos Energy Marketing	6/1/06	6/30/2006	15.0	7/16/06	16.0	07/25/06	9	40.00	16,456.49	658,259.60
149	Atmos Energy Marketing	6/1/06	6/30/2006	15.0	7/21/06	21.0	07/25/06	4	40.00	279,095.69	11,163,827.60
150	Columbia Gulf Transmission	6/1/06	6/30/2006	15.0	7/3/06	3.0	07/18/06	15	33.00	1,530.00	50,490.00
151	Coral Resources	6/1/06	6/30/2006	15.0	7/7/06	7.0	07/25/06	18	40.00	801,406.82	32,056,272.80
152	Heritage Propane [1]	7/11/06	7/11/2006	0.5	7/13/06	2.0	08/01/06	19	21.50	142.44	3,062.46
153	Heritage Propane [1]	6/26/06	6/26/2006	0.5	6/27/06	1.0	07/17/06	20	21.50	255.35	5,490.03

Atmos Energy Corporation-Tennessee
Per Books Purchase Gas Cost
For Test Year Ended December 30, 2006

THP-CWC3

Line No.	Supplier	Production Month Start Service	Production Month Finish Service	Service Lag	Date of Invoice	Invoice Lag	Date Paid	Payment Lag	Total Lag	Amount	$ Days (h) x (i)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
154	Heritage Propane [1]	7/14/06	7/14/2006	0.5	7/17/06	3.0	08/01/06	15	18.50	433.66	8,022.71
155	Heritage Propane [1]	7/25/06	7/25/2006	0.5	7/27/06	2.0	07/17/06	(10)	(7.50)	601.28	(4,509.60)
156	Heritage Propane [1]	7/10/06	7/10/2006	0.5	7/12/06	2.0	07/26/06	14	16.50	742.35	12,248.78
157	Heritage Propane [1]	5/31/06	5/31/2006	0.5	6/2/06	2.0	07/17/06	45	47.50	1,473.12	69,973.20
158	Nashville Gas	6/1/06	6/30/2006	15.0	7/6/06	6.0	07/20/06	14	35.00	2,453.28	85,864.80
159	Anadarko Energy Service	6/1/06	6/30/2006	15.0	7/16/06	16.0	07/25/06	9	40.00	351,082.76	14,043,310.40
160	Atmos Energy Marketing	6/1/06	6/30/2006	15.0	7/18/06	18.0	07/25/06	7	40.00	39,629.45	1,585,178.00
161	Atmos Energy Marketing	7/1/06	7/31/2006	15.5	8/17/06	17.0	08/25/06	8	40.50	31,971.19	1,294,833.20
162	Anadarko Energy Service	7/1/06	7/31/2006	15.5	8/10/06	10.0	08/25/06	15	40.50	4,434,772.10	179,608,270.05
163	Atmos Energy Marketing	7/1/06	7/31/2006	15.5	8/17/06	17.0	08/25/06	8	40.50	173,914.26	7,043,527.53
164	Atmos Energy Marketing	7/1/06	7/31/2006	15.5	8/22/06	22.0	08/25/06	3	40.50	2,139,590.92	86,653,432.26
165	Atmos Energy Marketing	7/1/06	7/31/2006	15.5	8/22/06	22.0	08/25/06	3	40.50	279,075.33	11,302,550.87
166	Atmos Energy Marketing	7/1/06	7/31/2006	15.5	8/17/06	17.0	08/25/06	8	40.50	16,456.66	666,494.73
167	Coral Resources	7/1/06	7/31/2006	15.5	8/7/06	7.0	08/25/06	18	40.50	704,278.60	28,523,283.30
168	Nashville Gas	7/1/06	7/31/2006	15.5	8/4/06	4.0	08/15/06	11	30.50	2,453.28	74,825.04
169	Anadarko Energy Service	7/1/06	7/31/2006	15.5	8/10/06	10.0	08/25/06	15	40.50	348,984.22	14,133,860.91
170	Anadarko Energy Service	7/1/06	7/31/2006	15.5	7/31/06	-	09/25/06	56	71.50	(790.23)	(56,501.45)
171	Atmos Energy Marketing	7/1/06	7/31/2006	15.5	8/23/06	23.0	09/25/06	33	71.50	4,279.18	305,961.37
172	Atmos Energy Marketing	8/1/06	8/31/2006	15.5	9/15/06	15.0	09/25/06	10	40.50	16,456.66	666,494.73
173	Anadarko Energy Service	8/1/06	8/31/2006	15.5	9/13/06	13.0	09/25/06	12	40.50	5,220,490.21	211,429,853.51
174	Atmos Energy Marketing	8/1/06	8/31/2006	15.5	9/19/06	19.0	09/25/06	6	40.50	172,504.98	6,986,451.69
175	Atmos Energy Marketing	8/1/06	8/31/2006	15.5	9/19/06	19.0	09/25/06	6	40.50	2,404,528.07	97,383,386.84
176	Atmos Energy Marketing	8/1/06	8/31/2006	15.5	9/19/06	19.0	09/25/06	6	40.50	32,692.64	1,324,051.92
177	Atmos Energy Marketing	8/1/06	8/31/2006	15.5	9/19/06	19.0	09/25/06	6	40.50	278,659.48	11,285,708.94
178	Coral Resources	8/1/06	8/31/2006	15.5	9/7/06	7.0	09/25/06	18	40.50	693,736.69	28,096,335.95
179	Heritage Propane [1]	8/14/06	8/14/2006	0.5	8/15/06	1.0	09/12/06	28	29.50	477.54	14,087.43
180	Heritage Propane [1]	8/14/06	8/14/2006	0.5	8/15/06	1.0	09/12/06	28	29.50	687.36	20,277.12
181	Heritage Propane [1]	8/14/06	8/14/2006	0.5	8/15/06	1.0	09/12/06	28	29.50	871.75	25,716.63
182	Heritage Propane [1]	7/21/06	7/21/2006	0.5	7/24/06	3.0	09/26/06	64	67.50	1,660.05	112,053.38
183	Heritage Propane [1]	9/12/06	9/12/2006	0.5	9/14/06	2.0	09/26/06	12	14.50	478.92	6,944.34
184	Heritage Propane [1]	9/18/06	9/18/2006	0.5	9/19/06	1.0	09/26/06	7	8.50	501.83	4,265.56
185	Heritage Propane [1]	9/12/06	9/12/2006	0.5	9/14/06	2.0	09/27/06	13	15.50	375.59	5,821.65
186	Nashville Gas	8/1/06	8/31/2006	15.5	9/6/06	6.0	10/16/06	40	61.50	2,453.28	150,876.72
187	Anadarko Energy Service	8/1/06	8/31/2006	15.5	9/13/06	13.0	09/25/06	12	40.50	413,030.14	16,727,720.67
188	Atmos Energy Marketing	8/1/06	8/31/2006	15.5	9/18/06	18.0	09/25/06	7	40.50	4,574.09	185,250.65
189	Atmos Energy Marketing	8/1/06	8/31/2006	15.5	9/13/06	13.0	09/25/06	12	40.50	(19,042.25)	(771,211.13)
190	Atmos Energy Marketing	8/1/06	8/31/2006	15.5	9/13/06	13.0	09/25/06	12	40.50	(9,109.17)	(368,921.39)
191	Atmos Energy Marketing	8/1/06	8/31/2006	15.5	9/13/06	13.0	09/25/06	12	40.50	(35,257.55)	(1,427,930.78)
192	Columbia Gulf Transmission	8/1/06	8/30/2006	15.0	8/31/06	1.0	10/19/06	49	65.00	1,530.00	99,450.00
193	Columbia Gulf Transmission	7/1/06	7/31/2006	15.5	7/31/06	-	10/19/06	80	95.50	1,530.00	146,115.00
194	Heritage Propane [1]	10/4/06	10/4/2006	0.5	10/6/06	2.0	10/18/06	12	14.50	288.53	4,183.69
195	Nashville Gas	9/1/06	9/30/2006	15.0	10/5/06	5.0	10/20/06	15	35.00	3,974.39	139,103.65
196	Atmos Energy Marketing	9/1/06	9/30/2006	15.0	10/16/06	16.0	10/25/06	9	40.00	32,005.78	1,280,231.20
197	Atmos Energy Marketing	9/1/06	9/30/2006	15.0	10/16/06	16.0	10/25/06	9	40.00	174,577.36	6,983,094.40
198	Atmos Energy Marketing	9/1/06	9/30/2006	15.0	10/12/06	12.0	10/25/06	13	40.00	16,373.53	654,941.20
199	Atmos Energy Marketing	9/1/06	9/30/2006	15.0	10/17/06	17.0	10/25/06	8	40.00	277,042.39	11,081,695.60
200	Coral Resources	9/1/06	9/30/2006	15.0	10/6/06	6.0	10/25/06	19	40.00	457,446.60	18,297,864.00
201	Coral Resources	9/1/06	9/30/2006	15.0	10/6/06	6.0	10/25/06	19	40.00	214,228.31	8,569,132.40
202	Atmos Energy Marketing	9/1/06	9/30/2006	15.0	10/17/06	17.0	10/25/06	8	40.00	2,252,990.55	90,119,622.00
203	Anadarko Energy Service	9/1/06	9/30/2006	15.0	10/17/06	17.0	10/25/06	8	40.00	1,801,848.26	72,073,930.40
204	Anadarko Energy Service	9/1/06	9/30/2006	15.0	10/17/06	17.0	10/25/06	8	40.00	1,019,295.00	40,771,800.00

Atmos Energy Corporation-Tennessee
Per Books Purchase Gas Cost
For Test Year Ended December 30, 2006

THP-CWC3

Line No.	Supplier	Production Month Start Service	Production Month Finish Service	Service Lag	Date of Invoice	Invoice Lag	Date Paid	Payment Lag	Total Lag	Amount	$ Days (h) x (i)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
205	Anadarko Energy Service	9/1/06	9/30/2006	15.0	10/17/06	17.0	10/25/06	8	40.00	1,238,784.00	49,551,360.00
206	Heritage Propane [1]	10/17/06	10/17/2006	0.5	10/19/06	2.0	10/30/06	11	13.50	431.52	5,825.52
207	Heritage Propane [1]	10/17/06	10/17/2006	0.5	10/19/06	2.0	10/30/06	11	13.50	478.29	6,456.92
208	Heritage Propane [1]	10/17/06	10/17/2006	0.5	10/19/06	2.0	10/30/06	11	13.50	588.25	7,941.38
209	Atmos Energy Marketing	9/1/06	9/30/2006	15.0	10/16/06	16.0	10/25/06	9	40.00	4,649.19	185,967.60
210	Anadarko Energy Service	9/1/06	9/30/2006	15.0	10/17/06	17.0	10/25/06	8	40.00	161,452.27	6,458,090.80
211	Heritage Propane [1]	10/30/06	10/30/2006	0.5	10/31/06	1.0	11/15/06	15	16.50	54.63	901.40
212	Heritage Propane [1]	11/3/06	11/3/2006	0.5	11/6/06	3.0	11/15/06	9	12.50	598.52	7,481.50
213	Heritage Propane [1]	10/30/06	10/30/2006	0.5	11/1/06	2.0	11/15/06	14	16.50	654.77	10,803.71
214	Heritage Propane [1]	11/17/06	11/17/2006	0.5	11/20/06	3.0	12/01/06	11	14.50	703.59	10,202.06
215	Heritage Propane [1]	10/30/06	10/30/2006	0.5	11/1/06	2.0	11/15/06	14	16.50	817.51	13,488.92
216	Heritage Propane [1]	11/17/06	11/17/2006	0.5	11/20/06	3.0	12/01/06	11	14.50	883.39	12,809.16
217	Heritage Propane [1]	11/17/06	11/17/2006	0.5	11/20/06	3.0	12/01/06	11	14.50	968.87	14,048.62
218	Heritage Propane [1]	10/24/06	10/24/2006	0.5	10/26/06	2.0	11/15/06	20	22.50	1,096.13	24,662.93
219	Heritage Propane [1]	11/14/06	11/14/2006	0.5	11/16/06	2.0	12/01/06	15	17.50	1,180.41	20,657.18
220	Heritage Propane [1]	10/23/06	10/23/2006	0.5	10/25/06	2.0	11/15/06	21	23.50	1,355.40	31,851.90
221	Heritage Propane [1]	11/17/06	11/17/2006	0.5	11/20/06	3.0	12/05/06	15	18.50	2,155.21	39,871.39
222	Nashville Gas	10/1/06	10/31/2006	15.5	11/3/06	3.0	11/17/06	14	32.50	11,643.83	378,424.48
223	Atmos Energy Marketing	10/1/06	10/31/2006	15.5	11/16/06	16.0	11/22/06	6	37.50	16,371.51	613,931.63
224	Atmos Energy Marketing	10/1/06	10/31/2006	15.5	11/17/06	17.0	11/22/06	5	37.50	32,997.13	1,237,392.38
225	Coral Resources	10/1/06	10/31/2006	15.5	11/20/06	20.0	11/22/06	2	37.50	97,914.16	3,671,781.00
226	Atmos Energy Marketing	10/1/06	10/31/2006	15.5	11/17/06	17.0	11/22/06	5	37.50	186,883.21	7,008,120.38
227	Atmos Energy Marketing	10/1/06	10/31/2006	15.5	11/17/06	17.0	11/22/06	5	37.50	276,139.95	10,355,248.13
228	Anadarko Energy Service	10/1/06	10/31/2006	15.5	11/20/06	20.0	11/22/06	2	37.50	640,723.50	24,027,131.25
229	Coral Resources	10/1/06	10/31/2006	15.5	11/20/06	20.0	11/22/06	2	37.50	715,697.04	26,838,639.00
230	Anadarko Energy Service	10/1/06	10/31/2006	15.5	11/20/06	20.0	11/22/06	2	37.50	771,455.37	28,929,576.38
231	Anadarko Energy Service	10/1/06	10/31/2006	15.5	11/20/06	20.0	11/22/06	2	37.50	1,473,446.61	55,254,247.88
232	Atmos Energy Marketing	10/1/06	10/31/2006	15.5	11/17/06	17.0	11/22/06	5	37.50	1,802,260.96	67,584,786.00
233	Atmos Energy Marketing	10/1/06	10/31/2006	15.5	11/16/06	16.0	11/22/06	6	37.50	8,294.68	311,050.50
234	Anadarko Energy Service	10/1/06	10/31/2006	15.5	11/20/06	20.0	11/22/06	2	37.50	217,510.12	8,156,629.50
235	Anadarko Energy Service	10/1/06	10/31/2006	15.5	10/17/06	(14.0)	10/25/06	8	9.50	161,452.27	1,533,796.57
236	Anadarko Energy Service	10/1/06	10/31/2006	15.5	10/17/06	(14.0)	10/25/06	8	9.50	161,452.27	1,533,796.57
237	Heritage Propane [1]	12/1/06	12/1/2006	0.5	12/4/06	3.0	12/14/06	10	13.50	364.66	4,922.91
238	Columbia Gulf Transmission	10/1/06	10/31/2006	15.5	11/3/06	3.0	11/30/06	27	45.50	1,530.00	69,615.00
239	Heritage Propane [1]	12/1/06	12/1/2006	0.5	12/4/06	3.0	12/18/06	14	17.50	1,300.17	22,752.98
240	Heritage Propane [1]	12/8/06	12/8/2006	0.5	12/11/06	3.0	12/18/06	7	10.50	1,876.44	19,702.62
241	Heritage Propane [1]	12/11/06	12/11/2006	0.5	12/12/06	1.0	12/22/06	10	11.50	1,189.88	13,683.62
242	Heritage Propane [1]	11/27/06	11/27/2006	0.5	11/28/06	1.0	12/22/06	24	25.50	2,607.93	66,502.22
243	ChevronTexaco	11/1/06	11/30/2006	15.0	12/11/06	11.0	12/22/06	11	37.00	231,578.70	8,568,411.90
244	Atmos Energy Marketing	11/1/06	11/30/2006	15.0	12/19/06	19.0	12/22/06	3	37.00	32,634.36	1,207,471.32
245	Atmos Energy Marketing	11/1/06	11/30/2006	15.0	12/19/06	19.0	12/22/06	3	37.00	207,336.03	7,671,433.11
246	Atmos Energy Marketing	11/1/06	11/30/2006	15.0	12/18/06	18.0	12/22/06	4	37.00	15,970.01	590,890.37
247	Anadarko Energy Service	11/1/06	11/30/2006	15.0	12/20/06	20.0	12/22/06	2	37.00	2,087,093.99	77,222,477.63
248	Anadarko Energy Service	11/1/06	11/30/2006	15.0	12/20/06	20.0	12/22/06	2	37.00	1,062,645.00	39,317,865.00
249	Anadarko Energy Service	11/1/06	11/30/2006	15.0	12/20/06	20.0	12/22/06	2	37.00	2,804,231.00	103,756,547.00
250	Atmos Energy Marketing	11/1/06	11/30/2006	15.0	12/28/06	28.0	12/31/06	3	46.00	2,642,256.02	121,543,776.92
251	Atmos Energy Marketing	11/1/06	11/30/2006	15.0	12/28/06	28.0	12/31/06	3	46.00	356,957.89	16,420,062.94
252	Heritage Propane [1]	12/5/06	12/5/2006	0.5	12/7/06	2.0	12/22/06	15	17.50	1,000.63	17,511.03
253	Heritage Propane [1]	12/5/06	12/5/2006	0.5	12/7/06	2.0	12/22/06	15	17.50	952.28	16,664.90
254	Heritage Propane [1]	12/5/06	12/5/2006	0.5	12/7/06	2.0	12/22/06	15	17.50	681.79	11,931.33
255	Heritage Propane [1]	12/11/06	12/11/2006	0.5	12/13/06	2.0	12/22/06	9	11.50	623.06	7,165.19

Atmos Energy Corporation-Tennessee
Per Books Purchase Gas Cost
For Test Year Ended December 30, 2006

Line No.	Supplier	Production Month Start Service	Production Month Finish Service	Service Lag	Date of Invoice	Invoice Lag	Date Paid	Payment Lag	Total Lag	Amount	$ Days (h) x (i)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
256	Atmos Energy Marketing	11/1/06	11/30/2006	15.0	12/18/06	18.0	12/31/06	13	46.00	23,040.11	1,059,845.06
257	Anadarko Energy Service	11/1/06	11/30/2006	15.0	12/20/06	20.0	12/31/06	11	46.00	146,144.46	6,722,645.16
258	ChevronTexaco	11/1/06	11/30/2006	15.0	12/11/06	11.0	12/31/06	20	46.00	600.00	27,600.00
321										139,764,777	5,662,147,367
											40.51

To Schedule 1, Line 3

[1] Heritage Propane does daily drops and bills daily for the drops.

Atmos Energy Corporation-Tennessee THP-CWC4

Payroll Lead Days

For Test Year Ended December 30, 2006

Line No.	Start Morning of 1st day of Pay Period	End Evening of Last Day of Pay Period	No. of Days	Service Lag	Date Paid	Payment Lag	Total Direct Payroll Lag
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	12/17/05	12/30/05	14	7.0	01/06/06	7	14
2	12/31/05	01/13/06	14	7.0	01/20/06	7	14
3	01/14/06	01/27/06	14	7.0	02/03/06	7	14
4	01/28/06	02/10/06	14	7.0	02/17/06	7	14
5	02/11/06	02/24/06	14	7.0	03/03/06	7	14
6	02/25/06	03/10/06	14	7.0	03/17/06	7	14
7	03/11/06	03/24/06	14	7.0	03/31/06	7	14
8	03/25/06	04/07/06	14	7.0	04/14/06	7	14
9	04/08/06	04/21/06	14	7.0	04/28/06	7	14
10	04/22/06	05/05/06	14	7.0	05/12/06	7	14
11	05/06/06	05/19/06	14	7.0	05/26/06	7	14
12	05/20/06	06/02/06	14	7.0	06/09/06	7	14
13	06/03/06	06/16/06	14	7.0	06/23/06	7	14
14	06/17/06	06/30/06	14	7.0	07/07/06	7	14
15	07/01/06	07/14/06	14	7.0	07/21/06	7	14
16	07/15/06	07/28/06	14	7.0	08/04/06	7	14
17	07/29/06	08/11/06	14	7.0	08/18/06	7	14
18	08/12/06	08/25/06	14	7.0	09/01/06	7	14
19	08/26/06	09/08/06	14	7.0	09/15/06	7	14
20	09/09/06	09/22/06	14	7.0	09/29/06	7	14
21	09/23/06	10/06/06	14	7.0	10/13/06	7	14
22	10/07/06	10/20/06	14	7.0	10/27/06	7	14
23	10/21/06	11/03/06	14	7.0	11/10/06	7	14
24	11/04/06	11/17/06	14	7.0	11/24/06	7	14
25	11/18/06	12/01/06	14	7.0	12/08/06	7	14
26	12/02/06	12/15/06	14	7.0	12/22/06	7	14
27							
28	TOTAL PAYROLL DIRECT DEPOSIT WEIGHTED AVG EXPENSE LAG						14.00
29							
30	ACTUAL CHECKS WRITTEN:						

		Date Paid	# of Days	Clearing from Pd Dt	Payroll Checks Weighted Avg
32		(e)	(h)	(i)	
34	Same day	12/22/06	0	5.56%	0.00
35	Next day	12/22/06	1	22.53%	0.23
36	2 days	12/22/06	2	13.27%	0.27
37	3-7 days	12/22/06	7	46.30%	3.24
38	8-14 days	12/22/06	14	8.33%	1.17
39	> 2 weeks	12/22/06	21	4.01%	0.84
40					
41	Total Payroll Check Lag				5.75
42					
43	% of Payroll Checks				3.95%
44					
45	WEIGHTED AVERAGE OF ACTUAL PAYROLL CHECKS				0.23
46					
47	TOTAL PAYROLL LAG				14.23

Atmos Energy Corporation-Tennessee THP-CWC5
Other O&M Payment Lag
For Test Year Ended December 30, 2006

Line No.	Vendor	Invoice Date	Weighted $ Days
	a		*b*
1	Other O&M Payment Lag Days:		19.58
2			
3	Check Clearing Lag Days:		2.23
4			
5	Total O&M Payment Lag Days:		21.81

Atmos Energy Corporation-Tennessee THP-CWC6
Taxes Other Than Income Taxes
For Test Year Ended December 30, 2006

Line No.	Description	As Adjusted $ Amount	Lead/Lag Days	Weighted Days
	(a)	(b)	(c)	(d)
1	**Ad Valorem - Previous calendar year taxes are paid February 28 of**			
2	**the current calendar year.**			
3	January 1, 2005 - December 31, 2005	2,659,524		241.50
4				
5	**State Gross Receipts Tax - Paid Annually August 1 for period of**			
6	**July 1 through June 30**			
7	July 1, 2006 - June 30, 2007	1,757,625		(151.50)
8				
9				
10	**Payroll Taxes:**			
11	FICA - Paid on the third banking day after each payday:			
12	Per Books FICA	225,885	16.6	16.15
13	Allocated adjustment to Payroll Taxes	(1,524)		(0.11)
14	Allocated SS Other taxes to FICA	0		-
15				
16	Federal Unemployment - Paid quarterly in arrears at the			
17	end of the month following each quarter:			
18	Per Books FUTA	3,680	76.0	1.21
19	Allocated adjustment to Payroll Taxes	0		-
20	Allocated SS Other taxes to FUTA	0		-
21				
22	State Unemployement - Paid quarterly in arrears at the end			
23	of the month following each quarter:			
24	Per Books SUTA	4,111	76.0	1.35
25	Allocated adjustment to Payroll Taxes	(130)		(0.04)
26	Allocated SS Other taxes to SUTA	0		-
27				
28	**TOTAL PAYROLL RELATED TAXES**	232,022		18.55
29				
30				
31	**State Franchise Tax - Paid quarteryly similar to state excise tax**	486,903		29.50
32				
33	**TRA Inspection Fee - Previous Calendar Year fees are paid on or**			
34	**before April 1 of the current calendar year.**			
35	January 1, 2005 - December 31, 2005	421,232		272.50
36				
37	**DOT - Previous calendar year taxes are paid February 28 of the**			
38	**current calendar year.**			
39	January 1, 2005 - December 31, 2005	12,470		241.50

Atmos Energy Corporation-Tennessee THP-CWC7
Federal Income Taxes
For Test Year Ended December 30, 2006

Line No.	Due Date	Description	Begin Test Period	End Test Period	Midpoint	Weight	Lead/Lag Days	Weighted ad/Lag Days	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)		
1	**Federal Income Tax Payments:**								
2	December 15, 2005	FY 06 1st Qtr. Estimated Pmt	10/1/2005	9/30/2006	182.00	25.00%	(107.00)	(26.75)	
3	March 15, 2006	FY 06 2nd Qtr. Estimated Pmt	10/1/2005	9/30/2006	182.00	25.00%	(17.00)	(4.25)	
4	June 15, 2006	FY 06 3rd Qtr. Estimated Pmt	10/1/2005	9/30/2006	182.00	25.00%	75.00	18.75	
5	September 15, 2006	FY 06 4th Qtr. Estimated Pmt	10/1/2005	9/30/2006	182.00	25.00%	167.00	41.75	
6									
						100.00%		29.50	To Sch 1

Source: Tax Department

Atmos Energy Corporation-Tennessee THP-CWC8
State Excise Taxes
For Test Year Ended December 30, 2006

Line No.	Due Date	Description	Begin Test Period	End Test Period	Midpoint	Weight	Lead/Lag Days	Weighted ad/Lag Days	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)		
1	**State Excise Tax Payments:**								
2	December 15, 2005	FY 06 1st Qtr. Estimated Pmt	10/1/2005	9/30/2006	182.00	25.00%	(107.00)	(26.75)	
3	March 15, 2006	FY 06 2nd Qtr. Estimated Pmt	10/1/2005	9/30/2006	182.00	25.00%	(17.00)	(4.25)	
4	June 15, 2006	FY 06 3rd Qtr. Estimated Pmt	10/1/2005	9/30/2006	182.00	25.00%	75.00	18.75	
5	September 15, 2006	FY 06 4th Qtr. Estimated Pmt	10/1/2005	9/30/2006	182.00	25.00%	167.00	41.75	
6									
						100.00%		29.50	To Sch 1

Source: Tax Department

Atmos Energy Corporation-Tennessee
Long Term Debt
For Test Year Ended December 30, 2006

Atmos Consolidated Balances

Line No.	Lender	Maturity	Type of Payment	Pymt 1	Pymt 2	Pymt 3	Pymt 4	Begin Period	End Period	Lead/Lag Days	Annual Interest	% of Total Interest	Weighted $
	(a)	(b)											
1	MTN 1995-1	12/15/2015	SEMI ANNUAL	6/15/2006	12/15/2006			12/15/2005	12/15/2006	91.25	$ 667,000	0.55%	0.50
2	MTN 1995-2	12/19/2010	SEMI ANNUAL	6/15/2006	12/15/2006			12/15/2005	12/15/2006	91.25	$ 627,000	0.52%	0.47
3	Debentures	7/15/2028	SEMI ANNUAL	1/15/2006	7/15/2006			7/15/2005	7/15/2006	91.25	$ 10,125,000	8.34%	7.61
4	Fredericks	12/31/2011	QUARTERLY	3/31/2006	6/30/2006	9/30/2006	12/30/2006	12/31/2005	12/31/2006	45.63	$ 115,165	0.09%	0.04
5	Sr.Notes 5.125%	7/15/2013	SEMI ANNUAL	1/15/2006	7/15/2006			7/15/2005	7/15/2006	91.25	$ 12,812,500	10.55%	9.63
6	KingdomFdwn	12/31/2011	QUARTERLY	3/31/2006	6/30/2006	9/30/2006	12/30/2006	12/31/2005	12/31/2006	45.63	$ 115,165	0.09%	0.04
7	SrNote 7.375%	5/15/2011	SEMI ANNUAL	5/15/2006	11/15/2006			5/15/2005	5/15/2006	91.25	$ 25,812,500	21.26%	19.40
8	SrNote 3YR Floating	10/15/2007	QUARTERLY	1/15/2006	4/15/2006	7/15/2006	10/15/2006	10/15/2005	10/15/2006	45.63	$ 15,844,200	13.05%	5.95
9	SrNote 4.00%	10/15/2009	SEMI ANNUAL	4/15/2006	10/15/2006			10/15/2005	10/15/2006	91.25	$ 16,000,000	13.18%	12.03
10	SrNote 4.95%	10/15/2014	SEMI ANNUAL	4/15/2006	10/15/2006			10/15/2005	10/15/2006	91.25	$ 24,750,000	20.38%	18.60
11	SrNote 5.95%	10/15/2034	SEMI ANNUAL	4/15/2006	10/15/2006			10/15/2005	10/15/2006	91.25	$ 11,900,000	9.80%	8.94
12	FMB Series P	11/1/2017	SEMI ANNUAL	5/1/2006	11/1/2006			11/1/2005	11/1/2006	91.25	$ 912,625	0.75%	0.69
13	Atmos Leasing	7/1/2013	SEMI ANNUAL	1/1/2006	7/1/2006			7/1/2005	7/1/2006	91.25	$ 80,176	0.07%	0.06
14	Wells Fargo Equip	5/15/2008	MONTHLY					5/15/2005	5/15/2006	15.21	$ 656,825	0.54%	0.08
15	US Bancorp	4/1/2009	MONTHLY					5/1/2005	5/1/2006	15.21	$ 979,827	0.81%	0.12
16	Pulaski-Ingram	6/1/2008	SEMI ANNUAL	6/1/2006	12/1/2006			6/1/2005	6/1/2006	91.25	$ 7,750	0.01%	0.01
17	Pulaski - Carvell	6/1/2008	SEMI ANNUAL	6/1/2006	12/1/2006			6/1/2005	6/1/2006	91.25	$ 7,750	0.01%	0.01
18													
19													
20													
21	WEIGHTED AVERAGE LEAD DAYS OF LONG TERM DEBT EXPENSE										$121,413,483	100.00%	84.18

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

DONALD S. ROFF

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND BUSINESS AFFILIATION.

A. My name is Donald S. Roff and my address is 2832 Gainesborough Drive, Dallas, Texas 75287. I am President of Depreciation Specialty Resources.

Q. WHAT ARE YOUR QUALIFICATIONS AND EXPERIENCE?

A. My qualifications and experience are described on Exhibit DSR-1.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION?

A. Yes. A listing of my regulatory appearances is contained on Exhibit DSR-2.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have conducted a depreciation study of the depreciable natural gas distribution properties in Tennessee (referred to hereinafter as the "Tennessee System") of Atmos Energy Corporation ("Atmos" or "the Company") as of September 30, 2006, and I have made recommendations for revised depreciation rates for inclusion in the Company's revenue requirement. I have also conducted a depreciation study of the plant assets of the Company's Shared Services Unit (SSU)[1] as of September

[1] The Company's Shared Services Unit provides common services, such as accounting, legal, risk management, treasury, procurement, information technology, etc., to all of the Company's

30, 2006, and I have made recommendation for revised depreciation rates therefore, which rates are utilized by Company witness James C. Cagle for purposes of allocation of common costs to the Company's Tennessee Division. The purpose of my testimony is to present the results of the depreciation studies, describe the depreciation study process and recommend appropriate depreciation rates for use by the Company reflecting depreciation accounting principles and regulatory rules. I will show that my studies produce fair and reasonable levels of depreciation expense utilizing sound accounting practices and principles.

Q. DO YOU SPONSOR ANY ADDITIONAL EXHIBITS?

A. Yes. I am sponsoring Exhibit DSR-3 which is the depreciation study prepared for the Company's Tennessee System as of September 30, 2006 (hereinafter referred to as the "Tennessee Depreciation Study"). I am also sponsoring Exhibit DSR-4 which is the depreciation study prepared for the Company's SSU plant as of September 30, 2006 (hereinafter referred to as the "SSU Depreciation Study"). Both the Tennessee Depreciation Study and SSU Depreciation Study include a discussion of depreciation accounting principles, describe the methodology employed for the study, summarize the results of the study and make recommendations relating to depreciation rates and depreciation accounting.

Q. **WHY DID YOU PERFORM TWO SEPARATE STUDIES?**

A. Separate studies have been performed for the Tennessee System and the Company's SSU plant in order to recognize and accurately capture the fact that the assets which are the subject of each study have different characteristics. The assets which are the subject of the Tennessee Depreciation Study primarily consist of pipe, regulators, meters, facilities, etc. which are typically considered natural gas distribution operations assets that are used to provide natural gas service to end-use customers.

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utility divisions. All of this is more particularly explained in the direct testimony of Company witnesses James C. Cagle and Daniel M. Meziere.

The assets which are the subject of the SSU Depreciation Study consist primarily of hardware and software systems which are used by shared services to provide support services to the Company's utility divisions, such as customer support and billing systems, accounting systems, and other such systems which are not replicated at the division level. The preparation of separate studies is also consistent with the manner in which depreciation rates have been established for the Company's utility division plant and SSU plant assets in other rate proceedings.

Q. WERE THE EXHIBITS YOU ARE SPONSORING PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes. Both the Tennessee Depreciation Study and the SSU Depreciation Study were prepared by me or by persons under my direct supervision.

II. DEPRECIATION STUDY PROCESS

Q. WHAT IS DEPRECIATION?

A. The most widely recognized accounting definition of depreciation is that of the American Institute of Certified Public Accountants, which states:

> *Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation.*[2]

Q. WHAT IS THE SIGNIFICANCE OF THIS DEFINITION?

A. This definition of depreciation accounting forms the accounting framework under which both the Tennessee Depreciation Study and SSU Depreciation Study were conducted. Several aspects of this definition are particularly significant, as follows:

- Salvage (net salvage) is to be recognized
- Allocation of costs is over the useful life of the assets
- Grouping of assets is permissible

[2] Accounting Research Bulletin No. 43, Chapter 9, Paragraph 5 (June 1953).

- Depreciation accounting is a process of cost allocation, not a valuation process
- Cost allocation must be both systematic and rational

Q. WHAT IS MEANT BY THE TERMINOLOGY "SYSTEMATIC AND RATIONAL"?

A. "Systematic" implies the use of a formula. The formula used for calculating the recommended depreciation rates for the Tennessee System is shown on Page 7 of the Tennessee Depreciation Study. This same formula was used for calculating the recommended depreciation rates for the Company's SSU plant and is shown on Page 11 of the SSU Depreciation Study. "Rational" means that the pattern of depreciation (or, in this case, the depreciation rate itself) must match either the pattern of revenues produced by the asset or match the consumption of the asset. Because revenues for the Company's utility operations in Tennessee are determined through regulation and are expected to be so determined in the future, asset consumption must be directly measured and reflected in depreciation rates. The measurement of asset consumption is accomplished by conducting a depreciation study which, as is more fully explained herein below, formulates depreciation rates based upon the mortality characteristics of an asset or group of assets.

Q. ARE THERE OTHER DEFINTIONS OF DEPRECIATION?

A. Yes. The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA)[3] provides a series of definitions related to depreciation and which are shown on Page 5 of the Tennessee Depreciation Study as well as on Page 5 of the SSU Depreciation Study. The depreciation definitions make reference to asset consumption and therefore relate very well to the accounting framework for depreciation. These definitions also form the regulatory framework under which both depreciation Studies were conducted. Under the both Tennessee Depreciation Study and the SSU Depreciation Study, I recommend

[3] *See* 18 CFR Part 201 for the USOA applicable to natural gas utilities.

remaining life rates that provide for full recovery of net investment adjusted for net salvage over the future useful life of each asset category, consistent with the Company's past practices.

Q. HOW ARE DEPRECIATION RATES FORMULATED?

A. Appropriate depreciation rates are formulated through a study of the mortality characteristics of an asset or group of assets including average service life, retirement dispersion defined by Iowa-type curves and net salvage factors.

Q. WHAT IS AVERAGE SERVICE LIFE?

A. The average service life of a depreciable asset is the number of years the asset is expected to provide service. For a group of depreciable assets, it is the estimated service life of the group.

Q. WHAT IS RETIREMENT DISPERSION?

A. Retirement dispersion is the scattering of retirements by age for the individual depreciable assets within a group around the average service life for the entire group of depreciable assets. Standard dispersion patterns are useful and necessary because they make calculations of the remaining life of existing property possible and allow life characteristics to be compared. Iowa-type curves provide a set of standard definitions for retirement dispersion.

Q. PLEASE DESCRIBE THE IOWA-TYPE CURVES.

A. The Iowa-type curves were devised empirically over 60 years ago by the Engineering Research Institute (ERI) at what is now Iowa State University (hence, the namesake). The ERI collected retirement information on many types of industrial and utility property and devised empirical curves that matched the range of retirement patterns found. A total of 18 curves were defined varying from wide to narrow dispersion patterns. There were six left-skewed curves, which are known as the "L series", seven symmetrical curves, which are known as the "S series" and five right-skewed curves, which are known as the "R series". A number identifies the range of dispersion – a low number indicating a wide dispersion

pattern and a high number indicating a narrow dispersion pattern. The combination of one letter and one number defines a unique dispersion pattern.

In addition, there is also an "SQ" pattern that has no dispersion and is the equivalent of an amortization period, that is, all assets survive for their entire average life. This pattern has been used for certain general plant accounts.

Q. IN ADDITION TO AVERAGE SERVICE LIFE AND RETIREMENT DISPERSION, YOU MENTIONED PREVIOUSLY THAT NET SALVAGE FACTORS ANOTHER CATEGORY OF MORTALITY CHARACTERISTICS THAT IS EXAMINED IN DETERMINING APPROPRIATE DEPRECIATION RATES. WHAT IS NET SALVAGE?

A. Net salvage is the difference between gross salvage and cost of removal. If cost of removal exceeds gross salvage, negative net salvage occurs.

Q. IS THERE ANY AUTHORITATIVE REGULATORY SOURCE THAT ADDRESSES THE TOPIC OF NET SALVAGE?

A. Yes. The following quotation directly addresses this topic:

> *Under presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. Net salvage, as the name implies, is the difference between the gross salvage that will be obtained when the asset is disposed of and the cost of removing it. Positive net salvage occurs when gross salvage exceeds cost of removal, and negative salvage occurs when cost of removal exceeds gross salvage. Thus the intent of the present concept is to allocate the net cost of an asset to annual accounting periods, making due allowance for the net salvage, positive or negative, that will be obtained when the asset is retired. This concept carries with it the thought that ownership of property entails the responsibility for its ultimate abandonment or removal. Hence if current users of the property benefit from its use, they should pay their pro rata share of the costs involved in the abandonment or removal of the property.*
>
> *This treatment of salvage is in harmony with generally accepted accounting practices and tends to remove from the income statement fluctuations caused by erratic, although necessary, abandonment or uneconomical removal operations. It also has the advantage that current customers pay a fair share, even though*

estimated, of costs associated with the property devoted to their service.[4]

Q. WHY IS THIS QUOTATION IMPORTANT?

A. This quotation is important because it addresses several key accounting and ratemaking issues concerning the treatment of net salvage as a component of depreciation. First and foremost, net salvage is an appropriate component of depreciation. Second, inclusion of net salvage in depreciation results in a fair and equitable allocation of cost. Third, from a ratemaking perspective, inclusion of net salvage in depreciation expense fulfills the regulatory precept of having customers pay their fair share of costs of the life of the property used to provide service to them. As a result, such treatment is beneficial for both accounting and ratemaking purposes.

Q. DOES THE USOA CONTEMPLATE THE INCLUSION OF NET SALVAGE AS A COMPONENT OF DEPRECIATION?

A. Yes. The USOA instructions clearly intend net salvage to be a component of depreciation as it must be charged to Account 108, Accumulated Provision for Depreciation.[5]

Q. THUS FAR YOU HAVE DESCRIBED THE MORTALITY CHARACTERISTICS WHICH ARE EVALUATED IN CONNECTION WITH PERFORMING A DEPRECIATION STUDY. CAN YOU DESCRIBE THE DEPRECIATON STUDY PROCESS ITSELF?

A. Certainly. A depreciation study consists of four distinct yet interrelated phases – data collection, analysis, evaluation and calculation. Each of these phases occurred in connection with preparing both the Tennessee Depreciation Study and the SSU Depreciation Study. Data collection refers to the gathering of historical investment activity data that was provided by the Company. After the data was assembled, I or persons

[4] *Public Utility Depreciation Practices,* NARUC, 1968 Edition, page 24.

[5] 18 CFR Part 201, Gas Plant Instruction 10.F provides "the book cost less net salvage of depreciable gas plant retired shall be charged in its entirety to account 108, Accumulated Provision for Depreciation of Gas Plant in Service".

under my direction performed two separate analyses[6] - one analysis for the determination of life and another one for the determination of the net salvage percentage for the different asset groups being studied (each analysis is more fully discussed later herein).

Once the analysis phase was completed, the evaluation phase was then conducted which entailed the development of an understanding of asset history and its applicability to the surviving asset base into the future. This phase also gave consideration to the changing asset base and the Company's plans and expectations. I conducted the evaluation phase with the assistance and input from Company personnel.

The last phase of each depreciation study was the calculation phase and was performed by me or Atmos employees under my direct supervision. This phase utilized the information and results determined in the first three phases of the depreciation study process in the computation of recommended depreciation rates.

Q. DURING THE ANALYSIS PHASE, YOU INDICATED THAT TWO ANALYSES, LIFE ANALYSIS AND NET SALVAGE, WERE PERFORMED. WHAT DID THE LIFE ANALYSIS ENTAIL?

A. For some categories of transmission, distribution and general plant, the age of both surviving and retired property is known and an actuarial analysis was utilized for these property groups. The actuarial[7] analysis process is more particularly described on pp. 8-10 of the Tennessee Depreciation Study and on pp. 8-10 of the SSU Depreciation Study. For those asset categories for which the age of retirements is not known, a simulation[8] analysis was utilized. The simulated analysis technique is more particularly described on p. 10 of the Tennessee Depreciation Study.

[6] Analysis refers to the statistical processing of the data gathered in the first phase of the study process.
[7] Technically referred to as the Actuarial Method of Life Analysis.
[8] Technically referred to as the Simulated Plant Record Method.

Q. AFTER THE LIFE ANALYSIS WAS PERFORMED, WHAT ACTIONS WERE UNDERTAKEN IN CONNECTION THEREWITH DURING THE EVALUATION PHASE?

A. Summaries of the individual asset category life analysis indications were prepared and discussed with Company personnel. Anomalies and trends were identified and input from the Company's engineering and operations personnel was requested and obtained where necessary. The types of assets surviving and retiring were also discussed. A single average service life and Iowa-type curve was then selected for each asset category best reflecting the combination of the historical results and the additional information obtained from and during discussions with the Company's engineering, operations and accounting personnel.

Q. HOW WERE NET SALVAGE PERCENTAGES DETERMINED?

A. As I stated previously, determination of net salvage percentages is performed as part of the second phase of the preparation of a depreciation study. This entails the determination of both salvage and cost of removal. In connection with this, annual salvage amounts, cost of removal and retirements were provided by the Company by account for the period of 2001 through September 30, 2006 for the Tennessee Depreciation Study and the for the period of 1993 through 2006 for the SSU Depreciation Study.

Q. AFTER PERFORMING THE NET SALVAGE ANALYSIS, WHAT ACTIONS WERE UNDERTAKEN IN CONNECTION THEREWITH DURING THE EVALUATION PHASE?

A. As with the life analysis, discussions were held with applicable Company personnel to the extent necessary to examine salvage cost, cost of removal, cost of retirements and the Company's present and future plans associated with retirement and removal of depreciable assets.

Q. WHAT ACTIONS WERE PERFORMED AS PART OF THE FINAL PHASE OF THE PREPARATION OF THE DEPRECIATION STUDIES?

A. In the calculation phase, annual salvage, cost of removal and net salvage percentages were then calculated for purposes of each study by dividing the annual salvage, cost of removal and net salvage amounts by the retirement amounts applicable to the asset groups of each depreciation category.

Q. WHAT OCCURRED AFTER THE PERFORMANCE OF EACH PHASE OF BOTH DEPRECIATION STUDIES YOU HAVE DISCUSSED?

A. Both studies were formalized into written reports and presented to the Company. The formalized written reports are the Tennessee Depreciation Study and the SSU Depreciation Study attached to my testimony as Exhibit DSR-3 and Exhibit DSR-4, respectively.

Q. IS THE PROCESS YOU HAVE DESCRIBED IN YOUR TESTIMONY FOR PERFORMANCE AND REPARATION OF THE DEPRECIATION STUDIES RECOGNIZED FOR BOTH REGULATORY RATEMAKING AND ACCOUNTING PURPOSES AS THE ACCEPTED PROCESS FOR DETERMINING REASONABLE DEPRECIATION RATES FOR THE ASSETS SUBJECT OF THE STUDIES?

A. Yes.

III. THE TENNESSEE DEPRECIATION STUDY RESULTS

Q. DID YOU PERFORM AND PREPARE THE TENNESSEE DEPRECIATION STUDY IN ACCORDANCE WITH THE PROCESS THAT YOU HAVE DESCRIBED IN YOUR TESTIMONY?

A. Yes.

Q. IS THIS THE STUDY UPON WHICH THE COMPANY RELIES IN THIS CASE TO ESTABLISH DEPRECIATION RATES FOR ITS TENNESSEE SYSTEM?

A. Yes. In this docket, Atmos is relying on the Tennessee Depreciation Study that I prepared for its Tennessee System. As stated previously, the Tennessee System consists of the Company's net plant in service in Tennessee used to provide natural gas service to its customers, which

includes physical plant, property and equipment. For purposes of the Depreciation Study, the net plant comprising the Tennessee System is categorized according to function – transmission, distribution and general plant.

Q. WHAT WERE YOUR FINDINGS AND RECOMMENDATIONS?

A. I found that changes were needed to the mortality characteristics for every asset category resulting in revised depreciation rates. A summary comparison of the existing depreciation rates and those recommended in the Tennessee Depreciation Study by asset functional category is as follows:

Function	Existing	Recommended
	%	%
Transmission	2.99	2.87
Distribution	3.59	2.79
General	5.15	10.63
Total Depreciable Plant	3.58	2.91

Q. HAVE YOU QUANTIFIED THE IMPACT ON ANNUAL DEPRECIATION EXPENSE DUE TO YOUR RECOMMENDED CHANGES?

A. Yes. The above summary was taken from Schedule 1 of Exhibit DSR-3. Using September 30, 2006, depreciable balances, the effect of the recommended depreciation rates on annual depreciation expense is a decrease of approximately $2,001,751.

Q. **WHAT ARE THE PRIMARY FORCES THAT ARE DRIVING THE RECOMMENDED CHANGE IN ANNUAL DEPRECIATION EXPENSE?**

A. The change in annual depreciation expense is affected by three separate factors – changes in average service life, changes in net salvage and the effect of reserve position. Based upon the magnitude and direction of the change in depreciation rates and annual depreciation expense, average

service lives have increased thereby producing lower annual depreciation expense. This decrease, however, is offset by negative net salvage.

Q. PLEASE DESCRIBE THE RESULTS REFLECTED IN THE TABLE ABOVE REGARDING TRANSMISSION PLANT.

A. For the Transmission Plant functional group, the depreciation rate decreases from 2.99% to 2.87%. Asset lives have increased, resulting in reduced annual depreciation expense. This reduction was offset by more negative net salvage. The net dollar impact of the change in the depreciation rate is a decrease in annual depreciation expense of $16,543.

Q. PLEASE DESCRIBE THE RESULTS REFLECTED IN THE TABLE ABOVE REGARDING DISTRIBUTION PLANT.

A. For the Distribution Plant functional group, the depreciation rate decreases from 3.59% to 2.79% as a result of increased lives. The impact on annual depreciation expense is a decrease of approximately $2,211,405 due to the longer lives. This decrease was offset by more negative net salvage for certain asset categories, in particular, Account 376, Mains.

Q. PLEASE DESCRIBE THE RESULTS REFLECTED IN THE TABLE ABOVE REGARDING GENERAL PLANT.

A. The composite depreciation rate for the General Plant functional group has increased from 5.15% to 106.63%, primarily because of reserve position for certain asset categories, in particular, Accounts 394, Tools, Shop and Garage Equipment and Account 396, Power Operated Equipment. The accumulated depreciation balances for these two accounts have been reduced by significant retirements in recent years. The impact of the change in the depreciation rate is an increase in annual depreciation expense by approximately $226,197.

Q. PLEASE DESCRIBE THE RESULTS REFLECTED IN THE TABLE ABOVE FOR THE TOTAL COMPANY.

A. At the Total Company depreciable level, the composite depreciation rate decreases from 3.58% to 2.91%, or $2,001,751 less in depreciation expense on an annual basis.

Q. DO YOU HAVE ANY RECOMMENDATIONS AS A RESULT OF THE TENNESSEE DEPRECIATION STUDY?

A. Yes. I recommend that the Commission approve and the Company adopt the depreciation rates shown on Schedule 1 of the Tennessee Depreciation Study.

Q. UPON WHAT TO YOU BASE THIS RECOMMENDATION?

A. I base this recommendation on the fact that I have conducted a comprehensive depreciation study, giving appropriate recognition to historical experience, recent trends and Company expectations. The Tennessee Depreciation Study results in a fair and reasonable level of depreciation expense which, when incorporated into a revenue stream, will provide the Company with adequate capital recovery until such time as a new depreciation study indicates a need for change.

IV. THE SSU DEPRECIATION STUDY RESULTS

Q. DID YOU PERFORM AND PREPARE THE SSU DEPRECIATION STUDY IN ACCORDANCE WITH THE PROCESS THAT YOU HAVE DESCRIBED IN YOUR TESTIMONY?

A. Yes.

Q. IS THIS THE STUDY UPON WHICH THE COMPANY RELIES IN THIS CASE TO ESTABLISH DEPRECIATION RATES FOR SSU PLANT?

A. Yes. In this docket, Atmos is relying on the SSU Depreciation Study that I prepared for its SSU plant as part of allocated common costs more particularly described in the direct testimony of Company witnesses James C. Cagle and Daniel M. Meziere.[9] As stated previously, the SSU

[9] As more particularly described in the direct testimony of Mr. Cagle, a portion of depreciation expense on SSU general plant, calculated at the depreciation rates proposed in the SSU Depreciation Study, is allocated to the Tennessee Division as part of O&M expense included in the Company's revenue requirement in this rate filing. The SSU Depreciation Study does not

general plant consists primarily of software and hardware systems which are used in connection with the provision of common services to the Company's utility divisions. For purposes of the SSU Depreciation Study, the net plant comprising the SSU general plant is categorized according to function.

Q. WHAT WERE YOUR FINDINGS AND RECOMMENDATIONS?

A. I found that changes were needed to the mortality characteristics for every asset category resulting in revised depreciation rates. A summary comparison of the existing depreciation rates and those recommended in the SSU Depreciation Study by asset functional category is as follows:

	Existing Rate %	SSU Study Rate %
General Plant	9.09	10.32

Q. HAVE THE SSU DEPRECIATION RATES THAT RESULT FROM YOUR SSU DEPRECIATION STUDY BEEN ADOPTED BY OTHER STATE REGULATORY COMMISSION'S FOR ATMOS' USE?

A. No, because the SSU Depreciation Study is so new, this is only the second rate case in which it has been introduced by the Company and the first case is currently ongoing. However, based upon a similar study which I performed in 2002, Atmos has had SSU depreciation rates approved in several jurisdictions, including Louisiana, Texas and Virginia.

Q. WOULD YOU SUMMARIZE THE RESULTS OF THE SSU DEPRECIATION STUDY?

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address the Company's allocations of plant and expense, only depreciation rates for SSU general plant.

A. Yes. In general, average service lives have increased. Net salvage remained the same for each asset category. There are three asset categories to contain the largest changes in annual depreciation expense: Account 399.01, Server Hardware; Account 399.08, Application Software and Account 399.24, General Start-up Costs. For Account 399.01, the decrease in annual depreciation expense of $1,069,241 is due to an increase in average service life from 5 years to 10 years. For Account 399.08, the increase in annual depreciation expense of $3,217,244 is due to reserve position. For Account 399.24, the increase in annual depreciation expense of $1,751,828 is due to reserve position.

Q. WHEN YOU USE THE TERM "RESERVE POSITION", WHAT DO YOU MEAN?

A. The term "reserve position" refers to the difference between a theoretical reserve and the existing book reserve. If the theoretical reserve is greater than the book reserve, past depreciation has been inadequate compared to the depreciation parameters developed in the SSU study, and an upward adjustment to the depreciation rate is required. If the opposite is true, a downward adjustment to the depreciation rate is required.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE DEPRECIATION RATES THAT SHOULD BE ESTABLISHED FOR SSU IN THIS CASE.

A. I recommend that the Commission adopt the depreciation rates shown on Schedule 1 of Exhibit DSR-4. I base this recommendation on the fact that I have conducted a comprehensive depreciation study, giving appropriate recognition to historical experience, recent trends and Company expectations. My study results in a fair and reasonable level of depreciation expense which, when incorporated into a revenue stream, will provide the Company with adequate capital recovery until such time as a new depreciation study indicates a need for change.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

VERIFICATION

STATE OF TEXAS)
)
COUNTY OF DALLAS)

I, Donald S. Roff, being first duly sworn, state that I am President of Depreciation Specialty Resources, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Testimony of Donald S. Roff in support of Atmos Energy Corporation's Petition and the Exhibits thereto pre-filed in this docket on the date of filing of this Petition are true and correct to the best of my knowledge, information and belief.

Donald S. Roff

Sworn and subscribed before me this 5th day of April, 2007.

Ethel Z. Taylor
Notary Public

My Commission Expires: August 13, 2010

ETHEL Z TAYLOR
My Commission Expires
August 13, 2010

Academic Background

Donald S. Roff graduated from Rensselaer Polytechnic Institute with a Bachelor of Science degree in Management Engineering in 1972.

Mr. Roff has also received specialized training in the area of depreciation from Western Michigan University's Institute of Technological Studies. This training involved three forty-hour seminars on depreciation entitled "Fundamentals of Depreciation", "Fundamentals of Service Life Forecasting" and "Making a Depreciation Study" and included such topics as accounting for depreciation, estimating service life, and estimating salvage and cost of removal.

Employment and Professional Experience

Following graduation, Mr. Roff was employed for eleven and one-half years by Gilbert Associates, Inc., as an engineer in the Management Consulting Division. In this capacity, he held positions of increasing responsibility related to the conduct and preparation of various capital recovery and valuation assignments.

In 1984, Mr. Roff was employed by Ernst & Whinney and was involved in several depreciation rate studies and utility consulting assignments.

In 1985, Mr. Roff joined Deloitte Haskins & Sells (DH&S), which, in 1989, merged with Touche Ross & Co. to form Deloitte & Touche. In 1995, Mr. Roff was appointed as a Director with Deloitte & Touche.

In November, 2005, Mr. Roff formed Depreciation Specialty Resources to serve the utility industry.

During his tenure with Gilbert Associates, Inc., Ernst & Whinney, DH&S and Deloitte & Touche, Mr. Roff has participated in or directed depreciation studies for electric, gas, water and steam heat utilities, pipelines, railroad and telecommunication companies in over 30 states, several Canadian provinces and Puerto Rico. This work requires an in-depth knowledge of depreciation accounting and regulatory principles, mortality analysis techniques and financial practices. At these firms, Mr. Roff has had varying degrees of responsibility for valuation studies, development of depreciation accrual rates, consultation on the unitization of property records, and other studies concerned with the inspection and appraisals of utility property, preparation of rate case testimony and support exhibits, data responses and rebuttal testimony, in addition to appearing as an expert witness.

Industry and Technical Affiliations

Mr. Roff is a registered Professional Engineer in Pennsylvania (by examination).

Mr. Roff is a member of the Society of Depreciation Professionals and a Certified Depreciation Professional, and a Technical Associate of the American Gas Association (A.G.A.) Depreciation Committee. He currently serves as the lead instructor for the A.G.A.'s Principles of Depreciation Course.

DONALD S. ROFF

TESTIMONY EXPERIENCE

CASE NO.	DATE	COMPANY	JURISDICTION	SUBJECT
Docket No. 93-3005	July 1993	Southwest Gas Corporation	Nevada	Gas Depreciation Rates
Docket No. 93-3025	July 1993	Southwest Gas Corporation	Nevada	Gas Depreciation Rates
Docket No. 12820	June 1994	Central Power and Light Company	Texas	Electric Depreciation Rates
Case No. U-10380	Dec 1994	Consumers Power Company	Michigan	Gas Depreciation Rates and Accounting
Cause No. 39938	April 1995	Indianapolis Power & Light Company	Indiana	Electric Depreciation Rates
Case No. U-10754	July 1995	Consumers Power Company	Michigan	Electric Depreciation Rates and Accounting
Docket No. 13369	Aug 1995	West Texas Utilities Company	Texas	Electric Depreciation Rates
Docket No. 95-02116	Sept 1995	Chattanooga Gas Company	Tennessee	Gas Depreciation Rates
Docket No. 95-715-G	Oct 1995	Piedmont Natural Gas Company	South Carolina	Gas Depreciation Rates
Docket No. 14965	Dec 1995	Central Power and Light Company	Texas	Electric Depreciation Rates
Cause No. 40395 (I)	Feb 1996	Wabash Valley Power Association, Inc.	Indiana	Electric Depreciation Rates
GUD NO. 8664	Oct 1996	Lone Star Pipeline Company	Texas	Gas Depreciation Rates
Docket No. 96-360-U	Nov 1996	Entergy Arkansas Inc.	Arkansas	Electric Depreciation Rates
Docket No. 16705	Nov 1996	Entergy Gulf States Inc.	Texas	Electric Depreciation Rates/Competitive Issues
Docket No. ER-97-394	Mar 1997	Missouri Public Service	Missouri	Electric Depreciation Rates/Competitive Issues
Docket No. U-22092	Mar 1997	Entergy Gulf States Inc.	Louisiana	Electric Depreciation Rates/Competitive Issues
Docket No. 97-00982	May 1997	Chattanooga Gas Company	Tennessee	Gas Depreciation Rates
Cause No. 40395 (II)	June 1997	Wabash Valley Power Association, Inc.	Indiana	Electric Depreciation Rates
Case No. U-11509	Sept 1997	Consumers Energy Company	Michigan	Gas Depreciation Rates and Accounting
Docket No. ER98-11	Sept 1997	Long Island Lighting Company	FERC	Electric Depreciation Rates
Docket No. 8390-U	Dec 1997	Atlanta Gas Light Company	Georgia	Gas Depreciation Rates and Accounting
Cause No. 41118	Mar 1998	Wabash Valley Power Association, Inc.	Indiana	Electric Depreciation Rates
Case No. U-11722	Oct 1998	Detroit Edison Company	Michigan	Electric Depreciation Rates
Docket No. 98-2035-03	Nov 1998	PacifiCorp	Utah	Electric Depreciation Rates
Docket No. 99-4006	April 1999	Nevada Power Company	Nevada	Electric Depreciation Rates
GUD Docket No. 9030	March 2000	Atmos Energy Corporation	Texas	Gas Depreciation Rates and Accounting
GUD Docket No. 9145	April 2000	TXU Gas Distribution	Texas	Gas Depreciation Rates
City of Tyler	Dec 2000	Reliant Energy Entex	Texas	Gas Depreciation Rates and Accounting
Docket No. U-24993	March 2001	Entergy Gulf States Inc.	Louisiana	Electric Depreciation Rates and Accounting
Docket Nos. GR01050328/GR0105029	May 2001	Public Service Electric & Gas	New Jersey	Gas Depreciation Rates and Accounting
Case No. U-12999	July 2001	Consumers Energy Company	Michigan	Gas Depreciation Rates and Accounting
Docket No. 01-10002	Oct 2001	Nevada Power Company	Nevada	Electric Depreciation Rates
Docket No. 14618-U	Nov 2001	Savannah Electric and Power Company	Georgia	Electric Depreciation Rates
Docket No. 01-11031	Dec 2001	Sierra Pacific Power Company	Nevada	Electric Depreciation Rates
Docket No. 010949-EL	Jan 2002	Gulf Power Company	Florida	Electric Depreciation Rates
Docket No. 14311-U	Jan 2002	Atlanta Gas Light Company	Georgia	Gas Depreciation Rates and Accounting
Docket No. UD-00-2	March 2002	Entergy New Orleans, Inc.	New Orleans	Electric Depreciation Accounting
Cause No. PUD200200166	May 2002	Reliant Energy Entex	Oklahoma	Gas Depreciation Rates and Accounting
Docket No. 01-243-U	June 2002	Reliant Energy Entex	Arkansas	Gas Depreciation Rates and Accounting
Docket No. 02-035-12	Oct 2002	PacifiCorp	Utah	Electric Depreciation Rates
Docket No. 20000-ER-2-192	Oct 2002	PacifiCorp	Wyoming	Electric Depreciation Rates
Docket No. UE-021271	Oct 2002	PacifiCorp	Washington	Electric Depreciation Rates
Docket No. UM-1064	Oct 2002	PacifiCorp	Oregon	Electric Depreciation Rates
Docket No. PAC-E-02-5	Oct 2002	PacifiCorp	Idaho	Electric Depreciation Rates
Docket No. 02-0391	Oct 2002	Hawaiian Electric Company, Inc.	Hawaii	Electric Depreciation Rates and Accounting
Docket No. 03-ATMG-1036-RTS	June 2003	Atmos Energy Corporation	Kansas	Gas Depreciation Rates and Accounting
Docket No. 02-0391	Aug 2003	Hawaiian Electric Company, Inc.	Hawaii	Electric Depreciation Rates and Accounting
Cause No. 42458	Sept 2003	Wabash Valley Power Association, Inc.	Indiana	Electric Depreciation Rates and Accounting
Docket No. 03-ATMG-1036-RTS	Nov 2003	Atmos Energy Corporation	Kansas	Gas Depreciation Rates and Accounting
Case No. 12999	Dec 2003	Consumers Energy Company	Michigan	Gas Depreciation Rates and Accounting
Case No. 12999	Feb 2004	Consumers Energy Company	Michigan	Gas Depreciation Rates and Accounting
Docket No. ER-2004-0570	Apr 2004	The Empire District Electric Company	Missouri	Electric Depreciation Rates and Accounting
Docket No. 04-100-U	Apr 2004	The Empire District Electric Company	Arkansas	Electric Depreciation Rates and Accounting
Docket No. PUE 2003-00597	Aug 2004	Atmos Energy Corporation	Virginia	Gas Depreciation Rates and Accounting
Docket No. 18638-U	Oct 2004	Atlanta Gas Light Company	Georgia	Gas Depreciation Rates and Accounting
Docket No. ER-2004-0570	Nov 2004	The Empire District Electric Company	Missouri	Electric Depreciation Rates and Accounting
Docket No. ER-2004-0570	Nov 2004	The Empire District Electric Company	Missouri	Electric Depreciation Rates and Accounting
Cause No. 200400610	Jan 2005	Oklahoma Natural Gas Company	Oklahoma	Gas Depreciation Rates and Accounting
Docket No. 18638-U	March 2005	Atlanta Gas Light Company	Georgia	Gas Depreciation Rates and Accounting
Docket No. 20298	May 2005	Atmos Energy Corporation	Georgia	Gas Depreciation Rates and Accounting
Cause No. 200400610	June 2005	Oklahoma Natural Gas Company	Oklahoma	Gas Depreciation Rates and Accounting
Docket No. 20298	Oct 2005	Atmos Energy Corporation	Georgia	Gas Depreciation Rates and Accounting
Case No. GR-2006-0387	Apr 2006	Atmos Energy Corporation	Missouri	Gas Depreciation Rates and Accounting
GUD Docket No. 9670	Nov 2006	Atmos Energy Corporation	Texas	Gas Depreciation Rates and Accounting
Case No. 20060-00464	Dec 2006	Atmos Energy Corporation	Kentucky	Gas Depreciation Rates and Accounting

EXHIBIT
DSR-3

Atmos Energy Corporation

Book Depreciation Study of
Atmos Energy Corporation
Tennessee Properties
As of September 30, 2006

January 2007

Atmos Energy Corporation
Three Lincoln Center
5430 LBJ Freeway
Dallas, TX 75240

Attention: Mr. Thomas Petersen

In accordance with your request and with the cooperation and participation of your staff, a book depreciation study of Atmos Energy Corporation's Tennessee properties ("Atmos" or "the Company") has been conducted. The study covered all depreciable and amortizable property and recognized addition and retirement experience through September 30, 2006. The purpose of the study was to determine if the existing depreciation rates remain appropriate for the property and, if not, to recommend changes. Changes were found to be needed and are recommended. The changes in aggregate cause a decrease in depreciation rates used to calculate the annual depreciation expense.

A comparison of the effect of the existing rates and the recommended rates is shown below, based on depreciable plant balances as of September 30, 2006:

Function	Composite Depreciation Rate	
	Existing	Recommended
	%	%
Transmission	2.99	2.87
Distribution	3.59	2.79
General	5.15	10.63
Total	3.58	2.91

The summary above is taken from Schedule 1, which shows the annual depreciation amounts calculated from the existing rates and the recommended account rates and the differences. Based upon the September 30, 2006 depreciable balances, the recommended depreciation rates will result in an annual decrease in depreciation provisions of $2,001,751 or 18.8%. The study results are being driven by a decrease in depreciation rates for every functional asset category, except General Plant.

Schedule 2 shows the mortality characteristics used to calculate the recommended depreciation rates. The recommended depreciation rates are straight-line over life measured by time using the equal life group (ELG) procedure and the remaining life technique, consistent with the existing, approved rates.

The following sections of this report describe the methods of analysis used and the bases for the conclusions reached. The remainder of the report will present the results and recommendations for both immediate and future actions by the Company.

We appreciate this opportunity to serve Atmos Energy Corporation and would be pleased to meet with you to discuss further the matters presented in this report, if you desire.

Yours truly,

President

Depreciation Specialty Resources

PURPOSE OF DEPRECIATION

Book depreciation accounting is the process of recognizing in financial statements the consumption of physical assets in the process of providing a service or a product. Generally accepted accounting principles require the recording of depreciation to be systematic and rational. To be systematic and rational, depreciation should, to the extent possible, match either the consumption of the facilities or the revenues generated by the facilities. Accounting theory requires the matching of expenses with either consumption or revenues to ensure that financial statements reflect the results of operations and changes in financial position as accurately as possible. The matching principle is often referred to as the "cause and effect" principle; thus, both the cause and the effect are required to be recognized for financial accounting purposes. This study was conducted in a manner consistent with the matching principle of accounting.

Because utility revenues are determined through regulation, and this study assumes that such regulation will continue, asset consumption is not automatically in revenues. Therefore, the consumption of utility assets must be measured directly by conducting a book depreciation study to accurately determine the mortality characteristics of the assets.

Matching is also an essential element of basic regulatory philosophy, and it has become known as "intergenerational customer equity". Intergenerational customer equity means the costs are borne by the generation of customers that caused them to be incurred, not by some earlier or later generation. This matching is required to ensure that the charges to customers reflect the actual costs of providing service.

DEPRECIATION DEFINTIONS

The Uniform System of Accounts ("USOA") prescribed for gas utilities by the Federal Energy Regulatory Commission ("FERC") followed by Atmos states that:

> "Depreciation", as applied to depreciable gas plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities, and in the case of natural gas companies, the exhaustion of natural resources.
>
> "Service value" means the difference between original cost and net salvage value of gas plant.
>
> "Net salvage value" means the salvage value of property retired less the cost of removal.
>
> "Salvage value" means the amount received for the property retired, less any expenses incurred in connection with the sale or in preparing the property for sale or, if retained, the amount at which the material is chargeable to materials and supplies, or other appropriate account.
>
> "Cost of removal" means the cost of demolishing, dismantling, tearing down or otherwise removing gas plant, including the cost of transportation and handling incidental thereto.

As is clear from the wording of the salvage value and the cost of removal definitions, it is the salvage that will actually be received and the cost of removal that will actually be incurred, both measured at the price level at the time of receipt or incurrence that is required to be recognized in the depreciation rates of Atmos.

These definitions are consistent with the purpose of depreciation, and the study reported here was conducted in a manner consistent with both.

ACCOMPLISHMENT OF ACCOUNTING AND REGULATORY PRINCIPLES

Utility depreciation accounting is a group concept. Inherent in this concept is the assumption that all property is fully depreciated at the time of retirement, regardless of age, and there is no attempt to record the depreciation applicable to individual components of the groups. The depreciation rates are based on the recognition that each depreciable property group has an average service life. However, very little of the property group is "average". The group carries with it recognition that most property will be retired at an age less than or greater than the average service life. This study recognized the existence of this variation through the identification of Iowa-type retirement dispersions.

The study required to determine the applicable mortality characteristics is independent from the calculation of depreciation rates. The resulting mortality characteristics can be used to calculate either Average Life Group ("ALG") or Equal Life Group ("ELG") rates, both with either the whole life technique or the remaining life technique. Any set of mortality characteristics that is suitable for calculating ALG rates is just as suitable for calculating ELG rates. Conversely, any set that is not suitable for ELG is not suitable for ALG. ALG and ELG are straight-line over life measured by time, with ALG utilizing average life and ELG utilizing actual life. For ALG, all property in the group is assumed to have a life equal to the average life. ELG recognizes that, in reality, only a small

portion of the group retires at an age equal to the average service life. For the average to exist, about half the investment in an asset group will be retired at ages less than average life, a small amount at average life, and the rest at ages greater than average life. It is the use of this dispersion in the rate calculation that causes ELG rates to better match cost recovery with the use and benefit of the property. Thus, the ELG procedure best accomplishes the purpose of book depreciation accounting by ensuring the recording of depreciation provision match the actual consumption of physical assets. Since ELG matches the recording of consumption with actual consumption, customers will pay the actual cost incurred to serve them. The ELG procedure is recommended, consistent with the existing, approved rates. A detailed discussion of the ELG procedure is included in the Appendix A to this report.

THE BOOK DEPRECIATION STUDY

Implementation of a policy toward book depreciation that recognizes the purpose of depreciation accounting requires the determination of the mortality characteristics that are applicable to the surviving property. One purpose of the depreciation study reported here was to accurately measure those mortality characteristics and to use those characteristics to determine appropriate rates for the accrual of depreciation expenses.

The major effort of the study was the determination of the appropriate mortality characteristics. The remainder of this report describes how those characteristics were determined, describes how the mortality characteristics were used to calculate the recommended depreciation rates, and presents the results of the rate calculations.

The typical study consists of the following steps:

Step One is a Life Analysis consisting of the determination of historical experience and an evaluation of the applicability of that experience to surviving property.

Step Two is a Salvage and Cost of Removal Analysis consisting of a study of salvage and cost of removal experience and an evaluation of the applicability of that experience to surviving property.

Step Three consists of the determination of average service lives, retirement dispersion patterns identified by Iowa-type curves and the net salvage factors applicable to the surviving property.

Step Four is the determination of the depreciation rate applicable to each depreciable property group recognizing the results of the work in Steps One through Three, and a comparison with the existing depreciation rates.

LIFE ANALYSIS

The Life Analysis for the property concerns the determination of average service lives ("ASL") and Iowa-type dispersion patterns. An evaluation of investment experience suitably tempered by informed judgment as to the future applicability to surviving property formed the basis for the determination of average service lives and retirement dispersions.

An analysis of historical retirement activity, suitably tempered by informed judgment as to the future applicability of such activity to surviving plant, formed the basis for the determination of average service lives and retirement dispersion patterns for all property groups. For some accounts, retirement experience from transaction years 1950 through 2006 was analyzed using the Actuarial Method of Life Analysis. This method could be used because aged data are available for certain asset categories.

The actuarial method determines actual survivor curves (observed life tables) for selected periods of actual retirement experience. In order to recognize trends in life characteristics and to ensure that the valuable information in the curves is available to the analyst, observed life tables were calculated and plotted by computer, using several different periods of retirement experience. The average service lives and retirement dispersion patterns indicated by the actual survivor curves were identified by visually fitting Iowa-type dispersion curves to the actual curves. Retirement dispersion refers to the pattern of retirements as a function of age over the life of each property group. For each asset category, an Iowa-type curve combined with an estimated average service life was selected. This selection was based upon an analysis of historical investment activity, associated mortality trends and the types of assets surviving and retiring. The workpapers prepared as an integral part of the depreciation study contain the rationale for each selection.

Trends in historical mortality experience are helpful in understanding history. In order to determine trends, the periods (year bands) of retirement experience analyzed were the past five years, the past ten years, the past fifteen years, the past twenty years and the full band of band of retirement experience. The observed life tables and the Iowa curves fitted to each of these year bands were plotted. This visual approach ensures that the data contained in the observed life tables are available to the analyst and that the analyst does not allow the computer calculations to be the sole determinant of study results.

Where the age of retirement was not known, the Simulated Plant Record ("SPR") Method of life analysis was utilized. The SPR method determines retirement dispersion and average service life combinations for various bands of years which best match the actual retirements and balances for each asset category. The simulated balances procedure consists of applying survivor ratios (portion surviving at each age) from Iowa-type dispersion patterns in order to calculate annual balances, and then comparing the calculated balances with the actual balances for several periods, followed by statistical comparisons of differences in balances. The simulated retirements procedure is similar, except that the retirement frequency rates of the Iowa patterns are utilized to calculate annual retirements, and the comparisons are to actual retirements rather than to balances. Tabulations of the best ranking curves were made and this became the starting point for the evaluation phase of my review. In most cases, retirement history for a forty-year period was available.

For accounts having little experience or having retirement experience that is not an adequate measure of the expected mortality characteristics of surviving property, evaluation of the significance of history played a major role in selecting the mortality characteristics shown on Schedule 2.

SALVAGE AND COST OF REMOVAL ANALYSIS

Salvage and cost of removal experience was analyzed using experience from the period 2001 – 2006. Rolling and shrinking bands were analyzed to help expose trends. An evaluation of salvage and cost of removal experience suitably tempered by informed

judgment as to the future applicability to surviving property formed the basis for the determination of salvage and cost of removal factors.

The analysis consisted of calculating salvage and cost of removal factors by relating the recorded salvage and cost of removal for each property group to the retirements that caused the salvage and cost of removal to occur.

EVALUATION OF ACTUAL EXPERIENCE

The typical evaluation consists of Life Analysis and Salvage and Cost of Removal Analysis, which involve the measurement of what has occurred in the past. History is sometimes a misleading indicator of the future. There are many kinds of events that can cause history to be misleading, among them significant changes contemplated in the underlying accounting procedures and/or changes in other management practices, such as maintenance procedures. It is the evaluation phase of a depreciation study that identifies if history is a good indicator of the future. Blind acceptance of history often results in selecting mortality characteristics to use for calculating depreciation rates that will provide recovery over a time period longer than productive life.

For each property group, the typical analysis processes involve only historical investment experience. Since depreciation rates will be applied to surviving property, the historical mortality experience indicated by a Life Analysis and the Salvage and Cost of Removal Analysis is evaluated to ensure that the mortality characteristics used to calculate the

depreciation rates are applicable to the surviving property. The evaluation is required to ensure the validity of the depreciation rates.

The normal evaluation process requires knowledge of the type of property surviving; the type of property retired; the reasons for changing life, dispersion, salvage and cost of removal; and the effect of present and future Atmos plans on the property mortality characteristics.

CALCULATION OF DEPRECIATION RATES

A straight-line remaining life rate for each depreciable property group was calculated using the following formula:

$$\text{Rate} = \frac{\text{Plant Balance} - \text{Future Net Salvage} - \text{Book Reserve}}{\text{Average Remaining Life}}$$

Formula numerator elements in percent of depreciable plant balance and the denominator in years produce a rate in percent. This formula illustrates that a remaining life rate recognizes the book reserve position. The depreciable balances and book reserves were taken from accounting records, and the net salvage factors were determined by the study.

The remaining lives for each property group are a function of the age distribution of surviving plant and the selected average service life and retirement dispersion.

RESULTS

A comparison of the existing depreciation rates to the proposed study depreciation rates can be found on Schedule 1 in this report. A listing, by account, of the existing and the proposed mortality characteristics can be found on Schedule 2 in this report.

Transmission Plant

The depreciation rate for this functional category decreased from 2.99% to 2.87%. Longer lives were offset by negative net salvage. The major investment in this functional category is Account 367, Mains. An average service life of 55 years was selected with an S4 Iowa curve. Net salvage is estimated to be negative 35%. The decrease in annual depreciation expense is $16,543.

Distribution Plant

For this asset grouping, a decrease in the depreciation rate is indicated from 3.59% to 2.79%. Longer lives were offset by negative net salvage. Two accounts comprise the majority of the change in annual depreciation expense, Account 376, Mains and Account 380, Services. An average service life of 55 years with an S4 dispersion, was selected for Account 376. The net salvage allowance is negative 35%. For Account 380, the average service life is 48 years with an R0.5 curve. Net salvage is negative 20%. The decrease in annual depreciation is $2,211,405.

General Plant

There is an increase in depreciation rate indicated for this asset category from 5.15% to 10.63%. Average service life changes are in both directions. The single largest change

in annual depreciation expense is for Account 396, Power Operated Equipment. The recommended average service life is 10 years with an S5 curve. Net salvage is estimated to be 0%. The annual depreciation expense increase is $226,197, and is primarily due to reserve position.

RESERVE COMPARISON

Because remaining life rates are recommended (consistent with the existing rates), a comparison of the accumulated provision for depreciation with the calculated theoretical reserve at September 30, 2006, is not meaningful, and no comparison is presented. This is because the only way a reserve difference can exist is through the use of whole life rates.

RECOMMENDATIONS

Our recommendations for your future action in regard to book depreciation are as follows:

1. The depreciation rates shown in Column 6 of Schedule 1 are applicable to existing property and are recommended for implementation at such time as their effect can be incorporated into service rates.

2. Because of variation of life and net salvage experience with time, a depreciation study should be made during 2011 based upon retirement experience through September 30, 2010. Exact timing of the study should be coordinated with a retail rate case to ensure timely implementation of revised depreciation rates.

3. We recommend that Atmos consider the utilization of a vintage amortization accounting process. This approach has been implemented by numerous utilities all over the country. This approach solves the universal problem of unreported retirements, is intended to simplify the property accounting effort, and provides a better matching of the accounting effort with the magnitude of the asset base.

4. For new asset categories that arise in the future for which no depreciation rate is currently approved, or for asset categories that are presently fully depreciated and may have new assets added in the future, we recommend that the functional composite depreciation rates be used until future depreciation studies are conducted. The functional composite depreciation rates are as follows:

Transmission Plant	2.87%
Distribution Plant	2.79%
General Plant	10.63%

ATMOS ENERGY CORPORATION - TENNESSEE PROPERTIES **SCHEDULE 1**

Book Depreciation Study as of September 30, 2006

Comparison of Depreciation Rates and Annual Amounts

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Account Number	Description	9/30/2006 Balance $	Existing Rate %	Annual Amount $	Study Rate %	Annual Amount $	Increase or (Decrease) $
	TRANSMISSION PLANT						
365.2	Rights of Way	348,971	2.39	8,340	1.50	5,235	(3,106)
366.0	Structures and Improvements	2,679	3.47	93	2.47	66	(27)
367.0	Mains	11,671,967	2.92	340,821	2.84	331,484	(9,338)
369.0	M&R Station Equipment	1,629,191	3.61	58,814	3.36	54,741	(4,073)
	Total Transmission Plant	13,652,808	2.99	408,069	2.87	391,525	(16,543)
	DISTRIBUTION PLANT						
374.2	Rights of Way	641,460	0.00	0	0.49	3,143	3,143
375.0	Structures and Improvements	614,964	2.50	15,374	1.59	9,778	(5,596)
376.0	Mains	151,083,809	3.06	4,623,165	2.33	3,520,253	(1,102,912)
378.0	M&R Station Equipment	6,248,657	3.61	225,577	2.11	131,847	(93,730)
379.0	City Gate Equipment	2,381,748	3.46	82,408	2.96	70,500	(11,909)
380.0	Services	82,529,059	4.29	3,540,497	2.93	2,418,101	(1,122,395)
381.0	Meters	11,069,083	4.04	447,191	5.11	565,630	118,439
382.0	Meter Installations	21,126,176	4.38	925,327	4.79	1,011,944	86,617
383.0	House Regulators	3,088,762	4.38	135,288	1.76	54,362	(80,926)
385.0	Industrial M&R Equipment	323,828	3.88	12,565	3.22	10,427	(2,137)
	Total Distribution Plant	279,107,546	3.59	10,007,390	2.79	7,795,985	(2,211,405)
	GENERAL PLANT						
390.0	Structures and Improvements	1,014,374	2.52	25,562	2.16	21,910	(3,652)
391.0	Office Furniture and Equipment	569,786	5.69	32,421	6.40	36,466	4,045
393.0	Stores Equipment	25,154	7.15	1,799	1.73	435	(1,363)
394.0	Tools, Shop and Garage Equipment	720,715	4.02	28,973	12.62	90,954	61,981
396.0	Power Operated Equipment	397,306	11.11	44,141	36.50	145,017	100,876
397.0	Communication Equipment	503,915	7.49	37,743	6.00	30,235	(7,508)
398.0	Miscellaneous Equipment	882,304	4.40	38,821	12.68	111,876	73,055
399.0	Other Tangible Property*	18,299	18.68	3,418	11.92	2,181	(1,237)
	Total General Plant	4,131,853	5.15	212,878	10.63	439,075	226,197
	Total Depreciable Plant	296,892,207	3.58	10,628,337	2.91	8,626,586	(2,001,751)
	Fully Depreciated	1,852,336					
	Intangible Plant	241,284					
	Land	921,227					
	Total Gas Plant	299,907,054					

*** - Composite Existing Depreciation Rate.**

ATMOS ENERGY CORPORATION - TENNESSEE PROPERTIES **SCHEDULE 2**

Book Depreciation Study as of September 30, 2006

Comparison of Mortality Characteristics

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		EXISTING		RECOMMENDED					
Account Number	Description	ASL yrs.	Net Salvage %	ASL	Iowa Curve yrs.	Gross Salvage %	COR %	Net Salvage %	COR Rate %
	TRANSMISSION PLANT								
365.2	Rights of Way	44.0	0.0	65.0	R5	0	0	0	
366.0	Structures and Improvements	29.7	0.0	30.0	SQ	0	0	0	
367.0	Mains	44.0	(16.1)	55.0	S4	0	35	(35)	0.64
369.0	M&R Station Equipment	29.7	(4.0)	40.0	R2	0	5	(5)	0.13
	DISTRIBUTION PLANT								
374.2	Rights of Way	-	-	65.0	R5	0	0	0	
375.0	Structures and Improvements	40.0	2.5	45.0	R5	0	0	0	
376.0	Mains	42.3	(16.1)	55.0	S4	0	35	(35)	0.64
378.0	M&R Station Equipment	29.7	(4.0)	40.0	R2	0	5	(5)	0.13
379.0	City Gate Equipment	29.7	0.0	40.0	R2	0	5	(5)	0.13
380.0	Services	37.9	(39.5)	48.0	R0.5	0	20	(20)	0.42
381.0	Meters	26.4	4.1	36.0	R2.5	0	55	(55)	1.53
382.0	Meter Installations	30.4	(13.6)	40.0	R1	0	55	(55)	1.38
383.0	House Regulators	30.4	(13.6)	40.0	R3	0	0	0	
385.0	Industrial M&R Equipment	29.7	(11.0)	40.0	R2	0	5	(5)	0.13
	GENERAL PLANT								
390.0	Structures and Improvements	32.0	0.0	40.0	R3	5	5	0	0.13
391.0	Office Furniture and Equipment	18.6	(0.2)	20.0	S6	0	0	0	
393.0	Stores Equipment	25.0	0.0	35.0	R1	0	0	0	
394.0	Tools, Shop and Garage Equipment	24.5	3.3	20.0	L1	0	0	0	
396.0	Power Operated Equipment	9.4	5.4	10.0	S5	0	0	0	
397.0	Communication Equipment	15.0	2.1	15.0	S6	0	0	0	
398.0	Miscellaneous Equipment	23.5	(1.9)	10.0	S3	0	0	0	
399.0	Other Tangible Property *	5.1	4.8	6.0	S6	0	0	0	

*** Composite Existing Mortality Characteristics.**

CALCULATION OF EQUAL LIFE GROUP DEPRECIATION RATES

It is the group concept of depreciation that leads to the existence of the ELG procedure for calculating depreciation rates. This concept has been an integral part of utility depreciation accounting practices for many years. Under the group concept, there is no attempt to keep track of the depreciation applicable to individual items of property. This is not surprising, in view of the millions of items making up a utility system. Any item retired is assumed to be fully depreciated, no matter when the retirements occur. The group of property would have some average life. "Average" is the result of an arithmetic calculation, and there is no assurance that any of the property in the group is "average."

The term "average service life" used in the context of book depreciation is well known, and its use in the measurement of the mortality characteristics of property carries with it the concept of retirement dispersion. If every item was average, thereby having exactly the same life, there would be no dispersion. The concept of retirement dispersion recognizes that some items in a group live to an age less than average service life, and other items live longer than the average. Retirement dispersion is often identified by standard patterns.

The Iowa type dispersion patterns that are widely used by electric and gas utilities were devised empirically about 60 years ago to provide a set of standard definitions of retirement dispersion patterns. Figure 1 shows the dispersion patterns for three of these curves. The L series indicates the mode is to the Left of average service life, the R series to the Right, and the S series at average service life, and therefore, Symmetrical. There is also an O series which has the mode at the Origin, thereby identifying a retirement pattern that has the maximum percentage of original installations retired during the year of placement.

The subscripts on Figure 1 indicate the range of dispersion, with the high number (4) indicating a narrow dispersion, and the low number (1) indicating a wide dispersion pattern. For example, the R1 curve shown on the Figure indicates retirements start immediately and some of the property will last twice as long as the average service life. The dispersion patterns translate to survivor curves, which are the most widely recognized form of the Iowa curves. Other families of patterns exist, but are not as widely used as the Iowa type.

The methods of calculating depreciation rates are categorized as straight-line and non-straight-line. Non-straight-line methods can be accelerated or deferred. There are three basic procedures for calculating straight-line book depreciation rates:

Units-of-Production
Average Life Group (ALG)
Equal Life Group (ELG)

Each of these procedures can be calculated using either the whole life or the remaining life technique.

Productive life may be identified by (a) a life span or (b) a pattern of production or usage. Units-of-Production is straight-line over production or usage, while the others are straight-line over life measured by time. ALG is straight-line over the average life of the group, while ELG is straight-line over the actual life of the group.

The formulas for the whole life and remaining life techniques are shown on Table 1. For the ELG calculation procedure, Formulas 1 and 3 are applied to the individual equal life components of the property group. For the ALG calculation, the formulas are applied to the property group itself. Formula 2 is applied to the property group for either ELG or ALG. Use of the units (percent and years) in the formulas results in rates as a percent of the depreciable plant balance.

The depreciable plant balance is the surviving balance at the time the rate is calculated, and is expressed as a percentage (always 100) of itself. Salvage and reserves are expressed as a percent of the depreciable plant balance. For example, a property group having a 35 year average service life and negative 5% salvage would have an ALG whole life rate of (100 + 5)/35, or 3.00%.

The first term in Formula 2 is identical to Formula 1 for the whole life rate. The second term of Formula 2 illustrates that the difference between a remaining life rate and whole life rate is the allocation of the difference between the book and calculated theoretical reserves over the remaining life by a remaining life rate.

The widely used ALG procedure of depreciation rate calculation does not recognize the existence of retirement dispersion in the calculation. The difference between the ALG and ELG procedure is the recognition of retirement dispersion in the ELG rate calculation. ELG is a rate calculation procedure: nothing more. The data required to make the ELG calculation are average service life, retirement dispersion, net salvage and the age distribution of the property. The depreciation study required to determine the applicable mortality characteristics is independent from the calculation of the depreciation rates. The resulting mortality characteristics can be used to calculate either ALG or ELG rates, both with either the whole life technique or the remaining life technique. Any set of mortality characteristics that is suitable for calculating ALG rates is just as suitable for calculating ELG rates. Conversely, any set that is not suitable for ELG is not suitable for ALG either. The ELG procedure calculates the depreciation rates based on the expected life of each equal life component of the property rather than the average of all components. As discussed earlier, "average" is the result of a calculation and there may not be any "average" property. When curves are used to define retirement dispersion, the average service life and the retirement dispersion pattern define the equal life groups and the expected life applicable to each group.

When retirement dispersion does not exist, the ELG rate is identical to the ALG rate. When dispersion exists, the ELG rate for recently installed property is higher than the ALG rate and for old property is lower.

A Simple Illustration of ELG

This illustration provides a framework for visualizing the ELG methodology. Table 2 assumes 20% of the $5,000 investment is retired at the end of each year following placement. The retirement frequencies are shown on Line 7. As shown in Columns 2 through 6, this means $1,000 of investment is retired each year, with the retirement at Age 1 being recovered in its entirety during Year One; at Age 2 in Years One and Two, etc. The depreciation rate applicable to each equal life group is shown on Line 8. The annual provision in dollars for Year One shown in Column 7 is made up of the Age 1 annual amounts shown on Line 1, Columns 2 through 6. As shown on the Table, the annual provision for Age 2 is equal to the annual provision for Age 1 less the amount collected during Year One applicable to the group retired during Year One. Thus, the annual provisions can be thought of as a matrix, with the provision for any given year being produced by a portion of the matrix.

The depreciation rates shown in Column 9 are determined by dividing the annual provisions in Column 7 by the survivors in Column 8. The rate formula shown on Table 2 can also be used to calculate the rates and is used on the Table to illustrate the working of the matrix by calculating the depreciation rates for Year One and Year Three. For Year One, the numerator and denominator both consist of five terms. Each year, the left-hand term of both numerator and denominator drop off. It should be noted that the reverse summation of retirement ratios (starting with Column 6 and moving left on Line 7) is equal to the survivor ratio at the beginning of the period shown in Column 10.

The formula can illustrate how the matrix can be thought of in terms of a depreciation rate. If the multiplier of 100 is incorporated in each element of the numerator of the formula, such as (100 x 0.2)/2, it can be seen that 100/2 is a rate and the retirement frequency (0.2) is a weighting factor. This particular rate (50%) is the one shown for Age 2 property on Line 8, Column 3.

It can be seen that the only data required for the ELG rate calculation are the retirement frequencies for each year. These frequencies are defined by the average service life and the shape of the dispersion pattern.

A Real Illustration of ELG

The depreciation analyst deals with much larger groups of property than appearing on Table 2. Table 3 contains an ELG rate calculation for an actual depreciable property group. The retirement frequencies shown in Column 4 are defined by the 38 year average service life and the L5 Iowa type dispersion pattern. The ALG rate without salvage for this property is 2.632% (100%/38 years), while the ELG rate varies from 2.704% at age 0.5 years to 1.471% at the age just prior to the last retirement, 67.5 years.

The rate listed in Column 5 at each age is the weighted summation of individual rates applicable to that portion of the surviving property that the retirement frequencies in Column 4 indicate will be retired in each following year. The combination of average service life and dispersion pattern means that the first retirement will be from the age 18.5 property during the following year at an age of 19 years; therefore, it will require a rate of 5.263% (1005/19 years). (This example does not have any surviving balance at age 18.5). The last retirement will be from age 67.5 year property; consequently, it will require a rate of 1.471% (100%/68 years). The vintage composite rate shown in Column 5 at age 0.5 years is the weighted summation of rates varying from 5.263% to 1.471%.

Since this example is for a narrow dispersion pattern, the first retirement occurs at age 19 years and the vintage composite rate remains 2.704% at age 19.5 years, because the first retirement drops the 5.263% rate from the summation.

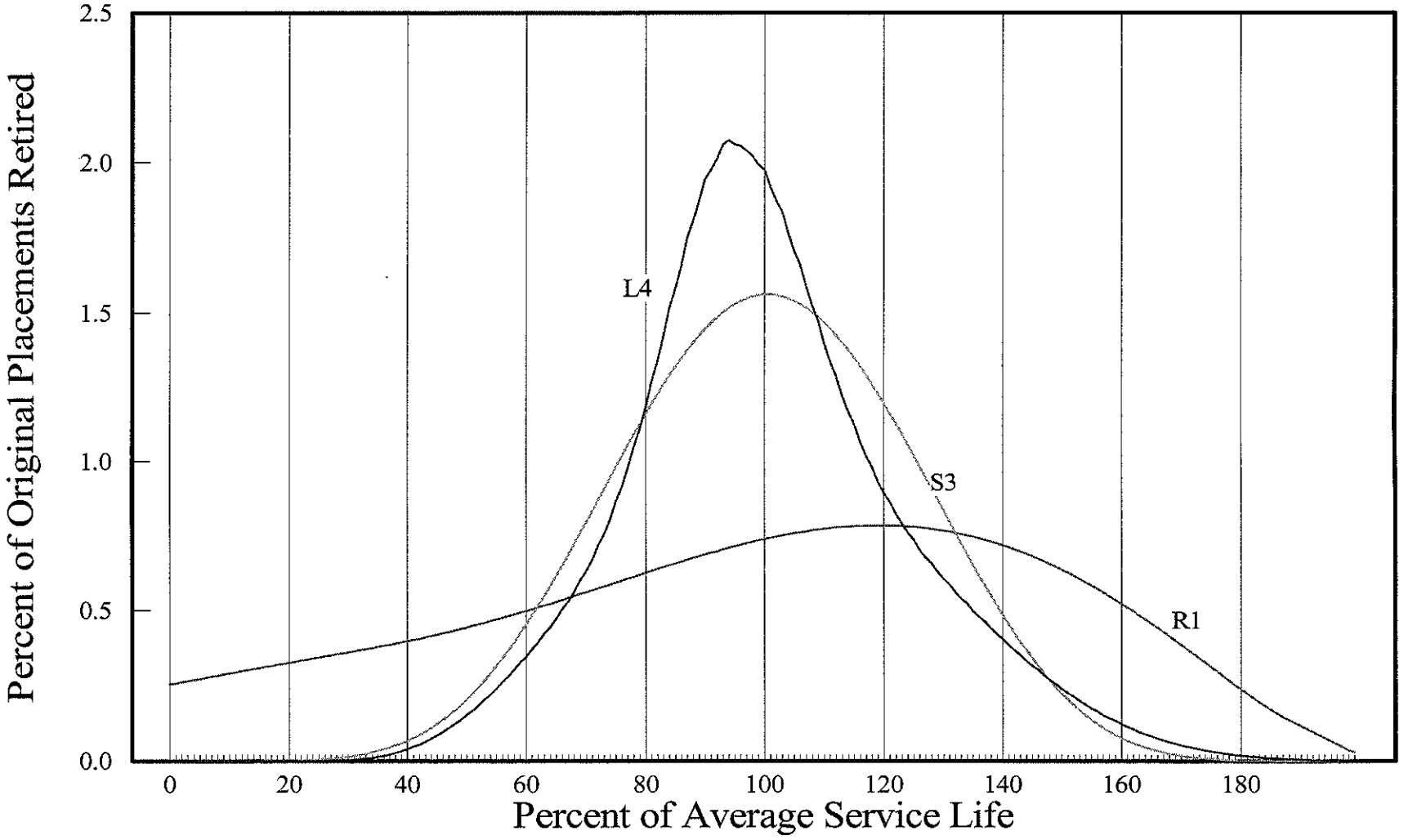
A wider dispersion would result in a wider range of vintage composite rates than defined by the L5 curve (i.e., 2.704% to 1.471%).

All that is necessary for calculating the depreciation rates applicable to each age of property are the retirement frequencies. These frequencies are defined by the average service life and the retirement dispersion pattern. The determination of average service life requires the determination of the dispersion, as without dispersion there would be no "average".

Depending on the dispersion pattern, the number of retirement frequencies making up the complete curve can be up to about 4.4 times the number of years of average service life. Thus, for an account whose number of retirement frequencies is three times average service life and whose average service life is 30 years, the rate applicable to the Age 1 property will be made up of the weighted summation of 89 components, etc. Thus, the rate calculation process is complex, but certainly not complicated. It is this complexity that makes the rate calculations much more practical using a computer.

RETIREMENT DISPERSION DEFINED

BY IOWA TYPE CURVES



DEPRECIATION RATE CALCULATION PROCEDURES

TABLE 1

Whole Life

$$\text{Rate (\%)} = \frac{PB - S}{ASL} \qquad \text{Formula 1}$$

Remaining Life

$$\text{Rate (\%)} = \frac{PB - FS}{ASL} _ \frac{BR - CT}{ARL} \qquad \text{Formula 2}$$

$$\text{Rate (\%)} = \frac{PB - FS - BR}{ARL} \qquad \text{Formula 3}$$

Where

PB	is Depreciable Balance, %
AS	is Average Net Salvage, %
FS	is Future Net Salvage, %
ASL	is Average Service Life, years
BR	is Depreciation Reserve, %
CTR	is Calculated Theoretical Reserve, %
ARL	is Average Remaining Life, years

DEVELOPMENT OF EQUAL LIFE GROUP CAPITAL RECOVERY RATE **TABLE 2**

Line	(1) Age Years	(2) Group 1 $	(3) Group 2 $	(4) Group 3 $	(5) Group 4 $	(6) Group 5 $	(7) Annual Provision $	(8) Beginning Survivors $	(9) Rate %	(10) Survivor Factor
1	1	1,000.00	500.00	333.33	250.00	200.00	2,283.33	5,000.00	45.67	1.00
2	2		500.00	333.33	250.00	200.00	1,283.33	4,000.00	32.08	0.80
3	3			333.33	250.00	200.00	783.33	3,000.00	26.11	0.60
4	4				250.00	200.00	450.00	2,000.00	22.50	0.40
5	5					200.00	200.00	1,000.00	20.00	0.20
6	Retirements	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00				
7	Frequency	0.20	0.20	0.20	0.20	0.20				
8	Rate	100%	50%	33.33%	25%	20%				

$$\text{Rate, \%} = \frac{\text{Retirements} \times \text{Frequencies}}{\text{Reverse of Retirement Frequencies}} \times \frac{\text{Frequencies}}{\text{Age at Retirement}} \times 100$$

$$\text{Year One Rate} = \frac{\frac{0.2}{1} + \frac{0.2}{2} + \frac{0.2}{3} + \frac{0.2}{4} + \frac{0.2}{5}}{0.2 + 0.2 + 0.2 + 0.2 + 0.2} \times 100 = 45.67\%$$

$$\text{Year Three Rate} = \frac{\frac{0.2}{3} + \frac{0.2}{4} + \frac{0.2}{5}}{0.2 + 0.2 + 0.2} \times 100 = 26.11\%$$

DETERMINATION OF DEPRECIATION RATES BY ELG PROCEDURES

[1]	[2]	[3]	[4]	[5]	[6]
Age	Year	Vintage Balance	Retirement Frequency	Rate	Amount
Years		$	ASL 38 Curve L5		$
0.5	1993	4,244,285	0.0000	0.02704	114,758.36
1.5	1992	800,784	0.0000	0.02704	21,651.86
2.5	1991	60,016	0.0000	0.02704	1,622.73
3.5	1990	43,455,063	0.0000	0.02704	1,174,952.00
4.5	1989	81,456	0.0000	0.02704	2,202.43
5.5	1988	172,463	0.0000	0.02704	4,663.11
6.5	1987	2,098,991	0.0000	0.02704	56,753.20
7.5	1986	2,685,949	0.0000	0.02704	72,623.55
9.5	1984	1,642,443	0.0000	0.02704	44,408.90
10.5	1983	222,602	0.0000	0.02704	6,018.78
11.5	1982	85,661	0.0000	0.02704	2,316.13
12.5	1981	4,985	0.0000	0.02704	134.79
13.5	1980	72,942	0.0000	0.02704	1,972.23
14.5	1979	219,163	0.0000	0.02704	5,925.80
15.5	1978	120,665	0.0000	0.02704	3,262.58
16.5	1977	37,042	0.0000	0.02704	1,001.55
17.5	1976	339,236	0.0000	0.02704	9,172.21
19.5	1974	336,723	0.0001	0.02703	9,101.41
20.5	1973	10,375,359	0.0004	0.02702	280,292.86
21.5	1972	4,481,906	0.0009	0.02699	120,963.25
22.5	1971	5,923,340	0.0018	0.02695	159,618.98
23.5	1970	78,848	0.0030	0.02689	2,119.97
24.5	1969	305,178	0.0047	0.02681	8,180.42
25.5	1968	10,312,586	0.0069	0.02670	275,375.94
26.5	1967	2,754,067	0.0094	0.02658	73,203.24
27.5	1966	9,558,786	0.0123	0.02644	252,715.77
29.5	1964	5,556,083	0.0194	0.02610	144,995.54
30.5	1963	23,383	0.0242	0.02589	605.42
31.5	1962	3,313,564	0.0305	0.02566	85,012.50
32.5	1961	32,271	0.0386	0.02538	819.15
33.5	1960	151,658	0.0482	0.02507	3,802.24
34.5	1959	171,483	0.0583	0.02472	4,238.70
35.5	1958	167,116	0.0674	0.02433	4,065.35
36.5	1957	70,420	0.0740	0.02390	1,683.22
37.5	1956	1,792,312	0.0768	0.02345	42,036.33
39.5	1954	2,270,555	0.0701	0.02252	51,131.79
40.5	1953	187	0.0622	0.02206	4.13
41.5	1952	20,185	0.0531	0.02161	436.14
42.5	1951	12,860	0.0442	0.02118	272.40
43.5	1950	706	0.0362	0.02078	14.67
44.5	1949	2,652	0.0296	0.02041	54.13
45.5	1948	6,422	0.0245	0.02006	128.81
46.5	1947	19,573	0.0205	0.01972	386.07
47.5	1946	323,058	0.0173	0.01940	6,268.69
49.5	1944	2,285,041	0.0123	0.01879	42,943.47
50.5	1943	15,614	0.0103	0.01850	288.86
51.5	1942	620,752	0.0085	0.01821	11,306.36
53.5	1940	684,610	0.0055	0.01766	12,090.28
54.5	1939	47,173	0.0043	0.01740	820.76
55.5	1938	22,725	0.0033	0.01714	389.52
56.5	1937	560	0.0025	0.01689	9.46
57.5	1936	722	0.0019	0.01664	12.02
59.5	1934	3,065	0.0005	0.01573	48.21
61.5	1932	944,400	0.0005	0.01573	14,853.98
67.5	1926	2	0.0000	0.01471	0.03
Totals		119,029,691			3,133,730.27
			SALVAGE (%) =		-5.0
			AFTER SALVAGE =		3,290,417
		ANNUAL DEPRECIATION RATE =			2.76

EXHIBIT
DSR-4

Atmos Energy Corporation

Book Depreciation Study of
Atmos Energy Corporation
Shared Services Properties
As of September 30, 2006

December 2006

Atmos Energy Corporation
Three Lincoln Center
5430 LBJ Freeway
Dallas, TX 75240

Attention: Mr. Thomas Petersen

In accordance with your request and with the cooperation and participation of your staff, a book depreciation study of Atmos Energy Corporation's Shared Services ("SSU") properties ("Atmos" or "the Company") has been conducted. The study covered all depreciable and amortizable property and recognized addition and retirement experience through September 30, 2006. The purpose of the study was to determine if the existing depreciation rates remain appropriate for the property and, if not, to recommend changes. Changes were found to be needed and are recommended. The changes in aggregate cause an increase in depreciation rates used to calculate the annual depreciation expense.

A comparison of the effect of the existing rates and the recommended rates is shown below, based on depreciable plant balances as of September 30, 2006:

Function	Composite Depreciation Rate	
	Existing	Recommended
	%	%
General	9.09	10.32

The summary above is taken from Schedule 1, which shows the annual depreciation amounts calculated from the existing rates and the recommended account rates and the differences. Based upon the September 30, 2006 depreciable balances, the recommended

depreciation rates will result in an annual increase in depreciation provisions of $2,662,501 or 13.5%.

Schedule 2 shows the mortality characteristics used to calculate the recommended depreciation rates. The recommended depreciation rates are straight-line over life measured by time using the equal life group (ELG) procedure and the remaining life technique, consistent with the existing, approved rates.

The following sections of this report describe the methods of analysis used and the bases for the conclusions reached. The remainder of the report will present the results and recommendations for both immediate and future actions by the Company.

We appreciate this opportunity to serve Atmos Energy Corporation and would be pleased to meet with you to discuss further the matters presented in this report, if you desire.

Yours truly,

President

Depreciation Specialty Resources

PURPOSE OF DEPRECIATION

Book depreciation accounting is the process of recognizing in financial statements the consumption of physical assets in the process of providing a service or a product. Generally accepted accounting principles require the recording of depreciation to be systematic and rational. To be systematic and rational, depreciation should, to the extent possible, match either the consumption of the facilities or the revenues generated by the facilities. Accounting theory requires the matching of expenses with either consumption or revenues to ensure that financial statements reflect the results of operations and changes in financial position as accurately as possible. The matching principle is often referred to as the "cause and effect" principle; thus, both the cause and the effect are required to be recognized for financial accounting purposes. This study was conducted in a manner consistent with the matching principle of accounting.

Because utility revenues are determined through regulation, and this study assumes that such regulation will continue, asset consumption is not automatically in revenues. Therefore, the consumption of utility assets must be measured directly by conducting a book depreciation study to accurately determine the mortality characteristics of the assets.

Matching is also an essential element of basic regulatory philosophy, and it has become known as "intergenerational customer equity". Intergenerational customer equity means the costs are borne by the generation of customers that caused them to be incurred, not by some earlier or later generation. This matching is required to ensure that the charges to customers reflect the actual costs of providing service.

DEPRECIATION DEFINTIONS

The Uniform System of Accounts ("USOA") prescribed for gas utilities by the Federal Energy Regulatory Commission ("FERC") followed by Atmos states that:

> "Depreciation", as applied to depreciable gas plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities, and in the case of natural gas companies, the exhaustion of natural resources.
>
> "Service value" means the difference between original cost and net salvage value of gas plant.
>
> "Net salvage value" means the salvage value of property retired less the cost of removal.
>
> "Salvage value" means the amount received for the property retired, less any expenses incurred in connection with the sale or in preparing the property for sale or, if retained, the amount at which the material is chargeable to materials and supplies, or other appropriate account.
>
> "Cost of removal" means the cost of demolishing, dismantling, tearing down or otherwise removing gas plant, including the cost of transportation and handling incidental thereto.

As is clear from the wording of the salvage value and the cost of removal definitions, it is the salvage that will actually be received and the cost of removal that will actually be incurred, both measured at the price level at the time of receipt or incurrence that is required to be recognized in the depreciation rates of Atmos.

These definitions are consistent with the purpose of depreciation, and the study reported here was conducted in a manner consistent with both.

ACCOMPLISHMENT OF ACCOUNTING AND REGULATORY PRINCIPLES

Utility depreciation accounting is a group concept. Inherent in this concept is the assumption that all property is fully depreciated at the time of retirement, regardless of age, and there is no attempt to record the depreciation applicable to individual components of the groups. The depreciation rates are based on the recognition that each depreciable property group has an average service life. However, very little of the property group is "average". The group carries with it recognition that most property will be retired at an age less than or greater than the average service life. This study recognized the existence of this variation through the identification of Iowa-type retirement dispersions.

The study required to determine the applicable mortality characteristics is independent from the calculation of depreciation rates. The resulting mortality characteristics can be used to calculate either Average Life Group ("ALG") or Equal Life Group ("ELG") rates, both with either the whole life technique or the remaining life technique. Any set of mortality characteristics that is suitable for calculating ALG rates is just as suitable for calculating ELG rates. Conversely, any set that is not suitable for ELG is not suitable for ALG. ALG and ELG are straight-line over life measured by time, with ALG utilizing average life and ELG utilizing actual life. For ALG, all property in the group is assumed to have a life equal to the average life. ELG recognizes that, in reality, only a small

portion of the group retires at an age equal to the average service life. For the average to exist, about half the investment in an asset group will be retired at ages less than average life, a small amount at average life, and the rest at ages greater than average life. It is the use of this dispersion in the rate calculation that causes ELG rates to better match cost recovery with the use and benefit of the property. Thus, the ELG procedure best accomplishes the purpose of book depreciation accounting by ensuring the recording of depreciation provision match the actual consumption of physical assets. Since ELG matches the recording of consumption with actual consumption, customers will pay the actual cost incurred to serve them. The ELG procedure is recommended, consistent with the existing, approved rates. A detailed discussion of the ELG procedure is included in the Appendix A to this report.

THE BOOK DEPRECIATION STUDY

Implementation of a policy toward book depreciation that recognizes the purpose of depreciation accounting requires the determination of the mortality characteristics that are applicable to the surviving property. One purpose of the depreciation study reported here was to accurately measure those mortality characteristics and to use those characteristics to determine appropriate rates for the accrual of depreciation expenses.

The major effort of the study was the determination of the appropriate mortality characteristics. The remainder of this report describes how those characteristics were determined, describes how the mortality characteristics were used to calculate the recommended depreciation rates, and presents the results of the rate calculations.

The typical study consists of the following steps:

> Step One is a Life Analysis consisting of the determination of historical experience and an evaluation of the applicability of that experience to surviving property.
>
> Step Two is a Salvage and Cost of Removal Analysis consisting of a study of salvage and cost of removal experience and an evaluation of the applicability of that experience to surviving property.
>
> Step Three consists of the determination of average service lives, retirement dispersion patterns identified by Iowa-type curves and the net salvage factors applicable to the surviving property.
>
> Step Four is the determination of the depreciation rate applicable to each depreciable property group recognizing the results of the work in Steps One through Three, and a comparison with the existing depreciation rates.

LIFE ANALYSIS

The Life Analysis for the property concerns the determination of average service lives ("ASL") and Iowa-type dispersion patterns. An evaluation of investment experience suitably tempered by informed judgment as to the future applicability to surviving property formed the basis for the determination of average service lives and retirement dispersions.

An analysis of historical retirement activity, suitably tempered by informed judgment as to the future applicability of such activity to surviving plant, formed the basis for the determination of average service lives and retirement dispersion patterns for all property groups. Retirement experience from transaction years 1987 through 2006 were analyzed using the Actuarial Method of Life Analysis. This method could be used because aged data are available for certain asset categories.

The actuarial method determines actual survivor curves (observed life tables) for selected periods of actual retirement experience. In order to recognize trends in life characteristics and to ensure that the valuable information in the curves is available to the analyst, observed life tables were calculated and plotted by computer, using several different periods of retirement experience. The average service lives and retirement dispersion patterns indicated by the actual survivor curves were identified by visually fitting Iowa-type dispersion curves to the actual curves. Retirement dispersion refers to the pattern of retirements as a function of age over the life of each property group. For each asset category, an Iowa-type curve combined with an estimated average service life was selected. This selection was based upon an analysis of historical investment activity, associated mortality trends and the types of assets surviving and retiring. The workpapers prepared as an integral part of the depreciation study contain the rationale for each selection.

Trends in historical mortality experience are helpful in understanding history. In order to determine trends, the periods (year bands) of retirement experience analyzed were the past five years, the past ten years, the past fifteen years, the past twenty years and the full band of band of retirement experience. The observed life tables and the Iowa curves fitted to each of these year bands were plotted. This visual approach ensures that the data contained in the observed life tables are available to the analyst and that the analyst does not allow the computer calculations to be the sole determinant of study results.

For accounts having little experience or having retirement experience that is not an adequate measure of the expected mortality characteristics of surviving property, evaluation of the significance of history played a major role in selecting the mortality characteristics shown on Schedule 2.

SALVAGE AND COST OF REMOVAL ANALYSIS

Salvage and cost of removal experience was analyzed using experience from the period 1993 – 2006. Rolling and shrinking bands were analyzed to help expose trends. An evaluation of salvage and cost of removal experience suitably tempered by informed judgment as to the future applicability to surviving property formed the basis for the determination of salvage and cost of removal factors.

The analysis consisted of calculating salvage and cost of removal factors by relating the recorded salvage and cost of removal for each property group to the retirements that caused the salvage and cost of removal to occur.

EVALUATION OF ACTUAL EXPERIENCE

The typical evaluation consists of Life Analysis and Salvage and Cost of Removal Analysis, which involve the measurement of what has occurred in the past. History is sometimes a misleading indicator of the future. There are many kinds of events that can cause history to be misleading, among them significant changes contemplated in the underlying accounting procedures and/or changes in other management practices, such as maintenance procedures. It is the evaluation phase of a depreciation study that identifies

if history is a good indicator of the future. Blind acceptance of history often results in selecting mortality characteristics to use for calculating depreciation rates that will provide recovery over a time period longer than productive life.

For each property group, the typical analysis processes involve only historical investment experience. Since depreciation rates will be applied to surviving property, the historical mortality experience indicated by a Life Analysis and the Salvage and Cost of Removal Analysis is evaluated to ensure that the mortality characteristics used to calculate the depreciation rates are applicable to the surviving property. The evaluation is required to ensure the validity of the depreciation rates.

The normal evaluation process requires knowledge of the type of property surviving; the type of property retired; the reasons for changing life, dispersion, salvage and cost of removal; and the effect of present and future Atmos plans on the property mortality characteristics.

CALCULATION OF DEPRECIATION RATES

A straight-line remaining life rate for each depreciable property group was calculated using the following formula:

$$\text{Rate} = \frac{\text{Plant Balance} - \text{Future Net Salvage} - \text{Book Reserve}}{\text{Average Remaining Life}}$$

Formula numerator elements in percent of depreciable plant balance and the denominator in years produce a rate in percent. This formula illustrates that a remaining life rate recognizes the book reserve position. The depreciable balances and book reserves were taken from accounting records, and the net salvage factors were determined by the study.

The remaining lives for each property group are a function of the age distribution of surviving plant and the selected average service life and retirement dispersion.

RESULTS

A comparison of the existing depreciation rates to the proposed study depreciation rates can be found on Schedule 1 in this report. A listing, by account, of the existing and the proposed mortality characteristics can be found on Schedule 2 in this report.

General Plant

There is an increase in the depreciation rate indicated for this asset category from 9.09% to 10.32%. Average service life changes are an increase for all accounts except two. The single largest change in annual depreciation expense is for Account 399.08, Application Software. The recommended average service life is 10 years with an S3 curve. Net salvage is estimated to be 0%. The annual depreciation expense increase is $3,217,244, and is primarily due to reserve position. There are two other significant changes in depreciation expense occurring for Account 399.01, Server Software and Account 399.24, General Start-up Costs. There is a decrease in annual depreciation expense for Account 399.01 of $1,069,241, due to a longer average service life. There is an increase

in annual depreciation expense for Account 399.24 of $1,751,828, due to reserve position.

RESERVE COMPARISON

Because remaining life rates are recommended (consistent with the existing rates), a comparison of the accumulated provision for depreciation with the calculated theoretical reserve at September 30, 2006, is not meaningful, and no comparison is presented. This is because the only way a reserve difference can exist is through the use of whole life rates.

RECOMMENDATIONS

Our recommendations for your future action in regard to book depreciation are as follows:

1. The depreciation rates shown in Column 6 of Schedule 1 are applicable to existing property and are recommended for implementation at such time as their effect can be incorporated into service rates.

2. Because of variation of life and net salvage experience with time, a depreciation study should be made during 2011 based upon retirement experience through September 30, 2010. Exact timing of the study should be coordinated with a retail rate case to ensure timely implementation of revised depreciation rates.

3. We recommend that Atmos consider the utilization of a vintage amortization accounting process. This approach has been implemented by numerous utilities all over the country. This approach solves the universal problem of unreported retirements, is intended to simplify the property accounting effort, and provides a better matching of the accounting effort with the magnitude of the asset base.

4. For new asset categories that arise in the future for which no depreciation rate is currently approved, or for asset categories that are presently fully depreciated and may have new assets added in the future, we recommend that the functional composite depreciation rates be used until future depreciation studies are conducted. The functional composite depreciation rate is as follows:

General Plant	10.32%

ATMOS ENERGY CORPORATION - SHARED SERVICES **SCHEDULE 1**

Book Depreciation Study as of September 30, 2006

Comparison of Depreciation Rates and Annual Amounts

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Account Number	Description	9/30/2006 Balance $	Existing Rates %	Annual Amount $	Study Rates %	Annual Amount $	Increase or (Decrease) $
	GENERAL PLANT						
390.09	Improvements to Leased Premises	9,949,143	7.43	739,221	9.10	905,372	166,151
391.00	Office Furniture and Equipment	9,074,352	4.89	443,736	2.13	193,284	(250,452)
397.00	Communication Equipment	25,311,861	7.12	1,802,205	8.45	2,138,852	336,648
398.00	Miscellaneous Equipment	633,466	5.36	33,954	8.15	51,627	17,674
399.00	Other Tangible Property	224,866	15.75	35,416	4.66	10,479	(24,938)
399.01	Servers Hardware	14,567,322	14.29	2,081,670	6.95	1,012,429	(1,069,241)
399.02	Servers Software	8,647,580	14.29	1,235,739	4.00	345,903	(889,836)
399.03	Network Hardware	2,377,029	14.29	339,677	9.30	221,064	(118,614)
399.06	PC Hardware	6,691,156	16.83	1,126,122	14.86	994,306	(131,816)
399.07	PC Software	3,928,199	17.73	696,470	9.02	354,324	(342,146)
399.08	Application Software	111,323,312	8.22	9,150,776	11.11	12,368,020	3,217,244
399.24	General Startup Cost	23,172,326	8.33	1,930,255	15.89	3,682,083	1,751,828
	Total Depreciable General Plant	215,900,612	9.09	19,615,241	10.32	22,277,742	2,662,501
	Fully Depreciated	5,331,910					
	Late Retirements	4,363,383					
	Total Shared Services Facilities	225,595,905					

ATMOS ENERGY CORPORATION - SHARED SERVICES **SCHEDULE 2**

Book Depreciation Study as of September 30, 2006

Comparison of Mortality Characteristics

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		EXISTING PARAMETERS			STUDY PARAMETERS				
Account Number	Description	ASL yrs.	Iowa Curve	Net Salvage %	ASL yrs.	Iowa Curve	Gross Salvage %	Cost of Removal %	Net Salvage %
	GENERAL PLANT								
390.09	Improvements to Leased Premises	10.0	SQ	0	12.0	S4	0	0	0
391.00	Office Furniture and Equipment (Gnl)	30.0	R2	0	25.0	R4	0	0	0
397.00	Communication Equipment	10.0	L3	0	12.0	S5	0	0	0
398.00	Miscellaneous Equipment	10.0	S6	5	15.0	S3	5	0	5
399.00	Other Tangible Property	5.0	SQ	0	7.0	R5	0	0	0
399.01	Servers Hardware	5.0	SQ	0	10.0	SQ	0	0	0
399.02	Servers Software	5.0	SQ	0	10.0	SQ	0	0	0
399.03	Network Hardware	5.0	SQ	0	10.0	SQ	0	0	0
399.06	PC Hardware	4.0	SQ	0	7.0	S1	0	0	0
399.07	PC Software	4.0	SQ	0	8.5	R5	0	0	0
399.08	Application Software	8.0	S1.5	0	10.0	S3	0	0	0
399.24	General Startup Cost	10.0	SQ	0	10.0	SQ	0	0	0

CALCULATION OF EQUAL LIFE GROUP DEPRECIATION RATES

It is the group concept of depreciation that leads to the existence of the ELG procedure for calculating depreciation rates. This concept has been an integral part of utility depreciation accounting practices for many years. Under the group concept, there is no attempt to keep track of the depreciation applicable to individual items of property. This is not surprising, in view of the millions of items making up a utility system. Any item retired is assumed to be fully depreciated, no matter when the retirements occur. The group of property would have some average life. "Average" is the result of an arithmetic calculation, and there is no assurance that any of the property in the group is "average."

The term "average service life" used in the context of book depreciation is well known, and its use in the measurement of the mortality characteristics of property carries with it the concept of retirement dispersion. If every item was average, thereby having exactly the same life, there would be no dispersion. The concept of retirement dispersion recognizes that some items in a group live to an age less than average service life, and other items live longer than the average. Retirement dispersion is often identified by standard patterns.

The Iowa type dispersion patterns that are widely used by electric and gas utilities were devised empirically about 60 years ago to provide a set of standard definitions of retirement dispersion patterns. Figure 1 shows the dispersion patterns for three of these curves. The L series indicates the mode is to the Left of average service life, the R series to the Right, and the S series at average service life, and therefore, Symmetrical. There is also an O series which has the mode at the Origin, thereby identifying a retirement pattern that has the maximum percentage of original installations retired during the year of placement.

The subscripts on Figure 1 indicate the range of dispersion, with the high number (4) indicating a narrow dispersion, and the low number (1) indicating a wide dispersion pattern. For example, the R1 curve shown on the Figure indicates retirements start immediately and some of the property will last twice as long as the average service life. The dispersion patterns translate to survivor curves, which are the most widely recognized form of the Iowa curves. Other families of patterns exist, but are not as widely used as the Iowa type.

The methods of calculating depreciation rates are categorized as straight-line and non-straight-line. Non-straight-line methods can be accelerated or deferred. There are three basic procedures for calculating straight-line book depreciation rates:

Units-of-Production
Average Life Group (ALG)
Equal Life Group (ELG)

Each of these procedures can be calculated using either the whole life or the remaining life technique.

Productive life may be identified by (a) a life span or (b) a pattern of production or usage. Units-of-Production is straight-line over production or usage, while the others are straight-line over life measured by time. ALG is straight-line over the average life of the group, while ELG is straight-line over the actual life of the group.

The formulas for the whole life and remaining life techniques are shown on Table 1. For the ELG calculation procedure, Formulas 1 and 3 are applied to the individual equal life components of the property group. For the ALG calculation, the formulas are applied to the property group itself. Formula 2 is applied to the property group for either ELG or ALG. Use of the units (percent and years) in the formulas results in rates as a percent of the depreciable plant balance.

The depreciable plant balance is the surviving balance at the time the rate is calculated, and is expressed as a percentage (always 100) of itself. Salvage and reserves are expressed as a percent of the depreciable plant balance. For example, a property group having a 35 year average service life and negative 5% salvage would have an ALG whole life rate of (100 + 5)/35, or 3.00%.

The first term in Formula 2 is identical to Formula 1 for the whole life rate. The second term of Formula 2 illustrates that the difference between a remaining life rate and whole life rate is the allocation of the difference between the book and calculated theoretical reserves over the remaining life by a remaining life rate.

The widely used ALG procedure of depreciation rate calculation does not recognize the existence of retirement dispersion in the calculation. The difference between the ALG and ELG procedure is the recognition of retirement dispersion in the ELG rate calculation. ELG is a rate calculation procedure: nothing more. The data required to make the ELG calculation are average service life, retirement dispersion, net salvage and the age distribution of the property. The depreciation study required to determine the applicable mortality characteristics is independent from the calculation of the depreciation rates. The resulting mortality characteristics can be used to calculate either ALG or ELG rates, both with either the whole life technique or the remaining life technique. Any set of mortality characteristics that is suitable for calculating ALG rates is just as suitable for calculating ELG rates. Conversely, any set that is not suitable for ELG is not suitable for ALG either. The ELG procedure calculates the depreciation rates based on the expected life of each equal life component of the property rather than the average of all components. As discussed earlier, "average" is the result of a calculation and there may not be any "average" property. When curves are used to define retirement dispersion, the average service life and the retirement dispersion pattern define the equal life groups and the expected life applicable to each group.

When retirement dispersion does not exist, the ELG rate is identical to the ALG rate. When dispersion exists, the ELG rate for recently installed property is higher than the ALG rate and for old property is lower.

A Simple Illustration of ELG

This illustration provides a framework for visualizing the ELG methodology. Table 2 assumes 20% of the $5,000 investment is retired at the end of each year following placement. The retirement frequencies are shown on Line 7. As shown in Columns 2 through 6, this means $1,000 of investment is retired each year, with the retirement at Age 1 being recovered in its entirety during Year One; at Age 2 in Years One and Two, etc. The depreciation rate applicable to each equal life group is shown on Line 8. The annual provision in dollars for Year One shown in Column 7 is made up of the Age 1 annual amounts shown on Line 1, Columns 2 through 6. As shown on the Table, the annual provision for Age 2 is equal to the annual provision for Age 1 less the amount collected during Year One applicable to the group retired during Year One. Thus, the annual provisions can be thought of as a matrix, with the provision for any given year being produced by a portion of the matrix.

The depreciation rates shown in Column 9 are determined by dividing the annual provisions in Column 7 by the survivors in Column 8. The rate formula shown on Table 2 can also be used to calculate the rates and is used on the Table to illustrate the working of the matrix by calculating the depreciation rates for Year One and Year Three. For Year One, the numerator and denominator both consist of five terms. Each year, the left-hand term of both numerator and denominator drop off. It should be noted that the reverse summation of retirement ratios (starting with Column 6 and moving left on Line 7) is equal to the survivor ratio at the beginning of the period shown in Column 10.

The formula can illustrate how the matrix can be thought of in terms of a depreciation rate. If the multiplier of 100 is incorporated in each element of the numerator of the formula, such as (100 x 0.2)/2, it can be seen that 100/2 is a rate and the retirement frequency (0.2) is a weighting factor. This particular rate (50%) is the one shown for Age 2 property on Line 8, Column 3.

It can be seen that the only data required for the ELG rate calculation are the retirement frequencies for each year. These frequencies are defined by the average service life and the shape of the dispersion pattern.

A Real Illustration of ELG

The depreciation analyst deals with much larger groups of property than appearing on Table 2. Table 3 contains an ELG rate calculation for an actual depreciable property group. The retirement frequencies shown in Column 4 are defined by the 38 year average service life and the L5 Iowa type dispersion pattern. The ALG rate without salvage for this property is 2.632% (100%/38 years), while the ELG rate varies from 2.704% at age 0.5 years to 1.471% at the age just prior to the last retirement, 67.5 years.

The rate listed in Column 5 at each age is the weighted summation of individual rates applicable to that portion of the surviving property that the retirement frequencies in Column 4 indicate will be retired in each following year. The combination of average service life and dispersion pattern means that the first retirement will be from the age 18.5 property during the following year at an age of 19 years; therefore, it will require a rate of 5.263% (1005/19 years). (This example does not have any surviving balance at age 18.5). The last retirement will be from age 67.5 year property; consequently, it will require a rate of 1.471% (100%/68 years). The vintage composite rate shown in Column 5 at age 0.5 years is the weighted summation of rates varying from 5.263% to 1.471%.

Since this example is for a narrow dispersion pattern, the first retirement occurs at age 19 years and the vintage composite rate remains 2.704% at age 19.5 years, because the first retirement drops the 5.263% rate from the summation.

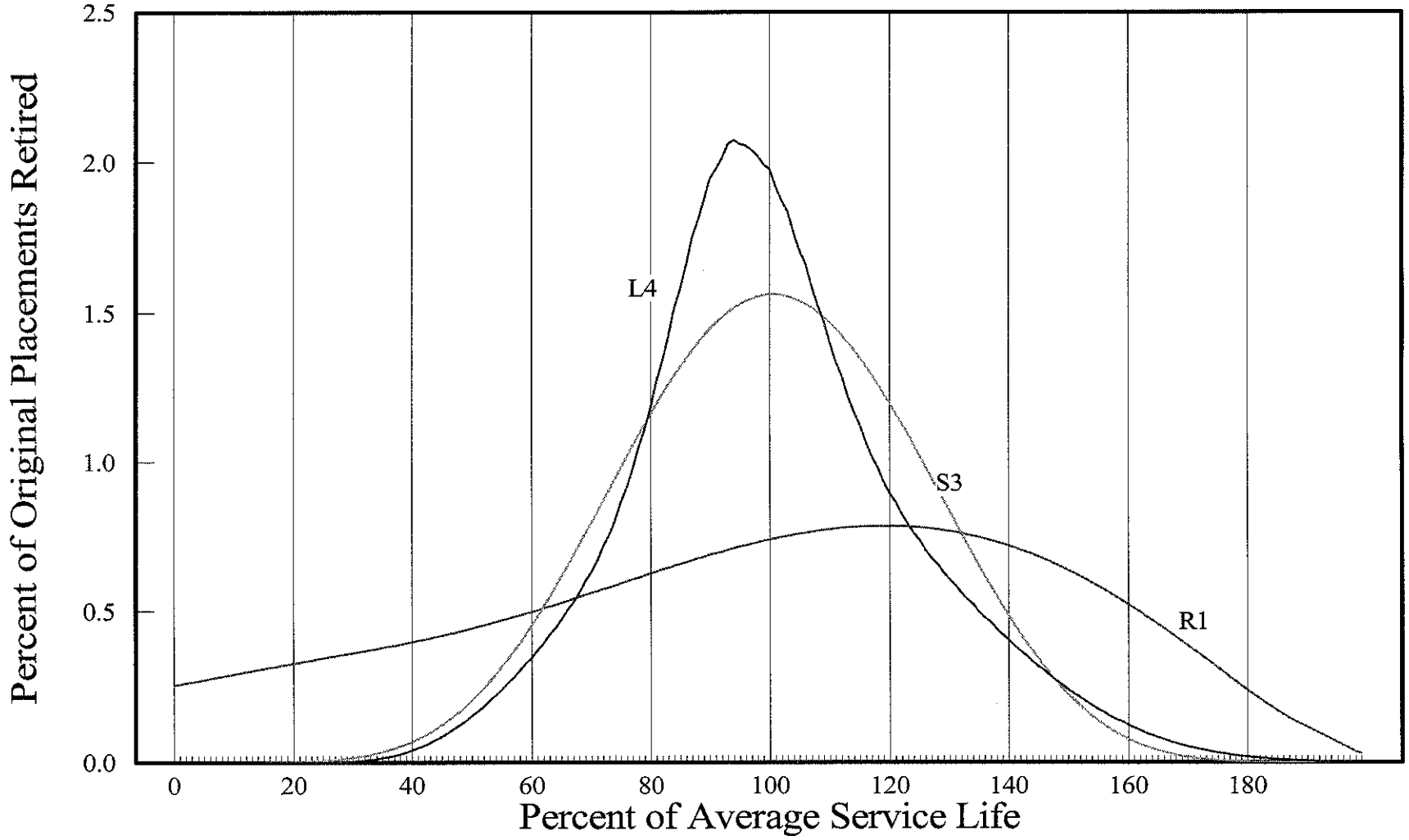
A wider dispersion would result in a wider range of vintage composite rates than defined by the L5 curve (i.e., 2.704% to 1.471%).

All that is necessary for calculating the depreciation rates applicable to each age of property are the retirement frequencies. These frequencies are defined by the average service life and the retirement dispersion pattern. The determination of average service life requires the determination of the dispersion, as without dispersion there would be no "average".

Depending on the dispersion pattern, the number of retirement frequencies making up the complete curve can be up to about 4.4 times the number of years of average service life. Thus, for an account whose number of retirement frequencies is three times average service life and whose average service life is 30 years, the rate applicable to the Age 1 property will be made up of the weighted summation of 89 components, etc. Thus, the rate calculation process is complex, but certainly not complicated. It is this complexity that makes the rate calculations much more practical using a computer.

RETIREMENT DISPERSION DEFINED

BY IOWA TYPE CURVES



DEPRECIATION RATE CALCULATION PROCEDURES

TABLE 1

Whole Life

$$\text{Rate (\%)} = \frac{PB - S}{ASL} \qquad \text{Formula 1}$$

Remaining Life

$$\text{Rate (\%)} = \frac{PB - FS}{ASL} - \frac{BR - CT}{ARL} \qquad \text{Formula 2}$$

$$\text{Rate (\%)} = \frac{PB - FS - BR}{ARL} \qquad \text{Formula 3}$$

Where

PB	is Depreciable Balance, %
AS	is Average Net Salvage, %
FS	is Future Net Salvage, %
ASL	is Average Service Life, years
BR	is Depreciation Reserve, %
CTR	is Calculated Theoretical Reserve, %
ARL	is Average Remaining Life, years

DEVELOPMENT OF EQUAL LIFE GROUP CAPITAL RECOVERY RATE **TABLE 2**

Line	(1) Age Years	(2) Group 1 $	(3) Group 2 $	(4) Group 3 $	(5) Group 4 $	(6) Group 5 $	(7) Annual Provision $	(8) Beginning Survivors $	(9) Rate %	(10) Survivor Factor
1	1	1,000.00	500.00	333.33	250.00	200.00	2,283.33	5,000.00	45.67	1.00
2	2		500.00	333.33	250.00	200.00	1,283.33	4,000.00	32.08	0.80
3	3			333.33	250.00	200.00	783.33	3,000.00	26.11	0.60
4	4				250.00	200.00	450.00	2,000.00	22.50	0.40
5	5					200.00	200.00	1,000.00	20.00	0.20
6	Retirements	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00				
7	Frequency	0.20	0.20	0.20	0.20	0.20				
8	Rate	100%	50%	33.33%	25%	20%				

$$\text{Rate, \%} = \frac{\text{Retirements} \times \text{Frequencies}}{\text{Age at Retirement}} \Big/ \text{Reverse of Retirement Frequencies} \times 100$$

$$\text{Year One Rate} = \frac{0.2 + 0.2 + 0.2 + 0.2 + 0.2}{1 \quad 2 \quad 3 \quad 4 \quad 5} \Big/ (0.2 + 0.2 + 0.2 + 0.2 + 0.2) \times 100 = 45.67\%$$

$$\text{Year Three Rate} = \frac{0.2 + 0.2 + 0.2}{3 \quad 4 \quad 5} \Big/ (0.2 + 0.2 + 0.2) \times 100 = 26.11\%$$

DETERMINATION OF DEPRECIATION RATES BY ELG PROCEDURES

[1]	[2]	[3]	[4]	[5]	[6]
Age	Year	Vintage Balance	Retirement Frequency	Rate	Amount
Years		$	ASL 38 Curve L5		$
0.5	1993	4,244,285	0.0000	0.02704	114,758.36
1.5	1992	800,784	0.0000	0.02704	21,651.86
2.5	1991	60,016	0.0000	0.02704	1,622.73
3.5	1990	43,455,063	0.0000	0.02704	1,174,952.00
4.5	1989	81,456	0.0000	0.02704	2,202.43
5.5	1988	172,463	0.0000	0.02704	4,663.11
6.5	1987	2,098,991	0.0000	0.02704	56,753.20
7.5	1986	2,685,949	0.0000	0.02704	72,623.55
9.5	1984	1,642,443	0.0000	0.02704	44,408.90
10.5	1983	222,602	0.0000	0.02704	6,018.78
11.5	1982	85,661	0.0000	0.02704	2,316.13
12.5	1981	4,985	0.0000	0.02704	134.79
13.5	1980	72,942	0.0000	0.02704	1,972.23
14.5	1979	219,163	0.0000	0.02704	5,925.80
15.5	1978	120,665	0.0000	0.02704	3,262.58
16.5	1977	37,042	0.0000	0.02704	1,001.55
17.5	1976	339,236	0.0000	0.02704	9,172.21
19.5	1974	336,723	0.0001	0.02703	9,101.41
20.5	1973	10,375,359	0.0004	0.02702	280,292.86
21.5	1972	4,481,906	0.0009	0.02699	120,963.25
22.5	1971	5,923,340	0.0018	0.02695	159,618.98
23.5	1970	78,848	0.0030	0.02689	2,119.97
24.5	1969	305,178	0.0047	0.02681	8,180.42
25.5	1968	10,312,586	0.0069	0.02670	275,375.94
26.5	1967	2,754,067	0.0094	0.02658	73,203.24
27.5	1966	9,558,786	0.0123	0.02644	252,715.77
29.5	1964	5,556,083	0.0194	0.02610	144,995.54
30.5	1963	23,383	0.0242	0.02589	605.42
31.5	1962	3,313,564	0.0305	0.02566	85,012.50
32.5	1961	32,271	0.0386	0.02538	819.15
33.5	1960	151,658	0.0482	0.02507	3,802.24
34.5	1959	171,483	0.0583	0.02472	4,238.70
35.5	1958	167,116	0.0674	0.02433	4,065.35
36.5	1957	70,420	0.0740	0.02390	1,683.22
37.5	1956	1,792,312	0.0768	0.02345	42,036.33
39.5	1954	2,270,555	0.0701	0.02252	51,131.79
40.5	1953	187	0.0622	0.02206	4.13
41.5	1952	20,185	0.0531	0.02161	436.14
42.5	1951	12,860	0.0442	0.02118	272.40
43.5	1950	706	0.0362	0.02078	14.67
44.5	1949	2,652	0.0296	0.02041	54.13
45.5	1948	6,422	0.0245	0.02006	128.81
46.5	1947	19,573	0.0205	0.01972	386.07
47.5	1946	323,058	0.0173	0.01940	6,268.69
49.5	1944	2,285,041	0.0123	0.01879	42,943.47
50.5	1943	15,614	0.0103	0.01850	288.86
51.5	1942	620,752	0.0085	0.01821	11,306.36
53.5	1940	684,610	0.0055	0.01766	12,090.28
54.5	1939	47,173	0.0043	0.01740	820.76
55.5	1938	22,725	0.0033	0.01714	389.52
56.5	1937	560	0.0025	0.01689	9.46
57.5	1936	722	0.0019	0.01664	12.02
59.5	1934	3,065	0.0005	0.01573	48.21
61.5	1932	944,400	0.0005	0.01573	14,853.98
67.5	1926	2	0.0000	0.01471	0.03
Totals		119,029,691			3,133,730.27
			SALVAGE (%) =		-5.0
			AFTER SALVAGE =		3,290,417
		ANNUAL DEPRECIATION RATE =			2.76

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

LAURIE M. SHERWOOD

I. NAME AND POSITION

Q. PLEASE INTRODUCE YOURSELF.

A. My name is Laurie M. Sherwood. I am the Vice President, Corporate Development and Treasurer of Atmos Energy Corporation ("Atmos", "Atmos Energy" or "the Company"). My business address is 5430 LBJ Freeway, Suite 700, Dallas, Texas 75240.

II. SUMMARY OF TESTIMONY

Q. IN WHAT GENERAL AREAS WILL YOU TESTIFY?

A. I will testify in two areas:

1. Proposed Capital Structure, and
2. Embedded Cost of Debt.

Q. PLEASE SUMMARIZE THE TESTIMONY YOU WILL GIVE IN THESE TWO AREAS.

A. Proposed Capital Structure: For the attrition period, the capital structure that should be applied is 51.5% long-term debt and 48.5% equity. This ratio of debt to equity reflects the Company's historical capital structure, as well as its announced

intent to maintain a capital structure comprising 50 to 55% debt. Fiscal 2005 through 2006 was an aberrant period, during which the acquisition of TXU Gas Company, extremely warm winter weather, and high gas prices caused the Company's debt to climb. (Immediately before the TXU acquisition, the Company had only 43.3% debt.) In furtherance of the debt-reduction plan, the Company recently implemented a $900 million universal shelf offering, under which 6.325 million shares of stock were issued on December 13, 2006. Atmos has demonstrated the ability to decrease its debt ratio after consummating large acquisitions, and will continue to do so. As of March 31, 2007, the Company had a capital structure of 51.9% long-term debt and 48.1% equity.

Embedded Cost of Debt: As of October 31, 2008, the end of the attrition period, the Company's average cost of long term debt will be 6.10%. This is the rate that should be applied.

III. EDUCATION AND BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I earned a Bachelor of Business Administration degree with a double major in Management and Finance from Texas A & M University in 1982 and a Master of Business Administration degree from Southern Methodist University in 1988. From August 1982 to April 1999, I was employed by Oryx Energy Company and its former parent, Sunoco Inc., in various financial positions, most recently as Manager, Corporate Finance.

I joined Atmos in May 1999 as Assistant Treasurer. I was named Vice President and Treasurer in September 2000 and became Vice President, Corporate Development and Treasurer in February 2001.

Q. WHAT ARE YOUR JOB RESPONSIBILITIES AT ATMOS?

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

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE TENNESSEE REGULATORY AUTHORITY ("TRA") OR OTHER REGULATORY ENTITIES?

A. Yes, I have testified previously before the TRA. I also have testified before the Georgia Public Service Commission, the Illinois Commerce Commission, the Kentucky Public Service Commission, the Louisiana Public Service Commission, the Missouri Public Service Commission, the Mississippi Public Service Commission and the Railroad Commission of Texas.

IV. RELEVANT COMPANY ORGANIZATIONAL STRUCTURE

Q. HOW IS ATMOS ENERGY ORGANIZED?

A. Atmos Energy Corporation conducts utility operations in twelve states through unincorporated divisions. The Atmos division relevant here is commonly referred to as the Kentucky / Mid-States Division.

Q. DO THE COMPANY'S UNINCORPORATED DIVISIONS ISSUE THEIR OWN DEBT OR EQUITY?

A. No. These divisions, including Kentucky / Mid-States, are not separate legal entities, and legally comprise part of Atmos Energy Corporation. Therefore, all debt or equity must be (and is) issued by Atmos Energy Corporation as a whole, on a consolidated basis.

V. PROPER CAPITAL STRUCTURE

Q. WHAT CAPITAL STRUCTURE SHOULD BE USED IN THIS PROCEEDING?

A. Although this proceeding only affects the rates that may be charged in Tennessee, the appropriate capital structure for each of the Atmos utility operating divisions, including Kentucky / Mid-States, is the consolidated capital structure for Atmos Energy as a whole. This is because Atmos provides the debt and equity capital that supports the assets serving Tennessee customers. The capital structure that is appropriate for the Company's Tennessee operations in this proceeding is 51.5% long-term debt and 48.5% equity for the attrition period.

Q. HOW DOES THIS RECOMMENDED CAPITAL STRUCTURE COMPARE TO THE COMPANY'S ACTUAL CAPITAL STRUCTURE AS OF MARCH 31, 2007?

A. Atmos Energy's capital structure and ratios as of March 31, 2007 were as follows ($ in thousands):

L-T Debt[1]	S-T Debt	Total Debt	Shareholder Equity	Total
$2,181,564	$ 0	$2,336,413	$2,021,951	$4,203,516
51.9%	0.0%	51.9%	48.1%	100.0%

Q. IS THE DEBT COMPONENT OF THE COMPANY'S CAPITAL STRUCTURE AS OF MARCH 31, 2007 HIGHER THAN THE CAPITAL STRUCTURE THAT YOU BELIEVE TO BE APPROPRIATE FOR THIS PROCEEDING?

A. Yes. The Company's capital structure as of March 31, 2007 contained approximately 51.9% total debt, slightly higher than the level at the end of the attrition period on October 31, 2008. The Company expects the debt component of its capital structure to decline, and the equity component to increase, during the attrition period due to ongoing issuances of common stock through the Company's various stock plans and generating earnings in excess of common dividends paid.

[1] Includes current maturities.

Q. HAS THE TRA MADE ANY RECENT FINDINGS REGARDING THE COMPANY'S CAPITAL STRUCTURE?

A. On October 25, 2006, in Docket No. 05-000258[2], Director Pat Miller made a Motion, unanimously adopted by the TRA directors. Director Miller's Motion made certain findings, among other things, with respect to capital structure, cost of debt and return on equity.

Q. HOW DOES THE CAPITAL STRUCTURE THAT YOU HAVE RECOMMENDED IN THIS PROCEEDING COMPARE TO THE CAPITAL STRUCTURE ADOPTED BY THE TRA IN DOCKET NO. 05-000258?

A. The capital structure adopted by the TRA in Docket No. 05-000258 was as follows:

L-T Debt	S-T Debt	Total Debt	Shareholder Equity	Total
53.03%	3.59%	56.62%	43.38%	100.0%

Q. ARE THE DEBT COMPONENTS OF THE COMPANY'S CAPITAL STRUCTURE ADOPTED BY THE TRA IN DOCKET NO. 05-000258 HIGHER THAN THE CAPITAL STRUCTURE THAT YOU BELIEVE TO BE APPROPRIATE FOR THIS PROCEEDING?

A. Yes. The capital structure adopted in that proceeding contained approximately 56.62% total debt, which included a short-term component of 3.59%. The TRA concluded that the Company's use of short-term debt is seasonal to finance natural gas purchases and that 3.59% excluded seasonal components.[3] But these findings were made before the Company's recent equity issuance, which I will discuss in more detail. In addition, the Company's historical practice is not to use short-term debt to finance additions to utility plant. Therefore, the appropriate capital structure for use in this proceeding should contain no short-term debt.

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[2] *Petition to Open an Investigation to Determine Whether Atmos Energy Corp. Should Be Required by the Tennessee Regulatory Authority to Appear and Show Cause That Atmos Energy Corp. Is Not Overearning In Violation of Tennessee Law and That it is Charging Rates That Are Just and Reasonable;* TRA Docket No. 05-000258.

[3] The TRA concluded that the Company had short-term debt each month for the most recent twelve months in the record before the TRA and each month prior to the summer of 2004. *See* Director Miller's Motion, p. 12.

Q. DOES THE COMPANY HAVE ANY PLANS TO FURTHER REDUCE THE DEBT COMPONENT OF ITS CAPITAL STRUCTURE?

A. Atmos Energy's objective is to maintain its debt within a range of 50 – 55% of total capitalization. This level is consistent with the Company's actual capital structure as of March 31, 2007, as well as with the Company's actual capital structure immediately prior to its acquisition of the operations of TXU Gas Company at the beginning of fiscal year 2005, and is also consistent with the objective of maintaining a solid investment grade credit rating on Atmos Energy's debt.

Q. CAN YOU EXPLAIN WHAT LED TO THE COMPANY'S CAPITAL STRUCTURE AS OF MARCH 31, 2007?

A. On September 30, 2004, debt comprised approximately 43.3% of the Company's capital structure. Then, on October 1, 2004, Atmos completed the acquisition of the operations of TXU Gas Company for approximately $1.9 billion in cash. To finance the acquisition, Atmos issued 9.9 million shares of common stock in a public offering in July 2004, followed by another offering of 16.1 million shares of common stock in October 2004, yielding combined net proceeds of approximately $617 million. The remainder of the purchase price was financed with long-term debt.

This acquisition, combined with warm winter weather and higher than expected natural gas prices, increased Atmos Energy's ratio of debt to total capitalization to approximately 59.3% as of its next fiscal year end on September 30, 2005. The Company's debt ratio as of September 30, 2006 was slightly higher, at 60.9% of total capitalization, due to elevated levels of short-term debt caused by continuing high natural gas prices and the extremely warm winter weather that Atmos continued to experience across its service territory during fiscal year 2006 (particularly in Texas, where over half of the Company's utility customers are located). However, in December 2006, the Company used the net proceeds of a 6.325 million share offering of common stock to reduce short-term debt outstanding. As previously noted, Atmos Energy's ratio of debt to total

capitalization as of March 31, 2007, was 51.9%, composed solely of long-term debt.

Q. WHY IS THE COMPANY'S CAPITAL STRUCTURE AT MARCH 31, 2007 NOT APPROPRIATE FOR USE IN SETTING RATES IN THIS PROCEEDING?

A. As explained above, the March 31, 2007 capital structure contains a slightly higher percentage of debt than the capital structure at the end of the attrition period. The capital structure at the end of the attrition period reflects ongoing additions to shareholders' equity through issuances under the Company's various stock plans and generating earnings in excess of common dividends paid.

Q. WHAT IS THE COMPANY'S OBJECTIVE FOR ITS PERMANENT CONSOLIDATED CAPITAL STRUCTURE AND HOW DOES ATMOS PLAN TO MAINTAIN IT?

A. As the Company has repeatedly stated, including in its 2006 Annual Report to Shareholders, Atmos Energy intends to maintain a capital structure comprising 50 – 55% total debt. The Company plans to fund future spending requirements by utilizing internally generated cash flows, credit facilities, and its access to the public debt and equity capital markets. In addition, Atmos will continue to increase shareholders' equity by issuing common stock from its various stock plans and by generating earnings in excess of common dividends paid.

Q. HAS THE COMPANY UNDERTAKEN ANY RECENT ACTION TO ACHIEVE ITS STATED CAPITALIZATION OBJECTIVE?

A. Yes. The Company recently implemented a $900 million universal shelf offering for issuances of long-term debt and equity. As discussed above, under the universal shelf, the Company issued 6,325,000 shares of stock as of December 13, 2006, which yielded net proceeds of approximately $191.9 million. The net proceeds from this equity issuance were used to pay down short-term debt outstanding under the Company's commercial paper program. As of March 31, 2007, the Company's capital structure consisted of 51.9% long-term debt and 48.1% equity.

Q. WHY HAVEN'T YOU INCLUDED ANY SHORT-TERM DEBT IN THE CAPITAL STRUCTURE FOR THE FORECAST PERIOD IN THIS RATE PROCEEDING?

A. The Company has not historically used short-term debt as a permanent form of capital. The Company has used short-term debt as the means to finance purchased gas costs during the heating season and the level of short-term debt typically reduces to zero during the warmer months.

Q. PLEASE SUMMARIZE YOUR DISCUSSION ON CAPITAL STRUCTURE.

A. Atmos Energy's actual capital structure as of March 31, 2007, included approximately 51.9% debt, composed solely of long-term debt. This reflects the seasonal nature of any short-term debt that may be outstanding from time to time, and affirms the Company's historical practice of not using short-term debt to finance additions to utility plant. Therefore, it is not appropriate to include short-term debt in the capital structure to be used in this proceeding. Additionally, the percentage of debt in the Company's capital structure at the end of the attrition period will be slightly lower than in the actual capital structure as of March 31, 2007, because the Company will continue to increase shareholders' equity by issuing common stock from its various stock plans and by generating earnings in excess of common dividends paid. Going forward, Atmos will use internally generated cash flow and ongoing additions to shareholders equity to maintain its capital structure within its permanent target range of 50 – 55% total debt. The Company's recent implementation of its universal shelf, and equity issuance thereunder, coupled with the Company's historically-demonstrated ability to improve its capitalization ratio after consummating large acquisitions such as TXU Gas[4], illustrates that the capital structure advocated by the Company for this proceeding, although forecasted, is realistic, achievable and entirely appropriate. The capital structure that I have proposed of 51.5% long-term debt and 48.5% shareholders' equity is therefore appropriate for use in this proceeding.

[4] *See* Direct Testimony of Dr. Don Murry.

Q. WHAT RATES DO YOU PROPOSE FOR THE EMBEDDED COST OF DEBT CAPITAL IN SETTING RATES IN THIS CASE?

A. As shown in Exhibit LMS-1 attached to my testimony, the Company's weighted average cost of long-term debt was 6.06% as of March 31, 2007. However, I do not recommend that the TRA adopt 6.06% as the weighted average cost of long-term debt capital for use in this proceeding because it does not reflect what the cost will be as of October 31, 2008, which is the end of the attrition period used in this proceeding. Exhibit LMS-2 attached to my testimony shows that at October 31, 2008, the Company's projected cost of long-term debt capital will be 6.10% and I recommend that the TRA adopt that as the weighted average cost of long-term debt capital for use in this proceeding.

Although the Company does not believe that it is appropriate to include short-term debt in the Company's capital structure herein, should the TRA find to the contrary, then I recommend that the TRA adopt the Company's projected cost of short-term debt at October 31, 2008. The Company had no short-term debt outstanding as of March 31, 2007. As shown in Exhibit LMS-3 attached to my testimony, the projected weighted average cost of short-term debt capital at October 31, 2008 will be 7.05%.

The calculations supporting these recommended costs of debt are shown on my Exhibits LMS-2 and LMS-3. These weighted average costs of debt will permit Atmos Energy to raise the debt capital required to support its operations and to continue to provide safe, reliable, and efficient natural gas service to its Tennessee customers.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

VERIFICATION

STATE OF TEXAS)
)
COUNTY OF DALLAS)

I, Laurie M. Sherwood, being first duly sworn, state that I am the Vice President, Corporate Development and Treasurer of Atmos, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Testimony of Laurie M. Sherwood in support of Atmos Energy Corporation's Petition and the Exhibits thereto pre-filed in this docket on the date of filing of this Petition are true and correct to the best of my knowledge, information and belief.

Laurie M. Sherwood

Sworn and subscribed before me this 24 day of April, 2007.

Notary Public

My Commission Expires: 11-16-2008

JEFFERY D PERRYMAN
NOTARY PUBLIC
State of Texas
Comm. Exp. 11-16-2008

Atmos Energy Corporation, TN **EXHIBIT LMS-1**

AVERAGE ANNUALIZED LONG-TERM DEBT
as of March 31, 2007

Line	Debt Series (a)	Year Issued (b)	Outstanding 3/31/2007	End Int Rate	Annual Int at 3/31/2007
1	10% Senior Notes due Dec 2011	1991	2,303,308	10.00%	230,331
2	7.38% Senior Notes due May 2011	2001	350,000,000	7.38%	25,812,500
3	6.75% Debentures Unsecured due July 2028	1998	150,000,000	6.75%	10,125,000
4	5.125% Senior Notes due Feb 2013	2003	250,000,000	5.13%	12,812,500
5	10.43% First Mortgage Bond P due 2017 (eff 2012)	1987	7,500,000	10.43%	782,250
6	6.67% MTN A1 due Dec 2025	1995	10,000,000	6.67%	667,000
7	6.27% MTN A2 due Dec 2010	1995	10,000,000	6.27%	627,000
8	2.465% Sr Note 3Yr Floating due 10/15/2007	2004	300,000,000	5.74%	17,205,000
9	4.00% Sr Note due 10/15/2009	2004	400,000,000	4.00%	16,000,000
10	4.95% Sr Note due 10/15/2014	2004	500,000,000	4.95%	24,750,000
11	5.95% Sr Note due 10/15/2034	2004	200,000,000	5.95%	11,900,000
12					
13	Subtotal -- Utility Long-Term Debt		$ 2,179,803,308		$ 120,911,581
14					
15	United Cities Propane Gas, Inc.				
16	Pulaski -- Ingas, Ingram & Carvell 06/08		150,000	8.00%	12,000
17	Total Propane		150,000		12,000
18					
19	Atmos Leasing, Inc.				
20	Industrial Develop Revenue Bond 07/13	1991	851,189	7.90%	67,244
21	Atmos Power Sys - Wells Fargo 05/08	2003	1,623,146	5.65%	91,708
22	US Bancorp - 04/09	2004	2,244,648	5.29%	118,742
23	**Total Long-Term Debt**		$ 2,184,672,292		$ 121,201,274
24	Less Unamortized Debt Discount		$ 3,108,428		
25	Annualized Amortization of Debt Exp. & Debt Dsct.				$ 11,103,566
26			$ 2,181,563,864		$ 132,304,840
27					
28	Effective Avg Cost of Consol Debt			**6.06%**	end of period

Atmos Energy Corporation, TN
Case No. _____
AVERAGE ANNUALIZED LONG-TERM DEBT
as of October 31, 2008

EXHIBIT LMS-2

Schedule _____

Witness:

Line No.	ISSUE		13 Mth Average Amount OUTSTANDING	Interest Rate	EFFECTIVE ANNUAL Cost	COMPOSITE Interest Rate
	(A)		(B)	(C)	(D)	(E=D/B)
1	10.43% First Mortgage Bond P due 2017 (eff 2012)		$6,346,154	10.43%	$661,904	
2	10% Senior Notes due Dec 2011		1,151,654	10.00%	115,165	
3	10% Senior Notes due Dec 2011		1,151,654	10.00%	115,165	
4	6.75% Debentures Unsecured due July 2028		150,000,000	6.75%	10,125,000	
5	7.38% Senior Notes due May 2011		350,000,000	7.38%	25,812,500	
6	5.125% Senior Notes due Feb 2013		250,000,000	5.13%	12,812,500	
7	6.67% MTN A1 due Dec 2025		10,000,000	6.670%	667,000	
8	6.27% MTN A2 due Dec 2010		10,000,000	6.270%	627,000	
9	Projected 6.00% Refinancing Issuance	[1]	300,000,000	6.00%	18,000,000	
10	4.00% Sr Note due 10/15/2009		400,000,000	4.00%	16,000,000	
11	4.95% Sr Note due 10/15/2014		500,000,000	4.95%	24,750,000	
12	5.95% Sr Note due 10/15/2034		200,000,000	5.95%	11,900,000	
13	Industrial Develop Revenue Bond 07/13		715,200	7.90%	56,501	
14	Atmos Power Sys - Wells Fargo 05/08		558,950	5.65%	31,581	
15	US Bancorp - 04/09		1,105,513	5.29%	58,482	
16	Pulaski -- Ingas, Ingram & Carvell 06/08		38,462	8.00%	3,077	
17						
18	Annualized Amortization of Debt Exp. & Debt Dsct.				11,103,566	
19	Less Unamortized Debt Discount		(2,627,285)			
20	Total LONG-TERM DEBT		$2,178,440,301		$132,839,441	6.10%

Atmos Energy Corporation, TN
Case No. _____
AVERAGE ANNUALIZED SHORT-TERM DEBT
as of October 31, 2008

EXHIBIT LMS-3

Schedule _____

Witness:

	ISSUE	Amount OUTSTANDING	Interest Rate	EFFECTIVE ANNUAL Cost	COMPOSITE Interest Rate
	(A)	(B)	(C)	(D)	(E=D/B)
		$000		$000	
1	Average SHORT-TERM DEBT (1)	84,196	5.58%	4,698	
2	COMMITMENT FEE (2)			429	
3	COMMITMENT FEE (3)			806	
4	Total SHORT-TERM DEBT	84,196		5,933	7.05%

NOTES:

(1) Interest Rate is the forecasted average rate for 2007.

(2) Amortization of Arrangement fees over 5 years for $600 million line of credit, and over one year for $300 million line of credit.

(3) Commitment fees associated with $900 million line of credit averaging .08667% on the unused portion, calculated using 360-day convention.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REFISED TARIFF	)	**DOCKET NO. 07-_____**

PRE-FILED TESTIMONY OF GARY L. SMITH
ON BEHALF OF ATMOS ENERGY CORPORATION

I. NAME AND POSITION

Q. PLEASE INTRODUCE YOURSELF.

A. My name is Gary L. Smith. I am Vice President – Marketing and Regulatory Affairs for Atmos Energy Corporation's (sometimes referred to as the "Company") Kentucky/Mid-States operations. My business address is 2401 New Hartford Road, Owensboro, Kentucky 42303.

II. SUMMARY OF TESTIMONY

Q. WHAT SUBJECTS ARE COVERED BY YOUR DIRECT TESTIMONY IN THIS CASE?

A. My testimony supports the Company's proposal to incorporate a Customer Utilization Adjustment (CUA). The CUA will complement the Company's Weather Normalization Adjustment (WNA) rider. It is designed to compensate for customer volume variances associated with factors other than weather.

Q. DID THE COMPANY MAKE A SIMILAR PROPOSAL DURING DOCKET NO. 05-00258?

A. Yes. Ms. Patricia Childers presented testimony on a CUA in that case. However, the Company has revised its proposal. Atmos Energy's proposal in this case is

similar to what was proposed to the Tennessee Regulatory Authority (TRA) recently by Chattanooga Gas Company.

Q. ARE YOU SPONSORING ANY OF THE MINIMUM FILING REQUIREMENTS IN THIS CASE?

A. No, I am not sponsoring any of the minimum filing requirements in this docket.

III. BACKGROUND AND QUALIFICATIONS OF WITNESS

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES, AND PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I am responsible for rates and regulatory affairs, as well as directing the marketing plans and strategies for natural gas utility services to residential, commercial, and industrial sales and transportation markets in the Kentucky/Mid-States division. I am a 1983 graduate of the University of Kentucky, with a Bachelor of Science degree in Civil Engineering. I have worked for Atmos Energy Corporation or its predecessor, Western Kentucky Gas Company, since 1984, initially as Project Engineer. After serving in a variety of technical and supervisory engineering positions, I transferred into the Industrial Marketing department in 1990. I became Director of Large Volume Sales in 1991, was named Vice President – Marketing in 1998, and named to my current position in 2003. I also serve on numerous corporate-wide committees, including chair of Atmos Energy's Utility Marketing Council, a group responsible for corporate-wide market development policies. I am active in civic and community organizations and associations relating to the natural gas industry. I am immediate past-chairman of the Utilization Technology Development, NFP Corporation and previously served as chair of the Strategic Marketing Committee for the American Gas Association (AGA).

Q. HAVE YOU EVER SUBMITTED TESTIMONY BEFORE THE TENNESSEE REGULATORY AUTHORITY?

A. Yes. In 2006, I served as witness rebutting an intervention group's proposal for a transportation customer storage service in TRA Docket No. 05-00258.

Q. HAVE YOU TESTIFIED ON MATTERS BEFORE OTHER STATE REGULATORY COMMISSIONS?

A. Yes, before the Kentucky Public Service Commission (KPSC), the Georgia Public Service Commission (GPSC), and the Missouri Public Service Commission (MPSC).

IV. REVIEW OF CUSTOMER VOLUME VARIANCES AND THEIR EFFECT ON COMPANY REVENUES

Q. PLEASE EXPLAIN THE IMPACT OF CUSTOMER VOLUME CHANGES ON ATMOS ENERGY'S FINANCIAL PERFORMANCE.

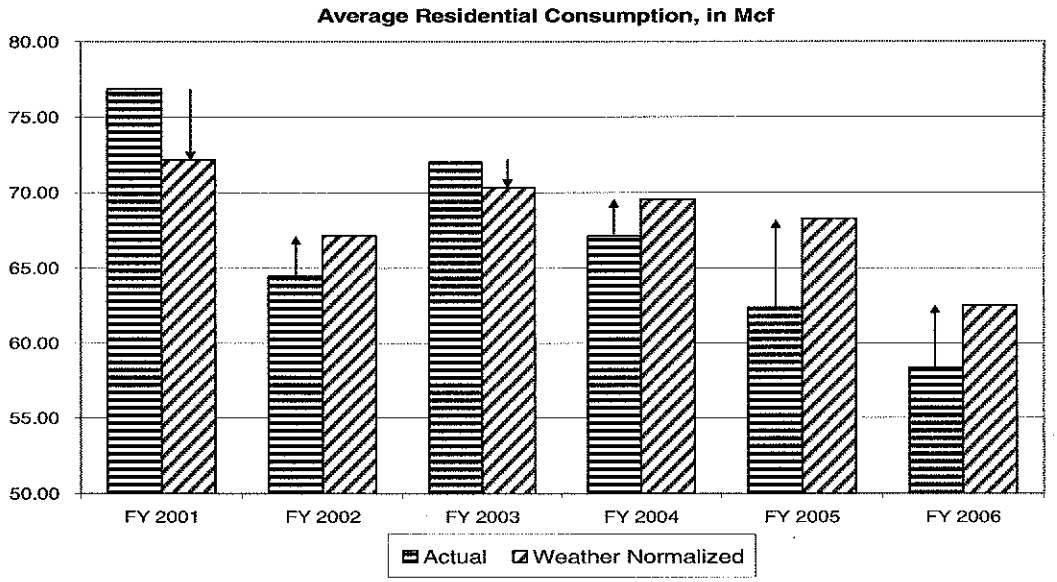
A. Under traditional rate design, a utility's authorized revenue requirement, exclusive of gas costs, is divided between a fixed monthly customer charge component and a volumetric rate component charged per unit of gas sold or transported. The volumetric charge is calculated based upon the level of sales or transportation volumes at normal weather conditions for the annual period. The vast majority of non-gas costs borne by a utility, and correspondingly its revenue requirements, are fixed, and are basically unaffected by the volumes sold or transported. Thus, as annual volumes drop below the weather-normalized rate case volumes upon which the revenue requirements were based, the utility under-recovers its authorized non-gas revenues. Alternatively, higher annual volumes lead to recovery of non-gas revenues above the established revenue requirement.

Q. WHAT FACTORS CAUSE VARIATIONS IN CUSTOMER USAGE PATTERNS FROM THE CONSUMPTION BASIS USED IN DETERMINING RATES?

A. Weather is the factor typically having the greatest influence on customer usage variations from the assumptions utilized in deriving volumetric distribution rates. Many customers, particularly in the residential and commercial classes, use natural gas for space heating. For most residential customers and for many commercial customers, the majority of their annual gas consumption is used for

space heating. Since volumetric rates are set in a comprehensive rate case based upon "normal" outdoor temperatures, if weather is warmer than normal, customer usage will be lower than the volumes assumed in setting the rates. Alternatively, if weather is colder than normal, customer usage will be greater than the volumes assumed in setting the rates. WNA mechanisms address the volume variances caused by weather. Chart GLS-1 shows the variability in actual residential volumes in Tennessee from year to year, and also shows the adjusted volumes that would have occurred if weather had been normal.

Chart GLS-1



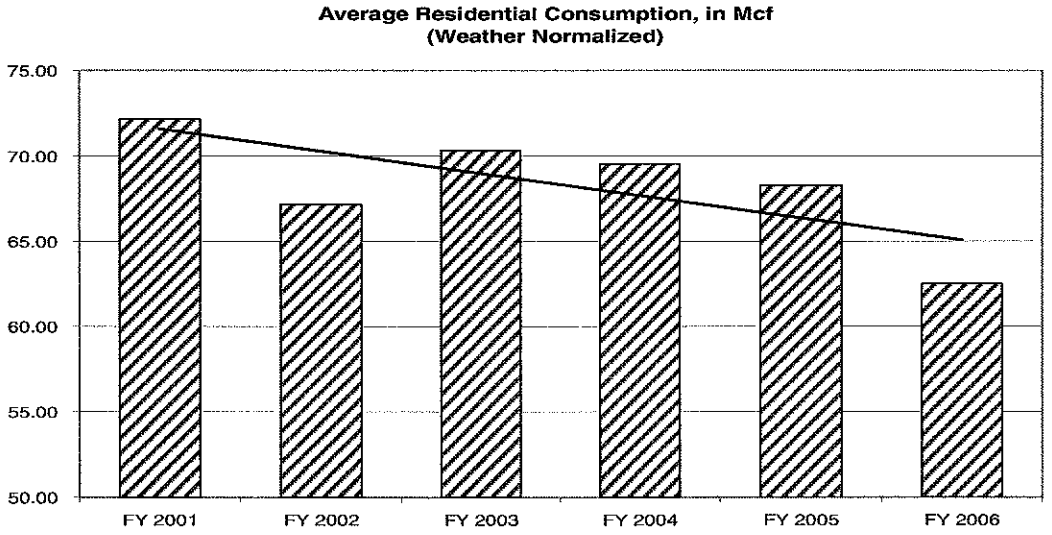
The WNA mechanism is designed to adjust the Company's non-gas revenues to compensate for the volume variances associated with abnormal weather, represented as arrows in the preceding chart. The benefit of a WNA is that neither the customer nor the Company bears an advantage or disadvantage as a result of abnormal weather during any heating season.

Q. ARE THERE FACTORS OTHER THAN WEATHER THAT INFLUENCE CUSTOMER CONSUMPTION?

A. Yes. Although weather is the primary driver, other factors, such as improved efficiency and conservation also influence gas consumption over time. The gas industry as a whole is faced with declining usage per customer, and Atmos

Energy's Tennessee service area is no exception. Chart GLS-2 graphs the weather-normalized consumption for Atmos Energy's residential customers in Tennessee, and a trendline for the period.

Chart GLS-2



A 2004 study conducted by the American Gas Association (AGA) concluded that, removing the effects of weather, natural gas usage per household, which has dropped by over 20% since 1980, will continue to decline over the next several years. This decline is due in large part to conservation measures, including progressive increases in the energy-efficiency of appliances and more efficient new homes. In addition, utilities have seen consumers heighten their conservation efforts in response to higher pass-through gas supply prices in recent years.

Q. HOW DO THESE CONSUMPTION PATTERNS IMPACT ATMOS ENERGY'S NON-GAS REVENUES?

A. While the WNA rider has neutralized the impact of weather on the Company's ability to recover its authorized revenue requirements, the Company remains fully exposed to changes in customer usage patterns beyond those associated with weather. In today's environment of higher natural gas supply prices, Atmos Energy wishes to align its interests with those of its customers in regard to efficient energy use. Unfortunately, traditional and current rate designs encourage

the promotion of increased gas consumption, as the way for a gas company to recover its fixed costs and its authorized revenue requirements.

V. WNA RIDER AND PROPOSED CUA RIDER

Q. IS ATMOS ENERGY PROPOSING ANY MODIFICATIONS TO THE EXISTING WNA RIDER?

A. The Company does not propose any changes to the WNA mechanism, other than updating the base load and heating sensitive load factors used in the calculation. Company witness James Cagle is addressing these updates in his testimony.

In 1991, in Docket No. 91-01712, the Tennessee Public Service Commission (now the TRA) adopted the WNA rider for the state's three regulated gas utilities, United Cities Gas Company (now Atmos Energy), Chattanooga Gas Company, and Nashville Gas (now Piedmont Natural Gas). The WNA Rider achieves its purpose by protecting both the consumer and the company from fluctuations in gas consumption caused by weather that is colder or warmer than normal. However, as I discussed above, even with the WNA, the Company's collection of non-gas revenues remains linked to volumes of gas sold.

Q. PLEASE DESCRIBE THE PURPOSE OF THE PROPOSED CUSTOMER UTILIZATION ADJUSTMENT.

A. The proposed CUA would further "decouple," or break the link between, the Company's revenue and the quantity of gas consumed by its customers. As noted previously, the Company's cost of service is recovered through both monthly and volumetric charges. However, excluding the cost of commodity gas supply, very few gas utility costs are variable and thus driven by changes in volume. Therefore, the Company's cost of service, while almost exclusively fixed in nature, is dependent on sustained volume levels to afford recovery of authorized revenues. As shown previously in Chart GLS-2, weather-normalized volumes consumed by the Company's customers have been declining and will continue to do so. The CUA would address these non-weather- related volume changes.

Atmos Energy's CUA, as set forth on the Company's proposed Original Tariff Sheet No. 51.1, would, annually, compare the actual non-gas revenues per customer for each applicable rate schedule, including the WNA revenue, to those established in this docket. The resulting difference within each class then would be multiplied by the actual number of customers, to determine the excess revenue to be refunded to, or the revenue deficiency to be collected from, each class. The excess or deficiency then would be divided by the annual projected volume for each class, to determine the CUA charge or credit rate.

Q. WILL THE CUA BE "TRUED UP"?

A. Yes. The calculation would include a cumulative annual "true up" to ensure that the Company does not over- or under-collect from the ratepayer. The true up will work similar to the ACA (actual cost adjustment) of the PGA (purchased gas adjustment).

Q. WILL THE APPROVAL OF THE CUA GUARANTEE THAT ATMOS ENERGY WILL ALWAYS EARN ITS ALLOWED RATE OF RETURN?

A. No. As previously stated, the CUA, like the WNA Rider, merely ensures that the Company's ability to recover the costs approved in this docket is not held hostage to fluctuations in gas consumption, which are beyond the Company's control. The Company is still responsible for controlling its costs, and remains subject to the overall risks and uncertainties associated with doing business. The proposed CUA only compensates the Company for lost non-gas revenues the Company has been authorized to recover by this Authority, and its approval will simply provide the Company with a reasonable opportunity to recover its TRA-authorized non-gas revenues.

Q. WHAT ARE THE LARGER POLICY IMPLICATIONS OF DECOUPLING?

A. The practice of allowing gas utilities to recover fixed costs through the use of volumetric rates was initiated years ago with the underlying objective of motivating gas utilities to sign up new customers and increase gas sales. Since the dramatic rise of natural gas prices in 2000-2001, public policy has shifted away from promoting increased gas consumption. Instead, policymakers have

stressed the importance of encouraging conservation in order to reduce overall demand, and place downward pressure on skyrocketing gas prices.

One industry analyst described volumetric rate design as an obsolete anomaly in light of recent changes in public policy towards conservation:

> As the fixed charges appear year in and year out regardless of gas usage, the volumetric approach to cost recovery for operating a gas distribution system is a faulty equation which needs to be rectified in ratemaking. It would appear therefore, that unless and until this anomaly is corrected, the LDC [Local gas Distribution Company] would lack the necessary tools with which to earn its allowed rate of return.[1]

To the extent that conservation efforts affect volumes sold, and correspondingly, the Company's non-gas commodity revenue recovery, the current rate design has the unintended consequence of pitting the Company's financial performance against conservation efforts. The proposed CUA will decouple the collection of non-gas revenues from the volumes of gas consumed, and thus remove the current disincentive to encourage energy efficiency and conservation.

Q. WHAT EVIDENCE EXISTS TO SUPPORT THIS SHIFT IN POLICY TOWARDS CONSERVATION AND AWAY FROM RATE DESIGNS THAT ENCOURAGE INCREASED GAS SALES?

A. Numerous policy groups and government bodies have issued public statements on the issue. The following list, while certainly not exhaustive, outlines the most recent examples of such public policy statements:

- In July 2004, the AGA and the Natural Resources Defense Council ("NRDC") issued a joint statement encouraging state commissions to consider mechanisms to decouple the link between volumes sold and revenues: "NRDC and AGA agree on the importance of state Public Utility Commissions' consideration of innovative programs that encourage total energy efficiency and conservation in ways that align the interests of state regulators, natural gas utility company customers, utility

[1] J Moody's Investors Service Special Comment *Local Gas Distribution Companies: Update on Revenue Decoupling and Implications for Credit Ratings*, p. 4 (June 2006).

shareholders, and other stakeholders." A copy of the Joint Statement is attached as Exhibit GLS 1. It expressly recognizes the link between conservation and controlling the rising costs of natural gas, and notes that if companies, commissions and consumers work together to make natural gas consumption more efficient, particularly on peak days, and reduce overall demand, many experts believe we can put more downward pressure on natural gas prices and decrease price volatility. The Joint Statement acknowledges that decoupling mechanisms could have significant widespread benefits, including:

- Customers could save money by using less natural gas;
- Reduced overall use will help to push down short-term natural gas prices at times when markets are under stress, thereby reducing costs for all customers (whether or not they participate in the utility program);
- Utilities would recover their costs and have a fair opportunity to earn their allowed return;
- State policies to encourage economic development could be enhanced by increased energy efficiency and lower business energy costs;
- State PUCs [Public Utility Commissions] would be able to support larger state policy objectives as well as programs that reflect the public's desire to use energy efficiently and wisely.

The Joint Statement concludes that in "today's climate of rapidly changing natural gas prices, such reforms make good sense for consumers, shareholders, state governments, and the environment."

- Also in July 2004, prompted by the concerns cited in the Joint Statement, the National Association of Regulatory Utility Commissioners ("NARUC") issued a resolution encouraging regulators to approve decoupling mechanisms for the utilities they regulate. A copy of the resolution is attached as Exhibit GLS-2. The 2004 NARUC Resolution states, in relevant part:

"WHEREAS, the Natural Resources Defense Council (NRDC), the American Gas Association (AGA) and the American Council for an Energy Efficient Economy (ACEEE) have urged public utility commissions to align the interests of consumers, utility shareholders, and society as a whole by encouraging conservation. Among the mechanisms supported by these groups are the use of automatic rate true-ups ***to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales.***" (emphasis added)

- In November 2005, NARUC issued a second resolution, which, citing record high gas prices and damage suffered from Hurricanes Katrina and Rita, again encouraged state commissions to "implement innovative rate designs that will encourage energy conservation and energy efficiency that will assist in moderating natural gas demand and reducing upward pressure on natural gas prices." A copy of the 2005 NARUC Resolution is attached as Exhibit GLS-3.
- Congress has weighed in on decoupling. The Energy Policy Act of 2005 requires the U.S. Department of Energy, in consultation with NARUC and the National Association of State Energy Officials, to conduct a study of state and regional policies to promote energy conservation. Under the Act, those policies should consider methods of removing disincentives for gas and electric utilities to implement energy efficient programs.
- Also at the national level, the U.S. Environmental Protection Agency's recently initiated Clean Energy Policy Initiative will review decoupling in terms of evaluating ways to remove disincentives for natural gas and electric utilities to promote energy efficiency.

Q. HAVE OTHER STATES ADOPTED MECHANISMS TO DECOUPLE REVENUES FROM VOLUMES?

A. Yes. In a recent Special Comment on decoupling, Moody's Investors Service concluded that "[w]hile RD [revenue decoupling] may have originally begun as a regional concept in certain jurisdictions, it has quickly become a nationwide

phenomenon that will challenge regulators and gas utilities alike, as they seek to correct a structural imbalance in their rate design that has become increasingly difficult to ignore."[2] In addition to WNA mechanisms, which have been in use since the 1980s, several states have approved decoupling mechanisms for gas utilities. Pacific Gas and Electric in California was the first gas utility to adopt a form of a decoupling mechanism, starting in 1978. As of March 2007, 10 state commissions have approved decoupling mechanisms for 18 gas utilities, including:

- Pacific Gas & Electric, San Diego Gas & Electric, Southern California Gas and Southwest Gas in California,
- Vectren in Indiana,
- Baltimore Gas & Electric and Washington Gas in Maryland,
- Atmos Energy and Missouri Gas Energy in Missouri,
- New Jersey Natural Gas and South Jersey Gas in New Jersey,
- Vectren in Ohio,
- Northwest Natural Gas and Cascade Natural Gas in Oregon,
- Piedmont Natural Gas in North Carolina,
- Questar Natural Gas in Utah, and
- Avista Corporation and Cascade in Washington.

Additionally, at least 12 gas utilities have filed decoupling proposals. Proposals include:

- CenterPoint Energy (Arkansas)
- UNS Gas (Arizona)
- PSC of Colorado (Colorado)
- Peoples Gas / Integrys (Illinois)
- CMS Energy (Michigan)
- Excel Energy (Minnesota)
- Public Service Company of New Mexico (New Mexico)

[2] Moody's Investors Service Special Comment *Local Gas Distribution Companies: Update on Revenue Decoupling and Implications for Credit Ratings*, p. 6 (June 2006).

- National Fuel Gas Distribution (New York)
- Chattanooga Gas (Tennessee)
- Washington Gas (Virginia and Washington, DC)

Many of the decoupling proposals have met with support from regulators. The decoupling proposal by Questar Gas has received the support of the Utah Division of Public Utilities, and Consumers' Counsel for the State of Ohio has come out publicly in support of decoupling, calling such mechanisms a "win-win" for utilities and consumers. Also, the Iowa Utilities Board has issued a Notice of Inquiry (NOI) in Docket No. NOI-06-01 into the effect of reduced usage on rate regulated gas utilities.

Q. HAVE THE DECOUPLING MECHANISMS THAT HAVE BEEN IMPLEMENTED IN OTHER STATES BEEN SUCCESSFUL IN PRODUCING POSITIVE BENEFITS TO COMPANIES AND CONSUMERS?

A. Yes. Members of the Maryland Public Service Commission Staff have reported that the decoupling mechanism implemented for Baltimore Gas and Electric has fulfilled the regulatory objectives, including: (1) producing more stable revenues by eliminating attrition caused by declining usage; (2) reducing the volatility of gas bills; and (3) providing incentives for conservation, while at the same time remaining easy for the utility to administer and the commission staff to monitor. A 2005 study conducted for Northwest Natural Gas concluded that under its decoupling mechanism: (1) revenues had stabilized; (2) the company had shifted its focus from marketing to promoting energy efficiency; and (3) service quality did not decline.

Q. HOW WOULD THE PROPOSED CUA BENEFIT CUSTOMERS?

A. The CUA would permit the Company to promote conservation without jeopardizing its recovery of authorized revenues. Conservation will benefit consumers, as it will aid in lowering their gas bills. The CUA merely seeks to remedy the current misalignment of interests between shareholders and customers. Rising natural gas market prices in recent years are generally attributed to the strain that growing demand has placed on the nation's gas supply.

While support for increased supplies is a part of the solution, conservation is equally important. In addition, conservation is something each individual can act upon and directly influence in his home or business. Subjecting the Company to traditional rate design does not afford a reasonable opportunity for the Company to achieve its authorized revenue requirements because the fixed costs that we incur are dependent on sustained usage at current levels. Failing to align the interests of the utility service provider with its consumers' efforts to conserve energy, in this price environment, does not promote the best interests of Tennessee ratepayers.

Q. **HAS THE TRA SUPPORTED CONSERVATION?**

A. Yes. As Ms. Childers mentions in her testimony, the TRA has been very proactive in recognizing the importance of energy conservation. A Home Energy Conservation Task Force ("Task Force") has been meeting and reviewing existing state conservation plans and has provided recommendations regarding conservation programs to assist Tennessee utility consumers served by utilities. The Task Force is comprised of a diverse group of individuals representing a cross section of stakeholders with interests in conservation. Among the Task Force members is a representative from each regulated natural gas utility (Atmos Energy, Piedmont Natural Gas and Chattanooga Gas Company) in Tennessee.

Q. PLEASE PROVIDE YOUR UNDERSTANDING OF THE TASK FORCE'S WORK TO DATE.

A. The Task Force has focused on three areas associated with energy conservation. These areas are customer education, diagnostics and remediation. On November 15, 2006, the Task Force submitted its report to the TRA. This report identifies short-term, medium-term and long-term issues and contains eight specific recommendations. Among those recommendations is the implementation of a modest pilot program to allow for learning and evaluation prior to making major implementation commitments. The pilot program includes in-home education after installation of energy saving measures.

Q. IS ATMOS ENERGY ENCOURAGEING ENERGY CONSERVATION IN JURISDICTIONS OTHER THAN TENNESSEE?

A. Yes. Atmos Energy is committed to educating its customers on energy efficiency as well as partnering with other stakeholders to achieve long-term benefits to customers through reducing the demand for energy and thus lowering the cost of energy. The Company's common conservation programs throughout its 12-state utility operations involve educational materials for customers and website energy management tools. Additionally, Atmos Energy supplements these efforts in certain jurisdictions with specific programs to aid energy efficiency improvements and weatherization efforts.

Q. PLEASE DESCRIBE THOSE SUPPLEMENTAL, STATE SPECIFIC EFFORTS.

A. Within the Kentucky/Mid States division, I am very familiar with ongoing programs in both Kentucky and Missouri.

Q. PLEASE DESCRIBE THE PROGRAM IN KENTUCKY.

A. The current demand side management program in Kentucky, ATMOS ENERGY CARES, began in 2000. The program provides supplemental funding for certain weatherization efforts by area community action agencies for low-income customers. The program is managed by a collaborative including Atmos Energy, the Kentucky Association for Community Action, the Attorney General of the Commonwealth of Kentucky, and the Kentucky Legal Aid Society. ATMOS ENERGY CARES annually funds approximately $200,000 toward weatherization programs, with targeted spending for qualifying homes at $1500 per home. The program cost is borne by Atmos Energy's residential customers in Kentucky.

Q. PLEASE DESCRIBE THE MISSOURI PROGRAM.

A. In March of this year, the MPSC approved a decoupled rate design for Atmos Energy, based upon an agreement between Commission Staff and the Company. As part of that agreement, and in an effort to align the interests of the Company with those of its customers, Atmos Energy committed to work collaboratively with the Staff, the Office of Public Counsel and the Department of Natural Resources to develop an Energy Efficiency and Weatherization Program. The program is intended to assist customers in reducing their consumption of natural gas through education, conservation and weatherization. There have been a

number of meetings between the members of the collaborative group over the past two months and the specific parameters of the program are near completion. The program should be implemented late this summer following approval by the MPSC.

The Company has committed to provide annual funding of approximately $165,000 for the program. If approved by the Commission, the program will likely include dollars dedicated to low-income weatherization, rebates for high energy efficiency furnaces and boilers, programmable thermostats, and customer education.

Q. HAS THE COMPANY UNDERTAKEN ANY SPECIFIC EFFORTS TO ENCOURAGE CONSERVATION IN TENNESSEE.

A. The Task Force's first recommendation is the initiation of a workshop specifically to address funding and study decoupling in order to support energy conservation and gas technology/energy conservation. Atmos Energy fully expects that the Task Force will continue its works and implement these recommendations. However, in the meantime, Atmos Energy is spending $50,000 developing an experimental residential weatherization "pilot program" that includes an energy education component. Although still in its formative stages, the Company is hopeful that it can implement the program by mid- to late-summer of this year.

Ideally, funding for such a program would be balanced between customers and shareholders, and be implemented in conjunction with rate designs that no longer penalize the Company financially for customer conservation efforts. However, Atmos Energy is committed to encourage conservation and working toward aligning its interests with those of its customers. We believe this Tennessee pilot program will afford an important learning opportunity for the Company on how to craft an effective weatherization effort. The Company is certainly willing to engage in discussions with the Authority Staff and the Consumer Advocate to develop specific programs to aid energy efficiency improvements and weatherization efforts in light of its CUA proposal to eliminate the long-standing disincentives associated with customer conservation.

Q. DOES THE CUA NEGATE THE BENEFITS OF CONSERVATION MEASURES TAKEN BY CUSTOMERS?

A. No, it does not. A customer's conservation efforts will continue to be rewarded through the avoidance of incremental gas costs. Gas commodity costs constitute the greatest portion of the customer's bill, and with gas supply prices still above historic levels, customers would remain fully motivated to avoid consuming any volume unnecessarily. The Company, which merely passes through the gas costs incurred dollar-for-dollar, would be pleased to fully support the customer's efforts to avoid purchasing an MCF of gas; unfortunately, traditional rate design attaches the largest portion of our authorized revenue requirement to that same MCF conserved. The CUA would realign the interests of customers and shareholders in support of gas conservation.

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Continuation of the WNA, along with approval of the CUA, is good regulatory policy because it is in the best interests of both ratepayers and Atmos Energy. It will benefit ratepayers by adding stability to their annual energy bill. The CUA will benefit Atmos Energy by providing the opportunity to collect the authorized revenue required to recover its costs and earn a fair return, regardless of fluctuations in sales due to weather and conservation efforts. This will afford the Company the ability to continually and consistently make new investments, and provide safe and reliable service year after year at the level of excellence ratepayers have come to expect. For the reasons stated above, and especially in such times of uncertainty in our nation's energy environment, approval of this rider is good regulatory policy, and good for the State of Tennessee.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

VERIFICATION

STATE OF KENTUCKY)
)
COUNTY OF DAVIESS)

I, Gary L. Smith, being first duly sworn, state that I am the Vice President-Marketing and Regulatory Affairs for the Kentucky/Mid-States Division of Atmos Energy Corporation, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Testimony of Gary L. Smith in support of Atmos Energy Corporation's Petition and the Exhibits thereto pre-filed in this docket on the date of filing of this Petition are true and correct to the best of my knowledge, information and belief.

Gary L. Smith

Sworn and subscribed before me this 9th day of April, 2007.

Notary Public - State of KY at Large

My Commission Expires: September 26, 2009





Joint Statement of the American Gas Association and the Natural Resources Defense Council

Submitted to the National Association of Regulatory Utility Commissioners
July 2004

The American Gas Association (AGA) and the Natural Resources Defense Council (NRDC) recognize the many benefits of using clean-burning natural gas efficiently to provide high quality energy services in all sectors of the economy. This statement identifies ways to promote both economic and environmental progress by removing barriers to natural gas distribution companies' investments in urgently needed and cost-effective resources and infrastructure.

NRDC and AGA agree on the importance of state Public Utility Commissions' consideration of innovative programs that encourage increased total energy efficiency and conservation in ways that will align the interests of state regulators, natural gas utility company customers, utility shareholders, and other stakeholders. Cost-effective opportunities abound to improve the efficiency of buildings and equipment in ways that promote the interests of both individual customers and entire utility systems, while improving environmental quality. For example, when energy supply and delivery systems are under stress, even relatively modest reductions in use can yield significant additional cost savings for all customers by relieving strong upward pressures on short-term prices.

NRDC and AGA also encourage state Commissions to support gas distribution company efforts to manage volatility in energy prices and reduce volatility risks for customers.

The Energy Efficiency Problem: Regulated Natural Gas Utilities are Penalized for Aggressively Promoting Energy Efficiency

Local natural gas distribution companies (gas utilities) have very high fixed costs. These fixed costs include the costs of maintaining system safety and reliability throughout the year, staffing customer service telephone lines 24 hours a day and doing what it takes each day of the year to ensure the safe and reliable delivery of natural gas to homes, schools, hospitals, retailers, factories and other customers.

Natural gas utilities typically purchase natural gas on behalf of their customers, and pass through the cost without markup. This means that natural gas utilities do not

profit from their acquisitions of natural gas to serve customer needs. The profit (authorized level of rate of return) comes from the rates utilities charge for transporting the natural gas to customers' homes and businesses.

The vast majority of the non-commodity costs of running a gas distribution utility are fixed and do not vary significantly from month to month. However, traditional utility rates do not reflect this reality. Traditional utility rates are designed to capture most of approved revenue requirements for fixed costs through volumetric retail sales of natural gas, so that a utility can recover these costs fully only if its customers consume a certain minimum amount of natural gas (these amounts are normally calculated in rate cases and generally are based on what customers consumed in the past). Thus, many states' rate structures offer – quite unintentionally – a significant financial disincentive for natural gas utilities to aggressively encourage their customers to use less natural gas, such as by providing financial incentives and education to promote energy-efficiency and conservation techniques.

When customers use less natural gas, utility profitability almost always suffers, because recovery of fixed costs is reduced in proportion to the reduction in sales. Thus, conservation may prevent the utility from recovering its authorized fixed costs and earning its state-allowed rate of return. In this important respect, traditional utility rate practices fail to align the interests of utility shareholders with those of utility customers and society as a whole. This need not be the case. Public utility commissions should consider utility rate proposals and other innovative programs that reward utilities for encouraging conservation and managing customer bills to avoid certain negative impacts associated with colder-than-normal weather. There are a number of ways to do this, and NRDC and AGA join in supporting mechanisms that use modest automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales.[1] We also support performance-based incentives designed to allow utilities to share in independently verified savings associated with cost-effective energy efficiency programs.

Many states' rate structures also place utilities at risk for variations in customer usage based on variations in weather from a normal pattern. This variation can be both positive and negative. Utilities' allowed rate of return is premised on the

[1]For example, in 2003 the Oregon Public Utility Commission approved a "conservation tariff" for Northwest Natural Gas Company (NW Natural) "to break the link between an energy utility's sales and its profitability, so that the utility can assist its customers with energy efficiency without conflict." The conservation tariff seeks to do that by using modest periodic rate adjustments to "decouple" recovery of the utility's authorized fixed costs from unexpected fluctuations in retail sales. See Oregon PUC Order No. 02-634, *Stipulation Adopting Northwest Natural Gas Company Application for Public Purpose Funding and Distribution Margin Normalization* (Sept. 12, 2003). In California, PG&E and other gas utilities have a long tradition of investment in energy efficiency services, including those targeting low-income households, and the PUC is now considering further expansion of these investments along with the creation of performance-based incentives tied to verified net savings. California also pioneered the use of modest periodic true-ups in rates to break the linkage between utilities' financial health and their retail gas sales, and has now restored this policy in the aftermath of an ill-fated industry restructuring experiment. Thus, in March 2004, Southwest Gas Company received an order that authorizes it to establish a margin tracker that will balance actual margin revenues to authorized levels.

expectation that weather will be normal, on average, and that customer use of gas will maintain a predictable pattern going forward. Proposals by utilities to decouple revenues from both conservation-induced usage changes and variations in weather from normal have sometimes been characterized as attempts to reduce utilities' risk of earning their authorized return. The result of these rate reforms, in this regulatory view, should be a lowered authorized return. But reducing authorized returns would penalize utilities for socially beneficial advocacy and action, including efforts to create mechanisms that minimize the volatility of customer bills.

Our shared objective is to give utilities real incentives to encourage conservation and energy efficiency. With properly designed programs, the benefits could be significant and widespread:

- Customers could save money by using less natural gas;
- Reduced overall use will help push down short-term prices at times when markets are under stress, reducing costs for all customers (whether or not they participate in the utility programs);
- Utilities would recover their costs and have a fair opportunity to earn their allowed return;
- State policies to encourage economic development could be enhanced by increased energy efficiency and lower business energy costs;
- State PUCs would be able to support larger state policy objectives as well as programs that reflect the public's desire to use energy efficiently and wisely.

In today's climate of rapidly changing natural gas prices, such reforms make good sense for consumers, shareholders, state governments, and the environment.

Natural Gas Consumers, Price Volatility and Resource Portfolio Management.

Another area of concern shared by NRDC and AGA is the impact of natural gas price volatility on natural gas consumers, which can be exacerbated by limited diversification of utilities' resource portfolios. Today many of the nation's natural gas utilities find themselves relying on short-term markets for most of their gas needs, with either the encouragement or the acquiescence of their regulators. During much of the 1990's this approach was typically advantageous to consumers, as the market price of natural gas was generally low and did not fluctuate dramatically. As wholesale natural gas prices have risen since 2000 and become more volatile, however, many utilities and commissions are reconsidering this emphasis on short-term market purchases.

While purchasing practices based on short-term supply contracts may offer consumers relatively low-cost natural gas, those consumers are also exposed to more volatile prices and natural gas bills that may rise and fall unpredictably. Public Utility Commissions should favorably consider gas distribution company proposals to manage volatility, such as through hedging, fixed-price contracts of various durations, energy-efficiency improvements in customers' buildings and equipment, and other measures designed to provide greater certainty about both supply

adequacy and price stability. Achieving these goals will sometimes require paying a premium over prevailing spot market prices. Like diversified investment portfolios that are designed to mitigate risk, prudent hedging plans should be encouraged as a way to help stabilize gas prices and ensure long-term access to affordable natural gas services.

This Joint Statement also has been reviewed and endorsed by:



ALLIANCE TO
SAVE ENERGY
Creating an Energy-Efficient World

Alliance to Save Energy



American Council for an Energy-Efficient Economy

L:NRDC-AGA Statement – 7-7-04 (FINAL with ACE3).doc

Resolution on Gas and Electric Energy Efficiency

WHEREAS, The National Association of Regulatory Utility Commissioners (NARUC), at its July 2003 Summer Meetings, adopted a *Resolution on State Commission Responses to the Natural Gas Supply Situation* that encouraged State and Federal regulatory commissions to review and reconsider the level of support and incentives for existing gas and electric utility programs designed to promote and aggressively implement cost-effective conservation, energy efficiency, weatherization, and demand response in both gas and electricity markets; *and*

WHEREAS, The National Petroleum Council (NPC), in its September 25, 2003 report on *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy*, found that greater energy efficiency and conservation are vital near-term and long-term mechanisms for moderating price levels and reducing volatility and recommended all sectors of the economy work toward improving demand flexibility and efficiency; *and*

WHEREAS, The NPC, in its report, identified key elements of the effort to maintain and continue improvements in the efficient use of electricity and natural gas, including (but not limited to):

(i) enhanced and expanded public education programs for energy conservation, efficiency, and weatherization,

(ii) DOE identification of best practices utilized by States for low-income weatherization programs and to encourage nation-wide adoption of these practices,

(iii) a review and upgrade of the energy efficiency standards for buildings and appliances (to reflect current technology and relevant life-cycle cost analyses) to ensure these standards remain valid under potentially higher energy prices

(iv) promote the use of high-efficiency consumer products including advanced building materials, Energy Star appliances, energy "smart" metering and information control devices

(v) on-peak electricity conservation to minimize the use of gas-fired electric generating plants,

(vi) the use of combined-cycle gas-fired electric generating units instead of less-efficient gas-fired boilers, and

(vii) clear natural gas and power price signals; and

(viii) remove regulatory and rate structure incentives to inefficient use of natural gas and electricity; and

WHEREAS, The NARUC, at its November 2003 annual convention, adopted a *Resolution Adopting Natural Gas Information "Toolkit"* which encouraged the NARUC Natural Gas Task Force, to review (among other things) the findings and recommendations in the NPC report that have regulatory implications for State commissions for improving and promoting energy efficiency and conservation initiatives, including consumer outreach and education, review of regulatory throughput incentives*; and*

WHEREAS, The American Council for an Energy-Efficient Economy ("ACEEE"), in its December 2003 report on *Responding to the Natural Gas Crisis: America's Best Natural Gas Energy Efficiency Programs*, (i) identified States and utilities with programs that many would consider best practice or model programs for all types of natural gas customers and all principal natural gas end-use technologies, and (ii) found that these programs are concentrated in relatively few States and regions and could be expanded in other parts of the country to great benefit; *and*

WHEREAS, the Natural Resources Defense Council (NRDC), the American Gas Association (AGA) and the ACEEE have recently adopted a Joint Statement noting that traditional rate structures often act as disincentives for natural gas utilities to aggressively encourage their customers to use less gas. Therefore, the NRDC, AGA, and the ACEEE have urged public utility commissions to align the interests of consumers, utility shareholders, and society as a whole by encouraging conservation. Among the mechanisms supported by these groups are the use of automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales; *now therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC), convened in its 2004 Summer Meetings in Salt Lake City, Utah, encourages State commissions and other policy makers to support the expansion of natural gas energy efficiency programs and electric energy efficiency programs, including those designed to promote consumer education, weatherization, and the use of high-efficiency appliances, where economic, and to address regulatory incentives to address inefficient use of gas and electricity; *and be it further*

RESOLVED, That the Board of Directors of the NARUC, encourages State and Federal policy makers to: (i) review and upgrade the energy efficiency standards for buildings and appliances, where economic, to ensure these standards remain valid under potentially higher energy prices, and (ii) promote the use of high-efficiency consumer products, where economic, including advanced building materials, Energy Star appliances, and energy "smart" metering and information control devices; *and be it further*

RESOLVED, That Board of Directors of NARUC encourages State Commissions to review and consider the recommendations contained in the enclosed *Joint Statement of the American Gas Association, the Natural Resources Defense Council, and the American Council for an Energy-Efficient Economy; and be it further*

RESOLVED, That the Board of Directors of the NARUC recognizes that the best approach towards promoting gas energy efficiency programs and electric energy efficiency programs for any single utility, State or region may likely depend on local issues, preferences and conditions.

Sponsored by the NARUC Natural Gas Task Force, Committee on Gas, Committee on Consumer Affairs, Committee on Electricity, and Committee on Energy Resources and the Environment
Adopted by the NARUC Board of Directors July 14, 2004

Resolution on Energy Efficiency and Innovative Rate Design

WHEREAS, The National Association of Regulatory Utility Commissioners (NARUC), at its July 2003 Summer Meetings, adopted a *Resolution on State Commission Responses to the Natural Gas Supply Situation* that encouraged State and Federal regulatory commissions to review the incentives for existing gas and electric utility programs designed to promote and aggressively implement cost-effective conservation, energy efficiency, weatherization, and demand response; *and*

WHEREAS, The NARUC at its November 2003 annual convention, adopted a *Resolution Adopting Natural Gas Information "Toolkit,"* which encouraged the NARUC Natural Gas Task Force to review the findings and recommendations of the September 23, 2003 report by the National Petroleum Council on *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy* and its recommendations for improving and promoting energy efficiency and conservation initiatives; *and*

WHEREAS, The NARUC at its 2004 Summer Meetings, adopted a *Resolution on Gas and Electric Energy Efficiency* encouraging State commissions and other policy makers to support expansion of energy efficiency programs, including consumer education, weatherization, and energy efficiency and to address regulatory incentives to inefficient use of gas and electricity; *and*

WHEREAS, These NARUC initiatives were prompted by the substantial increases in the price of natural gas in wholesale markets during the 2000-2003 period when compared to the more moderate prices that prevailed throughout the 1990s; *and*

WHEREAS, The wholesale natural gas prices of the last five years largely reflect the fact that the demand by consumers for natural gas has been growing steadily while, for a variety of reasons, the supply of natural gas has had difficulty keeping pace, leading to a situation where natural gas demand and supply are narrowly in balance and where even modest increases in demand produce sharp increases in price; *and*

WHEREAS, Hurricanes Katrina and Rita, in addition to damaging the States of Alabama, Mississippi, Louisiana, and Texas, significantly damaged the nation's onshore and offshore energy infrastructure, resulting in significant interruption in the production and delivery of both oil and natural gas in the Gulf Coast area; *and*

WHEREAS, The confluence of a tight balance of natural gas supply and demand and these natural disasters has driven natural gas prices in wholesale markets to unprecedented levels; *and*

WHEREAS, The present high and unprecedented level of natural gas prices are imposing significant burdens on the nation's natural gas consumers, whether residential, commercial, or industrial, and will likely be injurious to the nation's economy as a whole; *and*

WHEREAS, The recently enacted Energy Policy Act of 2005 contains a number of provisions aimed at encouraging further natural gas production in order to bring down prices for consumers,

but these actions, together with any further action on energy issues by Congress, are unlikely to bring forth additional supplies of natural gas in the short term; *and*

WHEREAS, Energy conservation and energy efficiency are, in the short term, the actions most likely to reduce upward pressure on natural gas prices and to assist in bringing energy prices down, to the benefit of all natural gas consumers; *and*

WHEREAS, Innovative rate designs including "energy efficient tariffs" and "decoupling tariffs" (such as those employed by Northwest Natural Gas in Oregon, Baltimore Gas & Electric and Washington Gas in Maryland, Southwest Gas in California, and Piedmont Natural Gas in North Carolina), "fixed-variable" rates (such as that employed by Northern States Power in North Dakota, and Atlanta Gas Light in Georgia), other options (such as that approved in Oklahoma for Oklahoma Natural Gas), and other innovative proposals and programs may assist, especially in the short term, in promoting energy efficiency and energy conservation and slowing the rate of demand growth of natural gas; *and*

WHEREAS, Current forms of rate design may tend to create a misalignment between the interests of natural gas utilities and their customers; *now therefore be it*

RESOLVED, That the National Association of Regulatory Utility Commissioners (NARUC), convened in its November 2005 Annual Convention in Indian Wells, California, encourages State commissions and other policy makers to review the rate designs they have previously approved to determine whether they should be reconsidered in order to implement innovative rate designs that will encourage energy conservation and energy efficiency that will assist in moderating natural gas demand and reducing upward pressure on natural gas prices; *and be it further*

RESOLVED, That NARUC recognizes that the best approach toward promoting energy efficiency programs for any utility, State, or region may likely depend on local issues, preferences, and conditions.

Sponsored by the Committee on Gas
Recommended by the NARUC Board of Directors November 15, 2005
Adopted by the NARUC November 16, 2005

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

JOHN R. ELLERMAN

I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, BUSINESS AFFILIATION AND BUSINESS ADDRESS.

A. My name is John R. Ellerman. I am employed by the international management consulting firm of Towers Perrin. I am a Managing Principal with the firm and I have responsibility for leading the executive compensation and rewards consulting practice of Towers Perrin for the Western Region of the United States. My business address is 12377 Merit Drive, Suite 1200, Dallas, Texas 75251.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND DESCRIBE YOUR WORK EXPERIENCE.

A. I have both B.B.A. and M.B.A. degrees from Stetson University. I have held an appointment to the Division of Sponsored Research at M.I.T. I have also served two years in the Department of Defense as a systems analyst in Washington D.C. Prior to joining Towers Perrin, I was a senior management consultant in the general management strategy practice of KPMG Peat Marwick for five years.

I joined Towers Perrin in 1978 as a compensation consultant in our firm's Atlanta office. I was transferred to the firm's Tampa office in 1981 where I initiated our firm's compensation consulting practice in Florida. I was elected Principal in 1983 and a Vice President in 1988.

Q. WHAT ARE YOUR JOB RESPONSIBILITIES?

A. I have specialized in the executive compensation area for the past 30 years. I consult with *Fortune 500* companies, including Atmos Energy Corporation ("Atmos" or the "Company"), on a daily basis regarding executive pay matters. I also have specialized in the design of incentive compensation plans that align company performance with reward opportunities. My clients are predominantly in the energy services sector.

I am also a frequent speaker on executive compensation and have given presentations at national forums of the Edison Electric Institute, the Conference Board, World at Work and other prominent groups.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE TENNESSEE REGULATORY AUTHORITY ("TRA") OR OTHER REGULATORY ENTITIES?

A. I have never testified before the TRA. However, I have testified before the Kansas Corporation Commission and the Oklahoma Corporation Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to sponsor the Company's inclusion of certain incentive compensation costs in this rate proceeding and to explain why such costs and the inclusion thereof is reasonable and necessary.

II. SUMMARY

Q. WHAT SUBJECT AREAS DO YOU INTEND TO COVER IN YOUR TESTIMONY?

A. I will testify concerning the following subject areas:

1. Overview of the Company's incentive compensation plans.
   a. Variable Pay Plan ("VPP").
   b. Management Incentive Plan ("MIP").
   c. Long-Term Incentive Plan for Management ("LTIP").
2. Benefits of incentive compensation.
3. Inclusion of the cost of variable incentive compensation plans for management and non-management employees as part of the cost of service in setting rates.

Q. PLEASE SUMMARIZE YOUR TESTIMONY IN THESE SUBJECT AREAS:

A.

- The Company's inclusion of incentive compensation costs in this rate proceeding is both reasonable and necessary.
- The Company's Variable Pay Plan ("VPP") is a broad based incentive compensation plan in which virtually all employees of the Company participate, except for those that are included in the Management Incentive Plan ("MIP"). The VPP provides all eligible employees of the Company with the opportunity to earn a cash-based incentive award based upon the Company's return on equity performance which is expressed to plan participants as a target for Earnings Per Share (EPS).
- The VPP provides awards equal to 1% of base compensation for the threshold level of performance and the maximum level of performance results in a payment of 3% of base compensation. Base compensation is defined in terms of the VPP as base salary plus other forms of base compensation (e.g., overtime and other premium pay rates).
- The VPP plan offers award opportunities only when the Company reaches or exceeds desired levels of profitability as measured by both return on equity and earnings per share.
- Earnings Per Share (EPS) is determined by dividing the Company's net income by the total shares outstanding. Plan participants are aware that net income is a function of both maximizing revenues and minimizing expenses and that the best way for an employee to influence EPS results is to be mindful of unnecessary costs, customer service levels, safety incidents and productivity. These actions are beneficial to all constituents of Atmos Energy: ratepayers, shareholders, employees and communities the Company serves.
- The Management Incentive Plan ("MIP") is an extension of the VPP and is limited to a select group of management employees who are responsible for directing and overseeing the day-to-day operations of the Company.

The MIP provides the management team with the opportunity to earn a cash-based incentive award based upon the Company's return on equity performance which is expressed to participants in the plan as an EPS target.

- Participants in the plan receive a target award opportunity each year expressed as a percentage of base compensation. Base compensation is defined for purposes of the MIP as base salary. These target award opportunity percentages are directly tied to the 50th percentile of competitive market survey data for positions of comparable responsibility for energy services companies of similar size.
- The annual performance targets for the MIP are the same performance targets used by the VPP as determined by a return on equity target converted to an EPS target.
- The MIP plan pays awards only when the Company reaches or exceeds desired levels of profitability as measured by both return on equity and earnings per share.
- The Long-Term Incentive Plan ("LTIP") for management is an equity-based incentive program which focuses upon the long-term strength and financial viability of the Company. The LTIP provides incentives to the management team in two forms, time-lapse restricted shares and performance-based restricted share units.
- The time-lapse restricted shares are subject to a three-year restricted period. The shares are paid to the participant free of restrictions following the three-year service period from the date of grant.
- The performance-based restricted share units must be earned over a three-year performance period.
- The performance measure is the Company's cumulative three-year earnings per share compared to the planned or targeted level of EPS for the same period.
- Incentive compensation is a variable cost, as opposed to a fixed element of cost, and the variable element of pay is awarded only when the Company

can justify and afford to make such payments based upon its financial performance.

- The Company's pay for performance philosophy incorporates the use of incentive compensation for all employees. Incentive pay improves the Company's ability to recruit and retain talented employees, since incentive compensation is widely prevalent in the labor markets in which the Company competes for key talent.
- Annual incentive plans for both management and non-management employees have become particularly prevalent throughout the gas utility industry.
- A 2005 American Gas Association ("AGA") survey of sixty-one (61) companies found that 90% of the surveyed companies have one or more types of incentive compensation plans. The surveyed companies rated their incentive plans as successful.
- Earnings per share goals are met not only by increasing revenues, but also by minimizing expenses. If the Company's management can eliminate or minimize unnecessary costs, reduce the number of accidents and safety incidents, deliver satisfactory customer service with reasonable expense and staff levels, and improve performance by increasing productivity, the Company's earnings per share will be increased, and shareholders, customers, employees and the communities served by the Company will all benefit.
- Both ratepayers and shareholders should recognize the full cost of incentive compensation, since it is to the mutual benefit of both constituents.
- In our experience, my firm and I have found that variable incentive compensation plans benefit all stakeholders--customers, shareholders and employees. The cost of incentive compensation plans is a variable expense and is tied to improvements in productivity, service, cost management, and other performance factors that drive a company's financial strength and success.

- Disallowance of the Company's incentive compensation costs as part of its cost of service would place the Company at a competitive disadvantage. Those industries that are not regulated utilities are free to factor in the cost of incentive compensation into the price of the products or services they sell. If Atmos is not permitted to factor in the cost of its incentive compensation programs in the setting of rates in this proceeding, the Company will be placed at a competitive disadvantage.
- If the rate set in this proceeding does not take into account the amount of expense that the Company must incur to fund these programs and to be competitive in the employment market, the rate set would not meet the goal of fair and effective regulation.
- If the TRA were to disallow any or all of the costs of the Company's incentive pay compensation plans to be recovered in its rates, the Company's employee compensation costs reflected in the cost of service would be below the average for the market and would result in levels in the cost of service that are not reasonable when compared to that market.

III. OVERVIEW OF THE COMPANY'S INCENTIVE COMPENSATION PLANS

Q. ARE YOU FAMILIAR WITH THE COMPANY'S INCENTIVE COMPENSATION PLANS?

A. Yes. The Company has three such plans – the Variable Pay Plan, the Management Incentive Plan and the Long Term Incentive Plan for Management.

Q. WHAT IS THE VARIABLE PAY PLAN?

A. The Variable Pay Plan, or "VPP", is a broad based incentive compensation plan in which virtually all employees of the Company participate (except for those included in the Management Incentive Plan or the "MIP"). The plan, which is developed around the same precepts as the MIP, provides all eligible employees with the opportunity to earn a cash-based incentive award based upon the

Company's return on equity performance which is expressed to participants as an earnings per share target (EPS).

Q. WHAT COMPANY EMPLOYEES ARE ELIGIBLE TO PARTICIPATE IN THE VPP?

A. With one exception, all Company employees that do not participate in the MIP plan participate in the VPP. The exception rests with a group of collective bargaining employees in Mississippi (reference, Mississippi Local Union 1047C) that has not bargained to participate in the VPP plan. It should be noted that the Company's other bargaining unit has negotiated with management to participate in the VPP plan.

Q. WHAT FORM OF AWARDS ARE MADE PURSUANT TO THE VPP?

A. The VPP pays an annual cash award which is targeted to be 2 percent of base salary plus other forms of base compensation (e.g., overtime and other premium pay rates are included in the determination of base compensation). Should the Company attain its target level of EPS during the course of the fiscal year, the plan will pay cash awards following the September 30 close of the fiscal year. Typically, such awards are paid to participants in the form of cash awards in November following the close of the Company's financial reporting. The plan also pays awards for determination of threshold and maximum levels of performance. The plan provides awards equal to 1 percent of base compensation for the threshold level of performance, and the maximum level of performance results in a payment of 3 percent of base compensation. Awards under the VPP are capped at 3 percent of base compensation. For performance levels achieved which are between the stated threshold, target, and maximum levels of performance, awards are calculated on a straight line interpolated basis.

Q. HOW ARE THE APPLICABLE THRESHOLDS FOR AWARDS UNDER THE VPP DETERMINED?

A. The range of outcomes between threshold, target, and maximum are based upon the Company's budgeted return on equity at target and moving 100 basis points below budgeted return on equity for the threshold and 100 basis points above budgeted ROE for maximum performance. As an example, the following

schedule sets forth the determination of the performance levels of threshold, target, and maximum performance targets for the VPP for the fiscal year 2006 plan year:

VPP Performance Schedule – 2006 Fiscal Year				
Performance Level	*Annual EPS*	*ROE*	*Basis for Performance Target*	*Payout as Percent of Base Compensation*
Threshold	$1.59	8.00%	100 basis points below budget ROE	1%
Target	$1.80	9.00%	2006 Budget	2%
Maximum	$2.01	10.0%	100 basis points above budget ROE	3%

As designed, the plan offers award opportunities only when the Company reaches or exceeds desired levels of profitability as measured by both return on equity and earnings per share. For participants, the performance targets are expressed only as levels of EPS so that participants have a clear line of sight to what they are being measured for as well as how they can influence results.

Q. HOW CAN VPP PARTICIPANTS INFLUENCE EPS RESULTS?

A. EPS is measured as the Company's net income divided by total shares outstanding. Participants understand that net income is a function of both revenues and expenses, and that the best way in which they can influence EPS results is being mindful of unnecessary costs, customer service levels, safety incidents, and productivity. These actions are beneficial to all constituents of Atmos: ratepayers, shareholders, employees and the communities served by the Company. Those who argue that EPS is only a measure which benefits a company's shareholders are shortsighted in understanding those factors and behaviors which have a direct bearing on EPS and who benefits therefrom.

Q. HAS THE COMPANY HISTORICALLY MADE AWARDS PURSUANT TO THE VPP TO PLAN PARTICIPANTS?

A. Yes. The VPP was developed in concert with the Company's development and adoption of a new overall compensation strategy set forth in 1998 and referred to

as "Total Rewards." The plan was initially implemented in fiscal year 1999 and the plan paid no awards for that year since the Company failed to reach its threshold level of EPS performance. The Company also failed to reach the threshold level of EPS in fiscal year 2000, and no awards were paid in that year as well. The plan paid its first awards to participants in fiscal year 2001, and in that year the plan paid awards at 2.15 percent of base compensation to 2,217 participants. In the schedule below, we have reported the payment history of the VPP from fiscal year 2001 through fiscal year 2006, including the number of participants, the total payment, average payment per participant, the corresponding EPS achievement for the performance period, and the percentage of a participant's base compensation for determination of the award level.

Variable Pay Plan ("VPP") Payment History

	2001	*2002*	*2003*	*2004*	*2005*	*2006*
Number of participants	2,217	2,108	2,475	2,362	3,846	4,161
Total payment	$1,661,441.00	$1,286,448.00	$1,741,541.74	$2,415,122.12	$3,703,635.58	$4,243,571.32
Average payment per participant	$749.41	$610.27	$703.65	$1,022.49	$962.98	$1,019.84
EPS	$1.56	$1.45	$1.54	$1.63	$1.72	$1.82
Award Percentage	2.15%	1.45%	1.71%	2.38%	2.12%	2.10%

Q. WHAT IS THE MANAGEMENT INCENTIVE PLAN?

A. The Management Incentive Plan, or "MIP", is an extension of the VPP and is limited to a select group of management employees who are responsible for directing and overseeing the day-to-day operations of the Company. In fiscal year 2006, 127 Company officers and other senior managers and directors participated in the plan and received awards. The MIP provides the management team with the opportunity to earn a cash-based incentive award based upon the Company's return on equity performance which is expressed to participants as an EPS target.

Q. WHAT AWARD OPPORTUNITIES ARE AVAILABLE TO PARTICIPANTS UNDER THE MIP?

A. Participants in the plan receive a target award opportunity each year expressed as a percentage of base compensation. The target award opportunities vary by salary grade, and the opportunities increase with corresponding higher salary grades as management responsibility increases. These target award opportunity percentages are directly tied to the 50th percentile of competitive market survey data for positions of comparable responsibility for energy services companies of similar size. The size of target awards range from 20 percent of base compensation at target for salary grade 7 up to a target opportunity of 80 percent of base compensation for the CEO position. In addition to a target incentive opportunity, there are threshold and maximum levels of payment opportunity based upon a predetermined set of performance outcomes. For the threshold level of performance, a participant would receive 50 percent of his target award opportunity. For attainment of the maximum level of performance, a participant would receive 200 percent of his target award opportunity.

Q. HOW ARE THE APPLICABLE THRESHOLDS FOR AWARDS UNDER THE MIP DETERMINED?

A. The annual performance targets for the MIP are the same performance targets for the VPP, as determined by the return on equity target converted to an EPS target. For example, the MIP performance scale for fiscal year 2006 was essentially the same as that for the VPP, as shown in the table below:

MIP Performance Schedule – 2006 Fiscal Year

Performance Level	*Annual EPS*	*ROE*	*Basis for Performance Target*	*Payout as Percent of Participant's Target Opportunity*
Threshold	$1.59	8.00%	100 basis points below budget ROE	50%
Target	$1.80	9.00%	2006 Budget	100%
Maximum	$2.01	10.0%	100 basis points above budget ROE	200%

Q. CAN MIP PARTICIPANTS INFLUENCE EPS RESULTS?

A. Yes. As with the VPP, the MIP pays awards only when the Company reaches or exceeds desired levels of profitability as measured by both return on equity and earnings per share. Participants in the MIP are cognizant of the EPS targets and manage for the same performance metrics that influence EPS results as with the VPP: managing unnecessary costs, being attentive to customer service levels, minimizing safety incidents, and enhancing employee productivity.

Q. HAS THE COMPANY HISTORICALLY MADE AWARDS PURSUANT TO THE MIP TO PLAN PARTICIPANTS?

A. The MIP was implemented at the same time that the VPP plan was implemented in fiscal year 1999 and has been an integral part of the Total Rewards program. The plan did not pay incentive awards in either fiscal year 1999 or fiscal year 2000 since the Company did not achieve its threshold level of EPS performance. Since fiscal year 2001, the plan has provided payments as follows to its participants:

Management Incentive Plan ("MIP") Payment History

	2001	*2002*	*2003*	*2004*	*2005*	*2006*
Number of participants	83	85	93	92	99	127
Total payments	$1,839,175.00	$1,824,300.00	$2,195,100.00	$3,805,400.00	$3,318,300.00	$6,244,400.00
Average payment per participant	$22,159	$21,462	$23,603	$41,363	$33,518	$49,169
EPS	$1.56	$1.45	$1.54	$1.63	$1.72	$1.82

Q. WHAT IS THE LONG TERM INCENTIVE PLAN FOR MANAGEMENT?

A. The Long Term Incentive Plan for Management, or "LTIP", is an equity-based incentive program which focuses upon the long-term strength and financial viability of the Company. Since 2003, the LTIP has provided long-term incentives to its management team in two forms: (1) time-lapse restricted shares; and (2) performance-based restricted share units. Long-term incentives are

granted annually to participants and are based upon competitive long-term expected values awarded at the 50th percentile of competitive market practice. The long-term awards are allocated by taking 50 percent of the total award opportunity and granting that portion in time-lapse restricted shares, and taking the remaining 50 percent of the total award opportunity and granting that portion in performance-based restricted shares.

Q. PLEASE EXPLAIN THE TWO FORMS OF LTIP AWARDS IN MORE DETAIL.

A. The time-lapse restricted shares are subject to a three-year restricted period. The shares are paid to the participant free of restrictions following the three-year service period from the date of grant. During the restricted period, the dividends on the time-lapse restricted shares are paid at the same rate as such dividends are declared for all of the Company's common shares.

The performance-based restricted share units must be earned over a three-year performance period. The performance measure for determination of the number of units earned is the Company's cumulative three-year earnings per share (EPS) compared to the planned or targeted level of EPS for the same period. If the Company achieves 100 percent of the EPS three-year target, the participant will receive 100 percent of the performance share units granted. If the Company achieves only the threshold level of three-year EPS performance, the participant will receive 50 percent of the performance share units granted. If the Company achieves the maximum level of three-year EPS performance, the participant will receive 150 percent of the performance share units granted. Dividends on the performance-based restricted share units are credited to the participant's account with the payment of such dividends not occurring until the three-year cumulative earnings per share performance targets are measured at the end of the three-year performance measurement cycle.

Q. WHAT IS THE PURPOSE OF THE THREE-YEAR PERIOD ATTACHED TO THE TWO FORMS OF LTIP AWARDS?

A. The purpose of the long-term performance incentive is to focus management's attention upon the long-term sustained results through superior earnings

performance. As with the annual incentive plan, superior earnings performance comes from actions like managing excessive and unnecessary costs, driving performance through enhanced productivity, eliminating accidents and safety incidents, and managing customer service levels. These actions are the focus of an extended time period of three years with respect to long-term incentives.

Q. IS THE LTIP A NECESSARY PART OF THE COMPANY'S COMPENSATION PACKAGE OFFERED TO ITS SENIOR MANAGERIAL AND EXECUTIVE EMPLOYEES?

A. Yes. Atmos, like its competitor companies, must provide attractive long-term incentive opportunities to its senior management team in order to attract qualified individuals to the Company. Equity incentives like restricted stock and restricted share units also provide the Company with a retention vehicle to ensure that the organization retains the management talent required to lead and operate a Company of the size and stature of Atmos. Atmos would be at a distinct competitive disadvantage were it not able to provide competitive long-term equity incentive opportunities to its management team.

Q. AS A REFERENCE POINT, CAN YOU EXPLAIN THE COMPANY'S OVERALL COMPENSATION PHILOSOPHY?

A. The Company aims to provide its executives and all employees with a fair, equitable and competitive total rewards program. The program is designed to help the Company attract and retain quality employees by targeting pay at the median (50^{th} percentile) of the competitive market in which the Company competes for talent. The competitive market, for purposes of the incentive programs described above, are defined as companies in the energy industry. The program is carefully monitored and managed to ensure that it fairly serves all of its stakeholders – employees, customers, and shareholders.

Q. HOW DOES INCENTIVE COMPENSATION FIT INTO THE COMPANY'S COMPENSATION PHILOSOPHY?

A. The Company's compensation program is comprised of many components. One integral component is the use of variable incentive compensation plans for both management and non-management employees. Atmos' variable incentive

compensation plans and the philosophy behind those plans contain a number of advantages. First, incentive compensation is a variable cost (as opposed to the fixed cost element of base salary) and the variable element of pay is awarded only when the Company can justify and afford to make such payments based upon financial performance. This is the underlying tenet of the Company's pay for performance philosophy.

Incentive pay also improves the Company's ability to recruit and retain talented employees since incentive compensation is widely prevalent in the labor markets in which the Company competes for key talent. Incentive compensation is viewed as pay at risk and motivates employees to achieve important performance goals in order to earn additional financial rewards. In this regard, incentive compensation is not an entitlement but instead represents the Company's willingness to pay for performance which exceeds reasonable expectations.

Properly designed incentive plans also encourage teamwork and the achievement of common purpose by helping employees become more engaged in their jobs, thereby benefiting customers, shareholders, other employees and the communities served by the Company.

Finally, incentive plans improve company communications about performance goals and other performance matters instrumental to the Company's success.

III. BENEFITS OF INCENTIVE COMPENSATION

Q. DO RATEPAYERS BENEFIT FROM THE COMPANY'S USE OF VARIABLE INCENTIVE COMPENSATION PLANS?

A. Yes. Until the 1990's, utilities were reluctant to adopt variable incentive compensation plans as a part of their overall pay strategy. Due to the many regulations imposed upon utilities by various authorities, it was commonly believed that variable pay incentive plans were an inappropriate form of compensation since shareholder and ratepayer interests could not be properly balanced. Therefore, it was easy for utilities to pay and justify high base salaries (as compared to other industries) and to add generous and expensive employee benefit plans in order to compete with other large employers.

The Company could easily follow this traditional path and could eliminate variable incentive compensation from its rewards program. In turn, Atmos would have to dramatically increase base salaries and employee benefit levels in order to provide a competitive rewards package in terms of total value. This would result in higher fixed costs, which would be directly borne by the ratepayers. Wisely, the Company's pay philosophy incorporates the use of incentive compensation for all employees because of the many advantages that such variable compensation provides to all stakeholders of the Company.

Q. ARE VARIABLE INCENTIVE COMPENSATION PLANS USED WIDELY IN THE UTILITY INDUSTRY TODAY?

A. Yes. Virtually all investor-owned gas and electric utilities have moved in the direction of incentive compensation as an integral component of their compensation plans. Annual incentive plans for both management and non-management employees have become particularly prevalent throughout the gas utility industry, clearly illustrating the requirement for offering competitive compensation opportunities throughout the organization.

Q. HAVE THERE BEEN ANY RECENT STUDIES WHICH SUPPORT YOUR CONCLUSION?

A. In 2005, the American Gas Association (AGA) undertook a major survey of competitive compensation practices in the gas utility industry. Sixty-one (61) companies participated in the survey, which was conducted by Effective Compensation, Inc. I have included several highlights from the AGA survey which clearly indicate the prominence of incentive compensation plans in U.S. gas utilities.

In Table 1 below, I have reported the percentage of companies reporting the use of incentive plans for either hourly, salaried, professional, supervisory, managerial or executive employees. The AGA survey indicates that 90% of the surveyed companies have one or more types of incentive plans. Such companies also indicate their ratings of success for their incentive plans.

Table 1 – Variable Plan Usage/Success by Revenue Category

Firm Revenue	% Have	% Consider	% of Firms With Plans That Include These Employees						Success* Average Rating
			Hourly	Salary	Prof.	Supv.	Mgmt.	Exec.	
All	90%	2%	65%	60%	95%	96%	98%	98%	2.1
<$350M	73%	0%	64%	64%	91%	100%	100%	91%	2.2
$350M – $1.5B	88%	6%	43%	43%	93%	93%	100%	100%	1.9
>$1.5B	100%	0%	67%	67%	97%	97%	97%	100%	2.1

* 1 = Very Successful 2 = Successful 3 = Limited Success 4 = Not Successful
Source: 2005 American Gas Association

Table 2 below includes competitive data regarding the type of incentive plans deployed by gas utilities. As noted, 85% of the surveyed companies have an organization-wide incentive plan, and that these types of plans go deep into their respective organizations. Of importance is the survey finding that 64% of the hourly employees, 57% of the salaried employees and 89% of the professional employees in those companies having organization-wide incentive plans participate in such plans. These plans are also rated as successful by the organizations having such plans.

Table 2 – Variable Compensation Programs – Usage and Success by Plan Type

Plan Type	% Have	% Consider	% of Firms With Plans That Include These Employees						Success* Average Rating
			Hourly	Salary	Prof.	Supv.	Mgmt.	Exec.	
Org-Wide Incentive	85%	0%	64%	57%	89%	89%	96%	95%	2.0
Small Group Incentive	24%	2%	46%	31%	92%	85%	85%	50%	2.0
Individual Incentive	55%	0%	50%	33%	88%	83%	93%	76%	2.1
Spot Bonuses	42%	0%	70%	61%	91%	91%	91%	48%	2.2

* 1 = Very Successful 2 = Successful 3 = Limited Success 4 = Not Successful
Source: 2005 American Gas Association

Finally, as illustrated in Table 3 below, the AGA survey also cites the types of performance measures found in incentive plans. As noted, the survey findings indicate that a balance of measures are used including financial as the most prevalent, customer satisfaction as the second most prevalent, and safety as the third most prevalent.

Table 3 – Payout Measures

Measure	All	Small	Medium	Large
Financial	98%	100%	93%	100%
Productivity	65%	50%	57%	71%
Quality	46%	50%	50%	43%
Safety	65%	67%	57%	68%
Cost Reduction	54%	67%	50%	54%
Attendance	4%	17%	0%	4%
Project Milestone	46%	67%	36%	46%
Output/Volume	19%	33%	14%	18%
Customer Satisfaction	83%	67%	93%	82%

Source: 2005 American Gas Association

Q. EVEN THOUGH INCENTIVE COMPENSATION PLANS ARE WIDELY USED IN THE GAS UTILITY INDUSTRY, HAVE YOU FOUND THAT THERE REMAINS RESISTANCE TO INCLUSION OF THESE COSTS IN RATES?

A. Yes. The common argument advocated by opponents is that incentive compensation that is tied to financial performance indicators, such as earnings per share or return on invested capital, is a cost that should be borne by a company's shareholders and not the ratepayers. This reasoning is based upon the erroneous assumption that such plans are designed solely to increase profit for shareholders to the exclusion of more customer-oriented aims such as controlling costs and providing superior customer service. This faulty assumption leads to the misconception that incentive plans only promote results whereby the utility's shareholders and employees reap all of the financial rewards of higher earnings to the detriment of ratepayers.

However, earnings are derived by not only increasing revenues, but also by minimizing expenses. To the extent that Company management can minimize unnecessary costs, reduce the number of accidents and safety incidents, deliver satisfactory customer service with reasonable expense and staff levels, and improve performance by increasing productivity, the Company's bottom line (i.e., earnings or earnings per share) will be increased and benefit all constituents.

Q. ARE THE COMPANY'S EMPLOYEES THE PRINCIPAL BENEFICIARIES OF INCENTIVE COMPENSATION PLANS THAT

HAVE NO UNDERLYING OBJECTIVE OF CONTROLLING COSTS OR EXPENSES?

A. Nothing could be further from the truth. The Company's incentive compensation plans are funded based upon the key financial metric of earnings per share (EPS). This metric considers both revenues and expenses in the determination of earnings levels and performance of the Company. Maximization of EPS requires the achievement of rate-based allowed revenues while at the same time controlling expense levels. The attainment of EPS is to the benefit of both shareholders and ratepayers, not one group exclusively. Therefore, both ratepayers and shareholders should recognize the full costs of incentive compensation since it is to the mutual benefit of both constituents.

Q. DO THE COMPANY'S INCENTIVE COMPENSATION PLANS ONLY PROMOTE HIGHER EARNINGS THAT DO NOT BENEFIT RATEPAYERS?

A. This is a common misconception by opponents of incentive compensation and fails to consider that important customer-based considerations are key components of EPS. EPS is the Company's net income divided by total shares outstanding and is considered to be a company's quantity of earnings. Net income is enhanced by both maximizing revenues and controlling expenses. Therefore, higher productivity, more careful management of operations and maintenance costs, and other customer-oriented goals improve net income. As a result, EPS is an important benchmark of the benefit provided to both customers and shareholders.

In my experience and that of my firm, we have found that variable incentive compensation plans benefit all stakeholders – customers, shareholders, employees and the communities served by the Company. It is a variable expense and is tied to improvements in productivity, service, cost management, and other performance factors that drive EPS. Variable incentive compensation plans provide the management of the utility the flexibility to motivate, recognize, and reward performance of their employees. These plans are an allowable part of payroll expenses and should be recovered in a utility's cost of service, especially

when such plans create a financial incentive for employees to achieve goals that are important to customers.

Q. WOULD THE DISALLOWANCE OF INCENTIVE COMPENSATION COSTS AS PART OF THE COMPANY'S RATES PLACE IT AT A COMPETITIVE DISADVANTAGE?

A. Yes. It is commonly understood that regulation is superimposed upon utilities such as the Company as a substitute for competition, but not to eliminate competition. In the context of recruiting and retaining valued employees, the Company faces competition not only from its own industry but also from other industries that are not regulated utilities. Those industries that are not regulated utilities are free to factor the cost of incentive compensation into the price of the products or services they sell. If the Company is not permitted to do so, then it is placed at a competitive disadvantage. Any rate that doesn't represent the amount of expense that a utility must incur to be competitive in the employment market does not meet the goal of fair and effective regulation.

Q. HAVE YOU COMPARED THE COMPENSATION LEVELS OF ATMOS TO OTHER COMPANIES FOR WHICH ATMOS COMPETES FOR TALENT?

A. Yes. When employee salaries and total cash compensation levels are compared to other similar positions in the applicable markets, we find that on average, the Company is paying at the 50th percentile in the market, including both base and variable incentive pay. Towers Perrin periodically conducts an analysis of the competitive levels of selected benchmark positions to determine whether the compensation offered by the Company remains competitive.

Q. WHY IS THIS IMPORTANT?

A. As stated above, the Company's total compensation, including both base and variable incentive pay, positions its employees at the 50th percentile for the market. If the regulatory authority were to disallow any or all of the variable incentive pay component from recovery in rates, then the Company's employee compensation costs reflected in the cost of service would be below the average for

the market and would result in levels in the cost of service that are not reasonable when compared to that market.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

VERIFICATION

STATE OF TEXAS)
)
COUNTY OF DALLAS)

I, John R. Ellerman, being first duly sworn, state that I am a Managing Principal with the consulting firm of Towers Perrin, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Testimony of John R. Ellerman in support of Atmos Energy Corporation's Petition thereto pre-filed in this docket on the date of filing of this Petition are true and correct to the best of my knowledge, information and belief.

John R. Ellerman

Sworn and subscribed before me this 11 day of April, 2007.

MARLENE A. IREY
Notary Public, State of Texas
My Commission Expires
August 29, 2009

Notary Public

My Commission Expires: August 29, 2009

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:

PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

GREGORY K. WALLER

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Gregory K. Waller. I am Vice President of Finance for the Kentucky/Mid-States Division of Atmos Energy Corporation ("Atmos" or the "Company"). My business address is 810 Crescent Centre Drive, Suite 600, Franklin, TN 37067.

Q. PLEASE STATE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Arts degree in economics from Dartmouth College in 1994 and an MBA degree from the University of Texas in 2000. I worked as a management consultant from 1994 to 2003 at Harbor Research in Boston, MA (1994-1996) and Towers Perrin in Dallas, TX (1997 – 2003). I joined Atmos Energy in 2003 in the Planning and Budgeting Department in Dallas. In November of 2005 I became Vice President of Finance for the Mid-States Division, which includes the Company's Tennessee operations, and added Kentucky to my scope of responsibility in April, 2006.[1]

Q. WHAT ARE YOUR RESPONSIBILITIES AT ATMOS?

A. I am responsible for monitoring and analyzing the financial performance of the Kentucky/Mid-States Division, and implementing necessary actions based on those results. I also direct the development of the Division's annual budget. Other

[1] Effective October 1, 2006, the Company's Kentucky and Mid-States Divisions were organizationally consolidated and are now, in effect, one division – the Kentucky/Mid-States Division. "Division" as used in my testimony means the Company's Kentucky/Mid-States Division. "Tennessee" when used in my testimony, unless indicated otherwise, refers exclusively to the Company's operations in Tennessee.

responsibilities include establishing and maintaining policies, procedures, and controls to ensure compliance with corporate accounting policies, Generally Accepted Accounting Principles (GAAP) and regulatory requirements.

Q. HAVE YOU TESTIFIED BEFORE THIS OR ANY OTHER REGULATORY COMMISSION?

A. Yes. I testified before the Tennessee Regulatory Authority in 2006. I have also submitted direct testimony in the Company's rate proceeding pending before the Kentucky Public Service Commission.

II. SUMMARY

Q. WHAT SUBJECT AREAS DO YOU INTEND TO COVER IN YOUR TESTIMONY?

A. I will testify concerning the following subject areas:

1. The Operating and Maintenance (O&M) expense budgeting process used by Atmos Energy's utility divisions, including the Kentucky / Mid-States Division.
2. The Shared Services Unit (SSU) budgeting process.
3. Control and monitoring of O&M variances.
4. The historical test period costs and forecasted attrition year budget for O&M, depreciation expense, and taxes other than income taxes incurred directly by the Tennessee operations and allocated from the Kentucky / Mid-States General Office and Shared Services Unit.

Q. PLEASE SUMMARIZE YOUR TESTIMONY IN THESE SUBJECT AREAS:

A. <u>The Division and SSU Budgeting Process</u>

- The objectives of the Company's O&M budgeting process are to: (1) formalize the process of identifying the anticipated costs of operating and maintaining Atmos' systems each year; (2) ensure that all policies and procedures associated with the annual budgeting process are consistently adhered to by the functional managers and officers; (3) assess the appropriateness of routine maintenance requirements and non-capital expenditures proposed by the functional managers and officers to ensure that the amounts do not exceed a level necessary to deliver safe, reliable and efficient natural gas service to the Company's customers; and (4) ensure that the

O&M budget properly reflects our strategic operational and financial plans.

- O&M costs are budgeted on a fiscal year basis--from October 1 through September 30 of the following year. Budgets are reviewed and approved at multiple levels beginning with the supervisor/managers up through division and corporate leadership.
- The O&M budget is prepared by type of cost element. Within each cost element expenses are budgeted at the sub-account level. Although the budgets are not prepared by FERC account, Atmos Energy does convert its budget and forecast to FERC accounts.
- Effective October 1, 2006, Atmos Energy's Kentucky and Mid-States divisions were combined into a single operating division. In connection with this change, the Mid-States and Kentucky Division general offices were combined for accounting purposes to create one central rate division that houses all of the newly combined division's administrative costs.
- A composite allocation factor is used to allocate common costs to all seven (7) states served by the new general office rate division.
- The annual budget for SSU O&M is developed using the same methods and processes I have previously described.
- SSU is comprised of functional services groups such as planning and budgeting, accounting, legal, rates, information technology, gas supply, customer support and risk management. Each functional service group is comprised of one or more cost centers which may have additional cost centers below them.
- Each SSU cost center owner is responsible for developing his or her annual budget except for certain predetermined costs which are developed by the planning and budgeting group or another group that has knowledge of the predetermined cost.
- Once an SSU cost center budget has been prepared, it is subject to the same managerial review and approval processes that are used for the budgets for the Company's utility divisions and subsidiaries.
- The SSU capital expenditure (capex) budget is developed using the same methods and processes employed for the division's capital expenditure budget. This is more particularly described in the testimony of Mr. Cook.

- The majority of SSU capex costs consists of information technology hardware and software systems.
- O&M costs in an SSU cost center budget are allocated to the Company's utility divisions by using a process of common cost allocation more particularly described in the testimony of Mr. Meziere and Mr. Cagle.
- Unlike O&M costs, SSU capex is not directly charged to the Company's utility divisions or subsidiaries. Once an SSU capital project is completed and closed to plant, it then becomes part of SSU general plant that is allocated for rate making purposes within a rate filing as more particularly described by Mr. Cagle.
- An allocated portion of SSU costs have been included as part of the attrition period costs for purposes of this rate filing.

Control and Monitoring of O&M Variances

- On a quarterly basis, each division's actual to budget variances with explanations are presented to the Company's Management Committee, SSU department heads, select Board of Directors members and external auditors at a formal quarterly performance review.
- Each month, once the books are closed, the SSU Financial Reporting department publishes electronically the monthly Atmos Financial Package that details the financial performance of each of the Atmos operating divisions. This Financial Package, once complete, is available to all Atmos officers and Board members for review and is an official Sarbanes Oxley control document for the Company. Once the Financial Package is complete, I complete an online questionnaire generated by our Sarbanes Oxley Compliance Tool certifying that my department has conducted a thorough review of the division's financial performance and the Financial Package. The Company's external auditors look for this certification as evidence of Sarbanes Oxley compliance.

Historical Test Period Costs and Forecasted Attrition Year Budget

- The forecasted attrition period in this rate proceeding is November 1, 2007 through October 31, 2008.

- The historical test period is our calendar year 2006 (January 1, 2006 through December 31, 2006).
- The basis for the forecasted attrition period budget is the Company's fiscal year 2007 budget.
- Consistent with the organizational changes occasioned by combining the Kentucky and Mid-States divisions into a single division, the forecasted attrition period O&M is comprised of three parts: expenses incurred and booked directly in Tennessee, allocated expenses from the Kentucky/Mid-States division general office, and allocated expenses from SSU.
- The direct O&M for Tennessee for the historical test period is $7,968,549.
- The direct O&M for Tennessee for the attrition period is $8,986,151.
- The difference is $1,017,602 and reflects adjustments I have made for labor and benefits, rent, other O&M and bad debt.
- Labor expense is forecasted by projecting total labor expenditures and multiplying by one minus the forecasted labor capitalization rate.
- Overall total labor is projected to increase 6.1% or $469,219 from the test period to the attrition period or about 3.1% per year.
- The total labor amounts include an amount for capital labor that is not accounted for in an employee by employee schedule of Tennessee based employees. The explanation for this is that Tennessee is the highest growth state in our division. It is common for employees of surrounding states to work in Tennessee on capital projects when the existing work load dictates.
- This labor is accounted for in the Company's accounting systems as "capital labor transferred in." When netted against "capital labor transferred out" the result is net capital labor transferred into the State of Tennessee to work on capital projects.
- In Calendar 2006, the Company had $609,102 of net capital labor transferred into Tennessee. Because the Company budgets capital expenditures project by project rather than employee by employee, most of this labor is not budgeted in our Tennessee labor budget but is, in fact, captured in the amount of capital expenditures we have budgeted in the state.
- Therefore, we have used our Calendar 2006 amount of net capital labor transferred

in as a proxy for fiscal year 2007 and the attrition period.

- Labor capitalization rates are forecasted by analyzing annual historical patterns and considering known capital and expense initiatives that may alter anticipated rates. One minus the labor capitalization rate is multiplied by the total labor projections to arrive at the forecast for labor expense.
- The labor capitalization rate in the approved fiscal year 2007 budget averages 56.9% for the year. This is 1.8% lower than the capitalization rate in the test period.
- In developing our capitalization rate forecast for the attrition period, we took the actual booked amounts for the first three months (October – December) of fiscal 2007 and the last nine months (January – September) of our fiscal year 2007 budget, which resulted in an attrition period capitalization rate of 56.2%. Applying one minus that rate to our forecast of total labor results in labor expense forecasted to increase $399,583 from the test period to the attrition period.
- Benefits are projected as a fixed benefit load percentage of labor expense plus an amount for worker's compensation insurance. The attrition period benefits expense of $1,470,322 is $199,455 higher than the test period.
- Building rent is driven by leases already in place and the rent portion of O&M was projected by reviewing actual lease amounts. The adjustment is an increase of $354,859 from the test period, substantially offset by a decrease in the division General Office (see schedule GW-2).
- O&M expense types other than labor, benefits, rent and bad debt are forecasted using a standard inflation factor of 3.5% to arrive at the attrition period expense level.
- Our adjustment relating to bad debt seeks to reflect our goal that bad debt is no higher than .5% of residential, commercial and public authority gross margins during any given year. To arrive at the bad debt projection of $183,013 we simply calculated .5% of residential, commercial and public authority gross margins from the revenue projections. The projection is $82,088 higher than the test period.
- The General Office O&M allocated to Tennessee for the historical test period is $3,222,369.

- The General Office O&M allocated Tennessee for the attrition period is $2,832,105. The difference between the General Office test period O&M and the attrition period O&M allocated to Tennessee is a decrease of $390,264.
- Using the forecast methodologies I have described, labor expense is forecasted to decrease $62,638 from the test period to the attrition period. Benefits are forecasted to increase $59,309. Rent expense is forecasted to decrease $298,485 and other O&M is forecasted to decrease $73,762 from the test period to the attrition period. In addition, there is an adjustment to remove $14,688 of bad debt provision mistakenly booked to the General Office and allocated to Tennessee in October, 2006.
- The amount of shared services O&M allocated to Tennessee for the test period is $3,598,703. The amount of the shared services O&M allocated to Tennessee for the forecasted attrition period is $4,023,186.
- The differences between the shared services O&M for the test period and the forecasted attrition period is an increase of $424,483.
- When the three components of O&M are added together, total O&M is forecasted to increase 7.1% or approximately 3.6% per year from a test period level of $14,789,621 to an attrition period level of $15,841,442.
- The amount of depreciation expense for the test period is $11,498,043.
- The amount of depreciation expense for the attrition test period is $10,652,288.
- The expense level for taxes, other than income taxes for the test period, is $5,851,994. The level of taxes, other than income taxes for the forecasted attrition period is $7,010,933. The difference is $1,158,939.
- Taxes other than income taxes, like O&M, are comprised of three components: direct Tennessee taxes, taxes allocated from the General Office and taxes allocated from the SSU. These components are itemized by type of tax on Schedule GW-3. The primary reason for the increase is a significant expected increase in State Gross Receipts Taxes from $1,757,625 to $2,764,815.

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. Yes. I am sponsoring the following schedules.

Schedule GW-1 Total Operating Expenses

Schedule GW-2 O&M by Cost Element
Schedule GW-3 Taxes other than Income Tax
Schedule GW-4 Depreciation Expense

III. O&M BUDGETING PROCESS

Q. WHAT ARE THE OBJECTIVES OF THE COMPANY'S O&M BUDGETING PROCESS?

A. The objectives of the Company's O&M budgeting process are to: (1) formalize the process of identifying the anticipated costs of operating and maintaining Atmos' systems each year; (2) ensure that all policies and procedures associated with the annual budgeting process are consistently adhered to by the functional managers and officers; (3) assess the appropriateness of routine maintenance requirements and non-capital expenditures proposed by the functional managers and officers to ensure that the amounts do not exceed a level necessary to deliver safe, reliable and efficient natural gas service to the Company's customers; and (4) ensure that the O&M budget properly reflects our strategic operational and financial plans. These objectives are applicable to the Company as a whole (including SSU) as well as to its various division, state and local level operations.

Q. CAN YOU DESCRIBE THE COMPANY'S O&M BUDGETING PROCESS?

A. Yes. O&M costs are budgeted on a fiscal year basis, which begins on October 1 of each year (consistent with the seasonal operations of our business) and runs through September 30 of the following year. Preparation of operating and construction budgets for a fiscal year formally begins in late May of each year and culminates with completion of final budgets in late August, just prior to the beginning of the fiscal year. Budget preparation is based on meeting the four objectives described above. Budgets are approved at multiple levels beginning with supervisor/managers up through division leadership. Additional reviews are performed by corporate executive operations management and their staff. High level reviews of the division budgets are also performed by the Company's senior executives who are presiding members of the Company's Management Committee. The Board of Directors must review and approve the total Company budget before finalization and implementation. This approval typically occurs in September of each year.

Q. WHAT ROLE DOES THE O&M BUDGETING PROCESS PLAY IN THE COMPANY'S FINANCIAL PLANNING?

A. Atmos' Planning and Budgeting Department is responsible for financial planning at the enterprise level. That department receives direction from the Board of Directors concerning forward-looking financial objectives for the Company. Planning and Budgeting is responsible, with significant input and collaboration from division leadership, for translating those enterprise targets into a financial plan for each division and rate jurisdiction. It is the collaboration between Planning and Budgeting and division leadership that ensures that all four of the objectives described above are met each year. Spending targets are established as a result of this collaboration.

Q. WHAT IS YOUR ROLE IN THIS PROCESS?

A. My role is to facilitate the budget process within the Kentucky Mid-States Division that confirms the operational feasibility of the targets and produces an O&M budget consistent with the Company's processes and goals described above. My department communicates certain budget guidelines such as average wage increase percentages and anticipated benefits rates to managers and supervisors (cost center owners). Each cost center owner is responsible for building his or her department's budget and submitting it for review by me and approval along the appropriate approval chain. My department provides support to and often asks for clarifying information from cost center owners as needed to explain significant variances from the prior year. In addition, we budget several items on behalf of the entire Division such as bill print fees, insurance costs, bad debt provision, etc. An iterative process involving Division leadership (including myself), my department and the cost center owners ultimately produces an O&M budget that meets the needs of our operations, ensures that we operate safely, reliably and efficiently, and allows our Division to contribute to the financial success of Atmos. This process is used to develop the direct O&M budget for Tennessee, as well as the Division's general office O&M budget. A portion of the Division's general office O&M budget, as hereinafter discussed, is allocated to Tennessee in accordance with the allocation methods addressed in the direct testimony of Company witnesses Daniel M. Meziere and James C. Cagle.

Q. SO FAR YOU HAVE DESCRIBED THE O&M BUDGETING PROCESS. CAN

YOU EXPLAIN HOW THE BUDGET IS PREPARED WITHIN THE PARAMETERS OF THIS PROCESS?

A. Yes. The O&M budget is prepared by type of cost element, such as labor, benefits, transportation, rents, office supplies, etc. Within each cost element we budget expenses at the sub-account level. The prior year's actual costs, year to date actual costs and budgeted costs for the remainder of the fiscal year are used as guidelines for budgeting by functional managers and officers. The budgets are prepared using a web based software tool called PlanIt. This tool allows cost center owners to enter their budgets and allows my department and Division management to review budgets using a number of standard and ad hoc reports.

Q. ARE THESE BUDGETS PREPARED BY FERC ACCOUNT?

A. No. In our experience, FERC accounts do not provide a sufficient level of detail to enable us to understand the costs within each account. For budgeting purposes (and subsequent managing of expenses), we need individualized expense types that relate to the operation of each cost center. FERC accounts do not provide that level of detail. However, when we spend, we do identify our expenditures by FERC account as well as expense type. This provides a timely analysis of the type of charges being expensed by FERC account.

Q. HOW DOES ATMOS CONVERT ITS O&M BUDGET BY COST ELEMENT INTO FERC ACCOUNTS?

A. To convert our budget and forecast to FERC accounts, fiscal year 2006 actual expenditures were downloaded from the general ledger by FERC account and cost element. A calculation was then made to determine within each cost element type the percentage of spending attributable to each FERC account. Each percentage factor was then applied to the fiscal year 2007 budget and attrition period forecast by cost type to develop a budget and test period forecast by FERC account.

Q. WERE THERE ANY RECENT ORGANIZATIONAL CHANGES WITHIN THE DIVISION WHICH IMPACT THE PREPARATION OF THE O&M BUDGETS FOR EITHER THE DIVISION OR FOR TENNESSEE?

A. Yes. As alluded to earlier in my testimony[2], effective October 1, 2006, the Company's

[2] *See* footnote 1, *infra.*

Kentucky and Mid-States Divisions were combined into a single operating division. Combining the two divisions has allowed for some restructuring of responsibilities among the officers and managers of the two divisions. The Company began implementing some of these changes in early 2005 and progressively made further changes during 2006.

Q. PLEASE DESCRIBE THE CHANGES TO WHICH YOU REFER.

A. Upon the retirement of the Mid-States Division President in January 2005, John Paris, the President of the Kentucky Division and a Company witness in this case, assumed responsibility as President over both divisions. In addition, the Kentucky Vice President of Finance retired in April 2006, and the decision was made to continue to operate both divisions with one Vice President of Finance. Similarly, the Mid-States Vice President of Technical Services retired in October, 2006 and we now operate the Division with one Vice President of Technical Services.

Prior to combining the divisions, the Kentucky and Mid-States Divisions each had two Vice Presidents of Operations. In June 2006, the Mid-States Division's Eastern Region Vice President of Operations retired, allowing for a significant reorganization of our operating regions beginning October 1, 2006. The newly combined Division now operates with three Vice Presidents of Operations who are responsible for the Northern, Central, and Southern regions. The Northern Region includes parts of Kentucky, Missouri, Illinois and all of the Company's service territory in Iowa. The Central Region includes the remaining parts of Kentucky, Missouri, Illinois, and Union City, Tennessee. The Southern Region includes the remaining parts of Tennessee, and all of the Company's service territories in Virginia and Georgia. Some managers under these officers have also been assigned new areas of responsibility.

Q. ARE THERE ANY OTHER ORGANIZATIONAL CHANGES WHICH ARE PLANNED?

A. Currently, the changes I have described are the only planned changes that have or will take effect. There are no other plans to close or consolidate any offices, move employees, or make other physical changes to the operations of the Division at this time. Any other increased efficiencies and cost savings that can be achieved from the combination of the two divisions will be carefully considered and implemented if found

to be of benefit to the Company and its customers.

Q. DID THE ORGANIZATIONAL CHANGES YOU HAVE DESCRIBED IMPACT COMMON COST ALLOCATION?

A. Yes. Combining the Kentucky Division, a single state division, with Mid-States, a multi-state division, necessitated accounting changes as well. The Kentucky Division leadership and division support people (the Kentucky Division's "general office"), located in Owensboro, KY, had historically charged expenses to the same rate jurisdiction as the operations personnel because the state, rate jurisdiction, and division were the same. The Mid-States general office, located in Franklin, Tennessee, was accounted for as a separate rate jurisdiction that allocated costs to the six states that made up the division. Effective October 1, 2006, the Mid-States and Kentucky division general offices were combined, for accounting purposes, to create one central rate division that houses all of the newly combined division's administrative costs. In other words, the Company will keep these offices open physically, but will only house and allocate costs from one central administrative rate division. We use a composite allocation factor to allocate common costs to all seven states served by the new general office rate division. The composite factor methodology is further described in the direct testimony of Mr. Cagle. All costs charged to the new division general office can and should be allocated to the seven states using the composite allocation factor because each Division officer and all other employees in the general office rate division provide direction, administrative support, and various services for all states throughout the combined Kentucky Mid-States Division.

Q. WHAT AFFECT DID THE CHANGES YOU HAVE DESCRIBED HAVE UPON THE ALLOCATION OF SSU COMMON COSTS?

A. These changes also impact the amount of common costs allocated to the Division by SSU as well as the amount of SSU common costs ultimately allocated to Tennessee. The complete SSU common cost allocation process from SSU to the Division and then ultimately to the operating rate divisions within the Division (although briefly described above) is more particularly described in Mr. Cagle's testimony.

Q. HOW DO THESE CHANGES TO COMMON COST ALLOCATION AFFECT THE O&M BUDGETS FOR THE DIVISION AND FOR TENNESSEE?

A. The fiscal year 2007 budget, booking of actual expenditures and forecasted attrition period O&M reflect the new divisional structure and changes described above.

IV. SSU BUDGETING

Q. CAN YOU DESCRIBE THE SSU BUDGETING PROCESS?

A. The annual budget for SSU O&M is developed using the same methods, processes and controls which I have described hereinabove. SSU is, however, slightly different.

Q. HOW DOES SSU DIFFER?

A. Perhaps the easiest way to explain the SSU budgeting process is to begin with a brief explanation of how SSU is organized. SSU is comprised of functional service groups such as planning and budgeting, accounting, legal, rates, information technology, gas supply, customer support, risk management, etc. Each functional service group is comprised of one or more cost centers, such as accounting which, at the high level, consists of the Company's controller, general accounting services, tax services, revenue accounting and financial reporting. These cost centers may have additional cost centers below them which roll up into the cost center for total budgeting purposes, such as plant accounting within general accounting. The planning and budgeting group works with and supports the Company's utility divisions, subsidiaries and SSU cost center owners in the development of their annual budgets.

Each SSU cost center owner, whether an officer, managerial director, manager or supervisor of the Company, is responsible for developing his or her annual budget as part of the Company-wide annual budgeting process, except for certain pre-determined costs developed by planning and budgeting or another group that has knowledge of the pre-determined cost. An example of a pre-determined cost is the allocated portion of corporate office rent. Pre-determined costs are provided to cost center owners for inclusion in their cost center budgets.

Once an SSU cost center budget has been prepared, it is subject to the same managerial review and approval processes that are used for the budgets of the Company's utility divisions and subsidiaries. Once approved, the SSU cost center's budget is subject to the same ongoing control processes, including variance monitoring, that I have described hereinbelow.

Q. YOU HAVE DESCRIBED THE SSU O&M BUDGETING PROCESS, BUT WHAT ABOUT SSU CAPEX BUDGETING?

A. The SSU Capex budget is developed using the same methods and processes employed for the Division's Capex budget which is more particularly described in the direct testimony of Company witness Mr. Robert R. Cook, Jr. There are, however, some notable differences.

Q. PLEASE DESCRIBE THE DIFFERENCES.

A. Although a particular Capex item may be budgeted by an SSU cost center owner, such as the purchase of a new filing cabinet, the majority of SSU Capex costs consists of information technology hardware and software systems. These costs are budgeted in the SSU Information Technology (IT) costs centers. For example, if tax services required a new property tax management system, then the IT group would work with tax services to budget the costs of purchasing or developing and implementing the new system. IT will include these costs as part of the IT Capex budget for SSU information technology capital projects. The SSU Capex budget is subject to the same managerial review and pre-approval processes, as well as ongoing control processes, described in Mr. Cook's testimony.

Q. HOW ARE THE COSTS IN AN SSU COST CENTER BUDGET CHARGED OR ALLOCATED TO THE COMPANY'S UTILITY DIVISIONS, SUCH AS IN TENNESSEE?

A. For O&M costs, the Company employs a process of common cost allocation that is described in the direct testimony of Mr. Meziere and Mr. Cagle. For illustrative purposes only, if the SSU tax services cost center budgeted $100,000 in O&M for a fiscal year and the applicable allocation factor for Tennessee was 5%, then Tennessee would be allocated $5,000 of tax services budgeted O&M. Of course, budgeted allocation amounts are based upon actual budget numbers and actual allocation factors. Unlike O&M, SSU Capex is not directly charged to the Company's utility divisions or subsidiaries. Once an SSU capital project is completed and closed to plant, it then becomes part of SSU general plant that is allocated for ratemaking purposes within a rate filing as more particularly described by Mr. Cagle. In this rate filing, increases to SSU general plant for the attrition period pertain to spending on capital projects which

are reasonably expected to be closed to plant and in service for the benefit of the Company's utility divisions, including the Kentucky/Mid-States Division, before the end of the attrition period.

Q. HAVE ALLOCATED SSU COSTS BEEN INCLUDED AS PART OF THE ATTRITION PERIOD COSTS FOR PURPOSES OF THIS RATE FILING?

A. Yes. The Company's planning and budgeting group developed the forward-looking SSU costs (both O&M and Capex) for purposes of the attrition period used for this rate filing. The entirety of these forecasted costs are not attributable to Tennessee, only an allocated portion. The allocated costs were determined according to the cost allocation process described by Mr. Meziere and Mr. Cagle and are incorporated into the filing requirements sponsored by me (O&M) and Messrs. Cook and Petersen (Capex).

V. O&M CONTROL AND MONITORING

Q. DOES THE COMPANY EMPLOY ANY METHODOLOGY TO MONITOR AND CONTROL O&M ACCORDING TO BUDGETED LEVELS?

A. Yes. Atmos utilizes variance monitoring to ensure financial quality control of O&M expenses by formalizing the analysis of variances by cost type and cost center. On a quarterly basis, we present our Division's actual to budget variances with explanation to the Company's Management Committee, SSU department heads, select Board of Directors members and external auditors at a formal Quarterly Performance Review. The goal is to keep all levels of management informed of our O&M spending in comparison to budgeted amounts, in order to allow management to react to unanticipated events on a timely basis.

Q. ARE O&M VARIANCES EVALUATED MORE FREQUENTLY THAN ON A QUARTERLY BASIS?

A. Yes. My department conducts a thorough review of O&M actual to budget variances each month.

Q. PLEASE DESCRIBE YOUR MONTHLY VARIANCE REVIEW PROCESS.

A. We begin by examining, at the Division level, significant variances by cost type (labor, benefits, materials, rents, etc.). Significant variances are researched until an explanation

is found. Reasonable explanations could include events that affected the entire Division or a particular cost center or region. In some cases, clarifying information is sought from cost center owners to explain unusual variances or transactions. For some cost types, clarifying analysis is provided by SSU departments. If errors are found, they are most often corrected in the current month's business. Occasionally, however, errors are discovered after the books are closed, and, depending on materiality, they are corrected in the following month's business.

Q. DOES ANYONE ELSE WITHIN THE DIVISION HAVE THE ABILITY TO MONITOR OR REVIEW O&M VARIANCES?

A. In addition to the research conducted by my department, each cost center owner has the ability to run variance reports throughout the monthly closing process. Because cost center owners are held accountable for significant variances to budget, they conduct their own research and often contact my department when they find errors or have questions about the expenses that were charged to their cost centers.

Q. WHAT CONTROLS AND REPORTING ARE INVOLVED IN THE MONTHLY CLOSE PROCESS REGARDING O&M VARIANCES?

A. Once the monthly books are closed, the SSU Financial Reporting department in Dallas publishes (electronically) the monthly Atmos Financial Package. This package details the financial performance for Atmos Energy at the corporate and each division level. For each division, the report includes a comparative income statement, operating statistics (volumes, total spending) page, O&M detail page, balance sheet highlights page and financial highlights page. The financial highlights page reports the Division's monthly and year-to-date (YTD) performance versus budget for net income, gross profit, direct O&M and capital spending. I provide narrative comments on this page to describe our monthly and YTD variances. Once complete, this Financial Package is available to all Atmos officers and Board members for review and is an official Sarbanes Oxley control document of the Company. Once the package is complete, I complete an online questionnaire generated by our Sarbanes Oxley Compliance Tool certifying that my department has conducted a thorough review of the division's financial performance and the Financial Package and addressed all matters therein. The

Company's external auditors look for this certification as evidence of Sarbanes Oxley compliance.

After meeting the Financial Package control requirement, my department publishes (electronically) detailed O&M reports that include monthly and YTD variances for each cost center and these reports are then made available to each cost center owner and their respective managers (managers, Division Vice Presidents, Division President). This activity ensures that each cost center owner receives the same information in the same format each month in a timely fashion in order to make operational decisions and manage our operations effectively and efficiently.

VI. FORECASTED ATTRITION PERIOD O&M BUDGET

Q. WHAT IS THE FORECASTED ATTRITION PERIOD USED IN THIS RATE APPLICATION?

A. The forecasted attrition period is November 1, 2007 through October 31, 2008.

Q. HOW WAS THE FORECASTED ATTRITION PERIOD BUDGET DEVELOPED?

A. The basis for the forecasted attrition period is our fiscal year 2007 ("FY2007") budget. Consistent with our normal annual budgeting timelines, this budget was prepared during the summer of 2006 and approved by the Board of Directors in September of 2006. This budget was prepared in the manner I described earlier. In preparing the forecast for the attrition period, our first quarter (October 1, 2006 – December 31, 2006) actual results were also considered alongside the FY07 budget and forecast adjustments were made where appropriate. The projection of the forecasted attrition period then builds upon first quarter results and remaining FY07 budget. I will describe the methodology used for the projection period in detail below. The FY2007 O&M budget and forecasted attrition period projection were converted into FERC account detail using the method described above.

Q. WHAT ARE THE COMPONENTS OF O&M FOR THE FORECASTED ATTRITION PERIOD?

A. Consistent with the organizational changes discussed earlier in my testimony, the forecasted attrition period O&M is comprised of three parts: expenses incurred and

booked directly in Tennessee, allocated expenses from the Kentucky/Mid-States Division General Office, and allocated expenses from SSU. These components are itemized on schedule GW-1. I will describe the methodology used for the projection for each of the three components.

Q. WHAT COMPRISES THE HISTORICAL TEST PERIOD LEVEL OF COST FILED IN THIS RATE APPLICATION?

A. The historical test period level of cost is our calendar year 2006 (January 1, 2006 – December 31, 2006) .

Q. WHAT IS THE DIRECT O&M FOR THE HISTORICAL TEST PERIOD?

A. The direct O&M for Tennessee for the historical test period (hereinafter the "Test Period O&M") is $7,968,549.

Q. WHAT IS THE DIRECT O&M FOR THE FORECASTED ATTRITION PERIOD?

A. The direct O&M for Tennessee for the attrition period (the "Attrition Period O&M") is $8,986,151.

Q. WHAT IS THE DOLLAR DIFFERENCE BETWEEN THE TEST PERIOD O&M AND ATTRITION PERIOD O&M?

A. The difference is $1,017,602 and reflects adjustments I have made for labor and benefits, rent, other O&M and bad debt. These adjustments by cost element can be seen in Schedule GW-2.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR LABOR AND BENEFITS.

A. Labor expense is forecasted by projecting total labor expenditures and multiplying by one minus the forecasted labor capitalization rate. While there is always a normal level of position vacancy at any given point in time, we strive to fill open positions in a timely manner when and if filling the position is justified by current workload. The base period level of total labor expenditures represents a fully staffed level minus the normal level of vacancies. Therefore, employee levels are projected to remain relatively constant from the test period to the attrition period. The fact that we have maintained relatively stable employee levels for the past several years despite adding 2000 to 3000 net new customers annually is a tribute to our ability to run efficiently and continually improve productivity. Base pay increases go into effect each October 1 and

have averaged 3.5% annually for the past several years. The increases that took effect October 1, 2006 are captured as part of the FY2007 budget. An adjustment was made as part of the forecast to account for an average wage increase of 3.5% to become effective October 1, 2007. Overall, total labor is projected to increase 6.1%, or $469,219, from the test period to the attrition period or about 3.05% per year. It is important to note that these total labor amounts include an amount for capital labor that is not accounted for in an employee by employee schedule of Tennessee based employees. Because Tennessee is the highest growth state in our division, it is common for employees from surrounding states to work in Tennessee on capital projects when the existing workload dictates. This labor is accounted for in our accounting systems as "capital labor transferred in". When netted against "capital labor transferred out" the result is net capital labor transferred into the state of Tennessee to work on capital projects. This is labor that is necessary and critical to our Tennessee operation and must be included in any total labor calculation. In Calendar 2006, we had $609,102 of net capital labor transferred into Tennessee. Because we budget capital expenditures project by project rather than employee by employee, most of this labor is not budgeted in our Tennessee labor budget, but is, in fact, captured in the amount of capital expenditures we have budgeted in the state. Therefore, we have used our Calendar 2006 amount of net capital labor transferred in as a proxy for FY07 and the attrition period. This amount is added to our employee by employee schedule presented in MFR #31 and MFR #32 to arrive at the correct forecast of <u>total</u> direct labor for Tennessee.

Labor capitalization rates are forecasted by analyzing annual historical patterns and considering known capital and expense initiatives that may alter anticipated rates. One minus the labor capitalization rate is multiplied by the total labor projection to arrive at the forecast for labor expense. The labor capitalization rate in the approved FY07 budget averages 56.9% for the year. This is 1.8% lower than the labor capitalization rate in the test period. A higher than budgeted amount of capital work was done using in- house labor in the last quarter of fiscal 2006 causing the average test period capitalization rate to be higher than anticipated. In developing our capitalization rate forecast for the attrition period, we took the actual booked amounts for the first three months (October – December) of fiscal 2007 and the last nine months (January –

September) our fiscal year 2007 budget, which resulted in an attrition period capitalization rate of 56.2%. Applying one minus that rate to our forecast of total labor results in labor expense forecasted to increase $399,583 from the test period to the attrition period.

Benefits are projected as a fixed benefit load percentage of labor expense plus an amount for workers' comp insurance. The attrition period benefits expense of $1,470,322 is $199,455 higher than the test period.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT RELATING TO RENT.

A. Unlike other O&M categories that are likely to increase with normal inflation, our building rents are driven by leases already in place and can therefore be projected with a high level of accuracy. The rent portion of the O&M category "Rent, Utilities and Maintenance" was projected by reviewing actual lease amounts. The adjustment is an increase of $354,859 from the base period, substantially offset by a decrease in the division General Office.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT RELATING TO OTHER O&M.

A. For the purpose of this rate filing, O&M expense types other than labor, benefits, rent and bad debt are forecasted using a standard inflation factor. Using our FY2007 budget and first quarter results as a starting point, categories other than the ones listed above are inflated by 3.5% to arrive at the attrition period expense level. The 3.5% inflation factor is the average inflation rate for the southern region over the last two years as reported by the Bureau of Labor Statistics. Beginning in January, 2007, expenses for gas supply services have been moved from the Outside Services expense category in direct O&M to become a component of the allocated Shared Services expenses. This change is made consistent with an organizational change at the corporate level in which the department providing gas supply services was moved from Atmos Energy Services to SSU. The result of this change combined with the standard inflation factor for other categories is a $18,383 decrease over the test period level of expenses for other O&M categories.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT RELATING TO BAD DEBT

A. Our goal is to keep bad debt no higher than 0.50% of residential, commercial and public authority gross margins during any given year. We work vigorously to collect bad

debts from customers each year to achieve this goal so as to reduce the impact of good-paying customers subsidizing poor-paying customers who drive up our expenses. To arrive at the bad debt projection of $183,013 we simply calculated 0.50% of residential, commercial and public authority gross margins from the revenue projection discussed in the testimony of Tom Petersen. The projection is $82,088 higher than the test period.

Q. WHAT IS THE DIVISION GENERAL OFFICE O&M FOR THE HISTORICAL TEST PERIOD?

A. The General Office O&M allocated to Tennessee for the historical test period is $3,222,369.

Q. WHAT IS THE DIVISION GENERAL OFFICE O&M FOR THE FORECASTED ATTRITION PERIOD?

A. The General Office O&M allocated to Tennessee for the attrition period is $2,832,105.

Q. WHAT IS THE DOLLAR DIFFERENCE BETWEEN THE GENERAL OFFICE TEST PERIOD O&M AND ATTRITION PERIOD O&M ALLOCATED TO TENNESSEE?

A. The difference is a decrease of $390,264 and reflects adjustments I have made for labor and benefits, rent and other O&M. The budgeting process and forecast methodologies are identical for both direct O&M and General Office O&M. Therefore, the categories of adjustments made to forecast General Office O&M are also the same as direct with the exception of bad debt which is only budgeted and booked directly into operating rate divisions (i.e. states).

Q. PLEASE DOCUMENT THE AMOUNTS OF ADJUSTMENTS MADE TO GENERAL OFFICE O&M ALLOCATED TO TENNESSEE?

A. Using the forecast methodologies described above, labor expense is forecasted to decrease $62,638 from the test period to the attrition period. Benefits are forecasted to increase $59,309 from the test period to the attrition period. Rent expense is forecasted to decrease $298,485 from the test period to the attrition period. Other O&M is forecasted to decrease $73,762 from the test period to the attrition period. In addition, there is an adjustment to remove $14,688 of bad debt provision mistakenly booked to the General Office and allocated to Tennessee in October, 2006.

Q. WHAT IS THE AMOUNT OF SHARED SERVICES O&M ALLOCATED TO

TENNESSEE FOR THE TEST PERIOD?

A. $3,598,703.

Q. WHAT IS THE AMOUNT OF THE SHARED SERVICES O&M ALLOCATED TO TENNESSEE FOR THE FORECASTED ATTRITION PERIOD?

A. $4,023,186.

Q. PLEASE DISCUSS THE DIFFERENCE BETWEEN THE SHARED SERVICES TEST PERIOD AND FORECASTED ATTRITION PERIOD AMOUNTS.

A. The difference is an increase of $424,483. The forecasted SSU attrition period amounts are determined using the same methodology described earlier for the Direct O&M. In preparing the forecast for the attrition period, our first quarter (October 1, 2006 - December 31, 2006) actual results were also considered alongside the FY07 budget and forecast adjustments were made where appropriate. The projection of the forecasted attrition period then builds upon first quarter results and remaining FY07 budget. The SSU budget is prepared as I described above. Once the SSU department heads complete, submit and get approval for their budgets, the appropriate level of expenses are allocated to the Tennessee rate jurisdiction per the methodologies described in Mr. Cagle's testimony.

Q. HOW DO YOU MONITOR SHARED SERVICES BILLINGS TO THE KENTUCKY MID-STATES DIVISION?

A. Shared Services expense billings are reviewed as part of our monthly close process described earlier. It is my responsibility to contact Accounting in Dallas and obtain an explanation for any significant variances.

Q. ADDING THE THREE COMPONENTS OF O&M TOGETHER, WHAT IS THE TOTAL O&M FOR THE TEST PERIOD AND ATTRITION PERIOD IN THIS RATE FILING?

A. Total O&M is forecasted to increase 7.1% (or approximately 3.6% per year) from a test period level of $14,789,621 to an attrition period level of $15,841.442.

VII DEPRECIATION EXPENSE AND TAXES, OTHER THAN INCOME TAX

Q. WHAT IS THE DEPRECIATION EXPENSE FOR THE TEST PERIOD?

A. The amount of depreciation expense for the test period is $11,498,043.

Q. WHAT IS THE DEPRECIATION EXPENSE FOR THE FORECASTED ATTRITION PERIOD?

A. The amount of depreciation expense for the forecasted test period is $10,652,288

Q. PLEASE DISCUSS THE DIFFERENCES BETWEEN THE TEST PERIOD AND FORECASTED ATTRITION PERIOD DEPRECIATION AMOUNTS.

A. Depreciation rates for the forecasted attrition period are based on the results of the depreciation study for Tennessee recently conducted by Company witness Mr. Donald S. Roff. This study and the results thereof are more specifically discussed in Mr. Roff's direct testimony. The depreciation rates developed by Mr. Roff in his study for Tennessee have been applied to the applicable categories of plant, resulting in the total depreciation expense noted above. Please see Schedule GW-4 for details.

The depreciation expense allocated to Tennessee by SSU is also based on a study recently conducted by Mr. Roff. This study and the results thereof are more specifically discussed in Mr. Roff's direct testimony. The depreciation rates for SSU by Mr. Roff in his study have been applied to the applicable categories of SSU plant, resulting in an allocation of SSU depreciation expense to Tennessee based upon the cost allocation methodology more fully explained in the direct testimony of Mr. Cagle.

Q. WHAT IS THE EXPENSE LEVEL FOR TAXES, OTHER THAN INCOME TAXES FOR THE TEST PERIOD?

A. $5,851,994

Q. WHAT IS THE LEVEL OF TAXES, OTHER THAN INCOME TAXES FOR THE FORECASTED ATTRITION PERIOD?

A. $7,010,933.

Q. PLEASE DISCUSS THE DIFFERENCES BETWEEN THE TEST PERIOD AND FORECASTED ATTRITION PERIOD AMOUNTS.

A. The difference is $1,158,939. Taxes, other than income taxes, like O&M, are comprised of three components: direct Tennessee taxes, taxes allocated from the General Office, and taxes allocated from SSU. These components are itemized by type of tax on schedule GW-3. The primary reason for the increase is a significant expected increase in State Gross Receipts Taxes from $1,757,625 to $2,764,815. State gross receipts taxes are calculated based on the level of gross receipts from the most recently

completed year and paid each year in the summer. That amount is then amortized on the income statement for the following 12 months proportional to the gross receipts in that month. Due to this timing, there is approximately a two year lag on the timing of the actual gross receipts and the corresponding gross receipts taxes on the income statement. Therefore, the gross receipts taxes for the attrition period correspond approximately to gross receipts received in FY06, a time of historically high gas cost and therefore high gross receipts. State franchise taxes and excise taxes are taken as a deduction when calculating gross receipts taxes. The state franchise tax deduction has been included in the projection of gross receipts taxes. An excise tax deduction, however, has not been included because we will not owe excise taxes on the return to be filed this summer. Excise taxes due in Tennessee are calculated based upon our federal income tax return. Because the Atmos regulated utility experienced a taxable loss for the period, no excise taxes will be due. Since there are no excise taxes due, there will be no excise tax deduction in our gross receipts tax calculation which, in turn, contributes to gross receipts taxes being significantly higher than the base period.

Payroll taxes have been estimated by taking into account employee levels and anticipated merit increases. Ad valorem taxes have been held flat from our approved FY07 budget. The amount of taxes allocated from the Division General Office and SSU is based on the allocation methodologies discussed in the testimony of Jim Cagle.

VIII CONCLUSION

Q. DO YOU BELIEVE THAT THE ATTRITION PERIOD FORECASTS YOU HAVE PRESENTED ARE THE MOST REASONABLE ESTIMATE OF COSTS FOR THE ATTRITION PERIOD USED IN THIS PROCEEDING?

A. Yes. It is the best estimate we have of the Tennessee jurisdiction's future expenses.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF ATMOS ENERGY	)	
CORPORATION FOR APPROVAL OF	)	
ADJUSTMENT OF ITS RATES AND	)	
REVISED TARIFF	)	**DOCKET NO. 07-_____**

VERIFICATION

STATE OF TENNESSEE)
)
COUNTY OF WILLIAMSON)

I, Gregory K. Waller, being first duly sworn, state that I am Vice President of Finance for the Kentucky/Mid-States Division of Atmos Energy Corporation, that I am authorized to testify on behalf of Atmos Energy Corporation in the above referenced docket, that the Testimony of Gregory K. Waller in support of Atmos Energy Corporation's Petition and the Exhibits thereto pre-filed in this docket on the date of filing of this Petition are true and correct to the best of my knowledge, information and belief.

Gregory K. Waller

Gregory K. Waller

Sworn and subscribed before me this 17th day of April, 2007.

Pamela Todd

Notary Public

PAMELA TODD
STATE OF TENNESSEE
NOTARY PUBLIC
DAVIDSON COUNTY, TENN.

My Commission Expires: 05-24-08

My Commission Expires 05-24-08

Tennessee Distribution System
Total Operating Expenses
Schedule GW-1

	Test Period	Attrition Period
O&M		
Direct	7,968,549	8,986,151
SSU	3,598,703	4,023,186
Division General Office	3,222,369	2,832,104
Total O&M	14,789,621	15,841,442
Taxes Other		
Direct	5,569,778	6,755,373
SSU/Division General Office	282,216	255,560
Total Taxes Other	5,851,994	7,010,933
Depreciation		
Direct	10,419,926	9,516,217
SSU/Division General Office	1,078,117	1,136,071
Total Depreciation	11,498,043	10,652,288
Total Operating Expense (excl Gas costs)	32,139,658	33,504,663

Tennessee Distribution System
O&M by Cost Element
Schedule GW-2

	Tennessee			SSU			Division General Office			Total		
	Test	Attrition	Difference	Test	Attrition	Difference	Test	Attrition	Difference	Test	Attrition	Difference
Labor	3,186,567	3,586,151	399,583	1,661,990	1,963,118	301,128	782,785	720,147	(62,638)	5,631,342	6,269,415	638,073
Benefits	1,270,867	1,470,322	199,455	510,199	591,900	81,701	394,446	453,755	59,309	2,175,512	2,515,978	340,465
Materials & Supplies	247,678	213,355	(34,322)	21,916	22,386	469	48,576	84,982	36,406	318,170	320,723	2,553
Vehicles & Equip	565,870	1,473,080	907,210	(4,530)	(3,594)	936	18,869	(675,195)	(694,064)	580,209	794,292	214,083
Print & Postages	12,984	14,107	1,123	12,455	13,046	590	9,439	8,468	(971)	34,878	35,621	743
Insurance	163,719	226,240	62,521	246,281	292,042	45,761	(50,462)	72,472	122,933	359,539	590,754	231,216
Marketing	109,666	55,276	(54,390)	25,805	32,550	6,745	39,672	70,822	31,150	175,143	158,649	(16,494)
Employee Welfare	53,932	78,483	24,551	903,605	876,347	(27,258)	332,080	319,822	(12,258)	1,289,617	1,274,653	(14,964)
Information Technologies	295	(0)	(295)	235,234	300,184	64,950	57,105	56,634	(471)	292,634	356,818	64,184
Rent, Maint., & Utilities	493,607	848,466	354,859	210,391	210,380	(12)	93,346	(205,139)	(298,485)	797,344	853,707	56,363
Directors & Shareholders &PR	45,499	12,461	(33,037)	195,292	208,962	13,670	8,773	7,115	(1,659)	249,564	228,538	(21,026)
Telecom	114,345	28,335	(86,010)	219,083	184,000	(35,084)	64,333	144,207	79,874	397,761	356,542	(41,220)
Travel & Entertainment	184,689	108,067	(76,622)	75,769	69,114	(6,656)	145,940	151,790	5,850	406,399	328,972	(77,427)
Dues	72,517	64,868	(7,649)	8,530	9,424	895	23,374	81,922	58,548	104,421	156,214	51,794
Training	8,466	1,680	(6,786)	45,353	34,976	(10,376)	60,522	71,310	10,788	114,341	107,966	(6,375)
Outside Services	1,308,992	599,254	(709,739)	397,349	357,158	(40,191)	1,177,897	1,448,424	270,527	2,884,238	2,404,836	(479,403)
Provision for Bad Debt	100,925	183,013	82,088	-	-	-	14,688	-	(14,688)	115,613	183,013	67,400
Miscellaneous	27,930	22,992	(4,939)	(1,313,759)	(1,436,139)	(122,379)	985	20,569	19,584	(1,284,844)	(1,392,579)	(107,734)
Gas Control				147,740	113,713	(34,027)	-	-	-	147,740	113,713	(34,027)
Gas Supply				-	183,618	183,618	-	-	-	-	183,618	183,618
Total O&M Expenses	7,968,549	8,986,151	1,017,602	3,598,703	4,023,186	424,483	3,222,369	2,832,105	(390,264)	14,789,621	15,841,442	1,051,821

Tennessee Distribution System
Total Other Taxes
Schedule GW-3

		Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Total
	Tennessee													
1	FICA	25,151	23,971	26,202	23,052	25,151	24,102	26,202	24,102	25,151	26,202	23,052	26,031	298,369
2	FUTA	152	131	2,788	2,278	1,472	723	452	292	245	220	152	163	9,068
3	SUTA	95	82	1,743	1,423	920	452	282	183	153	137	95	102	5,668
5	Ad Valorem - Accrual	231,371	231,371	231,371	231,371	231,371	231,371	231,371	231,371	231,371	231,371	231,371	231,371	2,776,452
6	Franchise Taxes	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	41,667	500,001
7	State Gross receipts	273,725	359,999	542,251	471,173	353,765	188,140	109,656	97,672	74,551	80,191	81,837	131,855	2,764,815
11	Dot Transmission Us	0	0	0	13,000	0	0	0	0	0	0	0	0	13,000
12	State Supv & Inspec	31,000	31,000	31,000	31,000	33,000	33,000	33,000	33,000	33,000	33,000	33,000	33,000	388,000
13	Allocation for Call Center	5,344	5,034	5,637	5,637	5,637	4,264	4,573	4,821	3,689	4,542	2,970	4,693	56,842
14	Allocation for SSU	10,180	10,497	9,878	9,878	9,878	7,835	8,295	8,664	6,977	8,897	6,802	9,696	107,477
15	Allocation for General Office	7,225	6,928	8,741	7,658	7,891	7,553	7,963	7,485	7,703	7,878	6,929	7,287	91,241
16	Total	625,908	710,680	901,278	838,137	710,753	539,107	463,461	449,257	424,507	434,105	427,875	485,866	7,010,933
17														
18	**Shared Services**													
19	FICA	209,509	217,221	202,183	202,183	202,183	152,930	164,024	172,912	131,962	178,147	127,680	197,905	2,158,838
20	FUTA	732	689	773	773	773	585	627	661	781	1,074	823	671	8,964
21	SUTA	186	192	179	179	179	136	146	153	145	148	149	147	1,941
22	Ad Valorem	36,050	36,050	36,050	36,050	36,050	36,050	36,050	36,050	36,050	36,050	36,051	36,052	432,603
23	Allocated to Tennessee Div	(10,180)	(10,497)	(9,878)	(9,878)	(9,878)	(7,835)	(8,295)	(8,664)	(6,977)	(8,897)	(6,802)	(9,696)	(107,477)
24														
25														
26	**Shared Services Call center**													
27	FICA	131,310	123,598	138,636	138,636	138,636	104,863	112,470	118,565	90,486	111,654	72,649	115,392	1,396,894
28	FUTA	1,168	1,209	1,128	1,128	1,128	853	915	965	940	952	946	949	12,279
29	SUTA	117	110	123	123	123	93	100	105	103	104	103	104	1,307
30	Allocated to Tennessee Div	(5,344)	(5,034)	(5,637)	(5,637)	(5,637)	(4,264)	(4,573)	(4,821)	(3,689)	(4,542)	(2,970)	(4,693)	(56,842)
31														
32														
33	**General Office**													
34	FICA	16,515	15,437	19,045	16,561	18,217	17,390	19,045	17,390	18,217	18,888	15,411	16,730	208,845
35	FUTA	48	38	1,927	988	477	241	150	93	82	68	56	57	4,223
36	SUTA	29	25	1,199	635	349	167	113	67	52	41	34	34	2,746
37	Ad Valorem	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	120,000
	Allocated to Tennessee Div	(7,225)	(6,928)	(8,741)	(7,658)	(7,891)	(7,553)	(7,963)	(7,485)	(7,703)	(7,878)	(6,929)	(7,287)	(91,241)

Tennessee Distribution System
Divison 02 Depreciation Expense
Schedule GW-4

	Depr Rates		Gross Plant											
	Current	Proposed	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08
39000-Structures & Improvements	**7.43%**	**9.10%**	357,730	357,730	357,730	357,730	357,730	357,730	357,730	357,730	357,730	357,730	357,730	357,730
39009-Improv. to Leased Premises	7.43%	9.10%	7,120,815	7,150,255	7,161,716	7,178,772	7,207,240	7,219,280	7,242,896	7,249,385	7,272,339	7,275,921	7,279,334	7,333,099
39100-Office Furniture & Equipment	4.89%	2.13%	9,381,455	9,404,570	9,413,568	9,426,960	9,449,311	9,458,764	9,477,306	9,482,401	9,500,423	9,503,235	9,505,915	9,548,128
39102-Remittance Processing Equipme	11.37%	11.37%	25,380	25,380	25,380	25,380	25,380	25,380	25,380	25,380	25,380	25,380	25,380	25,380
39103-Office Furn. - Copiers & Type	2.22%	2.22%	436,305	436,305	436,305	436,305	436,305	436,305	436,305	436,305	436,305	436,305	436,305	436,305
39200-Transportation Equipment	28.96%	28.96%	18,885	18,885	18,885	18,885	18,885	18,885	18,885	18,885	18,885	18,885	18,885	18,885
39300-Stores Equipment	10.00%	10.00%	0	0	0	0	0	0	0	0	0	0	0	0
39400-Tools, Shop, & Garage Equip.	10.00%	10.00%	7,683	7,683	7,683	7,683	7,683	7,683	7,683	7,683	7,683	7,683	7,683	7,683
39700-Communication Equipment	7.12%	8.45%	1,416,088	1,416,088	1,416,088	1,416,088	1,416,088	1,416,088	1,416,088	1,416,088	1,416,088	1,416,088	1,416,088	1,416,088
39800-Miscellaneous Equipment	5.36%	8.15%	613,217	611,550	609,883	608,217	606,550	604,883	603,217	601,550	599,883	598,217	596,550	594,883
39900-Other Tangible Property	15.75%	4.66%	10,196	10,196	10,196	10,196	10,196	10,196	10,196	10,196	10,196	10,196	10,196	10,196
39901-Oth Tang Prop - Servers - H/W	14.29%	6.95%	10,674,324	11,184,526	11,383,149	11,678,733	12,172,093	12,380,747	12,790,020	12,902,474	13,300,267	13,362,348	13,421,490	14,353,247
39902-Oth Tang Prop - Servers - S/W	14.29%	4.00%	2,374,750	2,394,511	2,402,204	2,413,652	2,432,761	2,440,842	2,456,694	2,461,049	2,476,456	2,478,861	2,481,152	2,517,240
39903-Oth Tang Prop - Network - H/W	14.29%	9.30%	1,938,358	1,938,358	1,938,358	1,938,358	1,938,358	1,938,358	1,938,358	1,938,358	1,938,358	1,938,358	1,938,358	1,938,358
39904-Oth Tang Prop - CPU	26.26%	26.26%	1,095,465	1,095,465	1,095,465	1,095,465	1,095,465	1,095,465	1,095,465	1,095,465	1,095,465	1,095,465	1,095,465	1,095,465
39905-Oth Tang Prop - MF Hardware	15.76%	15.76%	1,159,964	1,159,964	1,159,964	1,159,964	1,159,964	1,159,964	1,159,964	1,159,964	1,159,964	1,159,964	1,159,964	1,159,964
39906-Oth Tang Prop - PC Hardware	16.83%	14.86%	3,194,197	3,310,057	3,222,924	3,198,961	3,303,850	3,223,251	3,273,357	3,130,085	3,172,711	2,996,621	2,818,616	3,199,335
39907-Oth Tang Prop - PC Software	17.73%	9.02%	1,418,873	1,461,006	1,477,409	1,501,819	1,542,562	1,559,793	1,593,592	1,602,879	1,635,730	1,640,857	1,645,741	1,722,688
39908-Oth Tang Prop - Appl Software	8.22%	11.11%	57,340,982	58,767,455	59,318,715	60,142,332	61,521,499	62,100,933	63,243,901	63,553,115	64,663,835	64,831,552	64,991,014	67,601,622
39909-Oth Tang Prop - Mainframe S/W	22.16%	22.16%	2,575,367	2,575,367	2,575,367	2,575,367	2,575,367	2,575,367	2,575,367	2,575,367	2,575,367	2,575,367	2,575,367	2,575,367
39924-Oth Tang Prop - Gen. Starup C	8.33%	15.89%	0	0	0	0	0	0	0	0	0	0	0	0
RWIP			0	0	0	0	0	0	0	0	0	0	0	0
TOTAL			**101,160,034**	**103,325,352**	**104,030,991**	**105,190,868**	**107,277,288**	**108,029,916**	**109,722,405**	**110,024,361**	**111,663,066**	**111,729,034**	**111,781,233**	**115,911,663**

Tennessee Distribution System
Divison 02 Depreciation Expense
Schedule GW-4

Depreciation at Proposed Rates

	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Total
39000-Structures & Improvements	2,713	2,713	2,713	2,713	2,713	2,713	2,713	2,713	2,713	2,713	2,713	2,713	32,553
39009-Improv. to Leased Premises	54,000	54,223	54,310	54,439	54,655	54,746	54,925	54,975	55,149	55,176	55,202	55,609	657,407
39100-Office Furniture & Equipment	16,652	16,693	16,709	16,733	16,773	16,789	16,822	16,831	16,863	16,868	16,873	16,948	201,555
39102-Remittance Processing Equipme	-	-	-	-	-	-	-	-	-	-	-	-	-
39103-Office Furn. - Copiers & Type	-	-	-	-	-	-	-	-	-	-	-	-	-
39200-Transportation Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
39300-Stores Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
39400-Tools, Shop, & Garage Equip.	-	-	-	-	-	-	-	-	-	-	-	-	-
39700-Communication Equipment	9,972	9,972	9,972	9,972	9,972	9,972	9,972	9,972	9,972	9,972	9,972	9,972	119,659
39800-Miscellaneous Equipment	4,165	4,153	4,142	4,131	4,119	4,108	4,097	4,086	4,074	4,063	4,052	4,040	49,230
39900-Other Tangible Property	-	-	-	-	-	-	-	-	-	-	-	-	-
39901-Oth Tang Prop - Servers - H/W	61,822	64,777	65,927	67,639	70,497	71,705	74,076	74,727	77,031	77,390	77,733	83,129	866,453
39902-Oth Tang Prop - Servers - S/W	7,916	7,982	8,007	8,046	8,109	8,136	8,189	8,203	8,255	8,263	8,271	8,391	97,767
39903-Oth Tang Prop - Network - H/W	15,022	15,022	15,022	15,022	15,022	15,022	15,022	15,022	15,022	15,022	15,022	15,022	180,267
39904-Oth Tang Prop - CPU	-	-	-	-	-	-	-	-	-	-	-	-	-
39905-Oth Tang Prop - MF Hardware	-	-	-	-	-	-	-	-	-	-	-	-	-
39906-Oth Tang Prop - PC Hardware	39,555	40,990	39,911	39,614	40,913	39,915	40,535	38,761	39,289	37,108	34,904	39,618	471,111
39907-Oth Tang Prop - PC Software	10,665	10,982	11,105	11,289	11,595	11,724	11,979	12,048	12,295	12,334	12,370	12,949	141,336
39908-Oth Tang Prop - Appl Software	530,882	544,089	549,192	556,818	569,587	574,951	585,533	588,396	598,679	600,232	601,708	625,878	6,925,946
39909-Oth Tang Prop - Mainframe S/W	-	-	-	-	-	-	-	-	-	-	-	-	-
39924-Oth Tang Prop - Gen. Starup C	0	0	0	0	0	0	0	0	0	0	0	0	-
RWIP													-
TOTAL	**753,363**	**771,595**	**777,010**	**786,414**	**803,954**	**809,782**	**823,862**	**825,733**	**839,342**	**839,141**	**838,819**	**874,270**	**9,743,285**

Depreciation at Current Rates

	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Total
39000-Structures & Improvements	2,215	2,215	2,215	2,215	2,215	2,215	2,215	2,215	2,215	2,215	2,215	2,215	26,579
39009-Improv. to Leased Premises	44,090	44,272	44,343	44,449	44,625	44,699	44,846	44,886	45,028	45,050	45,071	45,404	536,762
39100-Office Furniture & Equipment	38,229	38,324	38,360	38,415	38,506	38,544	38,620	38,641	38,714	38,726	38,737	38,909	462,725
39102-Remittance Processing Equipme	-	-	-	-	-	-	-	-	-	-	-	-	-
39103-Office Furn. - Copiers & Type	-	-	-	-	-	-	-	-	-	-	-	-	-
39200-Transportation Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
39300-Stores Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
39400-Tools, Shop, & Garage Equip.	-	-	-	-	-	-	-	-	-	-	-	-	-
39700-Communication Equipment	8,402	8,402	8,402	8,402	8,402	8,402	8,402	8,402	8,402	8,402	8,402	8,402	100,825
39800-Miscellaneous Equipment	2,739	2,732	2,724	2,717	2,709	2,702	2,694	2,687	2,679	2,672	2,665	2,657	32,377
39900-Other Tangible Property	-	-	-	-	-	-	-	-	-	-	-	-	-
39901-Oth Tang Prop - Servers - H/W	127,113	133,189	135,554	139,074	144,949	147,434	152,308	153,647	158,384	159,123	159,828	170,923	1,781,527
39902-Oth Tang Prop - Servers - S/W	28,279	28,515	28,606	28,743	28,970	29,066	29,255	29,307	29,490	29,519	29,546	29,976	349,273
39903-Oth Tang Prop - Network - H/W	23,083	23,083	23,083	23,083	23,083	23,083	23,083	23,083	23,083	23,083	23,083	23,083	276,991
39904-Oth Tang Prop - CPU	-	-	-	-	-	-	-	-	-	-	-	-	-
39905-Oth Tang Prop - MF Hardware	-	-	-	-	-	-	-	-	-	-	-	-	-
39906-Oth Tang Prop - PC Hardware	44,799	46,424	45,202	44,865	46,336	45,206	45,909	43,899	44,497	42,028	39,531	44,871	533,567
39907-Oth Tang Prop - PC Software	20,964	21,586	21,829	22,189	22,791	23,046	23,545	23,683	24,168	24,244	24,316	25,453	277,814
39908-Oth Tang Prop - Appl Software	392,786	402,557	406,333	411,975	421,422	425,391	433,221	435,339	442,947	444,096	445,188	463,071	5,124,327
39909-Oth Tang Prop - Mainframe S/W	-	-	-	-	-	-	-	-	-	-	-	-	-
39924-Oth Tang Prop - Gen. Starup C	0	0	0	0	0	0	0	0	0	0	0	0	0
RWIP													0
TOTAL	**732,699**	**751,298**	**756,651**	**766,126**	**784,009**	**789,789**	**804,097**	**805,788**	**819,608**	**819,157**	**818,581**	**854,963**	**9,502,768**

Tennessee Distribution System
Divison 12 Depreciation Expense
Schedule GW-4

	Depr Rates		Gross Plant										
	Current	Proposed	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08
39009-Improv. to Leased Premises	7.43%	9.10%	3,018,160	3,018,160	3,018,160	3,018,160	3,018,160	3,018,160	3,018,160	3,018,160	3,018,160	3,018,160	3,018,160	3,018,160
39100-Office Furniture & Equipment	4.89%	2.13%	56,077	56,077	56,077	56,077	56,077	56,077	56,077	56,077	56,077	56,077	56,077	56,077
39700-Communication Equipment	7.12%	8.45%	24,199,331	24,199,331	24,199,331	24,199,331	24,199,331	24,199,331	24,199,331	24,199,331	24,199,331	24,199,331	24,199,331	24,199,331
39800-Miscellaneous Equipment	5.36%	8.15%	1,916	1,916	1,916	1,916	1,916	1,916	1,916	1,916	1,916	1,916	1,916	1,916
39900-Other Tangible Property	15.75%	4.66%	214,670	214,670	214,670	214,670	214,670	214,670	214,670	214,670	214,670	214,670	214,670	214,670
39901-Oth Tang Prop - Servers - H/W	14.29%	6.95%	10,027,044	10,027,044	10,027,044	10,027,044	10,027,044	10,027,044	10,027,044	10,027,044	10,027,044	10,027,044	10,027,044	10,131,747
39902-Oth Tang Prop - Servers - S/W	14.29%	4.00%	6,861,747	6,861,747	6,861,747	6,861,747	6,861,747	6,861,747	6,861,747	6,861,747	6,861,747	6,861,747	6,861,747	6,861,747
39903-Oth Tang Prop - Network - H/W	14.29%	9.30%	459,784	459,784	459,784	459,784	459,784	459,784	459,784	459,784	459,784	459,784	459,784	459,784
39906-Oth Tang Prop - PC Hardware	16.83%	14.86%	3,182,336	3,232,078	3,198,744	3,165,411	3,132,078	3,098,744	3,065,411	3,032,078	2,998,744	2,965,411	2,932,078	2,898,744
39907-Oth Tang Prop - PC Software	17.73%	9.02%	2,854,097	2,854,097	2,854,097	2,854,097	2,854,097	2,854,097	2,854,097	2,854,097	2,854,097	2,854,097	2,854,097	2,854,097
39908-Oth Tang Prop - Appl Software	8.22%	11.11%	74,508,958	74,500,624	74,492,291	74,483,958	74,475,624	74,467,291	74,458,958	74,450,624	74,442,291	74,433,958	74,425,624	74,762,194
39924-Oth Tang Prop - Gen. Starup C	8.33%	15.89%	23,172,326	23,172,326	23,172,326	23,172,326	23,172,326	23,172,326	23,172,326	23,172,326	23,172,326	23,172,326	23,172,326	23,172,326
RWIP			0	0	0	0	0	0	0	0	0	0	0	0
TOTAL			**148,556,446**	**148,597,854**	**148,556,187**	**148,514,521**	**148,472,854**	**148,431,187**	**148,389,521**	**148,347,854**	**148,306,187**	**148,264,521**	**148,222,854**	**148,630,793**
ACTUAL BALANCES														
VARIANCE														

Tennessee Distribution System
Divison 12 Depreciation Expense
Schedule GW-4

Depreciation at Proposed Rates

	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Total
39009-Improv. to Leased Premises	22,888	22,888	22,888	22,888	22,888	22,888	22,888	22,888	22,888	22,888	22,888	22,888	274,653
39100-Office Furniture & Equipment	100	100	100	100	100	100	100	100	100	100	100	100	1,194
39700-Communication Equipment	170,404	170,404	170,404	170,404	170,404	170,404	170,404	170,404	170,404	170,404	170,404	170,404	2,044,843
39800-Miscellaneous Equipment	13	13	13	13	13	13	13	13	13	13	13	13	156
39900-Other Tangible Property	-	-	-	-	-	-	-	-	-	-	-	-	-
39901-Oth Tang Prop - Servers - H/W	58,073	58,073	58,073	58,073	58,073	58,073	58,073	58,073	58,073	58,073	58,073	58,680	697,486
39902-Oth Tang Prop - Servers - S/W	-	-	-	-	-	-	-	-	-	-	-	-	-
39903-Oth Tang Prop - Network - H/W	3,563	3,563	3,563	3,563	3,563	3,563	3,563	3,563	3,563	3,563	3,563	3,563	42,760
39906-Oth Tang Prop - PC Hardware	39,408	40,024	39,611	39,198	38,786	38,373	37,960	37,547	37,134	36,722	36,309	35,896	456,968
39907-Oth Tang Prop - PC Software	21,453	21,453	21,453	21,453	21,453	21,453	21,453	21,453	21,453	21,453	21,453	21,453	257,440
39908-Oth Tang Prop - Appl Software	689,829	689,752	689,674	689,597	689,520	689,443	689,366	689,289	689,212	689,134	689,057	692,173	8,276,046
39924-Oth Tang Prop - Gen. Startup C	306,840	306,840	306,840	306,840	306,840	306,840	306,840	306,840	306,840	306,840	306,840	306,840	3,682,083
RWIP													-
Total	**1,312,571**	**1,313,110**	**1,312,620**	**1,312,130**	**1,311,640**	**1,311,150**	**1,310,660**	**1,310,170**	**1,309,680**	**1,309,190**	**1,308,700**	**1,312,010**	**15,733,629**

Depreciation at Current Rates

	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Total
39009-Improv. to Leased Premises	18,687	18,687	18,687	18,687	18,687	18,687	18,687	18,687	18,687	18,687	18,687	18,687	224,249
39100-Office Furniture & Equipment	229	229	229	229	229	229	229	229	229	229	229	229	2,742
39700-Communication Equipment	143,583	143,583	143,583	143,583	143,583	143,583	143,583	143,583	143,583	143,583	143,583	143,583	1,722,992
39800-Miscellaneous Equipment	9	9	9	9	9	9	9	9	9	9	9	9	103
39900-Other Tangible Property	-	-	-	-	-	-	-	-	-	-	-	-	-
39901-Oth Tang Prop - Servers - H/W	119,405	119,405	119,405	119,405	119,405	119,405	119,405	119,405	119,405	119,405	119,405	120,652	1,434,111
39902-Oth Tang Prop - Servers - S/W	-	-	-	-	-	-	-	-	-	-	-	-	-
39903-Oth Tang Prop - Network - H/W	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	65,703
39906-Oth Tang Prop - PC Hardware	44,632	45,330	44,862	44,395	43,927	43,460	42,992	42,525	42,057	41,590	41,122	40,655	517,549
39907-Oth Tang Prop - PC Software	42,169	42,169	42,169	42,169	42,169	42,169	42,169	42,169	42,169	42,169	42,169	42,169	506,031
39908-Oth Tang Prop - Appl Software	510,386	510,329	510,272	510,215	510,158	510,101	510,044	509,987	509,930	509,873	509,816	512,121	6,123,231
39924-Oth Tang Prop - Gen. Startup C	160,855	160,855	160,855	160,855	160,855	160,855	160,855	160,855	160,855	160,855	160,855	160,855	1,930,255
RWIP													-
TOTAL	**1,045,430**	**1,046,071**	**1,045,546**	**1,045,022**	**1,044,497**	**1,043,973**	**1,043,448**	**1,042,923**	**1,042,399**	**1,041,874**	**1,041,350**	**1,044,434**	**12,526,967**

Tennessee Distribution System
Divison 91 Depreciation Expense
Schedule GW-4

	Depr Rates		Gross Plant											
	Current	Proposed	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08
30100-Organization	0.00%	0.00%	185,309	185,309	185,309	185,309	185,309	185,309	185,309	185,309	185,309	185,309	185,309	185,309
30300-Misc. Intangible Plant	0.00%	0.00%	1,109,552	1,109,552	1,109,552	1,109,552	1,109,552	1,109,552	1,109,552	1,109,552	1,109,552	1,109,552	1,109,552	1,109,552
37601-Mains - Steel	3.61%	3.61%	0	0	0	0	0	0	0	0	0	0	0	0
39001-Structures - Frame	2.52%	2.52%	179,339	179,339	179,339	179,339	179,339	179,339	179,339	179,339	179,339	179,339	179,339	179,339
39004-Air Conditioning Equipment	2.52%	2.52%	5,771	5,771	5,771	5,771	5,771	5,771	5,771	5,771	5,771	5,771	5,771	5,771
39009-Improv. to Leased Premises	2.52%	2.52%	38,834	38,834	38,834	38,834	38,834	38,834	38,834	38,834	38,834	38,834	38,834	38,834
39100-Office Furniture & Equipment	5.69%	5.69%	1,404,264	1,403,925	1,403,586	1,403,247	1,402,908	1,402,569	1,402,230	1,401,891	1,401,552	1,401,213	1,400,874	1,400,535
39103-Office Furn. - Copiers & Type	5.69%	5.69%	33,704	33,304	32,904	32,503	32,103	31,702	31,302	30,901	30,501	30,101	29,700	29,300
39200-Transportation Equipment	16.00%	16.00%	0	0	0	0	0	0	0	0	0	0	0	0
39300-Stores Equipment	7.15%	7.15%	10,698	10,698	10,698	10,698	10,698	10,698	10,698	10,698	10,698	10,698	10,698	10,698
39400-Tools, Shop, & Garage Equip.	4.02%	4.02%	129,367	129,113	128,859	128,604	128,350	128,096	127,842	127,588	127,334	127,080	126,826	126,572
39600-Power Operated Equipment	11.11%	11.11%	8,497	8,497	8,497	8,497	8,497	8,497	8,497	8,497	8,497	8,497	8,497	8,497
39700-Communication Equipment	7.49%	7.49%	337,971	348,079	347,777	347,475	347,172	346,870	346,568	346,265	345,963	345,661	345,358	352,992
39800-Miscellaneous Equipment	4.40%	4.40%	856,657	856,657	856,657	856,657	856,657	856,657	856,657	856,657	856,657	856,657	856,657	856,657
39900-Other Tangible Property	18.98%	18.98%	76,993	76,993	76,993	76,993	76,993	76,993	76,993	76,993	76,993	76,993	76,993	76,993
39901-Oth Tang Prop - Servers - H/W	14.29%	14.29%	71,663	71,663	71,663	71,663	71,663	71,663	71,663	71,663	71,663	71,663	71,663	71,663
39902-Oth Tang Prop - Servers - S/W	14.29%	14.29%	8,273	8,273	8,273	8,273	8,273	8,273	8,273	8,273	8,273	8,273	8,273	8,273
39903-Oth Tang Prop - Network - H/W	14.29%	14.29%	238,424	238,424	238,424	238,424	238,424	238,424	238,424	238,424	238,424	238,424	238,424	238,424
39906-Oth Tang Prop - PC Hardware	18.98%	18.98%	1,395,497	1,430,529	1,476,614	1,475,922	1,475,230	1,474,538	1,473,846	1,473,154	1,472,462	1,471,770	1,471,078	1,470,386
39907-Oth Tang Prop - PC Software	18.98%	18.98%	126,257	126,257	126,257	126,257	126,257	126,257	126,257	126,257	126,257	126,257	126,257	126,257
39908-Oth Tang Prop - Appl Software	18.98%	18.98%	766,349	766,349	766,349	794,871	794,871	794,871	794,871	794,871	794,871	794,871	794,871	794,871
RWIP														
TOTAL			**6,983,420**	**7,027,567**	**7,072,355**	**7,098,890**	**7,096,902**	**7,094,914**	**7,092,926**	**7,090,939**	**7,088,951**	**7,086,963**	**7,084,975**	**7,090,924**

Tennessee Distribution System
Divison 91 Depreciation Expense
Schedule GW-4

Depreciation at Proposed Rates

	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Total
30100-Organization	-	-	-	-	-	-	-	-	-	-	-	-	-
30300-Misc. Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
37601-Mains - Steel	-	-	-	-	-	-	-	-	-	-	-	-	-
39001-Structures - Frame	377	377	377	377	377	377	377	377	377	377	377	377	4,519
39004-Air Conditioning Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
39009-Improv. to Leased Premises	-	-	-	-	-	-	-	-	-	-	-	-	-
39100-Office Furniture & Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
39103-Office Furn. - Copiers & Type	160	158	156	154	152	150	148	147	145	143	141	139	1,792
39200-Transportation Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
39300-Stores Equipment	64	64	64	64	64	64	64	64	64	64	64	64	765
39400-Tools, Shop, & Garage Equip.	433	433	432	431	430	429	428	427	427	426	425	424	5,144
39600-Power Operated Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
39700-Communication Equipment	2,110	2,173	2,171	2,169	2,167	2,165	2,163	2,161	2,159	2,157	2,156	2,203	25,954
39800-Miscellaneous Equipment	3,141	3,141	3,141	3,141	3,141	3,141	3,141	3,141	3,141	3,141	3,141	3,141	37,693
39900-Other Tangible Property	1,218	1,218	1,218	1,218	1,218	1,218	-	-	-	-	-	-	7,307
39901-Oth Tang Prop - Servers - H/W	-	-	-	-	-	-	-	-	-	-	-	-	-
39902-Oth Tang Prop - Servers - S/W	-	-	-	-	-	-	-	-	-	-	-	-	-
39903-Oth Tang Prop - Network - H/W	2,839	2,839	-	-	-	-	-	-	-	-	-	-	5,678
39906-Oth Tang Prop - PC Hardware	22,072	22,626	23,355	23,344	23,333	23,322	23,311	23,300	23,289	23,278	23,268	23,257	277,757
39907-Oth Tang Prop - PC Software	-	-	-	-	-	-	-	-	-	-	-	-	-
39908-Oth Tang Prop - Appl Software	-	-	-	-	-	-	-	-	-	-	-	-	-
RWIP													0
TOTAL	**32,413**	**33,028**	**30,913**	**30,897**	**30,882**	**30,866**	**29,633**	**29,617**	**29,601**	**29,586**	**29,570**	**29,604**	**366,610**

Depreciation at Current Rates

	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Total
30100-Organization	-	-	-	-	-	-	-	-	-	-	-	-	-
30300-Misc. Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
37601-Mains - Steel	-	-	-	-	-	-	-	-	-	-	-	-	-
39001-Structures - Frame	377	377	377	377	377	377	377	377	377	377	377	377	4,519
39004-Air Conditioning Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
39009-Improv. to Leased Premises	-	-	-	-	-	-	-	-	-	-	-	-	-
39100-Office Furniture & Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
39103-Office Furn. - Copiers & Type	160	158	156	154	152	150	148	147	145	143	141	139	1,792
39200-Transportation Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
39300-Stores Equipment	64	64	64	64	64	64	64	64	64	64	64	64	765
39400-Tools, Shop, & Garage Equip.	433	433	432	431	430	429	428	427	427	426	425	424	5,144
39600-Power Operated Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
39700-Communication Equipment	2,110	2,173	2,171	2,169	2,167	2,165	2,163	2,161	2,159	2,157	2,156	2,203	25,954
39800-Miscellaneous Equipment	3,141	3,141	3,141	3,141	3,141	3,141	3,141	3,141	3,141	3,141	3,141	3,141	37,693
39900-Other Tangible Property	1,218	1,218	1,218	1,218	1,218	1,218	-	-	-	-	-	-	7,307
39901-Oth Tang Prop - Servers - H/W	-	-	-	-	-	-	-	-	-	-	-	-	-
39902-Oth Tang Prop - Servers - S/W	-	-	-	-	-	-	-	-	-	-	-	-	-
39903-Oth Tang Prop - Network - H/W	2,839	2,839	-	-	-	-	-	-	-	-	-	-	5,678
39906-Oth Tang Prop - PC Hardware	22,072	22,626	23,355	23,344	23,333	23,322	23,311	23,300	23,289	23,278	23,268	23,257	277,757
39907-Oth Tang Prop - PC Software	-	-	-	-	-	-	-	-	-	-	-	-	-
39908-Oth Tang Prop - Appl Software	-	-	-	-	-	-	-	-	-	-	-	-	-
RWIP													0
TOTAL	**32,413**	**33,028**	**30,913**	**30,897**	**30,882**	**30,866**	**29,633**	**29,617**	**29,601**	**29,586**	**29,570**	**29,604**	**366,610**

Tennessee Distribution System
Divison 93 Depreciation Expense
Schedule GW-4

	Depr Rates		Gross Plant											
	Current	Proposed	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08
30200-Franchises & Consents	5.00%	5.00%	241,284	241,284	241,284	241,284	241,284	241,284	241,284	241,284	241,284	241,284	241,284	241,284
30400:Land&Land Rights Grp	0.00%	0.00%	0	0	0	0	0	0	0	0	0	0	0	0
30500:Structures And Improv	3.03%	3.03%	0	0	0	0	0	0	0	0	0	0	0	0
31900:Gas Mixing Equipment	3.03%	3.03%	0	0	0	0	0	0	0	0	0	0	0	0
36510-Land & Land Rights	0.00%	0.00%	729,629	729,629	729,629	729,629	729,629	729,629	729,629	729,629	729,629	729,629	729,629	729,629
36520-Rights-Of-Way	2.39%	1.50%	348,971	348,971	348,971	348,971	348,971	348,971	348,971	348,971	348,971	348,971	348,971	348,971
36600-Structures & Improvem	3.47%	2.47%	2,679	2,679	2,679	2,679	2,679	2,679	2,679	2,679	2,679	2,679	2,679	2,679
36701-Mains - Steel	2.92%	2.84%	11,782,052	11,788,504	11,795,078	11,801,652	11,808,064	11,814,638	11,821,212	11,827,524	11,834,198	11,840,772	11,847,345	11,897,191
36900-Meas. & Reg. Sta. Equi	3.61%	3.36%	1,629,191	1,629,191	1,629,191	1,629,191	1,629,191	1,629,191	1,629,191	1,629,191	1,629,191	1,629,191	1,629,191	1,629,191
37400-Land & Land Rights	0.00%	0.00%	181,547	181,547	181,547	181,547	181,547	181,547	181,547	181,547	181,547	181,547	181,547	181,547
37402-Land Rights	0.00%	0.49%	667,525	667,525	667,525	667,525	667,525	667,525	667,525	667,525	667,525	667,525	667,525	667,525
37500-Structures & Improvem	2.50%	1.59%	619,716	619,716	619,716	619,716	619,716	619,716	619,716	619,716	619,716	619,716	619,716	624,705
37600-Mains - Cathodic Protec	3.06%	2.33%	2,065,875	2,100,684	2,135,510	2,183,446	2,258,585	2,293,411	2,328,237	2,363,040	2,397,866	2,432,692	2,467,518	2,510,121
37601-Mains - Steel	3.06%	2.33%	46,956,877	46,971,921	46,987,374	47,002,827	47,017,734	47,033,187	47,097,901	47,112,809	47,128,261	47,143,714	47,159,153	47,320,182
37602-Mains - Plastic	3.06%	2.33%	119,298,024	119,932,565	120,464,187	120,945,736	121,594,763	122,296,123	122,973,456	123,866,683	124,690,172	125,364,596	125,242,953	127,045,024
37800-Meas. & Reg. Sta. Eq-C	3.61%	2.11%	6,695,361	6,704,387	6,713,477	6,722,567	6,731,570	6,816,148	6,845,466	6,857,902	6,870,424	6,887,650	8,900,172	6,932,707
37900-Meas. & Reg. - City Ga	3.46%	2.96%	2,490,435	2,491,760	2,493,111	2,539,269	2,569,671	2,571,221	2,572,571	2,573,888	2,575,238	2,576,589	2,577,939	2,588,176
38000-Services	4.29%	2.93%	88,729,047	89,068,758	89,410,854	89,753,268	90,111,115	90,452,505	90,794,901	91,150,453	91,492,721	91,843,001	92,189,224	92,859,065
38100-Meters	4.04%	5.11%	12,002,096	12,074,314	12,174,862	12,247,196	12,329,907	12,419,922	12,502,188	12,574,368	12,664,983	12,737,317	12,805,669	12,945,724
38200-Meter Installations	4.38%	4.79%	22,094,113	22,158,650	22,243,408	22,318,167	22,392,729	22,468,084	22,542,942	22,617,504	22,691,865	22,766,723	22,841,102	22,997,929
38300-House Regulators	4.38%	1.76%	3,183,577	3,190,600	3,197,656	3,204,711	3,211,724	3,218,780	3,225,835	3,232,848	3,239,904	3,246,959	3,254,015	3,272,822
38500-Ind. Meas. & Reg. Sta.	3.88%	3.22%	323,828	323,828	323,828	323,828	323,828	323,828	323,828	323,828	323,828	323,828	323,828	323,828
38700-Other Equipment	6.01%	6.01%	0	0	0	0	0	0	0	0	0	0	0	0
38900-Land & Land Rights	0.00%	0.00%	10,051	10,051	10,051	10,051	10,051	10,051	10,051	10,051	10,051	10,051	10,051	10,051
39000-Structures & Improvem	2.52%	2.16%	1,036,762	1,052,602	1,052,602	1,068,442	1,068,442	1,068,442	1,068,442	1,068,442	1,068,442	1,068,442	1,068,442	1,123,680
39003-Improvements	2.52%	2.16%	49,277	49,277	49,277	49,277	49,277	49,277	49,277	49,277	49,277	49,277	49,277	49,277
39009-Improv. to Leased Prem	2.52%	2.52%	369,668	369,668	369,668	369,668	369,668	369,668	369,668	369,668	369,668	369,668	369,668	369,668
39100-Office Furniture & Equi	5.69%	6.40%	519,370	514,786	510,203	505,620	501,036	496,453	491,870	487,286	482,703	478,120	473,536	468,953
39200-Transportation Equipme	16.00%	16.00%	458,738	458,613	458,488	458,363	458,238	458,113	457,988	457,863	457,738	457,613	457,488	457,363
39300-Stores Equipment	7.15%	1.73%	25,154	25,154	25,154	25,154	25,154	25,154	25,154	25,154	25,154	25,154	25,154	25,154
39400-Tools, Shop, & Garage	4.02%	12.62%	944,583	960,508	964,844	983,087	982,212	1,043,699	1,041,825	1,039,160	1,034,911	1,029,077	1,023,244	1,148,604
39600-Power Operated Equipr	11.11%	36.50%	169,163	169,163	169,163	169,163	169,163	169,163	169,163	169,163	169,163	169,163	169,163	169,163
39603-Ditchers	11.11%	36.50%	22,875	22,875	22,875	22,875	22,875	22,875	22,875	22,875	22,875	22,875	22,875	22,875
39604-Backhoes	11.11%	36.50%	120,931	114,264	107,597	100,931	94,264	87,597	80,931	74,264	67,597	60,931	54,264	47,597
39605-Welders	11.11%	36.50%	62,506	62,506	62,506	62,506	62,506	62,506	62,506	62,506	62,506	62,506	62,506	95,771
39700-Communication Equipm	7.49%	6.00%	134,982	133,732	132,482	131,232	129,982	128,732	127,482	126,232	124,982	123,732	122,482	121,232
39701-Comm. Equip. - Mobile	7.49%	6.00%	13,344	13,344	13,344	13,344	13,344	13,344	13,344	13,344	13,344	13,344	13,344	13,344
39702-Comm. Equip. - Fixed F	7.49%	6.00%	0	0	0	0	0	0	0	0	0	0	0	0
39705-Comm. Equip. - Teleme	7.49%	6.00%	0	0	0	0	0	0	0	0	0	0	0	0
39800-Miscellaneous Equipme	4.40%	12.68%	940,082	940,082	940,082	940,082	940,082	940,082	940,082	940,082	940,082	940,082	940,082	940,082
39900-Other Tangible Property	18.98%	11.92%	10,963	10,963	10,963	10,963	10,963	10,963	10,963	10,963	10,963	10,963	10,963	10,963
39901-Oth Tang Prop - Server	14.29%	11.92%	1,169	1,169	1,169	1,169	1,169	1,169	1,169	1,169	1,169	1,169	1,169	1,169
39906-Oth Tang Prop - PC Ha	18.98%	18.98%	794,284	911,543	950,629	950,629	950,629	950,629	950,629	950,629	950,629	950,629	950,629	950,629
39907-Oth Tang Prop - PC So	18.98%	18.98%	256,541	256,541	256,541	256,541	256,541	256,541	256,541	256,541	256,541	256,541	256,541	256,541
RWIP														
TOTAL			**325,983,269**	**327,313,354**	**328,467,824**	**329,592,302**	**330,885,429**	**332,293,146**	**333,599,038**	**335,056,157**	**336,447,798**	**337,683,719**	**338,114,338**	**341,480,597**

Tennessee Distribution System
Divison 93 Depreciation Expense
Schedule GW-4

Depreciation at Proposed Rates

	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Total
30200-Franchises & Conse	0	0	0	0	0	0	0	0	0	0	0	0	0
30400:Land&Land Rights (	0	0	0	0	0	0	0	0	0	0	0	0	0
30500:Structures And Impi	0	0	0	0	0	0	0	0	0	0	0	0	0
31900:Gas Mixing Equipm	0	0	0	0	0	0	0	0	0	0	0	0	0
36510-Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0
36520-Rights-Of-Way	436	436	436	436	436	436	436	436	436	436	436	436	5,235
36600-Structures & Improv	6	6	6	6	6	6	6	6	6	6	6	6	66
36701-Mains - Steel	27,884	27,899	27,915	27,931	27,946	27,961	27,977	27,992	28,008	28,023	28,039	28,157	335,731
36900-Meas. & Reg. Sta. I	4,562	4,562	4,562	4,562	4,562	4,562	4,562	4,562	4,562	4,562	4,562	4,562	54,741
37400-Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0
37402-Land Rights	273	273	273	273	273	273	273	273	273	273	273	273	3,271
37500-Structures & Improv	821	821	821	821	821	821	821	821	821	821	821	828	9,860
37600-Mains - Cathodic Pr	4,011	4,079	4,146	4,240	4,385	4,453	4,521	4,588	4,656	4,723	4,791	4,874	53,468
37601-Mains - Steel	91,175	91,204	91,234	91,264	91,293	91,323	91,448	91,477	91,507	91,537	91,567	91,880	1,096,910
37602-Mains - Plastic	231,639	232,869	233,901	234,856	236,096	237,458	238,773	240,508	242,107	243,416	243,180	246,679	2,861,464
37800-Meas. & Reg. Sta. I	11,773	11,789	11,805	11,821	11,836	11,985	12,037	12,058	12,080	12,111	12,133	12,190	143,617
37900-Meas. & Reg. - City	6,143	6,146	6,150	6,264	6,339	6,342	6,346	6,349	6,352	6,356	6,359	6,384	75,530
38000-Services	216,647	217,476	218,312	219,148	220,021	220,856	221,691	222,559	223,395	224,250	225,095	226,731	2,656,180
38100-Meters	51,109	51,416	51,845	52,153	52,502	52,888	53,238	53,546	53,932	54,240	54,648	55,127	636,544
38200-Meter Installations	88,192	88,490	88,788	89,087	89,384	89,685	89,984	90,282	90,578	90,877	91,174	91,800	1,078,322
38300-House Regulators	4,669	4,680	4,690	4,700	4,711	4,721	4,731	4,742	4,752	4,762	4,773	4,800	56,730
38500-Ind. Meas. & Reg. S	869	869	869	869	869	869	869	869	869	869	869	869	10,427
38700-Other Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0
38900-Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0
39000-Structures & Improv	1,886	1,895	1,895	1,923	1,923	1,923	1,923	1,923	1,923	1,923	1,923	2,023	23,064
39003-Improvements	88	89	89	89	89	89	89	89	89	89	89	89	1,064
39009-Improv. to Leased P	0	0	0	0	0	0	0	0	0	0	0	0	0
39100-Office Furniture & E	2,770	2,746	2,721	2,697	2,672	2,648	2,623	2,599	2,574	2,550	2,526	2,501	31,626
39200-Transportation Equi	0	0	0	0	0	0	0	0	0	0	0	0	0
39300-Stores Equipment	36	36	36	36	36	36	36	36	36	36	36	36	435
39400-Tools, Shop, & Gara	9,934	10,101	10,147	10,339	10,330	10,976	10,957	10,928	10,884	10,822	10,761	12,082	128,261
39600-Power Operated Eq	5,145	5,145	5,145	5,145	5,145	5,145	5,145	5,145	5,145	5,145	5,145	5,145	61,745
39603-Ditchers	696	696	696	696	696	696	696	696	696	696	696	696	8,349
39604-Backhoes	3,678	3,476	3,273	3,070	2,867	2,664	2,462	2,259	2,056	1,853	1,651	1,448	30,758
39605-Welders	1,901	1,901	1,901	1,901	1,901	1,901	1,901	1,901	1,901	1,901	1,901	2,913	23,827
39700-Communication Equ	675	669	662	656	650	644	637	631	625	619	612	606	7,686
39701-Comm. Equip. - Mol	67	67	67	67	67	67	67	67	67	67	67	67	801
39702-Comm. Equip. - Fbe	0	0	0	0	0	0	0	0	0	0	0	0	0
39705-Comm. Equip. - Tel	0	0	0	0	0	0	0	0	0	0	0	0	0
39800-Miscellaneous Equi	9,934	9,934	9,934	9,934	9,934	9,934	9,934	9,934	9,934	9,934	9,934	9,934	119,202
39900-Other Tangible Prop	109	109	109	109	109	109	109	109	109	109	109	109	1,307
39901-Oth Tang Prop - Se	0	0	0	0	0	0	0	0	0	0	0	0	0
39906-Oth Tang Prop - PC	0	0	0	0	0	0	0	0	0	0	0	0	0
39907-Oth Tang Prop - PC	0	0	0	0	0	0	0	0	0	0	0	0	0
RWIP													0
TOTAL	**777,108**	**779,876**	**782,426**	**785,069**	**787,859**	**791,470**	**794,291**	**797,384**	**800,372**	**803,006**	**804,074**	**813,242**	**9,516,217**

Depreciation at Current Rates

	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Total
30200-Franchises & Conse	-	-	-	-	-	-	-	-	-	-	-	-	-
30400:Land&Land Rights (	-	-	-	-	-	-	-	-	-	-	-	-	-
30500:Structures And Impi	-	-	-	-	-	-	-	-	-	-	-	-	-
31900:Gas Mixing Equipm	-	-	-	-	-	-	-	-	-	-	-	-	-
36510-Land & Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-
36520-Rights-Of-Way	695	695	695	695	695	695	695	695	695	695	695	695	8,340
36600-Structures & Improv	8	8	8	8	8	8	8	8	8	8	8	8	93
36701-Mains - Steel	28,670	28,685	28,701	28,717	28,733	28,749	28,765	28,781	28,797	28,813	28,829	28,950	345,189
36900-Meas. & Reg. Sta. I	4,901	4,901	4,901	4,901	4,901	4,901	4,901	4,901	4,901	4,901	4,901	4,901	58,814
37400-Land & Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-
37402-Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-
37500-Structures & Improv	1,291	1,291	1,291	1,291	1,291	1,291	1,291	1,291	1,291	1,291	1,291	1,301	15,503
37600-Mains - Cathodic Pr	5,288	5,357	5,446	5,568	5,759	5,848	5,937	6,026	6,115	6,203	6,292	6,401	70,219
37601-Mains - Steel	119,740	119,778	119,818	119,857	119,895	119,935	120,100	120,138	120,177	120,216	120,256	120,686	1,440,575
37602-Mains - Plastic	304,213	305,828	307,184	308,412	310,067	311,855	313,582	315,860	317,960	319,680	319,370	323,965	3,757,974
37800-Meas. & Reg. Sta. I	20,142	20,169	20,196	20,224	20,251	20,505	20,593	20,631	20,669	20,720	20,758	20,856	245,714
37900-Meas. & Reg. - City	7,181	7,185	7,188	7,322	7,410	7,414	7,418	7,421	7,425	7,429	7,433	7,463	88,288
38000-Services	317,206	318,421	319,644	320,868	322,147	323,369	324,592	325,863	327,086	328,339	329,576	331,971	3,889,082
38100-Meters	40,407	40,650	40,989	41,232	41,509	41,814	42,091	42,334	42,639	42,882	43,126	43,584	503,256
38200-Meter Installations	80,644	80,916	81,188	81,461	81,733	82,009	82,282	82,554	82,825	83,099	83,370	83,942	986,023
38300-House Regulators	11,620	11,646	11,671	11,697	11,723	11,749	11,774	11,800	11,826	11,851	11,877	11,946	141,180
38500-Ind. Meas. & Reg. S	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	12,565
38700-Other Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
38900-Land & Land Rights	-	-	-	-	-	-	-	-	-	-	-	-	-
39000-Structures & Improv	2,177	2,210	2,210	2,244	2,244	2,244	2,244	2,244	2,244	2,244	2,244	2,360	26,908
39003-Improvements	103	103	103	103	103	103	103	103	103	103	103	103	1,242
39009-Improv. to Leased P	-	-	-	-	-	-	-	-	-	-	-	-	-
39100-Office Furniture & E	2,463	2,441	2,419	2,397	2,376	2,354	2,332	2,311	2,289	2,267	2,245	2,224	28,118
39200-Transportation Equi	-	-	-	-	-	-	-	-	-	-	-	-	-
39300-Stores Equipment	150	150	150	150	150	150	150	150	150	150	150	150	1,799
39400-Tools, Shop, & Gara	3,164	3,218	3,232	3,293	3,290	3,496	3,490	3,481	3,467	3,447	3,428	3,848	40,856
39600-Power Operated Eq	1,566	1,566	1,566	1,566	1,566	1,566	1,566	1,566	1,566	1,566	1,566	1,566	18,794
39603-Ditchers	212	212	212	212	212	212	212	212	212	212	212	212	2,541
39604-Backhoes	1,120	1,058	996	934	873	811	749	688	626	564	502	441	9,362
39605-Welders	579	579	579	579	579	579	579	579	579	579	579	887	7,252
39700-Communication Equ	843	835	827	819	811	804	796	788	780	772	764	757	9,595
39701-Comm. Equip. - Mol	83	83	83	83	83	83	83	83	83	83	83	83	999
39702-Comm. Equip. - Fbe	-	-	-	-	-	-	-	-	-	-	-	-	-
39705-Comm. Equip. - Tel	-	-	-	-	-	-	-	-	-	-	-	-	-
39800-Miscellaneous Equi	3,447	3,447	3,447	3,447	3,447	3,447	3,447	3,447	3,447	3,447	3,447	3,447	41,364
39900-Other Tangible Prop	173	173	173	173	173	173	173	173	-	-	-	-	1,387
39901-Oth Tang Prop - Se	-	-	-	-	-	-	-	-	-	-	-	-	-
39906-Oth Tang Prop - PC	-	-	-	-	-	-	-	-	-	-	-	-	-
39907-Oth Tang Prop - PC	-	-	-	-	-	-	-	-	-	-	-	-	-
RWIP													
TOTAL	**959,112**	**962,652**	**965,966**	**969,302**	**973,077**	**977,210**	**981,000**	**985,173**	**989,086**	**992,610**	**994,153**	**1,003,774**	**11,753,033**