UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form ~~10-K~~ ARS

P.E. 9-30-04

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

04053096

For the fiscal year ended September 30, 2004

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

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FINANCIAL

Commission file number 1-10042

Atmos Energy Corporation

(Exact name of registrant as specified in its charter)

Texas and Virginia *(State or other jurisdiction of incorporation or organization)*	**75-1743247** *(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 **5430 LBJ Freeway, Dallas, Texas** *(Address of principal executive offices)*	**75240** *(Zip code)*

DEC 28 04

Registrant's telephone number, including area code:
(972) 934-9227

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, No Par Value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check whether the recipient is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes ☑ No ☐

The aggregate market value of the voting stock held by non-affiliates of the registrant was $1,265,996,935 as of March 31, 2004. On March 31, 2004 the registrant had 52,235,980 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Definitive Proxy Statement to be filed for the Annual Meeting of Shareholders on February 9, 2005 are incorporated by reference into Part III of this report.

PART I

The terms "we," "our," "us," "Atmos" and "Atmos Energy" refer to Atmos Energy Corporation and its subsidiaries, unless the context suggests otherwise. The abbreviations "Mcf," "MMcf" and "Bcf" mean thousand cubic feet, million cubic feet and billion cubic feet.

Item 1. *Business*

Overview

Atmos Energy Corporation and its subsidiaries are engaged primarily in the natural gas utility business as well as other natural gas nonutility businesses. As of September 30, 2004 we distributed natural gas through sales and transportation arrangements to approximately 1.7 million residential, commercial, public authority and industrial customers through our six regulated utility divisions, which covered service areas in 12 states. Our primary service areas are located in Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee and Texas. We have more limited service areas in Georgia, Illinois, Iowa, Missouri and Virginia. In addition, we transport natural gas for others through our distribution system.

Through our nonutility businesses, we provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers in 18 states. We own or hold an interest in natural gas storage fields in Kentucky and Louisiana that we use to supply natural gas to our customers.

TXU Gas Acquisition

On October 1, 2004, we completed our acquisition of the natural gas distribution and pipeline operations of TXU Gas Company (TXU Gas). The TXU Gas operations we acquired are regulated businesses engaged in the purchase, transmission, distribution and sale of natural gas in the north-central, eastern and western parts of Texas. Through these newly acquired operations, we provide gas distribution services to approximately 1.5 million residential and business customers in Texas, including the Dallas/Fort Worth metropolitan area. We also now own and operate a system consisting of 6,162 miles of gas transmission and gathering lines and five underground storage reservoirs, all within Texas. The TXU Gas acquisition makes us one of the largest publicly-traded companies in the United States whose primary business is the transmission and distribution of natural gas and the provision of related services. It also makes us one of the largest intrastate pipeline operators in Texas.

The purchase price for the TXU Gas acquisition was approximately $1.905 billion (after preliminary closing adjustments), which we paid in cash. We acquired approximately $121 million of working capital of TXU Gas and did not assume any indebtedness of TXU Gas in connection with the acquisition. TXU Gas provided for the repayment of all of its indebtedness and redeemed all of its preferred stock prior to closing and retained and agreed to pay certain other liabilities under the terms of the acquisition agreement. The purchase price is subject to further adjustment sixty days after closing for the actual amount of working capital we acquired and other specified matters. We anticipate that any post-closing purchase price adjustments will not be material.

We funded the purchase price for the TXU Gas acquisition with approximately $235.7 million in net proceeds from our offering of 9,939,393 shares of common stock, which we completed on July 19, 2004, and approximately $1.7 billion in net proceeds from our issuance on October 1, 2004 of commercial paper backstopped by a senior unsecured revolving credit agreement, which we entered into on September 24, 2004 for bridge financing for the TXU Gas acquisition. In October 2004, we paid off the commercial paper used to fund the acquisition through the issuance of senior unsecured notes on October 22, 2004 which generated net proceeds of approximately $1.39 billion and the sale of 16.1 million shares of common stock on October 27, 2004, which generated net proceeds of approximately $382.5 million before other offering costs. As a result of this refinancing, we canceled the senior unsecured revolving bridge credit facility.

Operating Segments

Our operations are currently divided into three segments:

- the utility segment, which includes our related natural gas distribution and sales operations,
- the natural gas marketing segment, which includes a variety of natural gas management services and
- the other nonutility segment, which includes all of our other nonutility operations.

Financial information relating to our operating segments is contained in Note 17 to the consolidated financial statements.

Strategy

Our overall strategy is to:

- integrate the operations of TXU Gas that we acquired
- improve the quality and consistency of earnings growth, while operating our natural gas utility and nonutility businesses exceptionally well; and
- enhance and strengthen a culture built on our core values.

Over the last five years, we have grown through several acquisitions, including our acquisition in April 2001 of the remaining 55 percent interest in Woodward Marketing, L.L.C. that we did not already own, our acquisition in July 2001 of the assets of Louisiana Gas Service Company, our acquisition in December 2002 of Mississippi Valley Gas Company and our acquisition in October 2004 of the natural gas distribution and pipeline operations of TXU Gas.

We have experienced over 20 consecutive years of increasing dividends and earnings growth after giving effect to our acquisitions. We have achieved this record of growth while operating our utility operations efficiently by managing our operating and maintenance expenses, leveraging our technology, such as our 24-hour call center, to achieve more efficient operations, focusing on regulatory rate proceedings to increase revenue as our costs increase and mitigating weather-related risks through weather-normalized rates in many of our service areas. Additionally, we have strengthened our nonutility business by ceasing speculative trading activities, increasing gross profit margins and actively pursuing opportunities to increase the amount of storage available to us.

Our core values include focusing on our employees and customers while conducting our business with honesty and integrity. We are strengthening our culture through ongoing communication with our employees and enhanced employee training.

Utility Segment Overview

At September 30, 2004, we operated our utility segment through the following six regulated natural gas utility divisions:

- Atmos Energy Colorado-Kansas Division,
- Atmos Energy Kentucky Division,
- Atmos Energy Louisiana Division,
- Atmos Energy Mid-States Division,
- Atmos Energy Texas Division (now known as the Atmos Energy West Texas Division) and
- Mississippi Valley Gas Company Division

On October 1, 2004, we created the Atmos Energy Mid-Tex Division which represents the TXU Gas natural gas distribution operations we acquired as well as the Atmos Pipeline — Texas Division which represents the TXU Gas pipeline operations we acquired. Throughout this document, we refer to the six regulated natural gas utility divisions we operated as of September 30, 2004 as our historical operations.

Our natural gas utility distribution business is seasonal and dependent on weather conditions in our service areas. Gas sales to residential and commercial customers are greater during the winter months than during the remainder of the year. The volumes of gas sales during the winter months will vary with the temperatures during these months. The seasonal nature of our sales to residential and commercial customers is partially offset by our sales in the spring and summer months to our agricultural customers in Texas, Colorado and Kansas who use natural gas to operate irrigation equipment.

In addition to weather, our revenues are affected by the cost of natural gas and economic conditions in the areas that we serve. Higher gas costs, which we are generally able to pass through to our customers under purchased gas adjustment clauses, may cause customers to conserve, or, in the case of industrial customers, to use alternative energy sources.

The effect of weather that is above or below normal are partially offset through weather normalization adjustments, or WNA, in certain of our service areas. WNA allows us to increase the base rate portion of customers' bills when weather is warmer than normal and decrease the base rate when weather is colder than normal. As of September 30, 2004 we had, or had received regulatory approvals for, WNA in the following service areas for the following periods, which covered approximately 1.1 million of our meters in service:

Tennessee	November — April
Georgia	October — May
Mississippi	November — May
Kentucky	November — April
Kansas	October — May
Amarillo, Texas	October — May
West Texas[(1)]	October — May
Lubbock, Texas[(2)]	October — May

(1) Effective beginning in the 2004-2005 winter heating season.

(2) Effective beginning in April 2004.

The TXU Gas operations we acquired do not have WNA. However, their operations benefit from a rate structure that combines a monthly customer charge with a declining block rate schedule to mitigate the impact of warmer-than-normal weather on revenue. The combination of the monthly customer charge and the customer billing under the first block of the declining block rate schedule provides for the recovery of most of our fixed costs for such operations under most weather conditions.

We receive gas deliveries for our six historical divisions through 37 pipeline transportation companies, both interstate and intrastate, to satisfy our natural gas needs. The pipeline transportation agreements are firm and many of them have "pipeline no-notice" storage service which provides for daily balancing between system requirements and nominated flowing supplies. These agreements have been negotiated with the shortest term necessary while still maintaining our right of first refusal.

We purchase our gas supply for our six historical divisions from various producers and marketers. Supply arrangements are contracted on a firm basis with various terms at market prices. The firm supply consists of both base load and swing supply quantities. Base load quantities are those that flow at a constant level throughout the month and swing supply quantities provide the flexibility to change daily quantities to match increases or decreases in requirements related to weather conditions. Except for local production purchases, we select suppliers through a competitive bidding process by requesting proposals from suppliers that have demonstrated that they can provide reliable service. We select these suppliers based on their ability to deliver gas supply to our designated firm pipeline receipt points at the lowest cost. Major suppliers for our historical operations during fiscal 2004 were Anadarko Energy Services, BP Energy Company, ChevronTexaco Natural Gas, Duke Energy Trading and Marketing, Enbridge Marketing (US) L.P., Pioneer Natural Resources, Prior

Energy Corporation, Sempra Energy Trading Corporation, Tenaska Marketing and Atmos Energy Marketing, LLC, our natural gas marketing subsidiary. We do not anticipate problems with obtaining additional gas supply as needed for our customers.

The natural gas supply for our new Mid-Tex Division, formed from the TXU Gas operations we acquired, is delivered by the natural gas transmission and storage operations that we also acquired in the TXU Gas acquisition. This natural gas supply generally consists of a combination of base load, peaking and spot purchase agreements, as well as withdrawals of gas in storage held under gas storage capacity agreements. We estimate that the gas demand for the Mid-Tex Division for the upcoming winter heating season, assuming normal weather conditions, is approximately 113.0 Bcf. We have existing purchase agreements to cover a total gas demand of up to approximately 140.3 Bcf, consisting of approximately 40.5 Bcf under base load purchase agreements, up to approximately 47.2 Bcf under peaking purchase agreements, up to approximately 36.9 Bcf under spot purchase agreements and approximately 15.7 Bcf in storage. We anticipate that by the end of November 2004, additional amounts of gas totaling up to approximately 13.9 Bcf will be available under newly completed base load and peaking agreements and additional available gas in storage. The mixture of base load, peaking and spot purchase agreements, coupled with the withdrawal of storage gas, allows us the flexibility to adjust to changes in weather without requiring us to agree to excessive firm commitments. We anticipate that the natural gas supply for the upcoming winter heating season will consist of, in addition to withdrawals of gas in storage, a variety of suppliers, including independent producers, marketers and pipeline companies.

To maintain our deliveries to high priority customers, we have the ability, and have exercised our right, to curtail deliveries to certain customers under the terms of interruptible contracts, applicable state statutes or regulations. Our estimate of natural gas demand for our Mid-Tex division is not necessarily indicative of our ability to meet current or anticipated market demands or immediate delivery requirements because of factors such as the physical limitations of gathering, storage and transmission systems, the duration and severity of cold weather, the availability of gas reserves from our suppliers, the ability to purchase additional supplies on a short-term basis and actions by federal and state regulatory authorities. Curtailment rights provide us flexibility to meet the human-needs requirements of our customers on a firm basis. Priority allocations imposed by federal and state regulatory agencies, as well as other factors beyond our control, may affect our ability to meet the demands of our customers.

We also contract for storage service in underground storage facilities on many of the interstate pipelines serving us.

We estimate the peak-day availability of natural gas supply from long-term contracts, short-term contracts and withdrawals from underground storage to be approximately 4.2 Bcf, including approximately 2.2 Bcf associated with the TXU Gas operations we acquired. The peak-day demand for our historical operations in fiscal 2004 was on January 6, 2004, when sales to customers reached approximately 1.8 Bcf. The peak-day demand for the TXU Gas operations in the 12 months ended September 30, 2004 was also on January 6, 2004 when sales to customers reached approximately 1.6 Bcf.

The following is a brief description of our six natural gas utility divisions as well as the Mid-Tex Division acquired in October 2004. Additional information for our six natural gas utility divisions we operated at September 30, 2004 is presented under the caption "Operating Statistics".

Atmos Energy Colorado-Kansas Division. Our Colorado-Kansas Division operates in Colorado, Kansas and the southwestern corner of Missouri and is regulated by each respective state's public service commission with respect to accounting, rates and charges, operating matters and the issuance of securities. We operate under terms of non-exclusive franchises granted by the various cities. In May 2003, we received approval for WNA in Kansas which is effective October through May of each year. Colorado Interstate Gas Company, Southern Star Central Pipeline, Public Service Company of Colorado and Northwest Pipeline are the principal transporters of the Colorado-Kansas Division's gas supply requirements. Additionally, the Colorado-Kansas Division purchases substantial volumes from producers that are connected directly to its distribution system.

Atmos Energy Kentucky Division. Our Kentucky Division operates in Kentucky and is regulated by the Kentucky Public Service Commission, which regulates utility services, rates, issuance of securities and other matters. We operate in the various incorporated cities pursuant to non-exclusive franchises granted by these cities. Sales of natural gas for use as vehicle fuel in Kentucky are unregulated. We will operate under a performance-based rate program through 2006. Under the performance-based program, we and our customers jointly share in any actual gas cost savings achieved when compared to pre-determined benchmarks. Our rates are also subject to WNA. The Kentucky Division's gas supply is delivered primarily by Texas Gas Transmission LLC, Tennessee Gas Pipeline Company, Trunkline Gas Company and Midwestern Pipeline.

Atmos Energy Louisiana Division. Our Louisiana Division operates in Louisiana and includes the operations of the assets of Louisiana Gas Service Company acquired in July 2001 and our previously existing Trans La Division. Our Louisiana Division is regulated by the Louisiana Public Service Commission, which regulates utility services, rates and other matters. We operate most of our service areas pursuant to a non-exclusive franchise granted by the governing authority of each area. Direct sales of natural gas to industrial customers in Louisiana, who use gas for fuel or in manufacturing processes, and sales of natural gas for vehicle fuel are exempt from regulation and are recognized in our natural gas marketing segment. Louisiana Intrastate Gas Company, Acadian Pipeline, Trans Louisiana Gas Pipeline, Inc., Gulf South and Texas Gas Transmission LLC pipelines provide most of the Louisiana Division's natural gas requirements.

Atmos Energy Mid-States Division. Our Mid-States Division operates in Georgia, Illinois, Iowa, Missouri, Tennessee and Virginia. In each of these states, our rates, services and operations as a natural gas distribution company are subject to general regulation by each state's public service commission. We operate in each community, where necessary, under a franchise granted by the municipality for a fixed term of years. In Tennessee and Georgia, we have WNA and a performance-based rate program, which provides incentives for us to find ways to lower costs and share the cost savings with our customers. Beginning in July 2005, we will have WNA in Virginia that will cover the entire year. Our Mid-States Division is served by 13 interstate pipelines; however, the majority of the volumes are transported through East Tennessee Pipeline, Southern Natural Gas, Tennessee Gas Pipeline and Columbia Gulf.

Atmos Energy West Texas Division. Our West Texas Division, formerly known as the Atmos Energy Texas Division, operates in Texas in three primary service areas: the Amarillo service area, the Lubbock service area and the West Texas service area. The governing body of each municipality we serve has original jurisdiction over all utility rates, operations and services within its city limits, except with respect to sales of natural gas for vehicle fuel and agricultural use. We operate pursuant to non-exclusive franchises granted by the municipalities we serve, which are subject to renewal from time to time. The Railroad Commission of Texas has exclusive appellate jurisdiction over all rate and regulatory orders and ordinances of the municipalities and exclusive original jurisdiction over rates and services to customers not located within the limits of a municipality. During 2004, the West Texas Division received approval from the City of Lubbock, Texas and the 66 cities in our West Texas system, for WNA in these service areas, which will be effective October through May of each year, beginning with the 2004-2005 winter heating season. We also have WNA in our Amarillo service area. Our West Texas Division receives transportation service from ONEOK Pipeline. In addition, the West Texas Division purchases a significant portion of its natural gas supply from Pioneer Natural Resources which is connected directly to our Amarillo, Texas distribution system.

Mississippi Valley Gas Company Division. Our Mississippi Valley Gas Company Division, acquired in December 2002, operates in Mississippi and is regulated by the Mississippi Public Service Commission with respect to rates, services and operations. We operate under non-exclusive franchises granted by the municipalities we serve. Since the acquisition, we have been operating under a rate structure that allows us over a five-year period to recover a portion of our integration costs associated with the acquisition, and operations and maintenance costs in excess of an agreed-upon benchmark. In addition, we are required to file for rate adjustments based on our expenses every six months. We also have WNA in Mississippi. This division's gas supply is delivered by Gulf South Pipeline Company, Tennessee Gas Pipeline Company, Southern Natural Gas Company, Texas Eastern Transmission, Texas Gas Transmission LLC, Trunkline Gas Co. LLC and Enbridge Marketing LP.

Atmos Energy Mid-Tex Division. Our Mid-Tex Division, which represents the assets and operations that we acquired from TXU Gas on October 1, 2004, includes natural gas distribution operations that operate in the north-central, eastern and western parts of Texas and natural gas transmission and storage operations. This division purchases, distributes and sells natural gas to approximately 1.5 million residential and business customers in approximately 550 cities and towns, including the 11-county Dallas/Fort Worth metropolitan area. Under a May 2004 rate filing, this division operates under a system-wide rate jurisdiction with the pipeline operations we acquired in the acquisition. Similar to our West Texas Division, the governing body of each municipality served through this division has original jurisdiction over all utility rates, operations and services within its city limits, except with respect to sales of natural gas for vehicle fuel and agricultural use. We operate pursuant to non-exclusive franchises granted by the municipalities we serve, which are subject to renewal from time to time. The Texas Railroad Commission has exclusive appellate jurisdiction over all rate and regulatory orders and ordinances of the municipalities and exclusive original jurisdiction over rates and services to customers not located within the limits of a municipality. This division does not have WNA. However, our operations benefit from a rate structure that mitigates the impact of warmer-than-normal weather on revenue. The majority of this division's residential and business customers use natural gas for heating, and their needs are directly affected by the mildness or severity of the heating season.

The natural gas transmission and storage operations that we acquired in the TXU Gas acquisition, which will be operated in the Atmos Pipeline — Texas Division, also transport natural gas to third parties and represent one of the largest intrastate pipeline operations in Texas. These operations include interconnected natural gas transmission lines, five underground storage reservoirs (including a salt dome facility), 24 compressor stations and related properties, all within Texas. These operations may create additional gas marketing and other opportunities for our non-regulated subsidiaries.

The gas distribution and transmission lines we acquired have been constructed over lands of others pursuant to easements or along public highways, streets and rights-of-way as permitted by law. In addition to being heavily concentrated in the established natural gas-producing areas of central, northern and eastern Texas, the intrastate pipeline system we acquired also extends into or near the major producing areas of the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. Nine basins located in Texas are estimated to contain a substantial portion of the nation's remaining onshore natural gas reserves. This pipeline system provides access to all of these basins. We believe that we are well situated to receive large volumes into this pipeline system at the major hubs, such as Katy, Waha and Carthage as well as from storage facilities where we maintain high delivery capabilities.

At closing of the acquisition, TXU Gas and some of its affiliates entered into transitional services agreements with us to provide call center, meter reading, customer billing, collections, information reporting, software, accounting, treasury, administrative and other services to the Mid-Tex Division. The initial term of each of these agreements will expire on October 1, 2005. Any particular service may be terminated during the initial term on 90 days notice, except for call center, customer billing, collections, information reporting, administrative and other services provided under our agreement with TXU Gas, which may not be terminated during the initial term. After the initial term, all of the service agreements continue on a month-to-month basis until canceled by either party with at least 30 days prior written notice. In addition, we have an option to extend the business services provided during the initial term by TXU Gas for a period of six months beyond the initial term, so long as we exercise our option at least 120 days before the expiration of the initial term. The agreements require us to pay the service providers' costs for the services.

However, on November 4, 2004, we entered into an agreement with Capgemini Energy L.P. pursuant to which we will assume the operations of the Waco, Texas call center on April 1, 2005 and will close the purchase of the related assets on October 1, 2005. In connection therewith, all call center services provided by TXU Gas under the transitional services agreement will terminate on April 1, 2005.

Also at closing, we entered into a transitional access agreement with TXU Gas and some of its affiliates in order to allow the parties the same level of access to certain properties, facilities, software applications and other items that they were provided prior to the closing. The initial term of this agreement also expires on

October 1, 2005, and the agreement also continues on a month-to-month basis thereafter until canceled by either party with at least 30 days prior written notice.

In connection with the TXU Gas acquisition, we acquired the franchises held by TXU Gas to provide natural gas utility services to cities, towns and other municipalities in Texas. As part of the TXU Gas acquisition, we determined, on the basis of representations and warranties in the acquisition agreement and our diligence, that we needed the consent of two such cities for the acquisition of their franchises and we received the necessary consents prior to closing. However, we have received letters from two other cities, including the City of Dallas, raising the issue of whether, under the terms of their franchises, we should have also obtained their consents. We are currently in discussions with the City of Dallas on this issue. As these discussions are at an early stage, we cannot predict the outcome, but one alternative suggested by the City of Dallas is that we consider renewing our non-exclusive franchise with the City of Dallas prior to its 2009 expiration date. We do not currently know what changes, if any, the City of Dallas might propose in the terms of the franchise, were we to agree to an early renewal, or whether the City of Dallas will take other action with respect to the franchise, were we not to do so. However, we believe that the costs to us associated with a renewal would not be material. We have not received any similar inquiries from other cities, towns or municipalities, but we cannot be certain that we will not receive similar inquiries in the future.

Natural Gas Marketing Segment Overview

Our natural gas marketing and other nonutility segments, which are organized under Atmos Energy Holdings, Inc. (AEH), have operations in 18 states. Through September 30, 2003, Atmos Energy Marketing, LLC, together with its wholly-owned subsidiaries Woodward Marketing, L.L.C. and Trans Louisiana Industrial Gas Company, Inc., comprised our natural gas marketing segment. Effective October 1, 2003, our natural gas marketing segment was reorganized. The operations of Atmos Energy Marketing, L.L.C. and Trans Louisiana Industrial Gas Company, Inc. were merged into Woodward Marketing, L.L.C., which was renamed Atmos Energy Marketing, LLC (AEM).

We acquired a 45 percent interest in Woodward Marketing, L.L.C. in July 1997 as a result of the merger of Atmos and United Cities Gas Company, which had acquired that interest in May 1995. In April 2001, we acquired the remaining 55 percent interest that we did not own for 1,423,193 restricted shares of our common stock.

AEM provides a variety of natural gas management services to municipalities, natural gas utility systems and industrial natural gas consumers primarily in the southeastern and midwestern states and to our Kentucky, Louisiana and Mid-States divisions. These services primarily consist of furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price management through the use of derivative products. We use proprietary and customer-owned transportation and storage assets to provide the various services our customers' request. As a result, our revenues arise from the types of commercial transactions we have structured with our customers and include the value we extract by optimizing the storage and transportation capacity we own or control as well as revenues for services we deliver.

We participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers. Additionally, we participate in natural gas storage transactions in which we seek to capture the pricing differences that occur over time. We purchase or sell physical natural gas and then sell or purchase financial contracts at a price sufficient to cover our carrying costs and provide a gross profit margin. Through the use of transportation and storage services and derivatives, we are able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

AEM's management of natural gas requirements involves the sale of natural gas and the management of storage and transportation supplies under contracts with customers generally having one to two year terms. At September 30, 2004, Atmos Energy Marketing had a total of 638 industrial customers and 80 municipal customers. Atmos Energy Marketing also sells natural gas to some of its industrial customers on a delivered burner tip basis under contract terms from 30 days to two years.

Other Nonutility Segment Overview

Our other nonutility segment consists primarily of the operations of Atmos Pipeline and Storage, L.L.C. and Atmos Energy Services, LLC, which are wholly-owned by our subsidiary, Atmos Energy Holdings, Inc. Through Atmos Pipeline and Storage, we own or have an interest in underground storage fields in Kentucky and Louisiana. Atmos Pipeline and Storage's underground storage fields in Kansas were transferred to our Atmos Energy Colorado-Kansas utility division during fiscal 2004. Atmos Pipeline and Storage provides storage services to our customers and captures pricing arbitrage through the use of derivatives. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

Through Atmos Energy Services, we provide natural gas management services to our utility operations. Prior to the second quarter of fiscal 2004, this entity conducted limited operations. However, beginning April 1, 2004, Atmos Energy Services began providing natural gas supply management services to our utility operations in a limited number of states. These services include aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices. We have expanded these services to substantially all of our utility service areas as of the end of fiscal 2004.

Through January 20, 2004, United Cities Propane Gas, Inc., a wholly-owned subsidiary of Atmos Energy Holdings, Inc., owned an approximate 19 percent membership interest in U.S. Propane L.P. (USP), a joint venture formed in February 2000 with other utility companies to own a limited partnership interest in Heritage Propane Partners, L.P. (Heritage), a publicly-traded marketer of propane through a nationwide retail distribution network. During fiscal 2004, we sold our interest in USP and Heritage. As a result of these transactions, we no longer have an interest in the propane business.

Operating Statistics

The following tables present certain operating statistics for our historical utility, natural gas marketing and other nonutility segments for each of the five fiscal years from 2000 through 2004. These tables do not include data for the Mid-Tex Division acquired on October 1, 2004. However, note that based upon the number of meters in service in the Mid-Tex Division, approximately 90 percent of its customers are classified as residential, with approximately 9 percent commercial and industrial, which is substantially similar to that of our other six divisions.

Utility Sales and Statistical Data

	Year Ended September 30				
	2004	2003[(1)]	2002	2001[(1)]	2000
METERS IN SERVICE, end of year					
Residential	1,506,777	1,498,586	1,247,247	1,243,625	970,873
Commercial	151,381	151,008	122,156	122,274	104,019
Industrial	2,436	3,799	2,118	1,838	1,878
Agricultural	8,397	9,514	10,576	11,182	12,381
Public authority and other	10,145	9,891	7,244	7,404	7,448
Total meters	1,679,136	1,672,798	1,389,341	1,386,323	1,096,599
HEATING DEGREE DAYS[(2)]					
Actual (weighted average)	3,271	3,473	3,368	4,124	2,096
Percent of normal	96%	101%	94%	115%	82%
UTILITY SALES VOLUMES — MMcf[(3)]					
Gas Sales Volumes					
Residential	92,208	97,953	77,386	79,000	63,285
Commercial	44,226	45,611	35,796	36,922	30,707
Industrial	22,330	23,738	14,499	19,243	18,546
Agricultural	4,642	7,884	10,988	7,070	1,412
Public authority and other	9,813	9,326	5,875	6,892	5,520
Total gas sales volumes	173,219	184,512	144,544	149,127	119,470
Utility transportation volumes	87,746	70,159	69,589	69,492	77,767
Total utility throughput	260,965	254,671	214,133	218,619	197,237
UTILITY OPERATING REVENUES (000's)[(3)]					
Gas Sales Revenues					
Residential	$ 923,773	$ 873,375	$ 535,981	$ 788,902	$ 405,552
Commercial	400,704	367,961	221,728	342,945	176,712
Industrial	155,336	151,969	70,164	120,770	90,966
Agricultural	31,851	48,625	37,951	28,753	6,178
Public authority and other	77,178	65,921	31,731	58,539	27,198
Total utility gas sales revenues	1,588,842	1,507,851	897,555	1,339,909	706,606
Transportation revenues	31,714	30,461	28,786	28,750	28,726
Other gas revenues	17,172	15,770	11,185	11,489	4,619
Total utility operating revenues	$1,637,728	$1,554,082	$ 937,526	$1,380,148	$ 739,951
Utility average transportation revenue per Mcf	$ 0.36	$ 0.43	$ 0.41	$ 0.41	$ 0.37
Utility average cost of gas per Mcf sold	$ 6.55	$ 5.76	$ 3.87	$ 6.82	$ 3.67
Employees[(4)]	2,243	2,313	1,766	1,819	1,488

See footnotes following these tables.

Utility Sales and Statistical Data By Division[5]

	Year Ended September 30, 2004						
	Colorado-Kansas	Kentucky	Louisiana	Mid-States	West Texas	Mississippi	Total Utility
METERS IN SERVICE							
Residential	205,028	159,214	348,390	274,662	270,854	248,629	1,506,777
Commercial	19,190	18,077	22,754	36,187	25,818	29,355	151,381
Industrial	85	409	—	712	548	682	2,436
Agricultural	295	—	—	—	8,102	—	8,397
Public authority and other	1,757	1,655	931	880	2,158	2,764	10,145
Total	226,355	179,355	372,075	312,441	307,480	281,430	1,679,136
HEATING DEGREE DAYS[2]							
Actual	5,490	4,283	1,515	3,631	3,252	2,734	3,271
Percent of normal	99%	98%	93%	95%	101%	90%	96%
SALES VOLUMES — MMcf[3]							
Gas Sales Volumes							
Residential	16,271	10,980	14,997	17,257	18,402	14,301	92,208
Commercial	6,093	4,865	6,699	12,502	6,953	7,114	44,226
Industrial	304	1,713	—	7,852	3,393	9,068	22,330
Agricultural	526	—	—	—	4,116	—	4,642
Public authority and other	1,491	1,451	814	249	2,157	3,651	9,813
Total	24,685	19,009	22,510	37,860	35,021	34,134	173,219
Transportation Volumes	8,879	27,059	7,073	22,001	20,579	2,155	87,746
Total Throughput	33,564	46,068	29,583	59,861	55,600	36,289	260,965
OPERATING REVENUES (000's)[3]	$220,486	$195,116	$265,708	$379,887	$301,667	$274,864	$1,637,728
OTHER STATISTICS, at year end							
Miles of pipe	6,405	3,851	8,063	7,878	15,125	6,294	47,616
Employees[4]	278	239	431	427	349	519	2,243

See footnotes following these tables.

	Year Ended September 30, 2003						
	Colorado-Kansas	Kentucky	Louisiana	Mid-States	West Texas	Mississippi	Total Utility
METERS IN SERVICE							
Residential	199,853	159,024	346,866	274,025	271,198	247,620	1,498,586
Commercial	18,759	18,077	22,843	35,889	26,228	29,212	151,008
Industrial	36	406	—	729	933	1,695	3,799
Agricultural	413	—	—	—	9,101	—	9,514
Public authority and other	1,584	1,661	930	750	2,208	2,758	9,891
Total	220,645	179,168	370,639	311,393	309,668	281,285	1,672,798
HEATING DEGREE DAYS(2)							
Actual	5,704	4,364	1,735	3,843	3,487	2,243	3,473
Percent of normal	101%	101%	106%	101%	97%	101%	101%
SALES VOLUMES — MMcf(3)							
Gas Sales Volumes							
Residential	17,419	12,700	16,066	18,780	20,091	12,897	97,953
Commercial	6,506	5,442	6,841	13,106	7,448	6,268	45,611
Industrial	313	2,613	—	8,332	4,149	8,331	23,738
Agricultural	858	—	—	—	7,026	—	7,884
Public authority and other	1,233	1,559	867	277	2,342	3,048	9,326
Total	26,329	22,314	23,774	40,495	41,056	30,544	184,512
Transportation Volumes	9,615	24,848	7,960	20,011	5,671	2,054	70,159
Total Throughput	35,944	47,162	31,734	60,506	46,727	32,598	254,671
OPERATING REVENUES (000's)(3)	$206,653	$177,613	$261,896	$374,725	$274,520	$258,675	$1,554,082
OTHER STATISTICS, at year end							
Miles of pipe	6,341	3,840	7,952	7,790	13,261	6,083	45,267
Employees(4)	275	237	450	453	341	557	2,313

See footnotes following these tables.

Natural Gas Marketing and Other Nonutility Operations Sales and Statistical Data

	Year Ended September 30				
	2004	2003	2002	2001	2000
CUSTOMERS, end of year					
Industrial[6]	638	644	641	531	—
Municipal[6]	80	94	101	68	—
Other[6]	237	202	117	125	—
Total	955	940	859	724	—
NATURAL GAS MARKETING SALES VOLUMES — MMcf[3][6]	265,090	294,785	273,692	98,869	—
PROPANE — Gallons (000's)[7]	—	—	—	—	19,329
OPERATING REVENUES (000's)[3]					
Natural gas marketing	$1,618,602	$1,668,493	$1,031,874	$447,096	$ 929
Other nonutility	23,151	21,630	24,705	59,436	95,376
Propane revenues[7]	—	—	—	—	22,550
Total operating revenues	$1,641,753	$1,690,123	$1,056,579	$506,532	$118,855
Equity in earnings of Woodward Marketing L.L.C.[6]	—	—	—	$ 8,062	$ 7,307
Employees, at year end	122	88	83	62	28

Notes to preceding tables:

(1) The operational and statistical information includes the operations of LGS since the July 1, 2001 acquisition date and the operations of MVG since the December 3, 2002 acquisition date.

(2) A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the natural gas industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on 30-year average National Weather Service data for selected locations. Degree-day information for 2001-2004 is adjusted for service areas that have weather normalized operations. Degree day information for 2000 has not been adjusted for service areas with weather normalized operations as that information was not available.

(3) Sales volumes and revenues reflect segment operations, including intercompany sales and transportation amounts.

(4) The number of utility employees excludes 499, 504, 489, 480 and 369 Atmos shared services employees and 122, 88, 83, 62 and 28 other segment employees in 2004, 2003, 2002, 2001 and 2000.

(5) These tables present data for our six natural gas utility divisions. Their operations include the regulated local distribution companies located in their respective service areas. The operations of LGS are included in our Louisiana Division since the July 1, 2001 acquisition date, and the operations of MVG are included in our Mississippi Valley Gas Company Division since the December 3, 2002 acquisition date. These tables do not include data for the Mid-Tex Division acquired on October 1, 2004.

(6) Through March 31, 2001, substantially all of our natural gas marketing revenues and expenses were shown on the equity basis. Beginning April 1, 2001 natural gas marketing revenues and expenses are fully consolidated.

(7) Represents propane gallons sold for the period from October 1999 to August 2000. For the period from August 2000 to November 2003, the results of our propane operations were shown on the equity basis; therefore, gallons sold have not been presented. We no longer have an interest in the propane business.

Ratemaking activity

Overview

The method of determining regulated rates varies among the states in which our natural gas utility divisions operate. The regulators have the responsibility of ensuring that utilities under their jurisdictions operate in the best interests of customers while providing utility companies the opportunity to earn a reasonable return on investment. In a general rate case, the applicable regulatory authority establishes rates which allow a utility company an opportunity to collect revenue from customers to recover the cost of providing utility service.

Generally, the regulatory authority reviews our rate request and establishes a rate structure intended to generate revenue sufficient to cover our costs of doing business and provide a reasonable return on invested capital.

Rates established by regulatory authorities are adjusted for increases and decreases in our purchased gas cost through purchased gas adjustment mechanisms. Purchased gas adjustment mechanisms provide gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to address all of the utility's non-gas costs. These mechanisms are commonly utilized when regulatory authorities recognize a particular type of expense, such as purchased gas costs, that (i) is subject to significant price fluctuations compared to the utility's other costs, (ii) represents a large component of the utility's cost of service and (iii) is generally outside the control of the gas utility. There is no gross profit generated through purchased gas adjustments, but they do provide a dollar-for-dollar offset to increases or decreases in utility gas costs. Although substantially all of our utility sales to our customers fluctuate with the cost of gas that we purchase, utility gross profit (which is defined as operating revenues less purchased gas cost) is generally not affected by fluctuations in the cost of gas due to the purchased gas adjustment mechanism. Additionally, certain jurisdictions have introduced performance-based ratemaking adjustments to provide incentives to natural gas utilities to minimize purchased gas costs through improved storage management and use of financial hedges to lock in gas costs. Under the performance-based ratemaking adjustment, purchased gas costs savings are shared between the utility and its customers.

The following table summarizes certain information regarding our historical ratemaking jurisdictions. This table does not summarize the ratemaking activities of the Mid-Tex Division we acquired on October 1, 2004.

Division	Jurisdiction	Rate Base (thousands)[1]	Allowed Return on Equity[1]
Colorado-Kansas	Colorado	(2)	11.25% – 12.50%
	Kansas	(2)	(2)
Kentucky	Kentucky	(2)	(2)
Louisiana	Louisiana	$246,617	10.50% – 11.50%
Mid-States	Georgia	38,451	11.50%
	Illinois	24,564	11.56%
	Iowa	5,000	11.00%
	Missouri	(2)	12.15%
	Tennessee	(2)	(2)
	Virginia	30,672	10.00%
West Texas	Amarillo	36,844	12.00%
	Lubbock	43,300	11.25%
	West Texas	87,500	10.50%
Mississippi Valley Gas Company	Mississippi	198,103	9.8%

(1) The rate base and authorized rate of return presented in this table are the rate base and rate of return from the last base rate case for each jurisdiction. These rate bases and rates of return are not indicative of current or future rate bases or rates of return. The equity component of "allowed return on equity" is computed by multiplying the rate base in each state by the capitalization ratio of Atmos Energy as a whole.

(2) A rate base or rate of return were not included in the respective state commission's final decision.

Recent Ratemaking Activity

Approximately 97 percent, 97 percent and 96 percent of our utility revenues in the fiscal years ended September 30, 2004, 2003 and 2002 were derived from sales at rates set by or subject to approval by local or state authorities. Net annual rate increases totaling $16.2 million and $18.6 million became effective in fiscal 2004 and fiscal 2003. There were no rate increases which became effective in fiscal 2002.

The following table and discussion summarizes the major rate requests that we have made and other ratemaking developments during the most recent five fiscal years and the action taken on such requests. This table does not summarize the ratemaking activities of the Mid-Tex Division we acquired on October 1, 2004.

Jurisdiction	Effective Date	Amount Requested	Amount Received (Reduced)
		(In thousands)	
Colorado	05/04/01	$4,200	$2,750
	04/01/04	(a)	(1,900)
Illinois	10/23/00	3,100	1,367
Iowa	03/05/01	(a)	(326)
Kansas	03/01/04	7,400	2,500
Kentucky	12/21/99	14,127	9,900
Louisiana:			
Trans La System	11/01/02	(a)	364(b)
LGS System	11/01/02	(a)	11,890(c)
LGS System	10/01/04	(a)	225
Mississippi:			
FY 2003	(d)	5,771	—
FY 2004	(d)	11,593	10,545
West Texas:			
West Texas System	12/01/00	9,827	3,011
Amarillo System	01/01/00	4,354	2,200
Amarillo System	09/01/03	5,118	2,825
Lubbock System	03/01/04	3,000	1,525
West Texas System	05/01/04	7,700	3,200
Virginia	04/01/01	2,100	(534)
	08/01/04	1,000	372

(a) No requested amounts are presented because either (1) we file periodic requests for rate adjustments based upon our actual expenses in accordance with the respective state commission's rules or (2) the commission's ruling was not the result of a rate filing initiated by us. See further information in the following discussion.

(b) In 2002, we submitted our 2001 rate stabilization filing and received tariff revisions which resulted in an increase in annual revenues of $0.5 million during the first 24-month period. Subsequent to the first 24-month period, adjusted rates will provide an increase in annual revenues of $0.4 million.

(c) In 2002, we submitted our 2001 rate stabilization filing and received tariff revisions which resulted in an increase in annual revenues of $15.3 million during the first 24-month period. Subsequent to the first 24-month period, adjusted rates will provide an increase in annual revenues of $11.9 million.

(d) The Mississippi Public Service Commission (MPSC) requires that we file for rate adjustments every six months. The rate filings are made in May and November of each year and the rate adjustments typically become effective in June and December. See further information in the following discussion.

Atmos Energy Colorado-Kansas Division. In April 2004, the Colorado-Kansas Division agreed to provide a one-time credit to our Colorado customers of $1.9 million pending approval of the agreement by the Colorado Public Utility Commission. The agreement was a result of an inquiry by the Colorado Office of Consumer Counsel related to our earnings in Colorado. The staff of the Colorado Public Utility Commission was also a party to the agreement.

In May 2003, the Colorado-Kansas Division filed a rate case with the Kansas Corporation Commission for approximately $7.4 million in additional annual revenues. In January 2004, the Kansas Corporation Commission approved an agreement that allowed a $2.5 million increase in our rates effective March 1, 2004. Additionally, the agreement allows us to increase our monthly customer charges from $5 to $8 and provides that we will not file another full rate application prior to September 1, 2005. WNA became effective in Kansas in October 2003 in accordance with the Kansas Corporation Commission's ruling in May 2003.

In November 2000, the Colorado-Kansas Division filed a rate case with the Colorado Public Utilities Commission for approximately $4.2 million in additional annual revenues. In May 2001, we received an increase in annual revenues of approximately $2.8 million from the Colorado Public Utilities Commission. The new rates went into effect on May 4, 2001.

Atmos Energy Kentucky Division. On March 25, 2002, the Kentucky Commission issued an Order approving a four year extension, effective April 1, 2002, of the Performance-based Ratemaking mechanism related to gas procurement and gas transportation activities filed by the Kentucky Division. The Performance-based Ratemaking mechanism is incorporated into the Kentucky Division's gas cost adjustment clause and provides for the sharing of purchased gas cost savings between our customers and us. We recognized other income of $0.9 million, $1.3 million and $1.1 million under the Kentucky Performance-based-ratemaking mechanism in fiscal years 2004, 2003 and 2002.

In May 1999, the Kentucky Division requested from the Kentucky Public Service Commission a $14.1 million increase in revenues, a weather normalization adjustment and changes in rate design to shift a portion of revenues from commodity charges to fixed rates. In December 1999, the Kentucky Commission granted an increase in annual revenues of approximately $9.9 million. The new rates were effective for services rendered on or after December 21, 1999. In addition, the Kentucky Commission approved a five-year pilot program for weather normalization beginning in November 2000.

Atmos Energy Louisiana Division. During fiscal 2004, the Louisiana Public Service Commission approved tariff revisions for our LGS System totaling $0.2 million that became effective in October 2004.

In October 2002, Atmos received written notification from the Executive Secretary of the Louisiana Public Service Commission that he was asserting that a monthly facilities fee of approximately $0.6 million charged since July 2001 to Atmos by Trans Louisiana Gas Pipeline, Inc., a wholly-owned subsidiary of Atmos, pursuant to a contract between the parties, was excessive. The Executive Secretary asserted that all monthly facilities fees in excess of approximately $0.1 million from July 2001 should be refunded to ratepayers with interest. On October 8, 2003, the commission unanimously voted in open session to approve an agreement that was reached with the commission staff to allow us to charge a facilities fee of approximately $0.5 million per month (subject to future escalation) beginning November 1, 2003 for a period of 14 years. No retroactive adjustments were required under this agreement.

In January and February 2002, our Louisiana Division submitted its 2001 Rate Stabilization filings to the Louisiana Public Service Commission for the two gas systems we operate in Louisiana. The Louisiana Public Service Commission audited the filings and found our earnings to be deficient and that rate adjustments were appropriate. Approved tariff revisions, which became effective November 1, 2002, resulted in $15.3 million in additional revenues per year for our LGS System and $0.5 million for our Trans La System during the first 24-month period. Subsequent to the first 24-month period, adjusted rates provided total annual revenue increases of $11.9 million for our LGS System and $0.4 million for our Trans La System. As a result of the actions taken by the Louisiana Public Service Commission, we have decreased the overall weather impact to our revenues in Louisiana.

In 2001, in connection with its review of our acquisition of Louisiana Gas Service, the Louisiana Public Service Commission approved a rate structure that requires us to share with the customers of Louisiana Gas Service cost savings that result from the acquisition. The shared cost savings are the difference between operation and maintenance expense in any future year and the 1998 normalized expense for Louisiana Gas Service, indexed for inflation, annual changes in labor costs and customer growth. Since January 1, 2002, customers have been assured they will receive annual savings, which will be indexed for inflation, annual changes in labor costs and customer growth. The sharing mechanism will remain in place for 20 years subject to established modification procedures.

In June 1999, our Trans La operations were involved in a rate investigation before the Louisiana Public Service Commission, including the redesign of rates to mitigate the effects of warm winter weather. A decision was rendered by the Louisiana Commission in October 1999 that increased service charges associated with customer service calls and increased the monthly customer charges from $6 to $9, both effective November 1, 1999. While these changes were revenue neutral, they mitigated the impact of warmer than normal winter weather on earnings. The decision also included a three-year rate stabilization clause which will allow the Trans La operations of our Louisiana Division's rates to be adjusted annually to allow us to earn a return on equity within certain ranges that will be monitored on an annual basis. This clause expired in fiscal 2003.

Atmos Energy Mid-States Division. In February 2004, the Mid-States Division filed a rate case with the Virginia Corporation Commission to request a $1.0 million increase in our base rates, WNA and recovery of the gas cost component of bad-debt expense. The Virginia Corporation Commission (VCC) granted a rate increase in November 2004 of $0.4 million that was retroactively effective to July 27, 2004. Additionally, the VCC authorized WNA beginning in July 2005 and the ability to recover the gas cost component of bad debt expense.

In March 2001, the Mid-States Division and the Iowa Consumer Advocate Division of the Department of Justice reached an agreement for an annual rate reduction of $0.3 million relating to our Iowa operations, which was effective in March 2001. Also in 2001, the Mid-States Division filed requests for accounting orders related to uncollectible delinquencies in three states. As a result, we were able to defer $1.5 million as a regulatory asset.

In February 2000, the Mid-States Division filed a rate case in Illinois with the Illinois Commerce Commission requesting an increase in annual revenues of approximately $3.1 million. After review by the Illinois Commerce Commission, we received an increase in annual revenues of approximately $1.4 million. The new rates went into effect on October 23, 2000 and are collected primarily through an increase in monthly customer charges.

In March 2000, the Mid-States Division filed a rate case in Virginia with the Virginia Corporation Commission requesting an increase in annual revenues of approximately $2.3 million. A revised filing was submitted in July 2000 requesting an increase in revenues of approximately $2.1 million. In April 2001, the Mid-States Division agreed to an annual rate reduction of $0.5 million effective beginning with the April 2001 billing cycle.

Atmos Energy West Texas Division. During fiscal 2004, our West Texas Division initiated compliance with new Gas Reliability Infrastructure Program (GRIP) legislation which became law in Texas in 2003 and allows us to expedite the recovery of capital expenditures incurred in the Lubbock, Amarillo and West Texas jurisdictions.

In October 2003, the West Texas Division filed a rate case in Lubbock requesting a $3.0 million increase in annual revenues and WNA for our residential, commercial and public-authority customers. The City of Lubbock approved a $1.5 million increase effective March 1, 2004, as well as the proposed WNA.

In September 2003, the West Texas Division filed a rate case in its West Texas System to request a $7.7 million increase in annual revenues and WNA for its residential, commercial and public-authority customers. In May 2004, the 66 cities in its West Texas System approved an increase of $3.2 million in our annual utility revenues. The cities also approved a WNA Rider for residential, commercial, public-authority and state-institution customers. This Rider became effective in October 2004.

In June 2003, the West Texas Division filed a rate case in Amarillo, Texas, requesting a $5.1 million increase in annual revenues. In August 2003, the City of Amarillo, Texas approved an annual increase of approximately $2.8 million, which was effective for bills rendered on or after September 1, 2003. The increase was primarily comprised of an increase in monthly customer charges. The agreement with Amarillo also provided for changes in the rate structure to recover the cost of uncollectible accounts, adjustments to base rates to compensate for declining gas use per customer and provided WNA for the period October through May of each year, which became effective in October 2003.

In August 1999, the West Texas Division filed rate cases in its West Texas System cities and Amarillo, Texas, requesting rate increases of approximately $9.8 million and $4.4 million. The West Texas Division received an increase in annual revenues of approximately $2.1 million in base rates plus an increase of $0.1 million in service charges in Amarillo, Texas, effective for bills rendered on or after January 1, 2000. The agreement with Amarillo also provided for changes in the rate structure to reduce the impact of warmer than normal weather and to improve the recovery of the actual cost of service calls. The West Texas Division's request for its West Texas System cities was initially denied, and in March 2000 this decision was appealed to the Railroad Commission of Texas (Railroad Commission). After a series of appeals, the Railroad Commission approved a settlement which increased annual revenues by approximately $3.0 million that covered all 67 cities served by the West Texas System effective December 1, 2000.

Mississippi Valley Gas Company Division. The Mississippi Public Service Commission requires that we file for rate adjustments based on our expenses every six months. Typically, rate adjustments are filed in May and November of each year and the rate becomes effective in June and December. In October 2003, the Mississippi Public Service Commission (MPSC) issued a final order that denied our May 2003 request for a rate adjustment. We filed our second semiannual filing on November 5, 2003, and received an annual rate increase of $5.9 million effective on December 1, 2003. We filed our first semiannual filing for 2004 on May 5, 2004 and we received an annual rate increase of $4.7 million effective on June 1, 2004. However, in the same ruling, the MPSC disallowed certain deferred costs totaling $2.8 million. We are appealing the MPSC's decision regarding these deferred costs. We filed our second semiannual filing for 2004 on November 4, 2004.

Atmos Energy Mid-Tex Division. In May 2003, TXU Gas filed, for the first time, a system-wide rate case for the distribution and pipeline operations. The case was filed in all 437 incorporated cities served by the distribution operations, and at the Railroad Commission for the pipeline business and for unincorporated areas served by the distribution operations. The filing requested an annual revenue increase of $69.5 million or 7.24 percent. On May 25, 2004, TXU Gas received a decision from the Texas Railroad Commission that disallowed certain assets and liabilities for ratemaking purposes. However, the rate case is expected to prospectively increase the Mid-Tex Division's revenue by approximately $11.7 million. The decision in the rate case was available and considered by us as we finalized our offer for the TXU Gas operations. Additionally, pursuant to its May 2004 rate order, the Mid-Tex Division now operates under a system-wide rate jurisdiction with the pipeline operations we acquired in connection with the TXU Gas acquisition. Similar to our West Texas Division, the Mid-Tex Division operates under the new GRIP regulations. The conditions imposed by the States of Iowa, Missouri and Virginia, in their approvals of the TXU Gas Company acquisition, require that we protect the customers of each state from any adverse effects of the acquisition with respect to rates and quality of service.

Other Regulation

Each of our utility divisions is regulated by various state or local public utility authorities. We are also subject to regulation by the United States Department of Transportation with respect to safety requirements in the operation and maintenance of our gas distribution facilities. Our distribution operations are also subject to various state and federal laws regulating environmental matters. From time to time we receive inquiries regarding various environmental matters. We believe that our properties and operations substantially comply with and are operated in substantial conformity with applicable safety and environmental statutes and regulations. There are no administrative or judicial proceedings arising under environmental quality statutes pending or known to be contemplated by governmental agencies which would have a material adverse effect on us or our operations. Our environmental claims have arisen primarily from manufactured gas plant sites in

Tennessee, Iowa and Missouri and mercury contamination sites in Kansas. These claims are more fully described in Note 13 to the consolidated financial statements.

The TXU Gas operations we acquired are wholly intrastate in character and are subject to regulation by municipalities in Texas and the Texas Railroad Commission. These acquired operations do not include any certificated interstate transmission facilities subject to the jurisdiction of the Federal Energy Regulatory Commission (known as the FERC) under the Natural Gas Act, any sales for resale under the rate jurisdiction of the FERC or any transportation service that is subject to FERC jurisdiction under the Natural Gas Act. Since 1988, the FERC has allowed, pursuant to Section 311 of the Natural Gas Policy Act, gas transportation services through the intrastate transmission facilities we acquired "on behalf of" interstate pipelines or local distribution companies served by interstate pipelines, without subjecting the acquired operations to the jurisdiction of the FERC. We did not acquire any manufactured gas plant sites in the TXU Gas acquisition. Our acquisition agreement with TXU Gas addresses other environmental matters, which we do not expect to have a material adverse effect on us or our operations.

Competition

Our utility operations are not currently in significant direct competition with any other distributors of natural gas to residential and commercial customers within our service areas. However, we do compete with other natural gas suppliers and suppliers of alternative fuels for sales to industrial and agricultural customers. We compete in all aspects of our business with alternative energy sources, including, in particular, electricity. Electric utilities offer electricity as a rival energy source and compete for the space heating, water heating and cooking markets. Promotional incentives, improved equipment efficiencies and promotional rates all contribute to the acceptability of electrical equipment. The principal means to compete against alternative fuels is lower prices, and natural gas historically has maintained its price advantage in the residential, commercial and industrial markets. However, higher gas prices, coupled with the electric utilities' marketing efforts have increased competition for residential and commercial customers. In addition, our Natural Gas Marketing segment competes with other natural gas brokers in obtaining natural gas supplies for our customers.

Employees

At September 30, 2004, we had 2,864 employees, consisting of 2,742 employees in our utility segment and 122 employees in our other segments. The acquisition of the TXU Gas operations increased our number of employees by 1,344. See "Operating Statistics — Utility Sales and Statistical Data by Division" for the number of employees by division.

Other Information

We post our filings with the Securities and Exchange Commission on our website at *www.atmosenergy.com.*

Corporate Governance

In accordance with relevant provisions of the Sarbanes-Oxley Act of 2002, related releases of the Securities and Exchange Commission as well as corporate governance listing standards of the New York Stock Exchange, in November 2003 the Board of Directors of the Company adopted the Company's Corporate Governance Guidelines and revised the Company's Code of Conduct, which is applicable to all directors, officers and employees of the Company. In addition, the Board of Directors amended the charters for each of its Audit, Human Resources and Nominating and Corporate Governance Committees. All of the foregoing documents are posted on the Corporate Governance page of the Company's website.

Item 2. *Properties*

Distribution, transmission and related assets

At September 30, 2004 our utility segment owned an aggregate of 47,616 miles of underground distribution and transmission mains throughout our gas distribution systems. These mains are located on easements or rights-of-way which generally provide for perpetual use. We maintain our mains through a program of continuous inspection and repair and believe that our system of mains is in good condition. With the acquisition of the TXU gas operations, the number of miles of underground distribution mains increased by 26,431. Additionally, the acquisition added 6,162 miles of transmission and gathering lines to our system.

Our utility segment also holds franchises granted by the incorporated cities and towns that we serve. At September 30, 2004, we held 667 franchises having terms generally ranging from five to 25 years. We believe that each of our franchises will be renewed. With the acquisition of the TXU Gas operations, our number of franchises increased to 1,103. The additional franchises have initial terms generally ranging from ten to 35 years. We believe that each of these franchises will be renewed. A significant number of our franchises expire each year, which require renewal prior to the end of their terms.

Storage Assets

Our historical utility and other nonutility segments own underground gas storage facilities in several states to supplement the supply of natural gas in periods of peak demand. The following table summarizes key information regarding our underground gas storage facilities:

Facility	Location	Usable capacity (Mcf)	Cushion Gas (Mcf)[1]	Total Capacity (Mcf)	Maximum Daily Delivery Capability (Mcf)
Utility Segment					
St. Charles	Hopkins County, Ky	3,560,600	3,470,000	7,030,600	44,600
Liberty North[2]	Montgomery County, Ks	2,800,000	2,000,000	4,800,000	40,000
Goodwin	Monroe County, Ms	743,998	1,393,280	2,137,278	18,000
Amory	Monroe County, Ms	800,635	788,457	1,589,092	30,000
Bon Harbor	Daviess County, Ky	778,600	1,300,000	2,078,600	24,000
Hickory	Daviess County, Ky	451,600	850,000	1,301,600	24,000
Columbus LNG Plant	Muscogee County, Ga	450,000	50,000	500,000	30,000
Liberty South[2]	Montgomery County, Ks	439,000	300,000	739,000	5,000
Grandview	Daviess County, Ky	305,400	350,000	655,400	4,500
Buffalo[2]	Wilson County, Ks	200,000	180,000	380,000	5,000
Fredonia[2]	Wilson County, Ks	200,000	160,000	360,000	5,000
Kirkwood	Hopkins County, Ky	221,900	400,000	621,900	12,000
Total Utility Segment		10,951,733	11,241,737	22,193,470	242,100
Other Nonutility Segment					
East Diamond	Hopkins County, Ky	2,160,000	1,640,000	3,800,000	40,000
Barnsley	Hopkins County, Ky	1,278,900	1,600,000	2,878,900	30,000
Napoleonville[3]	Assumption Parish, La	438,583	300,973	739,556	56,000
Crofton	Christian County, Ky	54,000	55,000	109,000	1,000
Total Other Nonutility Segment		3,931,483	3,595,973	7,527,456	127,000
Total[4]		14,883,216	14,837,710	29,720,926	369,100

(1) Cushion gas represents the volume of gas that must be retained in a facility to maintain reservoir pressure.

(2) This field was transferred from the Other Nonutility segment to the Atmos Energy Colorado-Kansas Division during fiscal 2004.

(3) We own 25 percent of this facility and Acadian Gas Pipeline System owns the remaining 75 percent of this facility. Acadian Gas Pipeline System operates this facility.

(4) The TXU Gas operations we acquired include five underground storage reservoirs (including a salt dome facility), all within Texas. Our total storage capacity in these storage reservoirs is approximately 51.9 Bcf. However, approximately 12.9 Bcf of this gas represents cushion gas to maintain reservoir pressure. The maximum daily delivery capability of these storage facilities is approximately 1,235,000 Mcf.

Additionally, we contract for storage service in underground storage facilities on many of the interstate pipelines serving us to supplement our proprietary storage capacity. The following table summarizes our contracted storage capacity.

Division/Company	Contractor	Maximum Storage Quantity (MMBtu)	Maximum Daily Withdrawal Quantity (MMBtu)[1]
Utility Segment			
Colorado-Kansas Division	Southern Star Central Pipeline	2,699,598	44,217
	Tenaska Marketing Ventures	500,000	7,000
	Public Service Company of Colorado	434,997	15,000
	Colorado Interstate Gas Company	422,142	12,985
	Kinder Morgan, Inc.	90,000	2,000
	Centerpoint Energy Gas Transmission	28,500	950
Kentucky Division	Texas Gas Transmission	3,841,150	41,060
	Tennessee Gas Pipeline Company	1,313,538	22,698
Louisiana Division	Gulf South	1,941,280	97,064
	Louisiana Intrastate Gas Company	600,000	60,000
	Sonat	4,771	102
	Tennessee Gas Pipeline Company	4,466	91
Mid-States Division	Atmos Energy Marketing	2,173,543	19,634
	Southern Natural Gas Company	1,423,374	28,741
	Texas Eastern Transmission Company	1,165,734	19,636
	Panhandle Eastern Pipeline	972,462	15,241
	Tennessee Gas Pipeline Company	835,674	20,000
	Gallagher Drilling Company[2]	640,000	5,000
	ANR Pipeline Company	633,034	12,661
	Dominion	609,008	8,136
	Transco	521,580	12,212
	Virginia Gas Pipeline Company	200,000	20,000
	Egyptian Gas Storage Corp.	400,000	5,000
	East Tennessee	339,900	52,633
	Natural Gas Pipeline Company	312,750	5,580
	Texas Gas Transmission	239,576	5,108
	CMS Trunkline Gas Company	220,455	2,940
	MRT Energy Marketing	137,493	2,395
West Texas Division	ONEOK Texas Gas Storage LLP	1,125,000	50,000

See footnotes on the following page.

Division/Company	Contractor	Maximum Storage Quantity (MMBtu)	Maximum Daily Withdrawal Quantity (MMBtu)[1]
Mississippi Valley Gas Company Division	Gulf South	1,237,500	61,875
	Southern Natural Gas	1,049,436	21,191
	Texas Gas Transmission	826,390	36,420
	Texas Eastern	518,220	8,637
	Hattiesburg Gas Storage Company	400,000	40,000
	Trunkline Gas Company	24,840	331
	Tennessee Gas Pipeline Company	3,394	113
Total Utility Segment		27,889,805	756,651
Natural Gas Marketing Segment			
Atmos Energy Marketing, LLC	TCO	1,197,000	25,000
	Virginia Gas Pipeline Company	170,000	17,000
Total Natural Gas Marketing Segment		1,367,000	42,000
Other Nonutility Segment			
Trans Louisiana Gas Pipeline, Inc.	Gulf South Pipeline Company	750,000	20,000
	Bridgeline Gas Distribution LLC	300,000	30,000
Total Other Nonutility Segment		1,050,000	50,000
Total Contracted Storage Capacity		30,306,805	848,651

(1) Maximum daily withdrawal quantity (MDWQ) amounts will fluctuate depending upon the season and the month. Unless otherwise noted, MDWQ amounts represent the MDWQ amounts as of November 1, which is the beginning of the winter heating season.

(2) We contract for storage service in two underground storage facilities, Wiseman and Ellis, from this company.

Other facilities

Our utility segment owns and operates one propane peak shaving plant with a total capacity of approximately 180,000 gallons that can produce an equivalent of approximately 3,300 Mcf daily.

Offices

Our administrative offices are consolidated in Dallas, Texas under one lease. We also maintain field offices throughout our distribution system, the majority of which are located in leased facilities. Our nonutility operations are headquartered in Houston, Texas, with offices in Houston and other locations, primarily in leased facilities.

Item 3. ***Legal Proceedings***

See Note 13 to the consolidated financial statements.

Item 4. ***Submission of Matters to a Vote of Security Holders***

No matters were submitted to a vote of security holders during the fourth quarter of fiscal 2004.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information as of September 30, 2004, regarding the executive officers of the Company. It is followed by a brief description of the business experience of each executive officer.

Name	Age	Years of Service	Office Currently Held
Robert W. Best	57	7	Chairman, President and Chief Executive Officer
John P. Reddy	51	6	Senior Vice President and Chief Financial Officer
R. Earl Fischer	65	42	Senior Vice President, Utility Operations
JD Woodward III	54	3	Senior Vice President, Nonutility Operations
Louis P. Gregory	49	4	Senior Vice President and General Counsel
Wynn D. McGregor	51	16	Vice President, Human Resources

Robert W. Best was named Chairman of the Board, President and Chief Executive Officer in March 1997. He previously served as Senior Vice President — Regulated Businesses of Consolidated Natural Gas Company (January 1996-March 1997) and was responsible for its transmission and distribution companies.

John P. Reddy was named Senior Vice President and Chief Financial Officer in September 2000. From April 2000 to September 2000, he was Senior Vice President, Chief Financial Officer and Treasurer. Mr. Reddy previously served the Company as Vice President, Corporate Development and Treasurer from December 1998 to March 2000. He joined the Company in August 1998 from Pacific Enterprises, a Los Angeles, California based utility holding company whose principal subsidiary was Southern California Gas Co.

R. Earl Fischer was named Senior Vice President, Utility Operations in May 2000. He previously served the Company as President of the Texas Division from January 1999 to April 2000 and as President of the Kentucky Division from February 1989 to December 1998.

JD Woodward was named Senior Vice President, Nonutility Operations in April 2001. Prior to joining the Company, Mr. Woodward was President of Woodward Marketing, L.L.C. from January 1995 to March 2001.

Louis P. Gregory was named Senior Vice President and General Counsel in September 2000. Prior to joining the Company, he practiced law from April 1999 to August 2000 with the law firm of McManemin & Smith.

Wynn D. McGregor was named Vice President, Human Resources in January 1994. He previously served the Company as Director of Human Resources from February 1991 to December 1993 and as Manager, Compensation and Employment from December 1987 to January 1991.

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Our stock trades on the New York Stock Exchange under the trading symbol "ATO." The high and low sale prices and dividends paid per share of our common stock for fiscal 2004 and 2003 are listed below. The high and low prices listed are the closing NYSE quotes for shares of our common stock:

	2004			2003		
	High	Low	Dividends paid	High	Low	Dividends paid
Quarter ended:						
December 31	$24.99	$24.15	$ .305	$23.63	$20.70	$ .30
March 31	26.86	24.32	.305	24.20	20.95	.30
June 30	26.05	23.68	.305	25.45	21.43	.30
September 30	25.86	24.61	.305	25.07	23.20	.30
			$1.22			$1.20

Dividend payments are payable at the discretion of our Board of Directors out of legally available funds and are also subject to restriction under the terms of our First Mortgage Bond agreements. See Note 6 to the consolidated financial statements. The number of record holders of our common stock on September 30, 2004 was 27,555. We do not expect to change our current dividend policy as a result of the TXU Gas acquisition or the related financings. Future payments of dividends, and the amounts of these dividends, will depend on our financial condition, results of operations, capital requirements and other factors.

The following table sets forth the number of securities authorized for issuance under our equity compensation plans at September 30, 2004.

	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders:			
Long-Term Incentive Plan	1,492,177	$22.10	1,760,627
Long-Term Stock Plan for the Mid-States Division	300	15.50	168,550
Total equity compensation plans approved by security holders	1,492,477	22.10	1,929,177
Equity compensation plans not approved by security holders	—	—	—
Total	1,492,477	$22.10	1,929,177

Item 6. *Selected Financial Data*

The following table sets forth selected financial data of the Company and should be read in conjunction with the consolidated financial statements included herein.

	Year ended September 30				
	2004[1]	2003[2]	2002	2001[3]	2000[4]
	(In thousands, except per share data and ratios)				
Results of Operations					
Operating revenues	$2,920,037	$2,799,916	$1,650,964	$1,725,481	$ 850,152
Gross profit	562,191	534,976	431,140	375,208	325,706
Operating expenses	368,496	347,136	275,809	244,927	240,390
Operating income	193,695	187,840	155,331	130,281	85,316
Miscellaneous income (expense)[1]	9,507	2,191	(1,321)	6,188	14,744
Interest charges	65,437	63,660	59,174	47,011	43,823
Income before income taxes and cumulative effect of accounting change	137,765	126,371	94,836	89,458	56,237
Cumulative effect of accounting change, net income tax benefit	—	(7,773)	—	—	—
Income tax expense	51,538	46,910	35,180	33,368	20,319
Net income	86,227	71,688	59,656	56,090	35,918
Weighted average diluted shares outstanding	54,416	46,496	41,250	38,247	31,594
Diluted net income per share	$ 1.58	$ 1.54	$ 1.45	$ 1.47	$ 1.14
Cash flows from operations	270,734	49,541	297,395	82,995	54,196
Cash dividends paid per share	$ 1.22	$ 1.20	$ 1.18	$ 1.16	$ 1.14
Total utility throughput (MMcf)	246,033	247,965	208,541	217,774	197,564
Total natural gas marketing sales volumes (MMcf)	222,572	225,961	204,027	55,469	—
Financial Condition					
Net property, plant and equipment[5]	$1,722,521	$1,624,394	$1,380,070	$1,409,432	$1,045,484
Working capital[5]	262,644	16,248	(139,150)	(90,968)	(185,267)
Total assets[5][6]	2,869,883	2,625,495	2,059,631	2,108,841	1,410,668
Short-term debt, inclusive of current maturities of long-term debt	5,908	127,940	167,771	221,942	267,613
Total capitalization					
Shareholders' equity	1,133,459	857,517	573,235	583,864	392,466
Long-term debt (excluding current maturities)[6]	861,311	862,500	668,959	691,026	361,970
	1,994,770	1,720,017	1,242,194	1,274,890	754,436
Capital expenditures	190,285	159,439	132,252	113,109	75,557
Financial Ratios					
Capitalization ratio[6]	56.7%	46.4%	40.7%	39.0%	38.4%
Return on average shareholders' equity[7]	9.1%	9.9%	9.9%	10.4%	9.3%

See footnotes on the following page.

(1) Financial results for 2004 include a $5.9 million pre-tax gain on the sale of our interest in U.S. Propane, L.P. and Heritage Propane Partners, L.P.

(2) Financial results for fiscal 2003 include the results of MVG from December 3, 2002, the date of acquisition.

(3) Financial results for fiscal 2001 include the results of Louisiana Gas Service Company from July 1, 2001 and Woodward Marketing L.L.C. from April 1, 2001, the date of each acquisition, and the equity earnings from our 45 percent investment in Woodward Marketing L.L.C. for the period October 1, 2001 through March 31, 2002.

(4) Financial results for 2000 include a $5.8 million pre-tax gain on the contribution of our propane assets to U.S. Propane, L.P.

(5) We have reclassified our regulatory cost of removal obligation from accumulated depreciation to a liability. The amounts presented above for property, plant and equipment, working capital and total assets reflect this reclassification for all periods presented. These reclassifications did not impact our financial position, results of operations or cash flows as of and for the years ended September 30, 2003, 2002, 2001 and 2000.

(6) The capitalization ratio is calculated by dividing shareholders' equity by the sum of total capitalization, current maturities of long-term debt and short-term debt. We have reclassified our original issue discount costs from deferred charges and other assets to long-term debt. This reclassification did not materially impact our capitalization or our capitalization ratio as of September 30, 2003, 2002, 2001 and 2000. Note that as of October 1, 2004, in connection with the TXU Gas acquisition, the capitalization ratio decreased to 40.2%.

(7) The return on average shareholders' equity is calculated by dividing current year net income by the average of shareholders' equity for the previous five quarters.

The following table presents a condensed income statement by segment for the year ended September 30, 2004.

	For the Year Ended September 30, 2004				
	Utility	Natural Gas Marketing	Other Nonutility	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$1,636,636	$1,279,424	$ 3,977	$ —	$2,920,037
Intersegment revenues	1,092	339,178	19,174	(359,444)	—
	1,637,728	1,618,602	23,151	(359,444)	2,920,037
Purchased gas cost	1,134,594	1,571,971	9,383	(358,102)	2,357,846
Gross profit	503,134	46,631	13,768	(1,342)	562,191
Depreciation and amortization	92,954	2,089	1,604	—	96,647
Other operating expenses	250,290	16,816	6,119	(1,376)	271,849
Operating income	159,890	27,726	6,045	34	193,695
Miscellaneous income (expense)	5,847	843	8,579	(5,762)	9,507
Interest charges	65,399	2,711	3,055	(5,728)	65,437
Income before income taxes	100,338	25,858	11,569	—	137,765
Income tax expense	37,242	9,225	5,071	—	51,538
Net income	$ 63,096	$ 16,633	$ 6,498	$ —	$ 86,227
Capital expenditures	$ 189,291	$ 520	$ 474	$ —	$ 190,285

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

Introduction

This section provides management's discussion of the financial condition, changes in financial condition and results of operations of Atmos Energy Corporation with specific information on results of operations and liquidity and capital resources. It includes management's interpretation of our financial results, the factors affecting these results, the major factors expected to affect future operating results and future investment and financing plans. This discussion should be read in conjunction with the Company's consolidated financial statements and notes thereto.

Cautionary Statement for the Purposes of the Safe Harbor under the Private Securities Litigation Reform Act of 1995

The statements contained in this Annual Report on Form 10-K may contain "forward-looking statements" within the meaning of Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by the Company and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of the Company's documents or oral presentations, the words "anticipate", "believe", "expect", "estimate", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in [illegible] statements relating to the Company's strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: adverse weather conditions, such as warmer than normal weather in the Company's utility service territories or colder than normal weather that could adversely affect our natural gas marketing activities; regulatory trends and decisions, including deregulation initiatives and the impact of rate proceedings before various state regulatory commissions; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility and counterparty creditworthiness; national, regional and local economic conditions; the Company's ability to continue to access the capital markets; the effects of inflation and changes in the availability and prices of natural gas, including the volatility of natural gas prices; increased competition from energy suppliers and alternative forms of energy; risks relating to the acquisition of the TXU Gas operations, including without limitation, the Company's increased indebtedness resulting from the acquisition and the successful integration of the TXU Gas operations; and other uncertainties discussed herein, all of which are difficult to predict and many of which are beyond the control of the Company. Accordingly, while the Company believes these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, the Company undertakes no obligation to update or revise any of its forward-looking statements whether as a result of new information, future events or otherwise.

Factors that May Affect our Future Performance

Our performance in the future will primarily depend on the results of our utility and natural gas marketing operations. Several factors exist that could influence our future financial performance, some of which are described below. They should be considered in connection with evaluating forward-looking statements contained in this report or otherwise made by or on behalf of us since these factors could cause actual results and conditions to differ materially from those set out in these forward-looking statements.

Our operations are weather sensitive.

Weather is one of the most significant factors influencing our performance. Our natural gas utility sales volumes and related revenues are correlated with heating requirements that result from cold winter weather. Our agricultural sales volumes are associated with the rainfall levels during the growing season in our west Texas irrigation market. However, weather normalized rates in effect in several of our jurisdictions should mitigate the adverse effects of warmer than normal weather on our utility operating results. Finally, sustained cold weather could adversely affect our natural gas marketing operations as we may be required to purchase gas at spot rates in a rising market to obtain sufficient volumes to fulfill some customer contracts.

Our operations are subject to regulation which can directly impact our operations.

Our natural gas utility business is subject to various regulated returns on its rate base in each of the 12 states in which we operate. We monitor the allowed rates of return, our effectiveness in earning such rates and initiate rate proceedings or operating changes as needed. In addition, in the normal course of the regulatory environment, assets are placed in service and historical test periods are established before rate cases can be filed. Once rate cases are filed, regulatory bodies have the authority to suspend implementation of the new rates while studying the cases. Because of this process, we must temporarily suffer the negative financial effects of having placed assets in service without the benefit of rate relief, which is commonly referred to as "regulatory lag". In addition, our debt and equity financing programs are also subject to approval by regulatory bodies in certain states, which could limit our ability to take advantage of favorable short-term market conditions.

Our business could also be affected by deregulation initiatives, including the development of unbundling initiatives in the natural gas industry. Unbundling is the separation of the provision and pricing of local distribution gas services into discrete components. It typically focuses on the separation of the distribution and gas supply components and the resulting opening of the regulated components of sales services to alternative unregulated suppliers of those services. Because of our enhanced technology and distribution system infrastructures, we believe that we are now positively positioned as unbundling evolves. Consequently, we expect there would be no significant adverse effect on our business should unbundling or further deregulation of the natural gas distribution service business occur.

Finally, contractual limitations could adversely affect our ability to withdraw gas from storage, which could cause us to purchase gas at spot prices in a rising market to obtain sufficient volumes to fulfill customer contracts. We seek to minimize this risk by increasing our storage capacity and enhancing the flexibility of our natural gas marketing contracts.

Our operations are exposed to market risks that are beyond our control, which could result in financial losses.

Our risk management operations in our natural gas marketing segment are subject to market risks beyond our control including market liquidity, commodity price volatility and counterparty creditworthiness. Market liquidity is affected by the number of trading partners in the market.

Although we maintain a risk management control policy, we may not be able to completely offset the price risk associated with volatile gas prices or the risk in our gas trading activities which could lead to financial losses. Physical trading also introduces price risk on any net open positions at the end of each trading day, as well as a risk of loss resulting from intra-day fluctuations of gas prices and the potential for daily price movements between the time natural gas is purchased or sold for future delivery and the time the related purchase or sale is hedged. Although we manage our business to maintain no open positions, at times, limited net open positions related to our physical storage may occur on a short-term basis. The determination of our net open position as of any day requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the price risk associated with any net open position at the end of each day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. Net open positions may result in an adverse impact on our financial condition or results of operations if market prices move in an unfavorable manner.

Our utility segment uses a combination of storage and financial hedges to partially insulate us against volatility in gas prices and to help moderate the effects of higher customer accounts receivable caused by higher gas prices. Our natural gas marketing segment manages margins and limits risk exposure on the sale of natural gas inventory or the offsetting fixed-price purchase or sale commitments for physical quantities of natural gas through the use of a variety of financial derivatives.

We could realize financial losses on these activities as a result of volatility in the market value of the underlying commodities or if a counterparty fails to perform under a contract.

Further, the use of financial instruments to conduct our hedging and market risk activities subjects us to counterparty risk. Adverse changes in the creditworthiness of our counterparties could limit the level of trading activities with these parties and increase the risk that these parties may not perform under a contract. We believe this risk is mitigated due to the large number of counterparties used in our risk management activities.

Our net periodic pension and other postretirement costs are subject to market risk as the fluctuation in the fair value of the assets used to fund our various benefit plans could lead to significant fluctuations in these costs.

Finally, we are subject to interest rate risk on our commercial paper borrowings and the floating rate debt we issued in October 2004 to fund the TXU Gas acquisition. We could experience higher interest expense if interest rates increase or increased volatility if short-term interest rates become volatile.

National, regional and local economic conditions have a direct impact on our operations.

Our operations are affected by the conditions and overall strength of the national, regional and local economies, including interest rates, changes in the capital markets and increases in the costs of our primary commodity, natural gas. These factors impact the amount of residential, industrial and commercial growth in our service territories. Additionally, these factors could adversely impact our customer collections.

Further, AEM's operations are concentrated in the natural gas industry, and its customers and suppliers may be subject to economic risks affecting that industry.

The execution of our business plan could be affected by an inability to access financial markets.

We rely upon access to both short-term and long-term capital markets as a source of liquidity to satisfy our liquidity requirements. Although we believe we will maintain sufficient access to these financial markets, adverse changes in the economy, the overall health of the industries in which we operate, the increase in our indebtedness after the TXU Gas acquisition and changes to our credit ratings could limit access to these markets and restrict the execution of our business plan.

Inflation and increased gas costs could adversely impact our customer base and customer collections and increase our level of indebtedness.

Inflation has caused increases in certain operating expenses, and has required assets to be replaced at higher costs. We have a process in place to continually review the adequacy of our utility gas rates in relation to the increasing cost of providing service and the inherent regulatory lag in adjusting those gas rates. Historically, we have been able to budget and control operating expenses and investments within the amounts authorized to be collected in rates and intend to continue to do so. The ability to control expenses is an important factor that will influence future results.

The rapid increases in the price of purchased gas, which has occurred in some prior years, causes us to experience a significant increase in short-term debt because we must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow our utility collection efforts as customers are more likely to delay the payment of their gas bills, leading to higher than normal accounts receivable. This situation also results in higher short-term debt levels and increased bad debt expense. Should the price of purchased gas increase significantly in the upcoming heating season, we *would* expect increases in our short-term debt, accounts receivable and bad debt expense during fiscal 2005.

Finally, higher costs of natural gas in recent years have already caused many of our utility customers to conserve in the use of our gas services and could lead to even more customers utilizing such conservation methods.

Our operations are subject to increased competition.

We are facing increased competition from other energy suppliers as well as electric companies and from energy marketing and trading companies. In the case of industrial customers, such as manufacturing plants, and agricultural customers, adverse economic conditions, including higher gas costs, could cause these customers to use alternative sources of energy such as electricity or bypass our systems in favor of special competitive contracts with lower per-unit costs.

Risks Relating to the Acquisition of the TXU Gas Operations

In addition to the factors affecting our company and our industry, the risks outlined below relating to the TXU Gas acquisition could also adversely affect our business, financial condition or results of operations.

Our indebtedness and leverage increased materially with the TXU Gas acquisition.

On October 22, 2004, we issued senior unsecured notes which generated net proceeds of approximately \$1.39 billion. On October 27, 2004 we sold 16.1 million shares of common stock, which generated net proceeds of approximately \$382.5 million before other offering costs. These financings were used to pay off the commercial paper that was issued to fund the TXU Gas acquisition. Assuming these financings had occurred on September 30, 2004, our total debt, as of September 30, 2004, would have increased from \$867.2 million to \$2.3 billion and our ratio of total debt to capitalization (including short-term debt and current maturities of long-term debt), as of September 30, 2004 would have increased from 43.3 percent to 59.8 percent. Our ratio of total debt to capitalization is expected to be greater during the current winter heating season as we make additional short-term borrowings to fund natural gas purchases and meet our working capital requirements. We also increased our working capital facility from \$350.0 million to \$600.0 million on October 22, 2004 to meet our increased working capital requirements as a result of the TXU Gas acquisition. This increase in our indebtedness could limit our flexibility in planning for, or reacting to, changes in our business or economic conditions.

Our long-term debt is currently rated as "investment grade" by Standard & Poor's Corporation, Moody's Investors Service and Fitch Ratings, Inc., the three credit rating agencies that rate our long-term debt securities. There can be no assurance that these rating agencies will maintain investment grade ratings for our long-term debt. If we were to lose our investment-grade rating, the commercial paper markets and the commodity derivatives markets could become unavailable to us. This would increase our borrowing costs for working capital and reduce the borrowing capacity of our gas marketing affiliate. In addition, if our commercial paper ratings were lowered, it would increase the cost of commercial paper financing and could reduce or eliminate our ability to access the commercial paper markets. If we are unable to issue commercial paper, we intend to borrow under our bank credit facilities to meet our working capital needs. This would increase the cost of our working capital financing.

We may not be able to implement the TXU Gas acquisition successfully.

The TXU Gas acquisition is larger than any of the nine other acquisitions we have made since 1986. In addition to operating the natural gas distribution system we acquired in the TXU Gas acquisition, we will manage pipeline operations on a scale greater than in the past. As a consequence, we may experience the need for additional management attention and resources, we may be required to develop relationships with additional regulatory authorities in the service areas of the TXU Gas operations we acquired or we may face unanticipated challenges or delays in integrating the TXU Gas operations we acquired into our business. In addition, employees important to the TXU Gas operations we acquired may decide not to continue employment with us. If these events occur, the acquired operations may not achieve the results or otherwise perform as expected.

The TXU Gas operations we acquired are subject to their own risks, which we may not be able to manage successfully.

The financial results of the TXU Gas operations we acquired are subject to many of the same factors that have historically affected our financial condition and results of operations, including weather sensitivity, extensive federal, state and local regulation, increasing gas costs, competition, market risks and national, regional and local economic conditions.

In addition, the TXU Gas distribution operations we acquired do not have weather-normalized rates. This means we will not be able to increase customers' bills to offset lower gas usage when the weather is warmer than normal. However, their operations benefit from a rate structure that combines a monthly customer charge with a declining block rate schedule to mitigate the impact of warmer-than-normal weather on revenue. The combination of the monthly customer charge and the customer billing under the first block of the declining block rate schedule provides for the recovery of most of our fixed costs for such operations under most weather conditions. As a result, the financial results for the TXU Gas operations we acquired may be adversely affected in the event of a warmer-than-normal heating season.

The TXU Gas transmission operations we acquired include interconnected natural gas transmission lines, underground storage reservoirs, compressor stations and related properties within Texas. The operation of these transmission facilities also involves risks. These include the possibility of breakdown or failure of equipment or pipelines, the impact of unusual or adverse weather conditions or other natural events and the risk of performance below expected levels of throughput or efficiency. Breakdown or reduced performance of a transmission facility may prevent the facility from performing under applicable sales agreements which, in certain situations, could result in termination of those agreements or incurring a liability for liquidated damages. Insurance, warranties, indemnities or performance guarantees may not cover any or all of the liquidated damages, lost revenues or increased expenses associated with a breakdown or reduction in performance of a transmission facility. If we are unsuccessful in managing these risks, our business, financial condition and results of operations could be adversely affected.

We have only limited recourse under the acquisition agreement for losses relating to the TXU Gas acquisition.

The diligence conducted in connection with the TXU Gas acquisition and the indemnification provided in the acquisition agreement may not be sufficient to protect us from, or compensate us for, all losses resulting from the acquisition or TXU Gas's prior operations. For example, under the terms of the acquisition agreement, the first $15 million of many indemnifiable losses are to be borne by us, and the agreement provides for sharing of losses with respect to unknown environmental matters that may affect the assets we acquired after we have borne $10 million in costs relating to such matters. In addition, under the terms of the acquisition agreement, the maximum aggregate amount of such losses for which TXU Gas will indemnify us is approximately $192.5 million. A material loss associated with the TXU Gas acquisition for which there is not adequate indemnification could negatively affect our results of operations, our financial condition and our reputation in the industry and reduce the anticipated benefits of the acquisition.

There may be other risks or costs resulting from the TXU Gas acquisition that are not known to us.

We may not be aware of all of the risks associated with the TXU Gas acquisition. Any discovery of adverse information concerning the assets or operations we acquired could be material and, in many cases, would be subject to only limited rights of recovery. In addition, we will likely have to make capital expenditures, which may be significant, but which amount has not been fixed, to enhance or integrate the assets and operations we acquired.

Overview

- Our utility segment net income increased $1.0 million despite weather that was 4 percent warmer than normal during fiscal 2004. The increase reflects the full year impact of the Mississippi Valley Gas Company (MVG) operations and rate increases in Kansas, Texas and Mississippi, partially offset by a decline in our irrigation business and a one time $1.2 million net of tax refund to customers in our Colorado service area.

- Our natural gas marketing segment net income before the cumulative effect of an accounting change increased $9.8 million during fiscal 2004. This increase primarily was attributable to our continued efforts to amend contracts with third parties to transfer risk to our customers and to provide higher gross profit margins and improved position management during the current year.
- Our fiscal 2004 results reflect pretax gains from asset sales totaling $6.7 million attributable to the sale of our general and limited partnership interests in USP and the remaining limited partnership units in Heritage Propane Partners, L.P. formerly owned by USP during 2004 and the sale of real property. These asset sales provided $27.9 million in cash proceeds during 2004.
- In July 2004, we sold 9,939,393 shares of our common stock, including the underwriters' exercise of their overallotment option. The offering price was $24.75 and generated net proceeds of approximately $235.7 million after offering costs. In October 2004, we used the net proceeds from this offering, together with issuances in October 2004 of commercial paper backstopped by the bridge financing facility to consummate the acquisition of the natural gas distribution and pipeline operations of TXU Gas.
- In August 2004, we filed a shelf registration statement with the SEC to issue, from time to time, up to $2.2 billion in new common stock and/or debt, which was declared effective on September 15, 2004.
- In October 2004, we sold 16.1 million common shares under the new shelf registration statement, including the underwriters' exercise of their overallotment option generating net proceeds of approximately $382.5 million before other offering costs. Additionally, we issued senior unsecured debt under the new shelf registration statement which generated approximately $1.39 billion in net proceeds. These proceeds were used to refinance the $1.7 billion in commercial paper we issued on October 1, 2004 to fund the TXU Gas acquisition and for general corporate purposes.
- Our total debt to capitalization ratio at September 30, 2004 was 43.3 percent compared with 53.6 percent at September 30, 2003. The improvement in the debt to capitalization ratio was primarily attributable to the issuance of 9.9 million shares of our common stock in July 2004, and reduced short-term debt due to strong operating cash flow generated during fiscal 2004. Assuming the TXU Gas acquisition and financings described above had occurred on September 30, 2004, our debt-to-capitalization ratio would have increased to 59.8 percent.
- Our debt ratings were recently downgraded as a result of the TXU Gas acquisition; however, our ratings are still considered investment grade.

Critical Accounting Policies and Estimates

Our consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates, including those related to risk management and trading activities, allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Our critical accounting policies are reviewed by the Audit Committee on a quarterly basis. Actual results may differ from estimates.

Regulation — Our utility operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. Our regulated utility operations are accounted for in accordance with Statement of Financial Accounting Standards (SFAS) 71, *Accounting for the Effects of Certain Types of Regulation.* This statement requires cost-based, rate-regulated entities that meet certain criteria to reflect the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions in their financial statements. We record regulatory assets for costs that have been deferred for which future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. As a result, certain costs that would normally be expensed under accounting principles generally accepted in the United States are permitted to be capitalized because they can be recovered through rates. Further, regulation may impact the period in which revenues or expenses are recognized. The amounts to be recovered or recognized are based upon historical experience and our understanding of the regulations. The impact of regulation on our utility operations may be affected by decisions of the regulatory authorities or the issuance of new regulations.

Revenue recognition — Sales of natural gas to our utility customers are billed on a monthly cycle basis; however, the billing cycle periods for certain classes of customers do not necessarily coincide with accounting periods used for financial reporting purposes. We follow the revenue accrual method of accounting for utility segment revenues whereby revenues applicable to gas delivered to customers, but not yet billed under the cycle billing method, are estimated and accrued and the related costs are charged to expense.

Rates established by regulatory authorities are adjusted for increases and decreases in our purchased gas cost through purchased gas adjustment mechanisms. Purchased gas adjustment mechanisms provide gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to address all of the utility's non-gas costs. These mechanisms are commonly utilized when regulatory authorities recognize a particular type of expense, such as purchased gas costs, that (i) is subject to significant price fluctuations compared to the utility's other costs, (ii) represents a large component of the utility's cost of service and (iii) is generally outside the control of the gas utility. There is no gross profit generated through purchased gas adjustments, but they do provide a dollar-for-dollar offset to increases or decreases in utility gas costs. Although substantially all of our utility sales to our customers fluctuate with the cost of gas that we purchase, utility gross profit is generally not affected by fluctuations in the cost of gas due to the purchased gas adjustment mechanism. The effects of these purchased gas adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

Energy trading contracts resulting in the delivery of a commodity where we are the principal in the transaction are recorded as natural gas marketing sales or purchases at the time of physical delivery. Realized gains and losses from the settlement of financial instruments that do not result in physical delivery related to our natural gas marketing energy trading contracts and unrealized gains and losses from changes in the market value of open contracts are included as a component of natural gas marketing revenues.

Allowance for doubtful accounts — For the majority of our receivables, we establish an allowance for doubtful accounts based on our collections experience. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be different. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices and general economic conditions.

Derivatives and hedging activities — In our utility segment, we use a combination of storage and financial derivatives to partially insulate us and our natural gas utility customers against gas price volatility during the winter heating season. The financial derivatives we use in our utility segment are accounted for under the mark-to-market method pursuant to SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*. Changes in the valuation of these derivatives primarily result from changes in the valuation of the portfolio of contracts, maturity and settlement of contracts and newly originated transactions. However, because the costs of financial derivatives used in our utility segment will ultimately be recovered through our rates, current period changes in the assets and liabilities from these risk management activities are recorded as a component of deferred gas costs in accordance with SFAS 71. Accordingly, there is no earnings impact to our utility segment as a result of the use of financial derivatives. The changes in the assets and liabilities from risk management activities are recognized in purchased gas cost in the income statement when the related costs are recovered through our rates.

Our natural gas marketing risk management activities are conducted through AEM. AEM is exposed to risks associated with changes in the market price of natural gas, which we manage through a combination of storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Option contracts provide the right, but not the requirement, to buy or sell the commodity at a fixed price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date. The use of these contracts is subject to our risk management policies, which are monitored for compliance on a daily basis.

We participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers. Additionally, we engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We purchase or sell physical natural gas and then sell or purchase financial contracts at a price sufficient to cover our carrying costs and provide a gross profit margin. Through the use of transportation and storage services and derivatives, we are able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Under SFAS 133, natural gas inventory is the hedged item in a fair-value hedge and is marked to market on a monthly basis using the inside FERC (iFERC) price at the end of each month. Changes in fair value are recognized as unrealized gains and losses in the period of change. Costs to store the gas are recognized in the period the costs are incurred. We recognize revenue and the carrying value of the inventory as an associated purchased gas cost in our consolidated statement of income when we sell the gas and deliver it out of the storage facility.

Derivatives associated with our natural gas inventory are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains and losses in the period of change. The difference in the indices used to mark to market our physical inventory (iFERC) and the related fair-value hedge (NYMEX) is reported as a component of revenue and can result in volatility in our reported net income. Over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction. In addition, we continually manage our positions to optimize value as market conditions and other circumstances change.

Similar to our inventory position, we attempt to mitigate substantially all of the commodity price risk associated with our fixed-price contracts with minimum volume requirements through the use of various offsetting derivatives. Prior to April 1, 2004, these derivatives were not designated as hedges under SFAS 133 because they naturally locked in the economic gross profit margin at the time we entered into the contract. The fixed-price forward and offsetting derivative contracts were marked to market each month with changes in fair value recognized as unrealized gains and losses recorded in revenue in our consolidated statement of income. The unrealized gains and losses were realized as a component of revenue in the period in which we fulfilled the requirements of the fixed-price contract and the derivatives settled. To the extent that the unrealized gains and losses of the fixed-price forward contracts and the offsetting derivatives did not offset exactly, our earnings experienced some volatility. At delivery, the gains and losses on the fixed-price contracts were offset by gains and losses on the derivatives, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction. In addition, we continually manage our positions to optimize value as market conditions and other circumstances change.

Effective April 1, 2004, we elected to treat our fixed-price forward contracts as normal purchases and sales. As a result, we ceased marking the fixed-price forward contracts to market. We designated the offsetting derivative contracts as cash flow hedges of anticipated transactions. As a result of this change, unrealized gains and losses on these open derivative contracts are now recorded as a component of accumulated other comprehensive income and are recognized in earnings as a component of revenue when the hedged volumes are sold. This designation is expected to partially reduce the amount of volatility in our consolidated income statement and better reflect the economics of this type of transaction. Hedge ineffectiveness, to the extent incurred, is reported as a component of revenue.

During fiscal 2004, we entered into four Treasury lock agreements to fix the Treasury yield component of the interest cost of financing associated with the anticipated issuance of $875 million of long-term debt. We designated these Treasury lock agreements as cash flow hedges of an anticipated transaction. Accordingly, to the extent effective, unrealized gains and losses associated with the Treasury lock agreements are recorded as a component of accumulated other comprehensive income. Unrealized gains are recorded when interest rates increase and unrealized losses are recorded when interest rates decline. These Treasury lock agreements were terminated in October 2004 and the $43.8 million unrealized loss will be recognized as a component of interest expense over the life of the related financing arrangement.

The fair value of our financial derivatives is determined through a combination of prices actively quoted on national exchanges, prices provided by other external sources and prices based on models and other valuation methods. Changes in the valuation of our financial derivatives primarily result from changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our derivatives. We believe the market prices and models used to value these derivatives represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under present market conditions.

Impairment assessments — We perform impairment assessments of our goodwill, intangible assets subject to amortization and long-lived assets. We currently have no indefinite-lived intangible assets. We annually evaluate our goodwill balances for impairment during our second fiscal quarter or as impairment indicators arise. We use a present value technique based on discounted cash flows to estimate the fair value of our reporting units. Our reporting units and our operating segments are the same as each operating unit represents a component of our business. Goodwill is allocated to the reporting units responsible for the acquisition that gave rise to the goodwill.

The discounted cash flow calculations used to assess goodwill impairment are dependent on several subjective factors including the timing of future cash flows, future growth rates and the discount rate. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its fair value.

We periodically evaluate whether events or circumstances have occurred that indicate that our intangible assets subject to amortization and other long-lived assets may not be recoverable or that the remaining useful life may warrant revision. When such events or circumstances are present, we assess the recoverability of these assets by determining whether the carrying value will be recovered through expected future cash flows. These cash flow projections consider various factors such as the timing of the future cash flows and the discount rate and are based upon the best information available at the time the estimate is made. Changes in these factors could materially affect the cash flow projections and result in the recognition of an impairment charge. An impairment charge is recognized as the difference between the carrying amount and the fair value if the sum of the undiscounted cash flows is less than the carrying value of the related asset.

Pension and other postretirement plans — Pension and other postretirement plan expenses and liabilities are determined on an actuarial basis and are affected by the market value of plan assets, estimates of the expected return on plan assets and assumed discount rates and demographic data. The assumed return on plan assets is based on management's expectation of the long-term return on the portfolio of plan assets. The discount rate used to compute the present value of plan liabilities generally is based on rates of high grade corporate bonds with maturities similar to the average period over which benefits will be paid. Actual changes in the fair market value of plan assets and differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension expense ultimately recognized.

Results of Operations.

The following table presents our financial highlights for the three fiscal years ended September 30, 2004:

	For the year ended September 30		
	2004	2003	2002
	(In thousands, unless otherwise noted)		
Operating revenues	$2,920,037	$2,799,916	$1,650,964
Gross profit	562,191	534,976	431,140
Operating expenses	368,496	347,136	275,809
Operating income	193,695	187,840	155,531
Miscellaneous income (expense)	9,507	2,191	(1,321)
Interest charges	65,437	63,660	59,174
Income before income taxes and cumulative effect of accounting change	137,765	126,371	94,836
Cumulative effect of accounting change, net of income tax benefit	—	(7,773)	—
Income tax expense	51,538	46,910	35,180
Net income	$ 86,227	$ 71,688	$ 59,656
Utility sales volumes — MMcf	173,219	184,512	145,488
Utility transportation volumes — MMcf	72,814	63,453	63,053
Total utility throughput — MMcf	246,033	247,965	208,541
Natural gas marketing sales volumes — MMcf	222,572	225,961	204,027
Heating Degree Days[1]			
Actual (weighted average)	3,271	3,473	3,368
Percent of normal	96%	101%	94%
Consolidated utility average transportation revenue per Mcf	$ 0.42	$ 0.47	$ 0.58
Consolidated utility average cost of gas per Mcf sold	$ 6.55	$ 5.71	$ 3.78

(1) Adjusted for service areas that have weather normalized operations.

The following table shows our operating income by utility division and by segment for the three fiscal years ended September 30, 2004. The presentation of our utility operating income is included for financial reporting purposes and may not reflect operating income for ratemaking purposes.

	2004		2003		2002	
	Operating Income	Heating Degree Days Percent of Normal[1]	Operating Income	Heating Degree Days Percent of Normal[1]	Operating Income	Heating Degree Days Percent of Normal[1]
	(In thousands, except degree day information)					
Colorado-Kansas	$ 20,876	99%	$ 23,756	101%	$ 20,083	95%
Kentucky	22,738	98%	21,841	101%	21,934	100%
Louisiana	40,762	93%	41,672	106%	26,974	90%
Mid-States	38,778	95%	37,535	101%	34,146	94%
Mississippi Valley Gas Company	18,709	101%	17,617	101%	—	—
West Texas	22,090	90%	19,650	97%	19,593	92%
Other	(4,063)	—	(937)	—	2,776	—
Utility segment	159,890	96%	161,134	101%	125,506	94%
Natural gas marketing segment	27,726	—	13,569	—	20,610	—
Other nonutility segment	6,079	—	13,137	—	9,215	—
Consolidated operating income	$193,695	96%	$187,840	101%	$155,331	94%

(1) Adjusted for service areas that have weather normalized operations.

Year ended September 30, 2004 compared with year ended September 30, 2003

Utility segment

Our utility segment has historically contributed 70 to 85 percent of our consolidated net income. The primary factors that impact the results of our utility operations are seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Natural gas sales to residential, commercial and public-authority customers are affected by winter heating season requirements. This generally results in higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either lower net income or net losses during the period from April through September of each year. Accordingly, our second fiscal quarter has historically been our most critical earnings quarter with an average of approximately 68 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years. Utility sales to industrial customers are much less weather sensitive. Utility sales to agricultural customers, which typically use natural gas to power irrigation pumps during the period from March through September, are primarily affected by rainfall amounts and the price of natural gas.

Changes in the cost of gas impact revenue but do not directly affect our gross profit from utility operations because the fluctuations in gas prices are passed through to our customers. Accordingly, we believe gross profit margin is a better indicator of our financial performance than revenues. However, higher gas costs may cause customers to conserve, or, in the case of industrial customers, to use alternative energy sources. Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense.

The effects of weather that is above or below normal are partially offset through weather normalization adjustments, or WNA, in certain of our service areas. WNA allows us to increase the base rate portion of customers' bills when weather is warmer than normal and decrease the base rate when weather is colder than normal.

Operating income

Utility gross profit margin increased to $503.1 million for the year ended September 30, 2004 from $491.4 million for the year ended September 30, 2003. Total throughput for our utility business was 261.0 Bcf during the year compared to 254.7 Bcf in the prior year. Excluding intercompany throughput, consolidated throughput for our utility business was 246.0 Bcf during the year, compared with 248.0 Bcf in the prior year.

The increase in utility gross profit margin primarily reflects the impact of the acquisition of Mississippi Valley Gas Company (MVG) whose operations are included for the entire first quarter in fiscal year 2004, compared with one month in the first quarter of the prior fiscal year resulting in an increase in utility gross profit margin and total throughput of $12.8 million and 5.0 Bcf. Utility gross profit margin was also favorably impacted by rate increases received in Kansas, Texas and Mississippi and a $10.2 million year-over-year increase in the effect of WNA in our WNA service areas. These increases were offset partially by the impact of weather that was 6 percent warmer than that of the prior year and 4 percent warmer than normal, resulting in a decrease of approximately $13.8 million and lower irrigation sales in our West Texas Division resulting in a decrease of approximately $2.1 million. Warmer than normal weather particularly impacted our service areas in our Louisiana, Mid-States and West Texas divisions. The decrease in throughput also reflects a decrease in consumption attributable to the impact of conservation and the continued introduction of more efficient gas appliances in our service areas. Finally, our utility gross profit margin for the year ended September 30, 2004 reflects a one-time reduction resulting from a regulatory ruling to refund $1.9 million to our customers in our Colorado service area.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased 3.9 percent to $343.2 million for the year ended September 30, 2004 from $330.3 million for the year ended September 30, 2003. Operation and maintenance expense increased, primarily due to the addition of $6.1 million related to the MVG acquisition in December 2002 and higher labor and benefit costs. Taxes other than income taxes increased $1.5 million, primarily due to additional franchise, payroll and property taxes associated with the MVG assets acquired in December 2002. Franchise and state gross receipts taxes are paid by our customers as a component of their monthly bills; thus, these amounts are offset in revenues through customer billings and have no effect on net income. Depreciation and amortization expense increased $9.1 million, which primarily reflects MVG depreciation for the full year of fiscal 2004 compared with ten months in the prior year. These increases were partially offset by a $7.9 million reduction in our provision for doubtful accounts attributable to continued improvement in accounts receivable collections during fiscal 2004.

As a result of the aforementioned factors, our utility segment operating income for the year ended September 30, 2004 decreased to $159.9 million from $161.1 million for the year ended September 30, 2003.

Miscellaneous income (expense)

Miscellaneous income for the year ended September 30, 2004 was $5.8 million, compared with expense of $0.2 million for the year ended September 30, 2003. The $6.0 million change was attributable primarily to the absence in 2004 of weather insurance amortization totaling $5.0 million, which was recognized in the prior year due to the termination of our weather insurance policy in the third quarter of fiscal 2003 and the recognition of a $0.8 million gain on the sale of real property during fiscal 2004.

Interest charges

Interest charges increased 3.5 percent for the year ended September 30, 2004 to $65.4 million from $63.2 million for the year ended September 30, 2003. The increase was attributable primarily to a higher average outstanding debt balance resulting from the financing obtained to fund the acquisition of MVG in December 2002.

Natural gas marketing segment

Our natural gas marketing segment aggregates and purchases gas supply, arranges transportation and/or storage logistics and ultimately delivers the gas to our customers at competitive prices. To facilitate this process, we utilize proprietary and customer-owned transportation and storage assets to provide the various services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of derivative products. As a result, our revenues arise from the types of commercial transactions we have structured with our customers and include the value we extract by optimizing the storage and transportation capacity we own or control as well as revenues for services we deliver.

We participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers. Additionally, we engage in natural gas storage transactions in which we seek to find and profit from the pricing differences that occur over time. We purchase or sell physical natural gas and then sell or purchase financial contracts at a price sufficient to cover our carrying costs and provide a gross profit margin. Through the use of transportation and storage services and derivatives, we are able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Operating income

Gross profit margin for our natural gas marketing segment consists primarily of marketing activities, which represent the utilization of proprietary and customer-owned transportation and storage assets to provide the various services our customers request, and storage activities, which are derived from the optimization of our managed proprietary and third party storage and transportation assets.

Our natural gas marketing segment's gross profit margin was comprised of the following for the years ended September 30, 2004 and 2003:

	September 30	
	2004	2003
	(In thousands, except storage balances)	
Storage Activities		
Realized margin	$(1,900)	$(7,250)
Unrealized margin	357	5,362
Total Storage Activities	(1,543)	(1,888)
Marketing Activities		
Realized margin	51,347	25,077
Unrealized margin	(3,173)	976
Total Marketing Activities	48,174	26,053
Gross profit	$46,631	$24,165
Ending storage balance (BCF)	5.5	5.7

Our natural gas marketing segment's gross profit was $46.6 million for the year ended September 30, 2004 compared to gross profit margin of $24.2 million for the year ended September 30, 2003. Natural gas marketing sales volumes were 265.1 Bcf during the current year compared with 294.8 Bcf for the prior year. Excluding intercompany sales volumes, natural gas marketing sales volumes were 222.6 Bcf during the current year compared with 226.0 Bcf in the prior year. The decrease in consolidated natural gas marketing sales volumes was primarily due to overall warmer temperatures during the 2003-2004 heating season compared with the prior-year period. Our natural gas marketing gross profit margin for the year ended September 30, 2004 included an unrealized loss on open contracts of $2.8 million compared with an unrealized gain on open contracts of $6.3 million in the prior-year period.

The contribution to gross profit from our storage activities was a loss of $1.5 million for the year ended September 30, 2004 compared to a loss of $1.9 million for the year ended September 30, 2003. The $0.4 million improvement primarily was attributable to a $5.4 million improvement in the realized storage contribution for the year ended September 30, 2004 compared to the prior year offset by a $5.0 million decrease in unrealized income associated with our storage portfolio compared to the prior-year period. The improvement in the realized storage contribution for the year ended September 30, 2004 primarily was due to our inability during the 2002-2003 heating season to withdraw planned volumes from storage to meet our customer requirements caused by operational, contractual and regulatory limitations relating to our storage facilities, which reduced our realized storage contributions during fiscal 2003. This situation did not recur in fiscal 2004. The decrease in unrealized income in the current period was primarily attributable to a less favorable movement during the year ended September 30, 2004 in the forward indices used to value the storage financial instruments than in the prior year combined with slightly lower physical natural gas storage quantities at September 30, 2004 compared to the prior year.

Our marketing activities contributed $48.2 million to our gross profit margin for the year ended September 30, 2004 compared to $26.1 million for the year ended September 30, 2003. The increase in the marketing contribution primarily was attributable to our continued efforts to amend contracts with third parties to transfer risk to our customers and to provide higher gross profit margins and improved position management during the current year.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to $18.9 million for the year ended September 30, 2004 from $10.6 million for the year ended September 30, 2003. The increase in operating expense was attributable primarily to higher labor and benefit costs resulting from the improvement in earnings for the fiscal year and an increase in temporary and permanent personnel due to systems and process improvements in the marketing segment.

The improved gross profit margin resulted in an increase in our natural gas marketing segment operating income to $27.7 million for the year ended September 30, 2004 compared with operating income of $13.6 million for the year ended September 30, 2003.

Miscellaneous income

Miscellaneous income for the year ended September 30, 2004 was $0.8 million, compared with income of $1.9 million for the year ended September 30, 2003. The $1.1 million decrease was attributable primarily to lower interest income earned on cash held on deposit in margin accounts due to favorable valuations on our financial derivatives, which reduced the need to deposit cash into margin accounts.

Other nonutility segment

Operating income

Our other nonutility operating income decreased to $6.0 million for the year ended September 30, 2004 from $13.1 million for the year ended September 30, 2003. The decrease in our other nonutility operating income was attributable primarily to a decrease in demand charges recognized by Atmos Pipeline and Storage for storage services provided during the year ended September 30, 2004 compared to the prior-year period and lower transported volumes of approximately 2.3 Bcf by Atmos Pipeline and Storage due to overall warmer weather during the winter heating season. The decrease was also attributable to a $1.5 million decrease in a monthly facilities fees charged by Trans Louisiana Gas Pipeline, Inc. as a result of a settlement reached with the Louisiana Public Service Commission in October 2003. Our other nonutility operating income for the year ended September 30, 2004 also included an unrealized loss on open contracts of $1.1 million compared with no unrealized gain our loss in the prior year as Atmos Pipeline and Storage started to hedge its storage inventory during the fourth quarter of 2004.

Miscellaneous income

Miscellaneous income for the year ended September 30, 2004 was $8.6 million, compared with income of $5.0 million for the year ended September 30, 2003. The $3.6 million increase was attributable primarily to a $5.9 million pretax gain associated with the sale in January 2004 of our general and limited partnership interests in USP and the sale in June 2004 of the remaining limited partnership units in Heritage Propane Partners, L.P. formerly owned by USP. This increase was offset partially by lower equity earnings from our investment in USP resulting from the sale and the absence in 2004 of a $3.9 million gain recorded in 2003 associated with a sales-type lease of a distributed electric generation plant.

Interest charges

Interest charges increased to $3.1 million for the year ended September 30, 2004 from $2.0 million for the year ended September 30, 2003. The increase was attributable to a higher average outstanding debt balance resulting from increased third-party borrowings of $5.0 million used to reduce AEH's intercompany borrowings with Atmos Energy Corporation.

Year ended September 30, 2003 compared with year ended September 30, 2002

Utility segment

Operating income

Utility gross profit increased to $491.4 million for the year ended September 30, 2003 from $377.6 million for the year ended September 30, 2002. Total throughput for our utility business was 254.7 billion cubic feet (Bcf) during the year ended September 30, 2003 compared to 214.1 Bcf in the prior year. Excluding intercompany throughput, total consolidated throughput for our utility business was 248.0 Bcf during fiscal 2003, compared with 208.5 Bcf in the prior year.

The increase in utility gross profit and total throughput was primarily attributable to the impact of the MVG acquisition in December 2002, which increased utility gross profit and total throughput by $73.2 million and 32.6 Bcf. The increase in utility gross profit was also attributable to a $13.3 million increase in our base charges primarily in Louisiana as a result of our annual rate stabilization clause filing which became effective in November 2002. These increases were partially offset by a $3.9 million decrease in revenues from the impact of WNA as a result of weather in our WNA service areas being 1 percent colder than normal for the year ended September 30, 2003.

Operating expenses increased 31 percent to $330.3 million for the year ended September 30, 2003 from $252.1 million for the year ended September 30, 2002. Operation and maintenance expense increased primarily due to the addition of $36.0 million related to the MVG acquisition in December 2002, a $14.2 million increase in the provision for doubtful accounts as a result of higher revenues and gas prices and higher employee costs. Taxes other than income taxes increased $18.8 million primarily due to additional franchise, payroll and property taxes associated with the MVG assets acquired in December 2002. Note that franchise and state gross receipts taxes are paid by our customers; thus, these amounts are offset in revenues through customer billings and have no effect on net income.

As a result of the aforementioned factors, our utility segment operating income for the year ended September 30, 2003 increased to $161.1 million from $125.5 million for the year ended September 30, 2002.

Miscellaneous income (expense)

Miscellaneous expense for the year ended September 30, 2003 was $0.2 million, compared with income of $1.4 million for the year ended September 30, 2002. The $1.6 million change was attributable primarily to a $0.6 million charge associated with the cancellation of our weather insurance policy during the third quarter of fiscal 2003, which increased our total insurance policy amortization to $5.0 million for fiscal 2003 compared with $4.4 million for fiscal 2002.

Interest charges

Interest charges increased seven percent for the year ended September 30, 2003 to $63.2 million from $58.8 million for the year ended September 30, 2002. The increase was attributable primarily to a higher average outstanding debt balance resulting from the financing obtained to fund the acquisition of MVG in December 2002.

Natural gas marketing segment

Operating income

Our natural gas marketing segment's gross profit margin was comprised of the following for the years ended September 30, 2003 and 2002:

	September 30	
	2003	2002
	(In thousands, except storage balances)	
Storage Activities		
Realized margin	$(7,250)	$ 8,022
Unrealized margin	5,362	(12,776)
Total Storage Activities	(1,888)	(4,754)
Marketing Activities		
Realized margin	25,077	40,021
Unrealized margin	976	2,289
Total Marketing Activities	26,053	42,310
Gross profit	$24,165	$ 37,556
Ending storage balance (BCF)	5.7	5.0

Our total natural gas marketing segment's gross profit margin was $24.2 million for the year ended September 30, 2003 compared to gross profit margin of $37.6 million for the year ended September 30, 2002. Natural gas marketing sales volumes were 294.8 Bcf during the year ended September 30, 2003 compared to 273.7 Bcf for the prior year. Excluding intercompany sales volumes, natural gas marketing sales volumes were 226.0 Bcf during the year ended September 30, 2003 compared with 204.0 Bcf in the prior year. The increase in natural gas marketing sales volumes was primarily due to overall colder temperatures during the 2002-2003 heating season compared with the prior year. Our natural gas marketing gross profit included an unrealized gain on open contracts of $6.3 million in fiscal 2003 compared with an unrealized loss on open contracts of $10.5 million in fiscal 2002.

Our storage activities within the natural gas marketing segment contributed a loss of $1.9 million to gross profit margin for the year ended September 30, 2003 compared to a $4.8 million loss for the year ended September 30, 2002. The $2.9 million improvement in the contribution from our storage activities was primarily attributable to a $15.3 million greater realized loss in the current year due to our inability during the 2002-2003 heating season to withdraw planned volumes from storage to meet our customer requirements caused by operational, contractual and regulatory limitations relating to our storage facilities offset by an $18.1 million increase in the unrealized storage contributions in the current year compared to the prior year. The greater unrealized contribution in the current year was primarily attributable to a favorable movement during the year ended September 30, 2003 in the forward indices used to value the storage financial instruments than in the prior year combined with higher physical natural gas storage quantities at September 30, 2004 compared to the prior year.

Our marketing activities contributed $26.1 million to our gross profit margin for the year ended September 30, 2003 compared to $42.3 million for the year ended September 30, 2002. The decrease in the marketing contribution primarily was attributable to a $14.9 million decrease in realized margin combined with a $1.3 million decrease in our unrealized margin. The decrease in realized margin was primarily attributable to price risk associated with certain full requirements contracts which reduced marketing margins during the winter of 2003. We have subsequently restructured these contracts to mitigate the price risk associated with these contracts. The decrease in unrealized margin was primarily attributable to accounting changes related to the rescission of EITF 98-10 and the impact on certain contracts which had previously been marked under EITF 98-10, which were not considered derivatives under SFAS 133.

Operating expenses decreased to $10.6 million for the year ended September 30, 2003 from $16.9 million for the year ended September 30, 2002. The decrease in operating expenses primarily was attributable to lower employee incentive compensation costs during the current year.

As a result of the above, our natural gas marketing segment generated operating income of $13.6 million for the year ended September 30, 2003 compared with operating income of $20.6 million for the year ended September 30, 2002.

Cumulative effect of change in accounting principle

On January 1, 2003, we recorded a cumulative effect of a change in accounting principle to reflect a change in the way we account for our storage and transportation contracts. We previously accounted for those contracts under EITF 98-10, *Accounting for Energy Trading and Risk Management Activities,* which required us to record estimated future gains on our storage and transportation contracts at the time we entered into the contracts and to mark those contracts to market value each month. Effective January 1, 2003, we no longer mark those contracts to market. As a result, we expensed $7.8 million, net of applicable income tax benefit, as a cumulative effect of a change in accounting principle.

Other nonutility segment

Operating income

Our other nonutility segment operating income increased to $13.1 million during the year ended September 30, 2003 compared with $9.2 million for the prior year. The increase in our nonutility segment operating income was primarily attributable to increased asset management activities in the current year and an increase in leasing income attributable to the commencement in 2003 of a new lease for a distributed electric generation plant.

Miscellaneous income

Miscellaneous income for the year ended September 30, 2003 was $5.0 million, compared with income of $0.6 million for the year ended September 30, 2002. The $4.4 million change was primarily attributable to a $3.9 million gain associated with a sales-type lease of a distributed electric generation plant which was recognized in the first quarter of 2003 and improved earnings from our indirect investment in Heritage Propane Partners L.P.

Liquidity and Capital Resources

Our working capital and liquidity for capital expenditures and other cash needs are provided from internally generated funds, borrowings under our credit facilities and commercial paper program and funds raised from the public debt and equity capital markets. We believe that these sources of funds will provide the necessary working capital and liquidity for capital expenditures and other cash needs for fiscal 2005. We believe that these needs can be provided from the same sources of capital.

Capitalization

The following presents our capitalization as of September 30, 2004 and 2003:

	September 30			
	2004		2003	
	(In thousands, except percentages)			
Short-term debt	$ —	—	$ 118,595	6.4%
Long-term debt	867,219	43.3%	871,845	47.2%
Shareholders' equity	1,133,459	56.7%	857,517	46.4%
Total capitalization, including short-term debt	$2,000,678	100.0%	$1,847,957	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 43.3 percent and 53.6 percent at September 30, 2004 and 2003. The improvement in the debt to capitalization ratio was primarily attributable to the issuance of 9.9 million shares of our common stock in July 2004, and reduced short-term debt due to strong operating cash flow generated during fiscal 2004. Assuming the TXU Gas acquisition and related debt and equity financings had occurred on September 30, 2004, our debt-to-capitalization ratio would have increased to 59.8 percent. Our ratio of total debt to capitalization is expected to be greater during the current winter heating season as we make additional short-term borrowings to fund natural gas purchases and meet our working capital requirements. Within three to five years from the closing of the acquisition, we intend to reduce our capitalization ratio to a target range of 53 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, access to the equity capital markets and reduced annual maintenance and capital expenditures.

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, the price for our products and services, the demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks, the successful integration of the natural gas distribution and pipeline operations of TXU Gas we acquired and other factors.

Cash flows from operating activities

Year-over-year changes in our operating cash flows are attributable primarily to working capital changes within our utility segment resulting from the impact of weather, the price of natural gas and the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

For the year ended September 30, 2004, we generated operating cash flow of $270.7 million compared with $49.5 million in fiscal 2003 and $297.4 million in fiscal 2002. The significant factors impacting our operating cash flow for the last three fiscal years are summarized below.

Year ended September 30, 2004

Fiscal 2004 operating cash flows were favorably impacted by several items. Improved customer collections during fiscal 2004, compared with the prior year, resulted in a $62.2 million increase in operating cash flow. Further, cash used for natural gas inventories decreased by $33.8 million compared with the prior year. The decrease was attributable to lower injections of natural gas into storage, partially offset by higher prices. The reduction in the lag between the time period when we purchase our natural gas and the period in which we can include this cost in our gas rates improved operating cash flow by $65.7 million. Changes in cash held on deposit in margin accounts resulted in an increase in operating cash flow of $25.6 million. This account represents deposits recorded to collateralize certain of our financial derivatives purchased in support of our natural gas marketing activities. The favorable change was attributable to the fact that the fair value of financial instruments held by AEM represented a net asset position at September 30, 2004, which eliminated the need to place cash in margin accounts. Finally, other working capital and other changes improved operating cash flow by $33.9 million. These changes primarily related to various increases in deferred credits and other liabilities, other current liabilities and income taxes payable partially offset by lower deferred income tax expense as compared with the prior year.

Year ended September 30, 2003

Fiscal 2003 operating cash flow was adversely impacted by a $60.0 million increase in accounts receivable due to higher revenues and the timing of customer account collections. The increase in revenues was attributable to a 19 percent increase in consolidated utility throughput as a result of the impact of our MVG acquisition. Operating cash flow was also adversely impacted by a significant increase in natural gas prices. These increases resulted in a $64.9 million increase in gas stored underground and a $24.2 million increase in deferred gas costs. Finally, operating cash flow reflects the impact of the funding of our pension plan in June 2003, which included a $48.6 million cash payment. This funding is discussed under the caption Pension and Postretirement Benefits Obligations below.

Year ended September 30, 2002

In fiscal 2002, operating cash flow was impacted favorably by a $56.5 million reduction in cash held on deposit in margin accounts. During the winter and spring of 2001, our cash deposit requirements increased as a result of higher unrealized losses on our financial derivatives. Operating cash flow was also favorably impacted by a $52.3 million increase in accounts payable and accrued liabilities and a $34.2 million increase in other current liabilities primarily attributable to the timing of payments as compared with the prior year. Finally, operating cash flow was favorably impacted by a $32.9 million decrease in deferred gas costs reflecting the favorable timing between the billing of gas costs to our customers and the purchase of natural gas.

These favorable impacts were partially offset by a $12.2 million increase in accounts receivable. This increase was attributable to revenue increases resulting from the inclusion of the LGS and Woodward Marketing operations for a full year and the timing of customer account collections.

Cash flows from investing activities

During the last three years, a substantial portion of our cash resources was used to fund acquisitions, our ongoing construction program to provide natural gas services to our customer base and technology improvements.

For the year ended September 30, 2004, we invested $164.9 million compared with $233.4 million for the year ended September 30, 2003 and $158.2 million for the year ended September 30, 2002. Capital expenditures were $190.3 million during the year ended September 30, 2004 compared to $159.4 million for the year ended September 30, 2003 and $132.3 million for the year ended September 30, 2002. Capital projects for fiscal years 2004, 2003 and 2002 include expenditures for additional mains, services, meters and equipment to grow our customer base. Additionally, capital expenditures for 2004 include approximately $21.5 million for Mississippi Valley Gas Company Division capital expenditures. Fiscal 2002 cash flows from investing activities also included $8.5 million for the acquisition of assets to be leased to third parties.

Cash used for investing activities for the current year includes the receipt of $27.9 million generated from the sale of our limited and general partnership interests in USP in January 2004 ($24.7 million), the sale of the remaining limited partnership units in Heritage Propane Partners, L.P. formerly owned by USP ($1.9 million) and the sale of real property ($1.3 million).

Capital expenditures for fiscal 2005 are expected to range from $250 million to $260 million. These expenditures include additional mains, services, meters and equipment. Of this amount, approximately $80 million is expected to be incurred by the Mid-Tex Division.

Payments for acquisitions

Our cash used for investing activities for fiscal 2004 included approximately $2.0 million for the ComFurT Gas Inc. acquisition in February 2004. Cash used for investing activities for fiscal 2003 included $74.7 million for the cash portion of the Mississippi Valley Gas Company acquisition completed in December 2002. Cash used for investing activities for fiscal 2002 included $15.7 million for the acquisition of Kentucky-based market area storage and associated pipeline facility assets, certain natural gas purchase and sales contracts and the outstanding common stock of Southern Resources, Inc., a natural gas marketing company.

Cash flows from financing activities

For the year ended September 30, 2004, our financing activities provided $80.4 million in cash. Fiscal 2003 cash from financing activities provided cash of $151.6 million, and in fiscal 2002 our financing activities represented a use of $106.4 million. Our significant financing activities for the three years ended September 30, 2004 are summarized as follows:

- In July 2004, we sold 9,939,393 shares of our common stock, including the underwriters' exercise of their overallotment option. The offering price was $24.75 and generated net proceeds of $235.7 million. In October 2004, we used the net proceeds from this offering, together with borrowings under the bridge financing facility to consummate the acquisition of the natural gas distribution and pipeline operations of TXU Gas. In June and July 2003, we sold a total of 4,100,000 shares of our common stock in a public offering, which generated net proceeds of $99.2 million. The net proceeds were used to finance a portion of our pension plan contribution, repay short-term debt and for general corporate purposes.

- During fiscal 2003, we received $147.0 million from a short-term acquisition credit facility which was used primarily to fund the $74.7 million cash portion of the purchase price for MVG in December 2002 and to repay $70.9 million of MVG's outstanding debt.

- On January 16, 2003, we issued $250.0 million of 5.125% Senior Notes due 2013. The net proceeds of $249.3 million were used to refinance the short-term acquisition credit facility of $147.0 million, to repay $54.0 million in unsecured senior notes held by institutional lenders, short-term debt under our commercial paper program and for general corporate purposes.

- During fiscal 2004, 2003 and 2002, total short-term debt decreased by $118.6 million, $27.2 million and $55.5 million due to improved operating cash flow and working capital management in the last three fiscal years.

- We repaid $73.2 million of long-term debt during fiscal 2003, which includes the $54.0 million repayment of unsecured senior notes with the proceeds received from our January 2003 debt offering. Fiscal 2004 and 2002 payments on long-term debt were $9.7 million and $20.7 million.

- During fiscal 2004, we paid $66.7 million in cash dividends compared with dividend payments of $55.3 million and $48.6 million for fiscal 2003 and 2002. The increase in dividends paid over the preceding three years reflects increases in the quarterly dividend rate and the number of shares outstanding. Dividend payments in fiscal 2005 will increase substantially as a result of the July 2004 and October 2004 equity offerings.

During the year ended September 30, 2004, we issued 11,323,925 shares of common stock. Of these shares, 9,939,393 shares were issued in July 2004 to provide cash to partially fund the acquisition of the TXU Gas operations. The following table shows the number of shares issued for the years ended September 30, 2004, 2003 and 2002:

	For the year ended September 30		
	2004	2003	2002
Shares issued:			
Direct stock purchase plan	556,856	585,743	505,202
Retirement savings plan	320,313	360,725	326,335
Long-term incentive plan	498,230	181,429	50,465
Long-term stock plan for Mid-States Division	6,000	13,000	—
Outside directors stock-for-fee plan	3,133	2,969	2,429
July 2004 Offering	9,939,393	—	—
Acquisition of MVG	—	3,386,287	—
Pension account plan funding	—	1,169,700	—
2003 Offering	—	4,100,000	—
Total shares issued	11,323,925	9,799,853	884,431

Shelf Registration

In December 2001, we filed a shelf registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $600.0 million in new common stock and/or debt. The registration statement was declared effective by the SEC on January 30, 2002. On January 16, 2003, we issued $250.0 million of 5.125% Senior Notes due in 2013 under the registration statement. The net proceeds of $249.3 million were used to repay debt under an acquisition credit facility used to finance our acquisition of MVG, to repay $54.0 million in unsecured senior notes held by institutional lenders and short-term debt under our commercial paper program and for general corporate purposes. Additionally, we sold 4,100,000 shares of our common stock in connection with our 2003 Offering under the registration statement to provide additional funding for our Pension Account Plan. In July 2004, we sold 9,939,393 shares of our common stock, including the underwriters' exercise of their overallotment option, which exhausted the remaining availability under this shelf registration statement.

In August 2004, we filed a shelf registration statement with the SEC to issue, from time to time, up to $2.2 billion in new common stock and/or debt, which became effective on September 15, 2004. In October 2004, we sold 16.1 million common shares, including the underwriters' exercise of their overallotment option of 2.1 million shares, under the new shelf registration statement, generating net proceeds of $382.5 million before other offering costs. Additionally, we issued senior unsecured debt under the shelf registration statement consisting of $400 million of 4.00% senior notes due 2009, $500 million of 4.95% senior notes due 2014, $200 million of 5.95% senior notes due 2034 and $300 million of floating rate senior notes due 2007. The floating rate notes will bear interest at a rate equal to the three-month LIBOR rate plus 0.375 percent per year. The initial weighted average effective interest rate on these notes is 4.76 percent. The net proceeds from the sale of these senior notes was $1.39 billion.

The net proceeds from the October 2004 common stock and senior notes offerings, combined with the net proceeds from our July 2004 offering were used to pay off the $1.7 billion in outstanding commercial paper backstopped by a senior unsecured revolving credit agreement, which we entered into on September 24, 2004 for bridge financing for the TXU Gas acquisition. After issuing the debt and equity in October 2004 we have approximately $405.1 million of availability remaining under the shelf registration statement.

Credit Facilities

We maintain both committed and uncommitted credit facilities. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the bank. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas charged by suppliers and the increased gas supplies required to meet customers' needs during periods of cold weather. Our cash needs for working capital and capital expenditures will increase substantially as a result of the acquisition of the natural gas distribution and pipeline operations of TXU Gas. On October 22, 2004, we replaced our $350.0 million credit facility with a new $600.0 million committed credit facility that will serve as a backup liquidity facility for our commercial paper program. We believe this facility, combined with our operating cash flow will be sufficient to fund these increased working capital needs. These facilities are described in further detail in Note 6 to the consolidated financial statements.

Credit Rating

Our credit ratings directly affect our ability to obtain short-term and long-term financing, in addition to the cost of such financing. In determining our credit ratings, the rating agencies consider a number of quantitative factors, including debt to total capitalization, operating cash flow relative to outstanding debt, operating cash flow coverage of interest and pension liabilities and funding status. In addition, the rating agencies consider qualitative factors such as consistency of our earnings over time, the quality of our management and business strategy, the risk associated with our utility and nonutility businesses and the regulatory structures that govern our rates in the states where we operate.

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Service (Moody's) and Fitch Ratings, Inc. (Fitch). Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Long-term debt	BBB	Baa3	BBB+
Commercial paper	A-2	P-3	F-2

These ratings reflect downgrades that each of the three rating agencies issued us as a result of the TXU Gas acquisition. Currently, S&P and Moody's maintains a stable outlook and Fitch maintains a negative outlook. None of our ratings are currently under review.

A credit rating is not a recommendation to buy, sell or hold securities. All of our current ratings for long-term debt are categorized as investment grade. The highest investment grade credit rating for S&P is AAA, Moody's is Aaa and Fitch is AAA. The lowest investment grade credit rating for S&P is BBB−, Moody's is Baa3 and Fitch is BBB−. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independent of any other rating. There can be no assurance that a rating will remain in effect for any given period of time or that a rating will not be lowered, or withdrawn entirely, by a rating agency if, in its judgment, circumstances so warrant.

Debt Covenants

In addition to the 70 percent limit on our total debt-to-capitalization ratio imposed by our committed credit facilities, our First Mortgage Bonds provide for certain cash flow requirements and restrictions on additional indebtedness, sale of assets and payment of dividends. Under the most restrictive of such covenants, cumulative cash dividends paid after December 31, 1988, may not exceed the sum of our accumulated net income for periods after December 31, 1988, plus $15.0 million. At September 30, 2004, approximately $103.6 million of retained earnings was unrestricted with respect to the payment of dividends.

We were in compliance with all of our debt covenants as of September 30, 2004. If we do not comply with our debt covenants, we may be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions. Our two public debt indentures relating to our senior notes and debentures, as well as our new $600.0 million revolving credit agreement, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity. In addition, AEM's credit agreement contains a cross-default provision whereby AEM would be in default if it defaults on any other financial obligation, as defined, by at least $250 thousand. Additionally, this agreement contains a provision that would limit the amount of credit available if Atmos is downgraded below an S&P rating of BBB and a Moody's rating of Baa2.

Except as described above, we have no trigger events in our debt instruments that are tied to changes in specified credit ratings or stock price, nor have we entered into any transactions that would require us to issue equity based on our credit rating or other trigger events.

Contractual Obligations and Commercial Commitments

The following tables provide information about contractual obligations and commercial commitments at September 30, 2004.

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
			(In thousands)		
Contractual Obligations					
Long-term debt[1]	$ 868,550	$ 5,908	$ 14,449	$ 12,616	$ 835,577
Short-term debt[1]	—	—	—	—	—
Interest charges	610,395	58,601	115,640	113,368	322,786
Capital lease obligations[2]	4,543	1,139	1,064	673	1,667
Operating leases[2]	80,051	9,648	16,974	15,676	37,753
Demand fees for contracted storage[3]	7,303	1,674	3,080	1,703	846
Derivative obligations[4]	50,062	48,924	1,138	—	—
Transitional services agreements[5]	41,000	41,000	—	—	—
Postretirement benefit plan contributions[6]	103,619	11,698	17,617	18,373	55,931
Total contractual obligations	$1,765,523	$178,592	$169,962	$162,409	$1,254,560

(1) See Note 6 to the consolidated financial statements. This line item excludes the debt maturities associated with the $1.39 billion in senior unsecured notes we sold in October 2004.

(2) See Note 14 to the consolidated financial statements.

(3) Represents third party contractual demand fees for contracted storage in our natural gas marketing and other utility segments. Contractual demand fees for contracted storage for our utility segment are excluded as these costs are fully recoverable through our purchase gas adjustment mechanisms.

(4) Represents liabilities for natural gas commodity derivative contracts and our treasury lock agreements. The less than one year amount includes the $43.8 million settlement of our Treasury lock agreements in October 2004, which is not subject to continuing market risk. The remaining liabilities represent natural gas commodity derivative contracts that were valued as of September 30, 2004. The ultimate settlement amounts of these remaining liabilities are unknown because they are subject to continuing market risk.

(5) Represents the baseline contractual obligation under our transitional services agreements we entered into in connection with the TXU Gas acquisition for call center, meter reading, customer billing, collections, information reporting, software, accounting, treasury, administration and other services.

(6) Represents expected contributions to our postretirement benefit plans.

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward Nymex strip or fixed price contracts. At September 30, 2004, AEM was committed to purchase 55.7 Bcf within one year and 11.1 Bcf between one to three years under indexed contracts. AEM was committed to purchase 0.5 Bcf within one year and 0.1 Bcf within one to three years under fixed price contracts with prices ranging from $4.08 to $6.25.

Our utility segment maintains supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract.

On September 22, 2004, we entered into a senior unsecured revolving credit agreement with a third party financing institution for bridge financing for the TXU Gas acquisition. There were no amounts outstanding under the facility at September 30, 2004. On October 1, 2004, we issued $1.7 billion in commercial paper that was backstopped by this facility. In October 2004, we repaid the $1.7 billion in commercial paper with proceeds received from our October 2004 debt and equity offerings and canceled the facility.

Risk Management Activities

We conduct risk management activities through both our utility and natural gas marketing segments. In our utility segment, we use a combination of storage, fixed physical contracts and fixed financial contracts to partially insulate us and our customers against gas price volatility during the winter heating season. In our natural gas marketing segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Finally, during fiscal 2004, we entered into four Treasury lock agreements to fix the Treasury yield component of the interest cost of financing associated with the anticipated issuance of $875 million of long-term debt. These Treasury lock agreements were settled in October 2004 with a net $43.8 million payment to the counterparties. Approximately $11.6 million of the $43.8 million obligation will be recognized as a component of interest expense over the next five years, and the remaining amount, approximately $32.2 million, will be recognized as a component of interest expense over the next ten years. Our risk management activities and related accounting treatment are described in further detail in Note 5 to the consolidated financial statements.

We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying derivative. Substantially all of our derivative financial instruments are valued using external market quotes and indices. The following table shows the components of the change in fair value of our utility and natural gas marketing derivative contract activities for the year ended September 30, 2004 (in thousands):

	Utility	Natural Gas Marketing
Fair value of contracts at September 30, 2003	$(7,739)	$10,144
Contracts realized/settled	(3,268)	(2,882)
Fair value of new contracts	(1,194)	(797)
Other changes in value	3,589	6,553
Fair value of contracts at September 30, 2004	$(8,612)	$13,018

The fair value of our utility and natural gas marketing derivative contracts at September 30, 2004, is segregated below by time period and fair value source.

	Fair Value of Contracts at September 30, 2004				
	Maturity in years				
Source of Fair Value	Less than 1	1-3	4-5	Greater than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$41,537	$ 107	$—	$—	$ 41,644
Prices provided by other external sources	(36,513)	(108)	—	—	(36,621)
Prices based on models and other valuation methods	(42)	(575)	—	—	(617)
Total Fair Value	$ 4,982	$(576)	$—	$—	$ 4,406

As of September 30, 2004, a significant portion of AEM's stored gas inventory was scheduled to be sold within six months. Since AEM actively manages and optimizes its portfolio, it may change its scheduled injection and withdrawal plans based on market conditions. Therefore, we cannot predict that our actual inventory withdrawals will match the planned schedule as of September 30, 2004. Generally, differences between injection and withdrawal prices are locked-in through the use of derivatives; therefore, there is generally no significant permanent earnings impact associated with changes in monthly prices in the interim between injections and withdrawals. However, there may be significant quarterly earnings volatility. Further, permanent earnings impacts may arise if we experience operational or other issues which limit our ability to optimally manage our stored gas positions. Any change in the timing of planned injections or withdrawals from one time period to another generally is conducted to enhance the future profitability of the storage position. Additionally, AEM monitors and adjusts the amount of storage capacity it holds on a discretionary basis.

Pension and Postretirement Benefits Obligations

For the fiscal year ended September 30, 2004, our total net periodic pension and other benefits costs was $26.1 million, compared with $28.0 million and $13.5 million for the period ended September 30, 2003 and 2002. A portion of these costs is capitalized into our utility rate base, as these costs are recoverable through our gas utility rates. Costs that are not capitalized are recorded as a component of operation and maintenance expense.

The decrease in total net periodic pension and other benefits cost during fiscal 2004 compared with fiscal 2003 primarily reflects the impact of adopting the provisions of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act), beginning with the second quarter of 2004, which reduced our accumulated postretirement benefit obligation by $24.3 million and our net postretirement benefit obligation costs by $4.1 million. The total income statement impact was $2.3 million as a portion of this benefit was capitalized. Further, the expected return on plan assets, which reduces the net periodic pension cost and other benefits cost, increased as compared with the prior year primarily due to an increase in total assets attributable to the full year effect of the contributions we made to the Atmos Pension Account Plan in fiscal 2003 and the inclusion of the MVG pension plan assets during fiscal 2003 partially offset by a 25 basis point decrease in the expected return on plan asset assumption used to determine fiscal 2004 net periodic pension cost. These decreases were partially offset by an increase in the service cost and the recognized actuarial loss attributable to a 125 basis point decrease in the discount rate used to determine the net periodic pension and other benefits costs, resulting from a decrease in interest rates at the time the assumptions were established.

The increase in total net periodic pension and other benefits costs during fiscal 2003 compared with fiscal 2002 was primarily attributable to an increase in the service cost and interest cost attributable to an increase in our projected benefit obligations. The increase in the projected benefit obligations reflected the increase in the number of plan participants due to the MVG acquisition and an increase attributable to a 125 basis point decrease in the discount rate used to determine the projected benefit obligation reflecting a decline in market interest rates.

We did not contribute to our pension plans during fiscal 2004. In June 2003, we contributed to the Atmos Energy Corporation Master Retirement Trust for the benefit of the Atmos Energy Corporation Pension Account Plan $48.6 million in cash and 1,169,700 shares of Atmos restricted common stock with a value of $28.8 million. As a result of this contribution and improved investment returns during fiscal 2003, the underfunded status of the plan improved by approximately $8.6 million, and the $39.4 million reduction to equity recorded as of September 30, 2002 was eliminated as of September 30, 2003. We are not required to make a minimum funding contribution to our pension plans during fiscal 2005 nor do we intend to make voluntary contributions during 2005. We contributed $13.8 million, $18.6 million and $5.9 million to our postretirement benefits plans for the years ended September 30, 2004, 2003 and 2002. We anticipate contributing $11.7 million to our postretirement benefit plans during fiscal 2005.

The projected pension liability, future funding requirements and the amount of pension expense or income recognized for the Plan are subject to change, depending upon the actuarial value of plan assets and the determination of future benefit obligations as of each subsequent actuarial calculation date. These amounts are impacted by actual investment returns, changes in interest rates and changes in the demographic composition of the participants in the plan. The discount rate used generally is based on rates of high grade corporate bonds with maturities similar to the average period over which benefits will be paid. The expected return on plan assets is based on management's expectation of the long-term return on the portfolio of plan assets. These rates have generally declined since fiscal 2002 due to a decline in interest rates and relatively weak market performance of the underlying plan assets. The rate of compensation increase is established based upon our internal budgets. The actuarial assumptions used to determine the pension liability and net periodic pension and other benefits costs are included in Note 9 to our consolidated financial statements.

We did not assume the existing employee benefit liabilities or plans of TXU Gas. However, for purposes of determining our annual pension cost we have agreed to give the transitioned employees credit for years of TXU Gas service under our pension plan. For purposes of our post-retirement medical plan, we received a credit of $20 million (subject to post-closing adjustment) against the purchase price to permit us to provide partial past service credits for retiree medical benefits under our retiree medical plan. The $20 million credit approximates the actuarially determined present value of the accumulated benefits related to the past service of the transferred employees. As a result of the TXU Gas acquisition on October 1, 2004, our pension and other postretirement benefits costs should increase substantially during fiscal 2005.

Recent Accounting Developments

Recent accounting developments and their impact on our financial position, results of operations and cash flows are described in Note 2 to the consolidated financial statements.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

We are exposed to risks associated with commodity prices and interest rates. Commodity price risk is the potential loss that we may incur as a result of changes in the fair value of a particular instrument or commodity. Interest-rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business.

We conduct risk management activities through both our utility and natural gas marketing segments. In our utility segment, we use a combination of storage, fixed physical contracts and fixed financial contracts to partially insulate us and our customers against gas price volatility during the winter heating season. In our natural gas marketing segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial derivatives including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Our risk management activities and related accounting treatment are described in further detail in Note 5 to the consolidated financial statements. Additionally, our earnings are affected by changes in short-term interest rates as a result of our issuance of short-term commercial paper, our other short-term borrowings and, beginning in fiscal 2005, our new floating rate borrowings.

Commodity Price Risk

Utility segment

We purchase natural gas for our utility operations. Substantially all of the cost of gas purchased for utility operations is recovered from our customers through purchased gas adjustment mechanisms. However, our utility operations have commodity price risk exposure to fluctuations in spot natural gas prices related to purchases for sales to our non-regulated energy services customers at fixed prices.

For our utility segment, we use a sensitivity analysis to estimate commodity price risk. For purposes of this analysis, we estimate commodity price risk by applying a hypothetical 10 percent increase in the portion of our gas cost related to fixed-price non-regulated sales. Based on these projected non-regulated gas sales, a hypothetical 10 percent increase in fixed prices based upon the September 30, 2004 three month market strip would increase our purchased gas cost by approximately $4.9 million in fiscal 2005.

Natural gas marketing segment

Our natural gas marketing segment is also exposed to risks associated with changes in the market price of natural gas. For our natural gas marketing segment, we use a sensitivity analysis to estimate commodity price risk. For purposes of this analysis, we estimate commodity price risk by applying a $0.50 change in the forward NYMEX price to our net open position (including existing storage) at the end of each period. Based on AEH's net open position (including existing storage) at September 30, 2004 of 0.2 Bcf, a $0.50 change in the forward NYMEX price would have had less than a $0.1 million impact on our consolidated net income.

Interest Rate Risk

Our earnings are exposed to changes in short-term interest rates associated with our short-term commercial paper program, other short-term borrowings and, beginning in fiscal 2005, our new floating rate debt. We use a sensitivity analysis to estimate our short-term interest rate risk. For purposes of this analysis, we estimate our short-term interest rate risk as the difference between our actual interest expense for the period and estimated interest expense for the period assuming a hypothetical average of a one percent increase in the interest rates associated with our short-term borrowings. Had interest rates associated with our short-term borrowings outstanding during fiscal 2004 increased by an average of one percent, our interest expense would have increased by approximately $1.7 million during 2004. As a result of the TXU Gas acquisition on October 1, 2004, our interest expense should increase substantially during fiscal 2005.

We also assess market risk for our fixed-rate, long-term obligations. We estimate market risk for our fixed-rate, long-term obligations as the potential increase in fair value resulting from a hypothetical one percent decrease in interest rates associated with these debt instruments. Fair value is estimated using a discounted cash flow analysis. Assuming this one percent hypothetical decrease, the fair value of our fixed-rate, long-term obligations outstanding as of September 30, 2004 would have increased by approximately $79.6 million.

As of September 30, 2004, we were not engaged in any other activities which would cause exposure to the risk of material earnings or cash flow loss due to changes in interest rates or market commodity prices.

Item 8. ***Financial Statements and Supplementary Data***

Index to financial statements and financial statement schedule:

All other financial statement schedules are omitted because the required information is not present, or not present in amounts sufficient to require submission of the schedule or because the information required is included in the financial statements and accompanying notes thereto.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Atmos Energy Corporation

We have audited the accompanying consolidated balance sheets of Atmos Energy Corporation as of September 30, 2004 and 2003, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2004. Our audits also included the financial statement schedule listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Atmos Energy Corporation at September 30, 2004 and 2003, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2004, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects, the financial information set forth therein.

ERNST & YOUNG LLP

Dallas, Texas
November 9, 2004

ATMOS ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	September 30 2004	September 30 2003
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$2,595,374	$2,463,992
Construction in progress	38,277	16,147
	2,633,651	2,480,139
Less accumulated depreciation and amortization	911,130	855,745
Net property, plant and equipment	1,722,521	1,624,394
Current assets		
Cash and cash equivalents	201,932	15,683
Cash held on deposit in margin account	—	17,903
Accounts receivable, less allowance for doubtful accounts of $7,214 in 2004 and $13,051 in 2003	211,810	216,783
Gas stored underground	200,134	168,765
Other current assets	63,236	38,863
Total current assets	677,112	457,997
Goodwill and intangible assets	238,272	273,499
Deferred charges and other assets	231,978	269,605
	$2,869,883	$2,625,495
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 100,000,000 shares authorized; issued and outstanding: 2004 — 62,799,710 shares, 2003 — 51,475,785 shares	$ 314	$ 257
Additional paid-in capital	1,005,644	736,180
Retained earnings	142,030	122,539
Accumulated other comprehensive loss	(14,529)	(1,459)
Shareholders' equity	1,133,459	857,517
Long-term debt	861,311	862,500
Total capitalization	1,994,770	1,720,017
Commitments and Contingencies		
Current liabilities		
Accounts payable and accrued liabilities	185,295	179,852
Other current liabilities	223,265	133,957
Short-term debt	—	118,595
Current maturities of long-term debt	5,908	9,345
Total current liabilities	414,468	441,749
Deferred income taxes	213,930	223,350
Regulatory cost of removal obligation	103,579	102,371
Deferred credits and other liabilities	143,136	138,008
	$2,869,883	$2,625,495

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

	Year ended September 30		
	2004	2003	2002
	(In thousands, except per share data)		
Operating revenues			
Utility segment	$1,637,728	$1,554,082	$ 937,526
Natural gas marketing segment	1,618,602	1,668,493	1,031,874
Other nonutility segment	23,151	21,630	24,705
Intersegment eliminations	(359,444)	(444,289)	(343,141)
	2,920,037	2,799,916	1,650,964
Purchased gas cost			
Utility segment	1,134,594	1,062,679	559,891
Natural gas marketing segment	1,571,971	1,644,328	994,318
Other nonutility segment	9,383	1,540	8,022
Intersegment eliminations	(358,102)	(443,607)	(342,407)
	2,357,846	2,264,940	1,219,824
Gross profit	562,191	534,976	431,140
Operating expenses			
Operation and maintenance	214,470	205,090	158,119
Depreciation and amortization	96,647	87,001	81,469
Taxes, other than income	57,379	55,045	36,221
Total operating expenses	368,496	347,136	275,809
Operating income	193,695	187,840	155,331
Miscellaneous income (expense)	9,507	2,191	(1,321)
Interest charges	65,437	63,660	59,174
Income before income taxes and cumulative effect of accounting change	137,765	126,371	94,836
Income tax expense	51,538	46,910	35,180
Income before cumulative effect of accounting change	86,227	79,461	59,656
Cumulative effect of accounting change, net of income tax benefit	—	(7,773)	—
Net income	$ 86,227	$ 71,688	$ 59,656
Per share data			
Basic income per share:			
Income before cumulative effect of accounting change	$ 1.60	$ 1.72	$ 1.45
Cumulative effect of accounting change, net of income tax benefit	—	(.17)	—
Net income	$ 1.60	$ 1.55	$ 1.45
Diluted income per share:			
Income before cumulative effect of accounting change	$ 1.58	$ 1.71	$ 1.45
Cumulative effect of accounting change, net of income tax benefit	—	(.17)	—
Net income	$ 1.58	$ 1.54	$ 1.45
Weighted average shares outstanding:			
Basic	54,021	46,319	41,171
Diluted	54,416	46,496	41,250

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common stock		Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total
	Number of Shares	Stated Value				
	(In thousands, except share data)					
Balance, September 30, 2001	40,791,501	$204	$ 489,948	$ (1,420)	$ 95,132	$ 583,864
Comprehensive income:						
Net income	—	—	—	—	59,656	59,656
Minimum pension liability, net	—	—	—	(39,432)	—	(39,432)
Unrealized holding losses on investments, net	—	—	—	(528)	—	(528)
Total comprehensive income						19,696
Cash dividends ($1.18 per share)	—	—	—	—	(48,646)	(48,646)
Common stock issued:						
Direct stock purchase plan	505,202	2	10,546	—	—	10,548
Retirement savings plan	326,335	2	7,137	—	—	7,139
Long-term incentive plan	50,465	—	579	—	—	579
Outside directors stock-for-fee plan	2,429	—	55	—	—	55
Balance, September 30, 2002	41,675,932	208	508,265	(41,380)	106,142	573,235
Comprehensive income:						
Net income	—	—	—	—	71,688	71,688
Minimum pension liability, net	—	—	—	39,432	—	39,432
Unrealized holding gains on investments, net	—	—	—	489	—	489
Total comprehensive income						111,609
Cash dividends ($1.20 per share)	—	—	—	—	(55,291)	(55,291)
Common stock issued:						
Public offering	4,100,000	20	99,102	—	—	99,122
Acquisition of Mississippi Valley Gas Company	3,386,287	17	74,633	—	—	74,650
Contribution to Atmos Pension Account Plan	1,169,700	6	28,757	—	—	28,763
Direct stock purchase plan	585,743	3	13,209	—	—	13,212
Retirement savings plan	360,725	2	8,277	—	—	8,279
Long-term incentive plan	181,429	1	3,664	—	—	3,665
Long-term stock plan for Mid-States Division	13,000	—	206	—	—	206
Outside directors stock-for-fee plan	2,969	—	67	—	—	67
Balance, September 30, 2003	51,475,785	257	736,180	(1,459)	122,539	857,517
Comprehensive income:						
Net income	—	—	—	—	86,227	86,227
Unrealized holding gains on investments, net	—	—	—	615	—	615
Treasury lock agreements, net	—	—	—	(21,268)	—	(21,268)
Cash flow hedges, net	—	—	—	7,583	—	7,583
Total comprehensive income						73,157
Cash dividends ($1.22 per share)	—	—	—	—	(66,736)	(66,736)
Common stock issued:						
Public offering	9,939,393	50	235,419	—	—	235,469
Direct stock purchase plan	556,856	3	13,726	—	—	13,729
Retirement savings plan	320,313	2	8,300	—	—	8,302
Long-term incentive plan	498,230	2	11,848	—	—	11,850
Long-term stock plan for Mid-States Division	6,000	—	94	—	—	94
Outside directors stock-for-fee plan	3,133	—	77	—	—	77
Balance, September 30, 2004	62,799,710	$314	$1,005,644	$(14,529)	$142,030	$1,133,459

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended September 30		
	2004	2003	2002
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 86,227	$ 71,688	$ 59,656
Adjustments to reconcile net income to net cash provided by operating activities:			
Cumulative effect of accounting change, net of income tax benefit	—	7,773	—
Gain on sales of assets	(6,700)	—	—
Depreciation and amortization:			
Charged to depreciation and amortization	96,647	87,001	81,469
Charged to other accounts	1,465	2,193	2,452
Deferred income taxes	36,997	53,867	14,509
Other	(1,772)	(5,885)	(3,371)
Changes in assets and liabilities:			
(Increase) decrease in cash held on deposit in margin account	17,903	(7,711)	56,474
(Increase) decrease in accounts receivable	2,158	(60,026)	(12,181)
Increase in gas stored underground	(31,030)	(64,875)	(2,228)
(Increase) decrease in other current assets	(9,233)	(15,747)	28,146
(Increase) decrease in deferred charges and other assets	17,178	21,258	(33,515)
Increase in accounts payable and accrued liabilities	4,586	19,417	52,302
Increase (decrease) in other current liabilities	48,877	(40,636)	34,195
Increase (decrease) in deferred credits and other liabilities	7,431	(18,866)	19,487
Net cash provided by operating activities	270,734	49,451	297,395
CASH FLOWS USED IN INVESTING ACTIVITIES			
Capital expenditures	(190,285)	(159,439)	(132,252)
Acquisitions, net of cash received	(1,957)	(74,650)	(15,747)
Retirements of property, plant and equipment, net	(570)	704	(1,725)
Assets for leasing activities	—	—	(8,511)
Proceeds from sales of assets	27,919	—	—
Net cash used in investing activities	(164,893)	(233,385)	(158,235)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net decrease in short-term debt	(118,595)	(27,196)	(55,456)
Net proceeds from issuance of long-term debt	5,000	253,267	—
Proceeds from bridge loan	—	147,000	—
Repayment of bridge loan	—	(147,000)	—
Repayment of long-term debt	(9,713)	(73,165)	(20,651)
Repayment of Mississippi Valley Gas debt	—	(70,938)	—
Cash dividends paid	(66,736)	(55,291)	(48,646)
Issuance of common stock	34,715	25,720	18,321
Net proceeds from equity offering	235,737	99,229	—
Net cash provided (used) by financing activities	80,408	151,626	(106,432)
Net increase (decrease) in cash and cash equivalents	186,249	(32,308)	32,728
Cash and cash equivalents at beginning of year	15,683	47,991	15,263
Cash and cash equivalents at end of year	$ 201,932	$ 15,683	$ 47,991

See accompanying notes to consolidated financial statements

1. Nature of Business

Atmos Energy Corporation and its subsidiaries are engaged primarily in the natural gas utility business as well as other nonutility businesses. We distribute natural gas through sales and transportation arrangements to approximately 1.7 million residential, commercial, public authority and industrial customers through our six regulated utility divisions, which covered the following service areas:

Division	Service Area
Atmos Energy Colorado-Kansas Division	Colorado, Kansas, Missouri(1)
Atmos Energy Kentucky Division	Kentucky
Atmos Energy Louisiana Division	Louisiana
Atmos Energy Mid-States Division	Georgia(1), Illinois(1), Iowa(1), Missouri(1), Tennessee, Virginia(1)
Atmos Energy West Texas Division(2)	Texas
Mississippi Valley Gas Company Division(3)	Mississippi

(1) Denotes locations where we have more limited service areas.

(2) The name of this division was changed from the Atmos Energy Texas Division in November 2004.

(3) Acquired in December 2002.

In addition, we transport natural gas for others through our distribution system. Our utility business is subject to federal and state regulation and/or regulation by local authorities in each of the states in which the utility divisions operate. Our shared services division is located in Dallas, Texas, and our customer support centers are located in Amarillo, Texas and Metairie, Louisiana.

As further described in Note 3, on October 1, 2004, we completed our acquisition of the natural gas distribution and pipeline operations of TXU Gas Company (TXU Gas). The TXU Gas operations we acquired are regulated businesses engaged in the purchase, transmission, distribution and sale of natural gas in the north-central, eastern and western parts of Texas. Through these newly acquired operations, we provide gas distribution services to approximately 1.5 million residential and business customers in Texas, including the Dallas/Fort Worth metropolitan area. We also now own and operate a system consisting of 6,162 miles of gas transmission and gathering lines and five underground storage reservoirs, all within Texas.

Our nonutility businesses are organized under Atmos Energy Holdings, Inc. (AEH), and have operations in 18 states. Through September 30, 2003, Atmos Energy Marketing, LLC, together with its wholly-owned subsidiaries Woodward Marketing, L.L.C. and Trans Louisiana Industrial Gas Company, Inc., comprised our natural gas marketing segment. Effective October 1, 2003, our natural gas marketing segment was reorganized. The operations of Atmos Energy Marketing, LLC and Trans Louisiana Industrial Gas Company, Inc. were merged into Woodward Marketing, L.L.C, which was renamed Atmos Energy Marketing, LLC (AEM).

AEM provides a variety of natural gas management services to municipalities, natural gas utility systems and industrial natural gas customers, primarily in the southeastern and midwestern states and to our Colorado-Kansas, Kentucky, Louisiana and Mid-States divisions. These services consist primarily of furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of derivative instruments.

Our other nonutility businesses consist primarily of the operations of Atmos Pipeline and Storage, L.L.C. and Atmos Energy Services, LLC (AES), which are wholly-owned by AEH. Through Atmos Pipeline and Storage, L.L.C., we own or have an interest in underground storage fields in Kentucky and Louisiana. Through Atmos Pipeline and Storage, L.L.C. we provide storage services to our customers, as well as capture pricing arbitrage through the use of derivatives. Through AES, we provide natural gas management services. Prior to the second fiscal quarter of 2004, this entity conducted limited operations. However, beginning, April 1, 2004, AES began providing natural gas supply management services to our utility operations in a limited number of states. As of September 30, 2004 we had expanded these services to substantially all of our utility service areas.

Prior to January 20, 2004, United Cities Propane Gas, Inc., a wholly-owned subsidiary of AEH, owned an approximate 19 percent membership interest in U.S. Propane L.P. (USP), a joint venture formed in February 2000 with three other utility companies. Through our ownership in USP, we owned an approximate 5 percent indirect interest in Heritage Propane Partners, L.P. (Heritage). During 2004, we sold our interest in USP and Heritage. We received cash proceeds of $26.6 million and recorded a pretax book gain of $5.9 million with these transactions. We no longer have an interest in the propane industry.

2. Summary of Significant Accounting Policies

Principles of consolidation — The accompanying consolidated financial statements include the accounts of Atmos Energy Corporation and its wholly-owned subsidiaries. All material intercompany transactions have been eliminated.

Basis of comparison — Certain prior-year amounts have been reclassified to conform with the current year presentation. Beginning in the second quarter of 2004 we have retroactively reclassified our regulatory removal obligation from accumulated depreciation to a liability for all periods presented. Additionally, beginning in the fourth quarter of 2004 we have reclassified our original issue discount costs from deferred charges and other assets to long-term debt. These reclassifications did not impact our financial position, results of operations, cash flows or ability to satisfy our financial covenants contained in our various credit agreements.

Use of estimates — The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The most significant estimates include the allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes, risk management and trading activities and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results could differ from those estimates.

Regulation — Our utility operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. Our accounting policies recognize the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions. Regulated utility operations are accounted for in accordance with Statement of Financial Accounting Standards (SFAS) 71, *Accounting for the Effects of Certain Types of Regulation.* This statement requires cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates.

We record regulatory assets as a component of deferred charges and other assets for costs that have been deferred for which future recovery through customer rates is considered probable. Regulatory liabilities are recorded either on the face of the balance sheet or as a component of current liabilities, deferred income taxes or deferred credits and other liabilities when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Significant regulatory assets and liabilities as of September 30, 2004 and 2003 included the following:

	September 30 2004	September 30 2003
	(In thousands)	
Regulatory assets:		
Deferred gas costs	$ —	$ 308
Merger and integration costs, net	15,484	23,380
Deferred MVG operating expenses	751	4,645
Environmental costs	4,057	4,057
Other	4,441	2,509
	$ 24,733	$ 34,899
Regulatory liabilities:		
Deferred gas costs	$ 39,097	$ —
Regulatory cost of removal obligation	111,232	108,405
Deferred income taxes, net	1,962	1,883
	$152,291	$110,288

Currently authorized rates do not include a return on certain of our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging from 5 to 20 years. During the fiscal years ended September 30, 2004, 2003 and 2002, we recognized $8.2 million, $8.2 million and $6.3 million in amortization expense related to these costs. Beginning in December 2004, these amortization costs will decrease substantially. Environmental costs have been deferred to future rate filings in accordance with rulings received from various regulatory commissions.

At September 30, 2004, we had a rate case pending in our Virginia jurisdiction. In November 2004, the Virginia Corporation Commission (VCC) granted a rate increase of $0.4 million that was retroactively effective to August 1, 2004. Additionally, the VCC authorized WNA beginning in July 2005 and the ability to recover the gas cost component of bad debt expense.

In our Mississippi Valley Company Division, we filed our first semiannual filing for 2004 on May 5, 2004 and we received an annual rate increase of $4.7 million effective on June 1, 2004. However, in the same ruling, the Mississippi Public Service Commission (MPSC) disallowed certain deferred costs totaling $2.8 million. We are appealing the MPSC's decision regarding these deferred costs. We filed our second semiannual filing for 2004 on November 4, 2004.

Revenue recognition — Sales of natural gas to our utility customers are billed on a monthly cycle basis; however, the billing cycle periods for certain classes of customers do not necessarily coincide with accounting periods used for financial reporting purposes. We follow the revenue accrual method of accounting for utility segment revenues whereby revenues applicable to gas delivered to customers, but not yet billed under the cycle billing method, are estimated and accrued and the related costs are charged to expense.

Rates established by regulatory authorities are adjusted for increases and decreases in our purchased gas cost through purchased gas adjustment mechanisms. Purchased gas adjustment mechanisms provide gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to address all of the utility's non-gas costs. These mechanisms are commonly utilized when regulatory authorities recognize a particular type of expense, such as purchased gas costs, that (i) is subject to significant price fluctuations compared to the utility's other costs, (ii) represents a large component of the utility's cost of service and (iii) is generally outside the control of the gas utility. There is no gross profit generated through purchased gas adjustments, but they do provide a dollar-for-dollar offset to increases or decreases in utility gas costs. Although substantially all of our utility sales to our customers fluctuate with the cost of gas that we purchase, utility gross profit is generally not affected by fluctuations in the cost of gas due to the purchased gas adjustment mechanism. The effects of these purchased gas adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

Energy trading contracts resulting in the delivery of a commodity where we are the principal in the transaction are recorded as natural gas marketing sales or purchases at the time of physical delivery. Realized gains and losses from the settlement of financial instruments that do not result in physical delivery related to our natural gas marketing energy trading contracts and unrealized gains and losses from changes in the market value of open contracts are included as a component of natural gas marketing revenues. For the years ended September 30, 2004, 2003 and 2002, we included unrealized gains (losses) on open contracts of ($2.8) million, $6.3 million and ($10.5) million as a component of natural gas marketing revenues.

Cash and cash equivalents — We consider all highly liquid investments with an initial or remaining maturity of three months or less to be cash equivalents.

Accounts receivable and allowance for doubtful accounts — Accounts receivable consist of natural gas sales to residential, commercial, industrial, municipal, agricultural and other customers. For the majority of our receivables, we establish an allowance for doubtful accounts based on our collections experience. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be different. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

Gas stored underground — Our gas stored underground is comprised of natural gas injected into storage to support the winter season withdrawals for our utility operations and natural gas held by our natural gas marketing and other nonutility subsidiaries to conduct their operations. The average cost method is used for all our utility divisions, except for the Mid-States Division, where it is valued on the first-in first-out method basis, in accordance with regulatory requirements. The average gas cost method is used for our natural gas marketing segment. Gas in storage that is retained as cushion gas to maintain reservoir pressure is classified as property, plant and equipment and is valued at cost.

Utility property, plant and equipment — Utility property, plant and equipment is stated at original cost net of contributions in aid of construction. The cost of additions includes direct construction costs, payroll related costs (taxes, pensions and other fringe benefits), administrative and general costs and an allowance for funds used during construction. The allowance for funds used during construction represents the estimated cost of funds used to finance the construction of major projects and are capitalized in the rate base for ratemaking purposes when the completed projects are placed in service. Interest expense of $1.2 million, $0.8 million and $1.3 million was capitalized in 2004, 2003 and 2002.

Major renewals and betterments are capitalized while the costs of maintenance and repairs are charged to expense as incurred. The costs of large projects are accumulated in construction in progress until the project is completed. When the project is completed, tested and placed in service, the balance is transferred to the utility plant in service account included in the rate base and depreciation begins.

Utility property, plant and equipment is depreciated at various rates on a straight-line basis over the estimated useful lives of the assets. These rates are approved by our regulatory commissions and are comprised of two components, one based on average service life and one based on cost of removal. Accordingly, we recognize our cost of removal expense as a component of depreciation expense. The related cost of removal accrual is reflected as a regulatory liability on the consolidated balance sheet. At the time property, plant and equipment is retired, removal expenses less salvage, are charged to the regulatory cost of removal accrual. The composite depreciation rate for the years ended September 30, 2004, 2003 and 2002 was 3.8 percent.

Nonutility property, plant and equipment — Nonutility property, plant and equipment is stated at cost. Depreciation is generally computed on the straight-line method for financial reporting purposes based upon estimated useful lives ranging from 8 to 38 years.

Asset retirement obligations — SFAS 143, *Accounting for Asset Retirement Obligations* which was effective for us October 1, 2002 requires that we record a liability at fair value for an asset retirement obligation when the legal obligation to retire the asset has been incurred with an offsetting increase to the carrying value of the related asset. Accretion of the asset retirement obligation due to the passage of time is recorded as an operating expense. As of September 30, 2004 and 2003, we have asset retirement obligations; however, we cannot determine when the legal obligation will be incurred.

Impairment of long-lived assets — We periodically evaluate whether events or circumstances have occurred that indicate that other long-lived assets may not be recoverable or that the remaining useful life may warrant revision. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, an impairment loss equal to the excess of the asset's carrying value over its fair value is recorded. To date, no impairment has been recognized.

Goodwill and intangible assets — We annually evaluate our goodwill balances for impairment during our second fiscal quarter or more frequently as impairment indicators arise. We use a present value technique based on discounted cash flows to estimate the fair value of our reporting units. These calculations are dependent on several subjective factors including the timing of future cash flows, future growth rates and the discount rate. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its fair value.

Intangible assets are amortized over their useful lives ranging from 3 to 10 years. These assets are reviewed for impairment as impairment indicators arise. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, an impairment loss equal to the excess of the asset's carrying value over its fair value is recorded. To date, no impairment has been recognized.

Marketable securities — As of September 30, 2004 and 2003, all of our marketable securities were classified as available-for-sale securities based upon the criteria of SFAS 115, *Accounting for Certain Investments in Debt and Equity Securities*. In accordance with that standard, these securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value.

Derivatives and hedging activities — Our derivative and hedging activities are tailored to the segment to which they relate. We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent, based upon the anticipated settlement date of the underlying derivative. These assets and liabilities are recorded as components of other current assets, deferred charges and other assets, other current liabilities or deferred credits and other liabilities depending on the expiration or maturity date of the instrument.

Utility Segment

In our utility segment, we use a combination of storage and financial derivatives to partially insulate us and our natural gas utility customers against gas price volatility during the winter heating season. The financial derivatives we use in our utility segment are accounted for under the mark-to-market method pursuant to SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*. Changes in the valuation of these derivatives primarily result from changes in the valuation of the portfolio of contracts, maturity and settlement of contracts and newly originated transactions. However, because the gains or losses of financial derivatives used in our utility segment will ultimately be recovered through our rates, current period changes in the assets and liabilities from these risk management activities are recorded as a component of deferred gas costs in accordance with SFAS 71. Accordingly, there is no earnings impact to our utility segment as a result of the use of financial derivatives. The changes in the assets and liabilities from risk management activities are recognized in purchased gas cost in the income statement when the related gain or loss is recovered through our rates.

Natural Gas Marketing Segment

Our natural gas marketing risk management activities are conducted through AEM. AEM is exposed to risks associated with changes in the market price of natural gas, and we manage our exposure to the risk of natural gas price changes through a combination of storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Option contracts provide the right, but not the requirement, to buy or sell the commodity at a fixed price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date. The use of these contracts is subject to our risk management policies, which are monitored for compliance on a daily basis.

We participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers. Additionally, we engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We purchase or sell physical natural gas and then sell or purchase financial contracts at a price sufficient to cover our carrying costs and provide a gross profit margin. Through the use of transportation and storage services and derivatives, we are able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Under SFAS 133, natural gas inventory is designated as the hedged item in a fair-value hedge and is marked to market on a monthly basis using the inside FERC (iFERC) price at the end of each month. Changes in fair value are recognized as unrealized gains and losses in revenue in the period of change. Costs to store the gas are recognized in the period the costs are incurred. We recognize revenue and the carrying value of the inventory as an associated purchased gas cost in our consolidated statement of income when we sell the gas and deliver it out of the storage facility.

Derivatives associated with our natural gas inventory are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains and losses in the period of change. The difference in the indices used to mark to market our physical inventory (iFERC) and the related fair-value hedge (NYMEX) is reported as a component of revenue and can result in volatility in our reported net income. Over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction. In addition, we continually manage our positions to optimize value as market conditions and other circumstances change.

Similar to our inventory position, we attempt to mitigate substantially all of the commodity price risk associated with our fixed-price contracts with minimum volume requirements through the use of various offsetting derivatives. Prior to April 1, 2004, these derivatives were not designated as hedges under SFAS 133 because they naturally locked in the economic gross profit margin at the time we entered into the contract. The fixed-price forward and offsetting derivative contracts were marked to market each month with changes in fair value recognized as unrealized gains and losses recorded in revenue in our consolidated statement of income. The unrealized gains and losses are realized as a component of revenue in the period in which we fulfill the requirements of the fixed-price contract and the derivatives are settled. To the extent that the unrealized gains and losses of the fixed-price forward contracts and the offsetting derivatives do not offset exactly, our earnings will experience some volatility. At delivery, the gains and losses on the fixed-price contracts were offset by gains and losses on the derivatives, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction. In addition, we continually manage our positions to optimize value as market conditions and other circumstances change.

Effective April 1, 2004, we elected to treat our fixed-price forward contracts as normal purchases and sales. As a result, we ceased marking the fixed-price forward contracts to market. We have designated the offsetting derivative contracts as cash flow hedges of anticipated transactions. As a result of this change, unrealized gains and losses on these open derivative contracts are now recorded as a component of accumulated other comprehensive income and are recognized in earnings as a component of revenue when the hedged volumes are sold. This designation is expected to partially reduce the amount of volatility in our consolidated income statement and better reflect the economics of this type of transaction. Hedge ineffectiveness, to the extent incurred, is reported as a component of revenues.

Treasury Activities

During fiscal 2004, we entered into four Treasury lock agreements to fix the Treasury yield component of the interest cost of financing associated with the anticipated issuance of $875 million of long-term debt. We designated these Treasury lock agreements as cash flow hedges of an anticipated transaction. Accordingly, to the extent effective, unrealized gains and losses associated with the Treasury lock agreements are recorded as a component of accumulated other comprehensive income. Unrealized gains are recorded when interest rates increase and unrealized losses are recorded when interest rates decline. These Treasury lock agreements were terminated in October 2004 and the $43.8 million unrealized loss will be recognized as a component of interest expense over the life of the related financing arrangement.

The fair value of our financial derivatives is determined through a combination of prices actively quoted on national exchanges, prices provided by other external sources and prices based on models and other valuation methods. Changes in the valuation of our financial derivatives primarily result from changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our derivatives. We believe the market prices and models used to value these derivatives represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under present market conditions.

Pension and other postretirement plans — Pension and other postretirement plan expenses and liabilities are determined on an actuarial basis and are affected by the market value of plan assets, estimates of the expected return on plan assets and assumed discount rates and demographical data. Actual changes in the fair market value of plan assets and differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension expense ultimately recognized. The assumed return on plan assets is based on management's expectation of the long-term return on the portfolio of plan assets. The discount rate used to compute the present value of plan liabilities generally is based on rates of high grade corporate bonds with maturities similar to the average period over which benefits will be paid.

Income taxes — Income taxes are provided based on the liability method, which results in income tax assets and liabilities arising from temporary differences. Temporary differences are differences between the tax bases of assets and liabilities and their reported amounts in the financial statements that will result in taxable or deductible amounts in future years. The liability method requires the effect of tax rate changes on current and accumulated deferred income taxes to be reflected in the period in which the rate change was enacted. The liability method also requires that deferred tax assets be reduced by a valuation allowance unless it is more likely than not that the assets will be realized.

Stock-based compensation plans — We have two stock-based compensation plans that provide for the granting of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, restricted stock and performance-based stock to officers and key employees: the 1998 Long-Term Incentive Plan and the Long-Term Stock Plan for the Mid-States Division. Nonemployee directors are also eligible to receive such stock-based compensation under the 1998 Long-Term Incentive Plan. The objectives of these plans include attracting and retaining the best personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire common stock. These plans are more fully described in Note 8. As permitted by SFAS 123, *Accounting for Stock-Based Compensation,* we account for these plans under the intrinsic-value method described in Accounting Principles Board (APB) Opinion 25, *Accounting for Stock Issued to Employees.* Under this method, no compensation cost for stock options is recognized for stock-option awards granted at or above fair-market value.

Awards of restricted stock are valued at the market price of the Company's common stock on the date of grant. The unearned compensation is amortized to operation and maintenance expense over the vesting period of the restricted stock.

Had compensation expense for our stock options issued under the Long-Term Incentive Plan been recognized based on the fair value on the grant date under the methodology prescribed by SFAS 123, our net income and earnings per share for the years ended September 30, 2004, 2003 and 2002 would have been impacted as shown in the following table:

	Year ended September 30		
	2004	2003	2002
	(In thousands, except per share data)		
Net income — as reported	$86,227	$71,688	$59,656
Restricted stock compensation expense included in income, net of tax	978	370	487
Total stock-based employee compensation expense determined under fair-value-based method for all awards, net of taxes	(2,092)	(1,362)	(974)
Net income — pro forma	$85,113	$70,696	$59,169
Earnings per share:			
Basic earnings per share — as reported	$ 1.60	$ 1.55	$ 1.45
Basic earnings per share — pro forma	$ 1.57	$ 1.53	$ 1.44
Diluted earnings per share — as reported	$ 1.58	$ 1.54	$ 1.45
Diluted earnings per share — pro forma	$ 1.56	$ 1.52	$ 1.43

Accounting pronouncements implemented — In January 2003, the Financial Accounting Standards Board (FASB) issued FASB Interpretation (FIN) 46, *Consolidation of Variable Interest Entities, An Interpretation of Accounting Research Bulletin No. 51.* The primary objectives of FIN 46 are to provide guidance on how to identify entities for which control is achieved through means other than through voting rights (variable interest entities (VIE)) and how to determine when to consolidate and which business enterprises should consolidate the VIE. Under the guidance of FIN 46, we are considered the primary beneficiary of the Rabbi Trust used to fund our supplemental executive retirement plan described in Note 9. However, since we already consolidate these assets and related liabilities, the adoption of this interpretation did not have a material impact on our financial position, results of operations or net cash flows.

During 2003, the Emerging Issues Task Force (the Task Force) added to its agenda Emerging Issues Task Force (EITF) Issue 03-01, *The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments,* to address the meaning of "other-than-temporary" impairment and its application to certain investments carried at cost. In November 2003, the Task Force developed new disclosure requirements concerning unrealized losses on available-for-sale debt and equity securities accounted for under SFAS 115, *Accounting for Certain Investments in Debt and Equity Securities.* We have adopted the disclosure requirements prescribed by EITF 03-01, which are contained in Note 9. In March 2004, the Task Force defined the meaning of "other-than-temporary" and issued guidance regarding the measurement and recognition of an investment that had experienced an "other-than-temporary" impairment. However, in September 2004 the Task Force delayed the effective date for the measurement and recognition criteria of EITF 03-01 while it considers additional questions pertaining to these issues.

In December 2003, the FASB issued SFAS 132 (revised), *Employers' Disclosures about Pensions and Other Postretirement Benefits.* These revisions require additional disclosures in annual reports on Form 10-K concerning the assets, obligations, cash flows and net periodic-benefit cost of defined-benefit pension plans and other defined-benefit postretirement plans which became effective for fiscal years ending after June 15, 2004. We have adopted these disclosure requirements which are contained in Note 9.

In January 2004, the FASB issued FASB Staff Position FAS (FSP) 106-1, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003,* which permitted a plan sponsor to defer recognizing the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) in accounting for its plan under SFAS 106 and in providing disclosures related to the plan required by SFAS 132 (revised). FSP 106-2, issued in March 2004, superseded FSP 106-1 and provided guidance on the accounting for the effects of the Act for employers that sponsor a single-employer defined benefit postretirement health care plan for which the employer has concluded that prescription drug benefits available under the plan are actuarially equivalent to the Medicare Part D benefit and the expected subsidy will offset or reduce the employer's share of the cost of the benefit. We determined that the prescription drug benefits of our plan were actuarially equivalent to the Medicare Part D benefit. The implementation of the Act reduced our accumulated postretirement benefit obligation by $24.3 million and our fiscal 2004 net postretirement benefit obligation costs by $4.1 million based upon calculations prepared by our independent actuaries. The total income statement impact for fiscal 2004 approximated $2.3 million, as a portion of this benefit was capitalized.

3. Acquisitions

TXU Gas Company

On October 1, 2004, we completed our acquisition of the natural gas distribution and pipeline operations of TXU Gas Company (TXU Gas). The TXU Gas operations we acquired are regulated businesses engaged in the purchase, transmission, distribution and sale of natural gas in the north-central, eastern and western parts of Texas. Through these newly acquired operations, we provide gas distribution services to approximately 1.5 million residential and business customers in Texas, including the Dallas/Fort Worth metropolitan area.

We also now own and operate a system consisting of 6,162 miles of gas transmission and gathering lines and five underground storage reservoirs, all within Texas.

The purchase price for the TXU Gas acquisition was approximately $1.905 billion (after preliminary closing adjustments), which we paid in cash. We acquired approximately $121 million of working capital of TXU Gas and did not assume any indebtedness of TXU Gas in connection with the acquisition. TXU Gas retained certain assets and provided for the repayment of all of its indebtedness and redeemed all of its preferred stock prior to closing and retained and agreed to pay certain other liabilities under the terms of the acquisition agreement. The purchase price is subject to further adjustment sixty days after closing for the actual amount of working capital we acquired and other specified matters. We anticipate that any post-closing purchase price adjustments will not be material.

We funded the purchase price for the TXU Gas acquisition with approximately $235.7 million in net proceeds from our offering of 9,939,393 shares of common stock, which we completed on July 19, 2004, and approximately $1.7 billion in net proceeds from our issuance on October 1, 2004 of commercial paper backstopped by a senior unsecured revolving credit agreement, which we entered into on September 24, 2004 for bridge financing for the TXU Gas acquisition. In October 2004, we paid off the outstanding commercial paper used to fund the acquisition through the issuance of senior unsecured notes on October 22, 2004, which generated net proceeds of approximately $1.39 billion, and the sale of 16.1 million shares of common stock on October 27, 2004, which generated net proceeds of $382.5 million before other offering costs.

The following table summarizes the fair values of the assets acquired and liabilities assumed on October 1, 2004, in thousands:

Cash purchase price	$1,905,000
Transaction costs and expenses	7,540
Total purchase price	$1,912,540
Net property, plant and equipment	$1,496,453
Accounts receivable	62,737
Gas stored underground	148,902
Other current assets	16,843
Goodwill and intangible assets	465,188
Deferred charges and other assets	39,548
Accounts payable and accrued liabilities	(44,359)
Other current liabilities	(68,463)
Regulatory cost of removal obligation	(138,991)
Deferred credits and other liabilities	(65,318)
Total	$1,912,540

The sale of TXU Gas's assets was held through a competitive bid process. We believe the resulting goodwill is recoverable given the expected synergies we can achieve as a result of the TXU Gas acquisition. To that end, the TXU Gas acquisition significantly expands our existing utility operations in Texas. The North Texas operations of TXU Gas bridge our geographic operations between our existing utility operations in West Texas and Louisiana. TXU Gas's headquarters and service area are centered in Dallas, Texas, which is also the location of our corporate headquarters. Further, the addition of the regulated pipelines in North Texas may create additional gas marketing and other opportunities for our non-regulated subsidiaries, which include gas marketing and storage operations. The goodwill generated in the acquisition is deductible for tax purposes.

Our allocation of the purchase is preliminary and is subject to change. The amount currently allocated to property, plant and equipment represents our estimate of the fair value of the assets acquired. We have based that estimate on the amount we believe will ultimately be approved as rate base for rate setting purposes.

The table below reflects the unaudited pro forma results of the Company and TXU Gas for the year ended September 30, 2004 as if the acquisition and related financing had taken place at the beginning of fiscal 2004 (in thousands, except per share data):

	Year ended September 30, 2004
Operating revenue	$4,174,500
Net income	118,746
Net income per diluted share	$ 1.68

ComFurT Gas Inc.

Effective March 1, 2004, we completed the acquisition of the natural gas distribution assets of ComFurT Gas Inc., a privately held natural gas utility and propane distributor based in Buena Vista, Colorado, for approximately $2.0 million in cash. This company served approximately 1,800 natural gas utility customers. The acquisition enabled us to expand our contiguous service area in our Colorado-Kansas division. Unaudited pro forma results of the Company and ComFurT have not been presented as the acquisition was not material to our financial position or results of operations.

Mississippi Valley Gas Company

On December 3, 2002, we completed the acquisition of Mississippi Valley Gas Company (MVG), Mississippi's largest natural gas utility. The acquisition of MVG enabled us to expand our service area into Mississippi. MVG served approximately 261,500 residential, commercial, industrial and other customers located primarily in the northern and central regions of Mississippi. MVG's rate design provides timely returns on capital investment and earnings stability and enabled us to leverage our existing centralized management structure, shared services organization and information systems to manage costs in all of Atmos Energy's utility service areas over the long term.

We paid approximately $74.7 million in cash and $74.7 million in Atmos Energy common stock consisting of 3,386,287 unregistered shares. We also repaid approximately $70.9 million of MVG's outstanding debt. The results of operations of MVG have been consolidated with our results of operations from the acquisition date.

4. Goodwill and Intangible Assets

Goodwill and intangible assets were comprised of the following as of September 30, 2004 and 2003.

	September 30 2004	September 30 2003
	(In thousands)	
Goodwill	$234,112	$268,469
Intangible assets	4,160	5,030
Total	$238,272	$273,499

The following presents our goodwill balance allocated by segment and changes in the balance for the year ended September 30, 2004:

	Utility Segment	Natural Gas Marketing Segment	Other Nonutility Segment	Total
		(In thousands)		
Balance as of September 30, 2003	$233,741	$22,600	$12,128	$268,469
Acquisition (See Note 3)	1,250	—	—	1,250
Deferred tax adjustments on prior acquisitions[(1)]	(39,933)	1,408	—	(38,525)
Intersegment transfer of assets[(2)]	1,698	—	(1,698)	—
Refinements to purchase price	2,644	274	—	2,918
Balance as of September 30, 2004	$199,400	$24,282	$10,430	$234,112

(1) During the preparation of the fiscal 2004 tax provision, we adjusted certain deferred taxes recorded in connection with a fiscal 2001 acquisition which resulted in a decrease to goodwill and deferred tax liabilities of $38.5 million.

(2) During 2004, we transferred Atmos Pipeline and Storage's underground storage fields in Kansas to our Atmos Energy Colorado-Kansas utility division. As a result of the transfer, approximately $1.7 million in goodwill was transferred from the other nonutility segment to the utility segment.

Information regarding our intangible assets is included in the following table. As of September 30, 2004 and 2003, we had no indefinite-lived intangible assets.

		September 30, 2004			September 30, 2003		
	Useful Life (Years)	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
				(In thousands)			
Customer contracts	10	$6,521	$(2,361)	$4,160	$6,521	$(1,574)	$4,947
Noncompete agreements	3	250	(250)	—	250	(167)	83
		$6,771	$(2,611)	$4,160	$6,771	$(1,741)	$5,030

The following table presents actual amortization expense recognized during 2004 and an estimate of future amortization expense based upon our intangible assets at September 30, 2004.

Amortization expense (in thousands):	
Actual for the fiscal year ending September 30, 2004	$870
Estimated for the fiscal year ending:	
September 30, 2005	652
September 30, 2006	585
September 30, 2007	585
September 30, 2008	585
September 30, 2009	585

5. Derivative Instruments and Hedging Activities

We conduct risk management activities through both our utility and natural gas marketing segments. We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying derivative. Our determination of the fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains and losses on open contracts. In our determination of fair value, we consider various factors, including closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts.

The following table shows the fair values of our risk management assets and liabilities by segment at September 30, 2004 and 2003:

	Utility	Natural Gas Marketing	Total
		(In thousands)	
September 30, 2004:			
Assets from risk management activities, current	$ 25,692	$ 18,748	$ 44,440
Assets from risk management activities, noncurrent	—	562	562
Liabilities from risk management activities, current	(34,304)	(5,154)	(39,458)
Liabilities from risk management activities, noncurrent	—	(1,138)	(1,138)
Net assets (liabilities)	$ (8,612)	$ 13,018	$ 4,406
September 30, 2003:			
Assets from risk management activities, current	$ 202	$ 22,057	$ 22,259
Assets from risk management activities, noncurrent	—	1,699	1,699
Liabilities from risk management activities, current	(7,941)	(12,849)	(20,790)
Liabilities from risk management activities, noncurrent	—	(763)	(763)
Net assets (liabilities)	$ (7,739)	$ 10,144	$ 2,405

Utility Hedging Activities

We use a combination of storage, fixed physical contracts and fixed financial contracts to partially insulate us and our customers against gas price volatility during the winter heating season. For the 2003-2004 heating season, we hedged between 50 and 55 percent of our anticipated winter flowing gas requirements at a weighted average cost of approximately $5.36 per MCF.

In June 2001, we purchased a three-year weather-insurance policy with an option to cancel the third year of coverage. The insurance covered our Texas and Louisiana operations to protect against weather that was at least 7 percent warmer than normal for the entire heating season of October through March, beginning with the 2001-2002 heating season. The prepaid cost of the three-year policy was $13.2 million and was amortized over the appropriate heating seasons based on heating degree days. In the third quarter of fiscal 2003, we cancelled this policy, primarily as a result of rate relief in Louisiana and at that time, prospects for weather normalization adjustments in Texas. During fiscal 2003 and 2002, we recognized amortization expense of $5.0 million and $4.4 million. However, we did not collect under this policy because weather was not at least 7 percent warmer than normal.

Out utility hedging activities also includes the fair value of our treasury lock agreements which are described in further detail below.

Nonutility Hedging Activities

For the year ended September 30, 2004, the increase in the deferred hedging gain in accumulated other comprehensive income was attributable to the initiation of cash flow hedge accounting treatment described above and increases in future commodity prices relative to the commodity prices stipulated in the derivative contracts, partially offset by the recognition of $3.5 million in net deferred hedge gains in net income when the derivatives matured according to their terms. The net deferred hedge losses associated with open cash flow hedges remain subject to market price fluctuations until the positions are either settled under the terms of the hedge contracts or terminated prior to settlement. Substantially all of the deferred hedging gain as of September 30, 2004 is expected to be recognized in net income within the next fiscal year.

Under our risk management policies, we seek to match our financial derivative positions to our physical storage positions as well as our expected current and future sales and purchase obligations to maintain no open positions at the end of each trading day. The determination of our net open position as of any day, however, requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the price risk associated with any net open position at the end of each day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. We can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on September 30, 2004, AEH had a net open position (including existing storage) of 0.2 Bcf.

Adoption of EITF 02-03

On October 25, 2002, EITF 02-03, *Accounting for Contracts Involved in Energy Trading and Risk Management,* was issued. It rescinded EITF 98-10, *Accounting for Energy Trading and Risk Management Activities,* and required that all energy trading contracts entered into after October 25, 2002 be accounted for pursuant to the provisions of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities.* Beginning January 1, 2003, we have no longer marked our storage and transportation contracts to market value each month in accordance with EITF 98-10 and adopted EITF 02-03. As a result, we recorded a $7.8 million, net of applicable income tax benefit, as a cumulative effect of a change in accounting principle in fiscal 2003.

Treasury Activities

During fiscal 2004, we entered into four Treasury lock agreements to fix the Treasury yield component of the interest cost of financing associated with the anticipated issuance of $875 million of long-term debt subsequent to September 30, 2004. This long-term debt was issued on October 22, 2004 and was used to repay a portion of the commercial paper used to fund the TXU Gas acquisition, as described in Note 3.

We designated these Treasury lock agreements as cash flow hedges of an anticipated transaction. Accordingly, to the extent effective, unrealized gains and losses associated with the Treasury locks are recorded as a component of accumulated other comprehensive income (loss). At September 30, 2004, we recorded deferred hedging losses of $21.3 million, net of tax, as a component of accumulated other comprehensive income (loss) related to these Treasury lock agreements due to a decline in the 5 and 10 year Treasury rates between the inception of the Treasury locks and September 30, 2004. These Treasury lock agreements were settled in October 2004 with a net $43.8 million payment to the counterparties. Approximately $11.6 million of the $43.8 million obligation will be recognized as a component of interest expense over the next five years, and the remaining amount, approximately $32.2 million, will be recognized as a component of interest expense over the next ten years.

The following table presents our hedging transactions that were recorded to other comprehensive income (loss), net of taxes during the year ended September 30, 2004. Prior to fiscal 2004, we did not designate any of our derivative instruments as cash flow hedges.

	Year Ended September 30, 2004
	(In thousands)
Increase (decrease) in fair value:	
Treasury lock agreements	$(21,268)
Forward commodity contracts	11,078
Recognition of (gains) losses in earnings due to settlements:	
Treasury lock agreements	—
Forward commodity contracts	(3,495)
Total other comprehensive income (loss) from hedging, net of tax(1)	$(13,685)

(1) Utilizing an income tax rate of approximately 38% comprised of the effective rates in each taxing jurisdiction.

The following amounts net of deferred taxes represent the expected recognition into earnings for our derivative instruments, based upon the fair values of these derivatives as of September 30, 2004:

	Treasury lock agreements	Forward Contracts	Total
		(In thousands)	
2005	$ (2,839)	$7,159	$ 4,320
2006	(2,839)	417	(2,422)
2007	(2,839)	7	(2,832)
2008	(2,839)	—	(2,839)
2009	(2,839)	—	(2,839)
Thereafter	(7,073)	—	(7,073)
Total	$(21,268)	$7,583	$(13,685)

6. Debt

Long-term debt

Long-term debt at September 30, 2004 and 2003 consisted of the following:

	2004	2003
	(In thousands)	
Unsecured 10% Notes, due 2011	$ 2,303	$ 2,303
Unsecured 7.375% Senior Notes, due 2011	350,000	350,000
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Medium term notes		
Series A, 1995-2, 6.27%, due 2010	10,000	10,000
Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
First Mortgage Bonds		
Series J, 9.40% due 2021	17,000	17,000
Series P, 10.43% due 2013	11,250	13,750
Series Q, 9.75% due 2020	16,000	17,000
Series R, 11.32% due 2004	—	2,160
Series T, 9.32% due 2021	18,000	18,000
Series U, 8.77% due 2022	20,000	20,000
Series V, 7.50% due 2007	4,167	6,733
Rental property, propane and other term notes due in installments through 2013	9,830	6,317
Total long-term debt	868,550	873,263
Less:		
Original issue discount on unsecured senior notes and debentures	(1,331)	(1,418)
Current maturities	(5,908)	(9,345)
	$861,311	$862,500

Most of the First Mortgage Bonds contain provisions that allow us to prepay the outstanding balance in whole at any time, subject to a prepayment premium. The First Mortgage Bonds provide for certain cash flow requirements and restrictions on additional indebtedness, sale of assets and payment of dividends. Under the most restrictive of such covenants, cumulative cash dividends paid after December 31, 1988 may not exceed the sum of accumulated net income for periods after December 31, 1988 plus $15.0 million. At September 30, 2004, approximately $103.6 million of retained earnings were unrestricted with respect to the payment of dividends. We were in compliance with all of our debt covenants as of September 30, 2004.

In December 2001, we filed a shelf registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $600.0 million in new common stock and/or debt. The registration statement was declared effective by the SEC on January 30, 2002. On January 16, 2003, we issued $250.0 million of 5.125% Senior Notes due 2013 under the registration statement. The net proceeds of $249.3 million were used to repay debt under an acquisition credit facility used to finance our acquisition of MVG, to repay $54.0 million in unsecured senior notes held by institutional lenders and short-term debt under our commercial paper program and to provide funds for general corporate purposes. Additionally, we sold 4,100,000 shares of our common stock in connection with our June and July 2003 Offering under the registration statement to provide additional funding for our Pension Account Plan. In July 2004, we sold

9,939,393 shares of our common stock, including the underwriters' exercise of their overallotment option. We used the net proceeds from this offering, together with borrowings under a bridge financing facility to consummate the acquisition of substantially all of the assets of TXU Gas and pay related fees and expenses. As a result of the offering, we exhausted the remaining availability under our December 2001 shelf registration statement.

In August 2004, we filed another shelf registration statement with the SEC to issue, from time to time, up to $2.2 billion in new common stock and/or debt, which became effective on September 15, 2004. In October 2004, we sold 16.1 million common shares, including the underwriters' exercise of their overallotment option, under the new shelf registration statement, generating net proceeds of $382.5 million before other offering costs. Additionally, we issued senior unsecured debt under the shelf registration statement consisting of $400 million of 4.00% senior notes due 2009, $500 million of 4.95% senior notes due 2014, $200 million of 5.95% senior notes due 2034 and $300 million of floating rate senior notes due 2007. The floating rate notes will bear interest at a rate equal to the three-month LIBOR rate plus 0.375 percent per year. The initial weighted average effective interest rate on these notes is 4.76 percent. The net proceeds from the sale of these senior notes were $1.39 billion.

The net proceeds from the October 2004 common stock and senior notes offerings, combined with the net proceeds from our July 2004 offering were used to pay off the $1.7 billion in outstanding commercial paper backstopped by a senior unsecured revolving credit agreement, which we entered into on September 24, 2004 for bridge financing for the TXU Gas acquisition. After issuing the debt and equity in October 2004 we have approximately $405.1 million in availability remaining under the shelf registration statement. Also, as a result of this refinancing in October 2004, we canceled the senior unsecured revolving credit facility.

As of September 30, 2004, all of the Colorado-Kansas Division utility plant assets with a net book value of approximately $219.7 million were subject to a lien under the 9.4 percent Series J First Mortgage Bonds assumed by us in the acquisition of Greeley Gas Company. Also, substantially all of the Mid-States Division utility plant assets, totaling $363.3 million, were subject to a lien under the Indenture of Mortgage of the Series P through V First Mortgage Bonds.

Based on the borrowing rates currently available to us for debt with similar terms and remaining average maturities, the fair value of long-term debt at September 30, 2004 and 2003 is estimated, using discounted cash flow analysis, to be $936.6 million and $1,003.9 million.

Maturities of long-term debt at September 30, 2004 were as follows (in thousands):

2005	$ 5,908
2006	7,055
2007	7,394
2008	7,206
2009	5,410
Thereafter	835,577
	$868,550

Short-term debt

At September 30, 2004, there were no short-term amounts outstanding under our commercial paper program or bank credit facilities. At September 30, 2003, short-term debt consisted of $118.6 million of commercial paper. The weighted average interest rate on short-term borrowings outstanding at September 30, 2003 was 1.7 percent.

Credit facilities

We maintain both committed and uncommitted credit facilities. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the bank. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas charged by suppliers and the increased gas supplies required to meet customers' needs during periods of cold weather.

Committed credit facilities

As of September 30, 2004, we had two short-term committed credit facilities totaling $368.0 million, one of which was an unsecured facility for $350.0 million that bore interest at the Eurodollar rate plus 0.625 percent and served as a backup liquidity facility for our commercial paper program. In July 2004, we renewed this facility with substantially the same terms as those of the existing facility that was set to expire in January 2005. However, on October 22, 2004 we replaced this credit facility with a new 364-day $600.0 million committed credit facility that will serve as a backup liquidity facility for our commercial paper program on terms that are substantially similar to our $350.0 million facility.

We have a second unsecured facility in place for $18.0 million that bears interest at the Fed Funds rate plus 0.5 percent and is used for working-capital purposes. At September 30, 2004, there were no amounts outstanding under these credit facilities. These credit facilities are negotiated at least annually. On April 1, 2004, the $18.0 million working-capital credit facility was renewed for an additional 12 months on terms substantially similar to those of the prior facility.

On October 7, 2002, we entered into a $150.0 million short-term unsecured committed credit facility. This credit facility was used to provide initial funding for the cash portion of the MVG acquisition and to repay MVG's existing debt. A total of $147.0 million was borrowed under this credit facility during the first quarter of fiscal 2003. This amount was paid off in January 2003 with a portion of the proceeds of our $250.0 million debt offering, as discussed above.

The availability of funds under our credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently meet. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in our $350.0 million credit facility to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At September 30, 2004, our total-debt-to-total-capitalization ratio, as defined, was 45 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under our $350.0 million credit facility are subject to adjustment depending upon our credit ratings. We and our lead bank amended this facility's terms prior to closing the TXU Gas acquisition to accommodate the expected increase in our debt to capital ratio that resulted from the acquisition. Under this amendment, the total debt to total capitalization ratio is calculated quarterly and up to $200 million in short-term debt will be excluded from the calculation as of December 31, 2004. This provision also was incorporated into the new $600.0 million credit facility that replaced the $350.0 million facility in October 2004.

Uncommitted credit facilities

AEM has a $250.0 million uncommitted-demand working capital credit facility that bears interest at the Eurodollar rate plus 2.5 percent and expires on March 31, 2005. Effective October 1, 2003, with the reorganization of our natural gas marketing segment, AEM became the borrower under the credit facility, and AEH became the sole guarantor of the facility. At September 30, 2004, no amounts were outstanding under this credit facility. AEM letters of credit totaling $55.0 million have been issued under the facility and reduce the amount available that can be borrowed. The amount available under this credit facility is also limited by various covenants, including covenants based on working capital. Under the most restrictive covenant, the amount available to AEM under this credit facility was $62.1 million at September 30, 2004.

We also have an unsecured short-term uncommitted credit line for $25.0 million that is used for working-capital and letter-of-credit purposes. There were no borrowings under this uncommitted credit facility at September 30, 2004, but Atmos Energy Corporation (AEC) letters of credit reduced the amount available by $3.8 million. This uncommitted line is renewed or renegotiated at least annually with varying terms, and we pay no fee for the availability of the line. Borrowings under this line are made on a when- and as-available basis at the discretion of the bank.

In addition, AEM has a $100.0 million intercompany credit facility with AEC through AEH for its nonutility business which bears interest at the Eurodollar rate plus 2.75 percent. Any outstanding amounts under this facility are subordinated to AEM's $250.0 million uncommitted-demand credit facility described above. This facility is used to supplement AEM's $250.0 million credit facility. This credit facility was renewed effective July 1, 2004 on substantially the same terms as those of the existing facility and has been approved by our state regulators through December 31, 2004. However, there is no assurance that our regulators will approve our use of this credit facility after that time. At September 30, 2004, $15.0 million was outstanding under this facility and is eliminated in consolidation.

7. Shareholders' Equity

Stock Issuances

During the years ended September 30, 2004, 2003 and 2002 we issued 11,323,925, 9,799,853, and 884,431 shares of common stock.

On October 27, 2004, we completed the public offering of 16,100,000 shares of our common stock including the underwriters' exercise of their overallotment option of 2,100,000 shares. The offering was priced at $24.75 and generated net proceeds of approximately $382.5 million, before other offering costs. On July 14, 2004, we completed the public offering of 8,650,000 shares of our common stock. The offering was priced at $24.75 and generated net proceeds of approximately $205.1 million. We sold an additional 1,289,393 shares of our common stock when our underwriters exercised their overallotment option, which generated net proceeds of approximately $30.6 million.

We used the net proceeds from these offerings, together with net proceeds of $1.39 billion received from the issuance of senior unsecured notes to pay off the $1.7 billion in outstanding commercial paper described in Note 3.

On June 23, 2003, we completed a public offering of 4,000,000 shares of our common stock, and we sold an additional 100,000 shares of our common stock in July 2003 when our underwriters exercised their overallotment option (the 2003 Offering). The 2003 Offering was priced at $25.31 per share and generated net proceeds of approximately $99.2 million. The proceeds were used to partially fund our pension plan, to repay short-term debt and for other general corporate purposes including the purchase of natural gas for storage.

Shareholder Rights Plan

On November 12, 1997, our Board of Directors declared a dividend distribution of one right for each outstanding share of our common stock to shareholders of record at the close of business on May 10, 1998. Each right entitles the registered holder to purchase from us a one-tenth share of our common stock at a purchase price of $8.00 per share, subject to adjustment. The description and terms of the rights are set forth in a rights agreement between us and the rights agent.

Subject to exceptions specified in the rights agreement, the rights will separate from our common stock and a distribution date will occur upon the earlier of:

- ten business days following a public announcement that a person or group of affiliated or associated persons has acquired, or obtained the right to acquire, beneficial ownership of 15 percent or more of the outstanding shares of our common stock, other than as a result of repurchases of stock by us or specified inadvertent actions by institutional or other shareholders;

- ten business days, or such later date as our Board of Directors shall determine, following the commencement of a tender offer or exchange offer that would result in a person or group having acquired, or obtained the right to acquire, beneficial ownership of 15 percent or more of the outstanding shares of our common stock; or

- ten business days after our Board of Directors shall declare any person to be an adverse person within the meaning of the rights plan.

The rights expire on May 10, 2008, unless extended prior thereto by our board or earlier if redeemed by us. The rights will not have any voting rights. The exercise price payable and the number of shares of our common stock or other securities or property issuable upon exercise of the rights are subject to adjustment from time to time to prevent dilution. We issue rights when we issue our common stock until the rights have separated from the common stock. After the rights have separated from the common stock, we may issue additional rights if the board of directors deems such issuance to be necessary or appropriate. The rights have "anti-takeover" effects and may cause substantial dilution to a person or entity that attempts to acquire us on terms not approved by our board of directors except pursuant to an offer conditioned upon a substantial number of rights being acquired. The rights should not interfere with any merger or other business combination approved by our board of directors because, prior to the time that the rights become exercisable or transferable, we can redeem the rights at $.01 per right.

Registration Rights and Other Agreements

As part of the consideration for our Mississippi Valley Gas Company acquisition in December 2002, we issued shares of common stock under an exemption from registration under the Securities Act of 1933, as amended. In the transaction, we entered into a registration rights agreement with the former stockholders of Mississippi Valley Gas Company that requires us, on no more than two occasions, and with some limitations, to file a registration statement under the Securities Act within 60 days of their request for an offering designed to achieve a wide distribution of shares through underwriters selected by us. We also granted rights, subject to some limitations, to participate in future registered offerings of our securities to these shareholders. As of September 30, 2004, 1,193,143 shares were covered by the registration rights agreement. Each of these shareholders has also agreed, for up to five years from the closing of the acquisition, and with some exceptions, not to sell or transfer shares representing more than 1 percent of our total outstanding voting securities to any person or group or any shares to a person or group who would hold more than 9.9 percent of our total outstanding voting securities after the sale or transfer. This restriction, and other agreed restrictions on the ability of these shareholders to acquire additional shares, participate in proxy solicitations or act to seek control, may be deemed to have an "anti-takeover" effect.

In addition, in connection with our funding of the Atmos Energy Corporation Pension Account Plan, we issued, in June 2003, to the Atmos Energy Corporation Master Retirement Trust, for the benefit of the Pension Account Plan, 1,169,700 shares of common stock under an exemption from registration under the Securities Act. In the transaction, we entered into a registration rights agreement with the asset manager of the Pension Account Plan that requires us, on no more than three occasions, and with some limitations, to file a registration statement under the Securities Act within 60 days of its request for an offering designed to achieve a wide distribution of shares through underwriters selected by us. We also granted rights, subject to some limitations, to participate in future registered offerings of our securities to the asset manager.

8. Stock and Other Compensation Plans

Stock-Based Compensation Plans

We have two stock-based compensation plans that provide for the granting of incentive stock options, nonqualified stock options, stock appreciation rights, bonus stock, restricted stock and performance-based stock to officers and key employees: the 1998 Long-Term Incentive Plan and the Long-Term Stock Plan for the Mid-States Division. Nonemployee directors are also eligible to receive such stock-based compensation under the 1998 Long-Term Incentive Plan. The objectives of these plans include attracting and retaining the best personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire common stock.

1998 Long-Term Incentive Plan

On August 12, 1998, the Board of Directors approved and adopted the 1998 Long-Term Incentive Plan, which became effective October 1, 1998 after approval by our shareholders. The Long-Term Incentive Plan is a comprehensive, long-term incentive compensation plan providing for discretionary awards of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, restricted stock and performance-based stock to help attract, retain and reward employees and non-employee directors of Atmos and its subsidiaries. We are authorized to grant awards for up to a maximum of 4,000,000 shares of common stock under this plan subject to certain adjustment provisions. As of September 30, 2004, non-qualified stock options, bonus stock and restricted stock have been issued under this plan, and 1,760,627 shares were available for issuance. The option price of the stock options issued under this plan is equal to the market price of our stock at the date of grant. These stock options expire 10 years from the date of the grant and vest annually over a service period ranging from one to three years.

A summary of activity for grants of stock options under the 1998 Long-Term Incentive Plan follows:

	2004		2003		2002	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Outstanding at beginning of year	1,827,310	$21.91	1,557,606	$21.87	1,009,330	$21.43
Granted	8,118	24.44	411,860	21.37	607,877	22.35
Exercised	(342,252)	20.91	(92,989)	17.79	(19,102)	16.69
Forfeited	(999)	22.49	(49,167)	23.89	(40,499)	20.53
Outstanding at end of year	1,492,177	$22.10	1,827,310	$21.91	1,557,606	$21.87
Exercisable at end of year	1,006,859	$22.23	868,199	$21.69	532,729	$21.81

Information about outstanding and exercisable options under the Long-Term Incentive Plan, as of September 30, 2004, follows:

	Options Outstanding			*Options Exercisable*	
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (in years)	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
$15.65 to $17.49	100,498	5.5	$15.79	100,498	$15.79
$17.50 to $20.24	20,000	5.9	$19.66	20,000	$19.66
$20.25 to $22.99	905,028	7.7	$21.92	434,628	$22.09
$23.00 to $25.66	466,651	5.8	$23.91	451,733	$23.91
$15.65 to $25.66	1,492,177	7.0	$22.10	1,006,859	$22.23

The stock options had a weighted average fair value per share on the date of grant of $3.82 in 2004, $3.32 in 2003 and $3.55 in 2002. We used the Black-Scholes pricing model to estimate the fair value of each option granted with the following weighted average assumptions for 2004, 2003 and 2002:

	Year ended September 30		
	2004	2003	2002
Expected Life *(years)*	7	7	7
Interest rate	4.3%	4.0%	3.9%
Volatility	22.8%	23.3%	24.2%
Dividend yield	4.8%	4.8%	4.8%

Long-Term Stock Plan for the Mid-States Division

Prior to the merger with Atmos, certain United Cities Gas Company officers and key employees participated in the United Cities Long-Term Stock Plan implemented in 1989. At the time of the merger on July 31, 1997, we adopted this plan by registering a total of 250,000 shares of Atmos stock to be issued under the Long-Term Stock Plan for the Mid-States Division. Under this plan, incentive stock options, nonqualified stock options, stock appreciation rights, restricted stock or any combination thereof may be granted to officers and key employees of the Mid-States Division. Options granted under the plan become exercisable at a rate of 20 percent per year and expire 10 years after the date of grant. No awards have been granted under this plan since 1996. During 2004, 6,000 options were exercised under the plan. At September 30, 2004, there were 300 options outstanding, all of which were fully vested. Because of the limited activities of this plan, the pro forma effects of applying SFAS 123 would have less than a $0.01 per diluted share effect on earnings per share.

Restricted Stock Plans

As noted above, the 1998 Long-Term Incentive Plan provides for discretionary awards of restricted stock to help attract, retain and reward employees and non-employee directors of Atmos and its subsidiaries. Certain of these awards vest based upon the passage of time and other awards vest based upon the passage of time and the achievement of specified performance targets. The associated expense is recognized ratably over the vesting period. Additionally, from October 1, 1987 through February 2002, we maintained a Restricted Stock Grant Plan for our management and key employees, which provided awards of common stock that were subject to certain restrictions. This plan was administered by the non-employee members of the Board of Directors, who made final determinations regarding participation in the Plan, awards under the Plan and restrictions on the restricted stock awarded. The following summarizes information regarding the restricted stock plans:

	Year ended September 30		
	2004	2003	2002
Shares granted during the year	134,257	82,933	22,204
Weighted average intrinsic value	$24.76	$21.34	$21.30
Compensation expense recognized, net of tax (in thousands)	$ 978	$ 370	$ 487
Unexpired shares with unmet restrictions at September 30	239,919	101,486	54,079

Other Plans

Direct Stock Purchase Plan

We maintain a Direct Stock Purchase Plan which allows participants to have all or part of their cash dividends paid quarterly in additional shares of our common stock. Through March 31, 2004, participants were permitted to reinvest their cash dividends at a three percent discount from market prices. Effective April 1, 2004, the three percent discount on reinvested dividends was eliminated and the minimum initial investment required to join the plan was increased to $1,250. Direct Stock Purchase Plan participants may purchase additional shares of Atmos common stock as often as weekly with voluntary cash payments of at least $25, up to an annual maximum of $100,000.

Outside Directors Stock-For-Fee Plan

In November 1994, the Board adopted the Outside Directors Stock-for-Fee Plan which was approved by the shareholders of Atmos in February 1995 and was amended and restated in November 1997. The plan permits non-employee directors to receive all or part of their annual retainer and meeting fees in stock rather than in cash.

Equity Incentive and Deferred Compensation Plan for Non-Employee Directors

In November 1998, the Board of Directors adopted the Equity Incentive and Deferred Compensation Plan for Non-Employee Directors which was approved by the shareholders of Atmos in February 1999. This plan amended the Atmos Energy Corporation Deferred Compensation Plan for Outside Directors adopted by the Company on May 10, 1990 and replaced the pension payable under the Company's Retirement Plan for Non-Employee Directors. The plan provides non-employee directors of Atmos with the opportunity to defer receipt, until retirement, of compensation for services rendered to the Company, invest deferred compensation into either a cash account or a stock account and to receive an annual grant of share units for each year of service on the Board.

Variable Pay Plan

The Variable Pay Plan was created to give each employee an opportunity to share in the success of Atmos based on the achievement of key performance measures considered critical to achieving business objectives for a given year. These performance measures may include earnings growth objectives, improved cash flow objectives or crucial customer satisfaction and safety results. We monitor progress towards the achievement of the performance measures throughout the year and record accruals based upon the expected payout using the best estimates available at the time the accrual is recorded.

9. Retirement and Post-Retirement Employee Benefit Plans

We have both funded and unfunded noncontributory defined benefit plans that together cover substantially all of our employees. We also maintain post-retirement plans that provide health care benefits to retired employees. Finally, we sponsor defined contribution plans which cover substantially all employees. These plans are discussed in further detail below.

Defined Benefit Plans

Employee Pension Plans

As of September 30, 2004, we maintained two defined benefit plans: the Atmos Energy Corporation Pension Account Plan and the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees. Both plans are held within the Atmos Energy Corporation Master Retirement Trust (the Master Trust).

The Atmos Energy Corporation Pension Account Plan (the Plan) was established effective January 1, 1999 and covers substantially all employees of Atmos. Opening account balances were established for participants as of January 1, 1999 equal to the present value of their respective accrued benefits under the pension plans which were previously in effect as of December 31, 1998. The Plan credits an allocation to each participant's account at the end of each year according to a formula based on the participant's age, service and total pay (excluding incentive pay).

The Plan also provides for an additional annual allocation based upon a participant's age as of January 1, 1999 for those participants who were participants in the prior pension plans. The Plan will credit this additional allocation each year through December 31, 2008. In addition, at the end of each year, a participant's account will be credited with interest on the employee's prior year account balance. A special grandfather benefit also applies through December 31, 2008, for participants who were at least age 50 as of January 1, 1999, and who were participants in one of the prior plans on December 31, 1998. Participants fully vest in their account balances after five years of service and may choose to receive their account balances as a lump sum or an annuity.

MVG maintained a defined benefit plan that covered substantially all full-time employees (the MVG Plan). On June 30, 2003, all retirees and the active non-union employees became eligible to participate in the Plan. Active union employees remained in the MVG Plan, which was renamed the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees on July 1, 2003. Under this plan, benefits are based upon years of benefit service and average final earnings. Participants vest in the plan after five years and will receive their benefit in an annuity.

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. However, additional voluntary contributions are made from time to time as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future. We did not contribute to the Master Trust during fiscal 2004. In June 2003, we contributed to the Master Trust for the benefit of the Plan $48.6 million in cash and 1,169,700 shares of Atmos restricted common stock with a value of $28.8 million. As a result of this contribution and improved investment returns during fiscal 2003, the underfunded status of the plan improved by approximately $8.6 million, and the $39.4 million reduction to equity recorded as of September 30, 2002 was eliminated as of September 30, 2003. We are not required to make a minimum funding contribution during fiscal 2005 nor do we anticipate making any voluntary contributions during fiscal 2005.

We manage the Master Trust's assets with the objective of achieving a real rate of return of approximately four percent per year. We make investment decisions and evaluate performance on a medium term horizon of at least three to five years. We also consider our current financial status when making recommendations and decisions regarding the Master Trust's assets. Finally, we strive to ensure the Master Trust's assets are appropriately invested to maintain an acceptable level of risk and meet the Master Trust's long term asset allocation policy.

To achieve these objectives, we invest the Master Trust's assets in equity securities, fixed income securities, interests in commingled pension trust funds and cash and cash equivalents.

Investments in equity securities are diversified among the market's various subsectors to diversify risk and maximize returns. Fixed income securities are invested in investment grade securities. Cash equivalents are invested in securities that either are short term (less than 180 days) or readily convertible to cash with modest risk.

The following table presents asset allocation information for the Master Trust as of September 30, 2004 and 2003.

		Actual Allocation September 30,	
Security Class	Targeted Allocation Range	2004	2003
Domestic equity	45% - 55%	49.8%	47.5%
International equity	10% - 20%	17.1%	15.9%
Domestic fixed income and other	25% - 45%	32.1%	36.5%
Cash and equivalents	NA	1.0%	0.1%

At September 30, 2004 and 2003, the Plan held 1,169,700 shares of Atmos common stock, which represented 9.0 percent and 8.6 percent of total Master Trust assets. These shares generated dividend income of approximately $1.4 million and $0.4 million during fiscal 2004 and 2003.

The following table presents the Master Trust's funded status for 2004 and 2003. The benefit obligation and related plan assets used to determine the funded status are determined as of June 30 of each fiscal year and are based upon actuarial projections and assumptions, including the discount rate, expected return on plan assets and the rate of compensation increase. Discount rates used to determine the projected benefit obligation and net periodic pension cost are based on rates of high grade corporate bonds with maturities similar to the average period over which benefits will be paid. The expected return on plan assets is based on management's expectation of the long-term return on the portfolio of plan assets. These expectations are based upon the historical returns earned by the Master Trust's assets, future market projections and expectations and surveys of assumptions used by other companies. The rate of compensation increase is established based upon our internal budgets.

	2004	2003
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$330,344	$226,197
Service cost	7,696	6,693
Interest cost	19,691	19,044
Actuarial loss (gain)	(16,803)	47,410
MVG acquisition	—	52,210
Plan amendments	—	(1,771)
Benefits paid	(27,931)	(19,439)
Benefit obligation at end of year	312,997	330,344
Change in plan assets:		
Fair value of plan assets at beginning of year	322,703	209,941
Actual return on plan assets	51,390	8,513
MVG acquisition	—	46,326
Employer contributions	—	77,362
Benefits paid	(27,931)	(19,439)
Fair value of plan assets at end of year	346,162	322,703
Reconciliation:		
Funded status	33,165	(7,641)
Unrecognized prior service cost	(6,967)	(7,995)
Unrecognized net loss	87,668	132,332
Net amount recognized	$113,866	$116,696

The accumulated benefit obligation for our employee pension plans was $305.1 million and $323.7 million at September 30, 2004 and 2003.

During 2003, we changed the mortality table for converting cash balance accounts into monthly annuities to better reflect the anticipated life expectancy of participants in the plan. The effects of this change are reflected in the above table as plan amendment.

The actuarial assumptions used to determine the pension liability for the Master Trust were determined as of June 30, 2004 and 2003 as follows:

	2004	2003
Discount rate	6.25%	6.00%
Rate of compensation increase	4.00%	4.00%
Expected return on plan assets	8.75%	9.00%

Net periodic pension cost for the Master Trust for 2004, 2003 and 2002 is recorded as a component of operating expense and included the following components:

	Year Ended September 30		
	2004	2003	2002
	(In thousands)		
Components of net periodic pension cost:			
Service cost	$ 7,696	$ 6,693	$ 5,247
Interest cost	19,691	19,044	15,544
Expected return on assets	(30,097)	(23,950)	(23,298)
Amortization of transition asset	—	—	(72)
Amortization of prior service cost	(1,028)	(883)	(883)
Recognized actuarial loss	6,555	1,756	—
Net periodic pension cost	$ 2,817	$ 2,660	$ (3,462)

The actuarial assumptions used to determine the net periodic pension cost for the Master Trust were determined as of June 30, 2003, 2002 and 2001 and are as follows:

	2004	2003	2002
Discount rate	6.00%	7.25%	7.50%
Rate of compensation increase	4.00%	4.00%	4.00%
Expected return on plan assets	9.00%	9.25%	10.00%

Supplemental Executive Benefits Plans

We have a nonqualified Supplemental Executive Benefits Plan which provides additional pension, disability and death benefits to the officers and certain other employees of Atmos. The Supplemental Plan was amended and restated in August 1998. In addition, in August 1998, we adopted the Performance-Based Supplemental Executive Benefits Plan which covers all employees who become officers or division presidents after August 12, 1998 or any other employees selected by our Board of Directors in its discretion.

The following table presents the funded status of the supplemental plans for 2004 and 2003:

	2004	2003
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 71,659	$ 59,152
Service cost	2,037	1,548
Interest cost	4,324	4,294
Actuarial loss (gain)	(682)	9,900
Benefits paid	(3,340)	(3,235)
Benefit obligation at end of year	73,998	71,659
Change in plan assets:		
Fair value of plan assets at beginning of year	—	—
Employer contribution	3,340	3,235
Benefits paid	(3,340)	(3,235)
Fair value of plan assets at end of year	—	—
Reconciliation:		
Funded status	(73,998)	(71,659)
Unrecognized transition obligation	4	100
Unrecognized prior service cost	3,728	4,750
Unrecognized net loss	20,987	24,349
Accrued pension cost	$(49,279)	$(42,460)

The accumulated benefit obligation for our supplemental executive plans was $64.8 million and $62.6 million at September 30, 2004 and 2003. The net liability for the supplemental plans is recorded as a component of deferred credits and other liabilities.

The actuarial assumptions used to determine the pension liability for the supplemental plans were determined as of June 30, 2004 and 2003 and are as follows:

	2004	2003
Discount rate	6.25%	6.00%
Rate of compensation increase	4.00%	4.00%
Expected return on plan assets	NA	NA

Assets for the supplemental plans are held in separate rabbi trusts and comprise the following:

	Cost	Unrealized Holding Gain (Loss)	Market Value
		(In thousands)	
As of September 30, 2004:			
Domestic equity mutual funds	$29,894	$(1,537)	$28,357
Foreign equity mutual funds	3,279	298	3,577
	$33,173	$(1,239)	$31,934
As of September 30, 2003:			
Domestic equity mutual funds	$28,540	$(2,359)	$26,181
Foreign equity mutual funds	3,195	9	3,204
	$31,735	$(2,350)	$29,385

At September 30, 2004, we maintained investments in domestic equity mutual funds that were in an unrealized loss position as of September 30, 2004. Information concerning these funds follows:

	Less than 12 months		12 months or more	
	Fair Value	Unrealized Loss	Fair Value	Unrealized Loss
		(In thousands)		
Domestic equity mutual funds	$3,445	$(240)	$16,600	$(1,867)
Foreign equity mutual funds	—	—	—	—
	$3,445	$(240)	$16,600	$(1,867)

Because these funds are only used to fund the supplemental plans, we evaluate investment performance over a long-term horizon. Based upon our intent and ability to hold these investments and to direct the source of the payments in order to maximize the life of the portfolio, the improved investment returns in the last year and the fact that the funds continue to receive high ratings from mutual fund rating companies, we consider this impairment to be temporary.

Net periodic pension cost for the supplemental plans for 2004, 2003 and 2002 is recorded as a component of operating expense and included the following components:

	Year Ended September 30		
	2004	2003	2002
		(In thousands)	
Components of net periodic pension cost:			
Service cost	$2,037	$1,548	$1,028
Interest cost	4,324	4,294	3,938
Amortization of transition asset	96	96	96
Amortization of prior service cost	1,022	1,022	1,022
Recognized actuarial loss	1,516	772	542
Net periodic pension cost	$8,995	$7,732	$6,626

The actuarial assumptions used to determine the net periodic pension cost for the supplemental plans were determined as of June 30, 2003, 2002 and 2001 and are as follows:

	2004	2003	2002
Discount rate	6.00%	7.25%	7.50%
Rate of compensation increase	4.00%	4.00%	4.00%
Expected return on plan assets	NA	NA	NA

Supplemental Disclosures For Defined Benefit Plans with Accumulated Benefit Obligations in Excess of Plan Assets

The following summarizes key information for our defined benefit plans with accumulated benefit obligations in excess of plan assets. For fiscal 2003, the accumulated benefit obligation for both the Plan and MVG's plan exceeded the fair value of plan assets for each plan. For fiscal 2004, this condition only existed for the MVG plan.

	Employee Pension Plans		Supplemental Plans	
	2004	2003	2004	2003
	(In thousands)			
Projected Benefit Obligation	$8,840	$330,344	$73,998	$71,659
Accumulated Benefit Obligation	6,555	323,663	64,754	62,642
Fair Value of Plan Assets	4,482	322,703	—	—

Estimated Future Benefit Payments

The following benefit payments for our defined benefit plans, which reflect expected future service, as appropriate, are expected to be paid in the following years:

	Pension Plans	Supplemental Plans
	(In thousands)	
2005	$ 25,723	$ 3,249
2006	25,070	3,205
2007	26,064	3,564
2008	26,042	3,709
2009	27,484	3,696
2010-2014	145,213	23,627

Postretirement Benefits

We sponsor three postretirement plans other than pensions that provide health care benefits to retired employees: the Retiree Medical Plan for Retirees and Disabled Employees of Atmos Energy Corporation, the Atmos Energy Corporation Retiree Welfare Benefits Plan for Certain MVG Non-Union Employees and the Atmos Energy Corporation Retiree Welfare Benefits Plan for MVG Union Employees. Substantially all of our employees become eligible for these benefits if they reach retirement age while working for us and attain certain specified years of service. In addition, participant contributions are required under the plan.

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. However, additional voluntary contributions are made annually as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future. We expect to contribute $11.7 million to our postretirement benefits plans during fiscal 2005.

We currently do not maintain a formal investment policy with respect to the assets in our postretirement benefits plans. However, we strive to ensure the assets funding the postretirement benefit plans are appropriately invested to maintain an acceptable level of risk. We also consider our current financial status when making recommendations and decisions regarding the postretirement benefits plans.

We currently invest the assets funding our postretirement benefit plans in money market funds, equity mutual funds, fixed income funds and a balanced fund. The following table presents asset allocation information for the postretirement benefit plan assets as of September 30, 2004 and 2003.

Security Class	Actual Allocation September 30 2004	2003
Diversified investment fund[1]	82.0%	84.3%
Equity mutual funds	9.9%	5.0%
Fixed income mutual funds	4.3%	4.9%
Cash and cash equivalents	3.8%	5.8%

(1) This fund invests in a diversified portfolio of common stocks, preferred stocks and fixed income securities. It may invest up to 75 percent of assets in common stocks and convertible securities.

The following table presents the funding status for the postretirement plans for 2004 and 2003. The benefit obligation and related plan assets used to determine the funded status are determined as of June 30 of each fiscal year and are based upon actuarial projection and assumptions, including the discount rate, expected return on plan assets and the rate of compensation increase. Discount rates used to determine the benefit obligation and net periodic pension cost are based on rates of high grade corporate bonds with maturities similar to the average period over which benefits will be paid. The expected return on plan assets is based on management's expectation of the long-term return on the portfolio of plan assets. These expectations are based upon the historical returns earned by the plan's assets, future market projections and expectations and surveys of assumptions used by other companies.

	2004	2003
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$137,285	$ 112,295
Service cost	5,941	5,902
Interest cost	7,355	9,078
Plan participants' contributions	1,900	306
Actuarial loss (gain)	(17,038)	5,786
MVG acquisition	—	13,647
Benefits paid	(10,254)	(9,729)
Benefit obligation at end of year	125,189	137,285
Change in plan assets:		
Fair value of plan assets at beginning of year	26,310	16,250
Actual return on plan assets	4,695	(4,056)
Employer contributions	13,757	18,618
Plan participants' contributions	1,900	306
MVG acquisition	—	4,921
Benefits paid	(10,254)	(9,729)
Fair value of plan assets at end of year	36,408	26,310
Reconciliation:		
Funded status	(88,781)	(110,975)
Unrecognized transition obligation	14,176	15,687
Unrecognized prior service cost	780	1,166
Unrecognized net loss	12,981	38,543
Accrued postretirement cost	$(60,844)	$ (55,579)

The current portion of the accrued post-retirement cost is recorded as a component of other current liabilities and the long-term portion of the accrued post-retirement cost is recorded as a component of deferred credits and other liabilities.

The actuarial assumptions used to determine the liability for the post-retirement plans were determined as of June 30, 2004 and 2003 and are as follows:

	2004	2003
Discount rate	6.25%	6.00%
Expected return on plan assets	5.30%	5.30%
Initial trend rate	10.00%	9.00%
Ultimate trend rate	5.00%	5.00%
Ultimate trend reached in	2010	2008

Net periodic postretirement cost for 2004, 2003 and 2002 is recorded as a component of operating expense and included the following components. The 2004 amounts reflect the impact of adopting the provisions of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) beginning in the second quarter of fiscal 2004 as the plan is considered "actuarially equivalent" to Medicare Part D.

	Year Ended September 30		
	2004	2003	2002
		(In thousands)	
Components of net periodic postretirement cost:			
Service cost	$ 5,941	$ 5,902	$ 2,891
Interest cost	7,355	9,078	6,199
Expected return on assets	(1,523)	(1,012)	(759)
Amortization of transition obligation	1,511	1,511	1,511
Amortization of prior service cost	386	368	520
Recognized actuarial loss	635	1,778	—
Net periodic postretirement cost	$14,305	$17,625	$10,362

The actuarial assumptions used to determine the net periodic benefit cost for the postretirement plans were determined as of June 30, 2003, 2002 and 2001 and are as follows:

	2004	2003	2002
Discount rate	6.19%	7.25%	7.50%
Expected return on plan assets	5.30%	5.30%	5.30%
Initial trend rate	9.00%	10.00%	7.00%
Ultimate trend rate	5.00%	5.00%	5.00%
Ultimate trend reached in	2008	2008	2003

Assumed health care cost trend rates have a significant effect on the amounts reported for the plan. A one-percentage point change in assumed health care cost trend rates would have the following effects on the latest actuarial calculations:

	1-Percentage Point Increase	1-Percentage Point Decrease
	(In thousands)	
Effect on total service and interest cost components	$1,093	$ (957)
Effect on postretirement benefit obligation	$4,269	$(3,736)

We are currently recovering other postretirement benefits costs through our regulated rates under SFAS 106 accrual accounting in substantially all of our service areas. Other postretirement benefits costs have been specifically addressed in rate orders in each jurisdiction served by our Mid-States Division and our Mississippi Valley Gas Company Division or have been included in a rate case and not disallowed. Management believes that accrual accounting in accordance with SFAS 106 is appropriate and will continue to seek rate recovery of accrual-based expenses in its ratemaking jurisdictions that have not yet approved the recovery of these expenses.

Estimated Future Benefit Payments

The following benefit payments paid by us and retirees for our postretirement benefit plans, which reflect expected future service, as appropriate, are expected to be paid in the following years:

	Company Payments	Retiree Payments	Total Postretirement Benefits
		(In thousands)	
2005	$11,698	$ 2,811	$14,509
2006	9,144	3,144	12,288
2007	8,473	3,284	11,757
2008	8,920	3,550	12,470
2009	9,453	3,859	13,312
2010-2014	55,931	22,328	78,259

Defined Contribution Plans

As of September 30, 2004, we maintained two contribution benefit plans: the Atmos Energy Corporation Retirement Savings Plan and Trust (the Retirement Savings Plan) and the Mississippi Valley Gas Company Savings Plan for Union Employees (the MVG 401K Plan).

The Retirement Savings Plan covers substantially all employees and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Effective January 1, 1999 the Retirement Savings Plan was amended to allow the deferral of a portion of a participant's salary ranging from a minimum of one percent of eligible compensation, as defined by the Plan, up to the maximum allowed by the Internal Revenue Service. We match 100 percent of a participant's contributions, limited to four percent of the participant's salary, in Atmos common stock. However, participants have the option to immediately transfer this matching contribution into other funds held within the plan. Participants are also permitted to take out loans against their accounts subject to certain restrictions.

The MVG 401K Plan covers substantially all employees who are members of the International Chemical Workers Union Council, United Food and Commercial Workers Union International (Union) and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Employees of the Union automatically become participants of the MVG 401K plan on the date of union employment. We match 50 percent of a participant's contribution, limited to six percent of the participant's eligible contribution. Participants are also permitted to take out loans against their accounts subject to certain restrictions.

Matching contributions to our defined contribution plans are expensed as incurred and amounted to $4.6 million, $4.1 million, and $3.6 million for 2004, 2003 and 2002. The Board of Directors may also approve discretionary contributions, subject to the provisions of the Internal Revenue Code of 1986 and applicable regulations of the Internal Revenue Service. No discretionary contributions were made for 2004, 2003 or 2002. At September 30, 2004 and 2003, the Retirement Savings Plan held 3.7 percent and 4.4 percent of our common stock.

10. Details of Selected Consolidated Balance Sheet Captions

The following tables provide additional information regarding the composition of certain of our balance sheet captions.

Accounts receivable

Accounts receivable was comprised of the following at September 30, 2004 and 2003:

	September 30	
	2004	2003
	(In thousands)	
Billed accounts receivable	$187,306	$197,341
Unbilled revenue	15,991	22,325
Other accounts receivable	15,727	10,168
Total accounts receivable	219,024	229,834
Less: allowance for doubtful accounts	(7,214)	(13,051)
Net accounts receivable	$211,810	$216,783

Other current assets

Other current assets as of September 30, 2004 and 2003 were comprised of the following accounts.

	September 30	
	2004	2003
	(In thousands)	
Assets from risk management activities	$44,440	$22,259
Prepaid expenses	9,194	8,187
Current portion of leased assets receivable	2,973	2,973
Materials and supplies	2,626	3,917
Deferred gas costs	—	308
Other	4,003	1,219
Total	$63,236	$38,863

Property, plant and equipment

Property, plant and equipment was comprised of the following as of September 30, 2004 and 2003:

	September 30 2004	September 30 2003
	(In thousands)	
Production plant	$ 4,288	$ 8,003
Storage plant	58,075	64,714
Transmission plant	134,174	122,014
Distribution plant	1,971,124	1,851,228
General plant	382,220	376,777
Intangible plant	45,493	41,256
	2,595,374	2,463,992
Construction in progress	38,277	16,147
	2,633,651	2,480,139
Less: accumulated depreciation and amortization	(911,130)	(855,745)
Net property, plant and equipment	$1,722,521	$1,624,394

Deferred charges and other assets

Deferred charges and other assets as of September 30, 2004 and 2003 were comprised of the following accounts.

	September 30 2004	September 30 2003
	(In thousands)	
Pension plan assets in excess of plan obligations	$113,866	$116,696
Marketable securities	31,934	29,385
Long-term receivable on leased assets	22,511	25,403
Investment in U.S. Propane L.P.	—	21,071
Regulatory assets	24,733	34,591
Rights of way	11,746	11,746
Deferred financing costs	14,588	16,322
Assets from risk management activities	562	1,699
Other	12,038	12,692
Total	$231,978	$269,605

Other current liabilities

Other current liabilities as of September 30, 2004 and 2003 were comprised of the following accounts.

	September 30 2004	September 30 2003
	(In thousands)	
Customer deposits	$ 44,474	$ 41,068
Accrued employee costs	15,729	11,480
Deferred gas costs	39,097	—
Accrued interest	21,893	20,972
Liabilities from risk management activities	39,458	20,790
Taxes payable	22,930	9,746
Post-retirement obligations	5,300	5,300
Regulatory cost of removal accrual	7,653	6,034
Other	26,731	18,567
Total	$223,265	$133,957

Deferred credits and other liabilities

Deferred credits and other liabilities as of September 30, 2004 and 2003 were comprised of the following accounts.

	September 30 2004	September 30 2003
	(In thousands)	
Post-retirement obligations	$ 51,772	$ 50,334
Nonqualified retirement plan obligation	48,448	42,327
Customer advances for construction	14,120	13,701
Liabilities from risk management activities	1,138	763
Deferred revenue	7,021	12,197
Other	20,637	18,686
Total	$143,136	$138,008

11. Earnings Per Share

Basic and diluted earnings per share at September 30 are calculated as follows:

	2004	2003	2002
	(In thousands, except per share data)		
Income before cumulative effect of accounting change	$86,227	$79,461	$59,656
Cumulative effect of accounting change, net of income tax benefit	—	(7,773)	—
Net income	$86,227	$71,688	$59,656
Denominator for basic income per share — weighted average common shares	54,021	46,319	41,171
Effect of dilutive securities:			
Restricted and other shares	281	109	54
Stock options	114	68	25
Denominator for diluted income per share — weighted average common shares	54,416	46,496	41,250
Income per share — basic:			
Before cumulative effect of accounting change	$ 1.60	$ 1.72	$ 1.45
Cumulative effect of accounting change, net of income tax benefit	—	(.17)	—
Net income per share	$ 1.60	$ 1.55	$ 1.45
Income per share — diluted:			
Before cumulative effect of accounting change	$ 1.58	$ 1.71	$ 1.45
Cumulative effect of accounting change, net of income tax benefit	—	(.17)	—
Net income per share	$ 1.58	$ 1.54	$ 1.45

There were approximately 3,000, 601,500 and 1,118,167 out-of-the-money options excluded from the computation of diluted earnings per share for the years ended September 30, 2004, 2003 and 2002 as their exercise price was greater than the average market price of the common stock during that period.

12. Income Taxes

The components of income tax expense from continuing operations for 2004, 2003 and 2002 were as follows:

	2004	2003	2002
		(In thousands)	
Current			
Federal	$ 9,003	$(13,446)	$17,638
State	2,021	(441)	3,575
Deferred			
Federal	35,970	54,656	12,964
State	5,079	6,690	1,420
Investment tax credits	(535)	(549)	(417)
	$51,538	$ 46,910	$35,180

The provision (benefit) for income taxes is included in the consolidated financial statements as follows:

	2004	2003	2002
		(In thousands)	
Income tax before cumulative effect of accounting change	$51,538	$46,910	$35,180
Cumulative effect of accounting change	—	(5,117)	—
Income tax expense	$51,538	$41,793	$35,180

During 2003, we recorded a cumulative effect of accounting change to reflect the adoption of EITF 02-03, as described in Note 5. The $5.1 million benefit on the cumulative charge reflects a federal and state tax benefit of 39.7 percent.

Reconciliations of the provision for income taxes before the cumulative effect of accounting change computed at the statutory rate to the reported provisions for income taxes from continuing operations for 2004, 2003 and 2002 are set forth below:

	2004	2003	2002
		(In thousands)	
Tax at statutory rate of 35%	$48,218	$44,230	$33,193
Common stock dividends deductible for tax reporting	(985)	(993)	(707)
State taxes (net of federal benefit)	4,615	4,062	3,489
Other, net	(310)	(389)	(795)
Income tax expense	$51,538	$46,910	$35,180

Deferred income taxes reflect the tax effect of differences between the basis of assets and liabilities for book and tax purposes. The tax effect of temporary differences that give rise to significant components of the deferred tax liabilities and deferred tax assets at September 30, 2004 and 2003 are presented below:

	2004	2003
	(In thousands)	
Deferred tax assets:		
Costs expensed for book purposes and capitalized for tax purposes	$ 1,029	$ 2,336
Accruals not currently deductible for tax purposes	8,563	5,254
Customer advances	5,579	6,158
Nonqualified benefit plans	21,171	17,435
Postretirement benefits	21,665	21,186
Treasury lock agreement	13,035	—
Unamortized investment tax credit	1,000	564
Regulatory liabilities	1,192	1,271
Tax net operating loss and credit carryforwards	15,761	29,257
Gas cost adjustments	14,858	—
Other, net	4,373	7,198
Total deferred tax assets	108,226	90,659
Deferred tax liabilities:		
Difference in net book value and net tax value of assets	(264,239)	(257,679)
Pension funding	(43,798)	(42,681)
Gas cost adjustments	—	(429)
Regulatory assets	(3,154)	(3,154)
Cost capitalized for book purposes and expensed for tax purposes	(7,288)	(8,054)
Other, net	(3,677)	(2,012)
Total deferred tax liabilities	(322,156)	(314,009)
Net deferred tax liabilities	$(213,930)	$(223,350)
SFAS No. 109 deferred credits for rate regulated entities	$ 2,457	$ 2,080

We have tax carryforwards amounting to $15.8 million. The tax carryforwards include capital losses for federal purposes amounting to $0.5 million and state net operating losses amounting to $0.5 million. The federal capital loss carryforwards will expire in 2007. Depending on the jurisdiction in which the net operating loss was generated, the state net operating losses will begin to expire between 2016 and 2021. Also included in the tax carryforward is $14.8 million in alternative minimum tax credits which do not expire.

During fiscal 2003, the Internal Revenue Service initiated a routine examination of our fiscal 1999, 2000 and 2001 tax returns. We believe all material tax items have been accrued related to the years under audit.

13. Commitments and Contingencies

Litigation

Colorado-Kansas Division

We are a defendant in a lawsuit filed by Quinque Operating Company, Tom Boles and Robert Ditto on September 23, 1999 in the District Court of Stevens County, Kansas against more than 200 companies in the natural gas industry as well as in another similar lawsuit entitled *In Re Natural Gas Royalties Qui Tam Litigation,* which was remanded to the same court in January 2001. The plaintiffs in these two lawsuits that have now been consolidated, who purport to represent a class of royalty owners, allege that the defendants have underpaid royalties on gas taken from wells situated on non-federal and non-Indian lands in Kansas, Colorado, and Wyoming, predicated upon allegations that the defendants' gas measurements are inaccurate. The plaintiffs have not specifically alleged an amount of damages. The District Court denied an earlier motion in these proceedings to certify a class but gave plaintiffs permission to try to seek certification of a revised class, which we intend to oppose. We believe that the plaintiffs' claims are lacking in merit, and we intend to vigorously defend this action. While the results of this litigation cannot be predicted with certainty, we believe the final outcome of such litigation will not have a material adverse affect on our financial condition, results of operations, or net cash flows.

West Texas Division

On February 13, 2002, a suit was filed in the 287th District Court of Parmer County, Texas, by Anderson Brothers, a Partnership, against Atmos Energy Corporation, *et al.* The plaintiffs' claims arose out of an alleged breach of contract by us and by a number of our divisions and subsidiaries concerning the sale of natural gas used in irrigation activities since 1998 and an alleged violation of the Texas Agricultural Gas Users Act of 1985. During fiscal 2004, we reached a settlement with the plaintiffs' attorneys in this case. The settlement agreement was approved by the court and then by the plaintiffs as a class. Substantially all of the material terms of the settlement were implemented during fiscal 2004. The settlement did not have a material adverse effect on our financial condition, results of operations or net cash flows.

We are a plaintiff in a case styled *Energas Company, a Division of Atmos Energy Corporation v. ONEOK Energy Marketing and Trading Company, L.P., ONEOK Westex Transmission, Inc., and ONEOK Energy Marketing and Trading Company II,* filed in December 2001, pending in the District Court of Lubbock County, Texas, 72nd Judicial District. In this case, we are seeking to collect our receivable related to approximately 5.0 Bcf of natural gas that we believe was not delivered. We have settled a portion of our claims with the parties and will continue to pursue recovery of the remaining claims, which we believe are fully recoverable. We are proceeding with discovery in this case, which has been set for trial in 2005.

United Cities Propane Gas, Inc.

United Cities Propane Gas, Inc., one of our wholly-owned subsidiaries, is a party to an action filed in June 2000 that is pending in the Circuit Court of Sevier County, Tennessee. The plaintiffs' claims arise out of injuries alleged to have been caused by a low-level propane explosion. The plaintiffs seek to recover damages of $13.0 million. Discovery activities continue in this case. We have denied any liability, and we intend to vigorously defend against the plaintiffs' claims. This case has been set for trial in the Spring of 2005. While the results of this litigation cannot be predicted with certainty, we believe the final outcome of such litigation will not have a material adverse effect on our financial condition, results of operations or net cash flows.

We are a party to other litigation and claims that arose in the ordinary course of our business, including certain litigation and claims that arose in the ordinary course of the business of TXU Gas Company, the natural gas distribution and pipeline operations we acquired on October 1, 2004. While the results of such litigation and claims cannot be predicted with certainty, we believe the final outcome of such litigation and claims will not have a material adverse effect on our financial condition, results of operations or net cash flows.

Environmental Matters

Manufactured Gas Plant Sites

We are the owner or previous owner of manufactured gas plant sites in Johnson City and Bristol, Tennessee, and Hannibal, Missouri, which were used to supply gas prior to the availability of natural gas. The gas manufacturing process resulted in certain byproducts and residual materials, including coal tar. The manufacturing process used by our predecessors was an acceptable and satisfactory process at the time such operations were being conducted. Under current environmental protection laws and regulations, we may be responsible for response actions with respect to such materials if response actions are necessary.

United Cities Gas Company and the Tennessee Department of Environment and Conservation (TDEC) entered into a consent order effective January 23, 1997, to facilitate the investigation, removal and remediation of the Johnson City site. Prior to our merger with United Cities Gas Company in July 1997, United Cities Gas Company began the implementation of the consent order in the first quarter of fiscal 1997, which we continued through September 30, 2004. The investigative phase of the work at the site has been completed, and an interim removal action was completed in June 2001. We installed four groundwater monitoring wells at the site in 2002 and have submitted the analytical results to the TDEC. We completed a risk assessment report that has been approved by the TDEC as well as a feasibility study for this site, which was submitted to the TDEC in October 2003. The feasibility study recommends a remedial action that will limit the use of and access to the impacted soil, cap the site with the addition of a clay fill and geosynthetic liner, and groundwater monitoring for a period of up to 30 years. The estimated cost of the proposed remedial action is $1.5 million, which is comprised primarily of operating and maintenance costs that would be associated with a groundwater monitoring project. The Tennessee Regulatory Authority granted us permission to defer, until our next rate case in Tennessee, all costs incurred in Tennessee in connection with state and federally mandated environmental control requirements.

In March 2002, the TDEC contacted us about conducting an investigation at a former manufactured gas plant located in Bristol, Tennessee. We agreed to perform a preliminary investigation at the site, which we completed in June 2002. The investigation identified manufactured gas plant residual materials in the soil beneath the site, and we have proposed performing a focused removal action to remove any such residuals. The TDEC requested that the focused removal action be conducted pursuant to a voluntary agreement. On April 13, 2004, we entered into a voluntary consent agreement with the TDEC for the performance of the removal action and anticipate completing such removal action prior to the end of calendar year 2004.

On July 22, 1998, we entered into an Abatement Order on Consent with the Missouri Department of Natural Resources to address the former manufactured gas plant located in Hannibal, Missouri. We agreed to perform a removal action and a subsequent site evaluation and to reimburse the response costs incurred by the state of Missouri in connection with the property. The removal action was conducted and completed in August 1998, and the site-evaluation field work was conducted in August 1999. A risk assessment for the site has been approved by the Missouri Department of Natural Resources. In preparation for the risk assessment, we executed and recorded certain site-use limitations, including restricting use of the site to commercial and industrial purposes and prohibiting the withdrawal of groundwater for use as drinking water. In addition, we have installed a geosynthetic liner over the surface of the site.

In 1995, United Cities Gas Company entered into an agreement with a third party to resolve its share of the costs of additional investigations and environmental-response actions for soil contamination at a former manufactured gas plant in Keokuk, Iowa. However, the extent of groundwater contamination at the site, if any, which is not covered by the agreement, has yet to be determined.

As of September 30, 2004, we had incurred costs of approximately $1.7 million for the investigations of the Johnson City and Bristol, Tennessee, and Hannibal, Missouri, sites and had a remaining accrual relating to these sites of $0.5 million, which is recorded as a component of other current liabilities.

Mercury Contamination Sites

We have completed investigation and remediation activities pursuant to Consent Orders between the Kansas Department of Health and Environment (KDHE) and United Cities Gas Company. The Orders provided for the investigation and remediation of mercury contamination at gas pipeline sites which utilize or formerly utilized mercury meter equipment in Kansas. The Final Interim Characterization and Remediation Report has been submitted to the KDHE. We amended the Orders with the KDHE to include all mercury meters that belonged to our Colorado-Kansas Division before the merger with United Cities Gas Company on July 31, 1997. All work on these sites has been completed. During fiscal 2004, we received a letter from the KDHE, stating that we fulfilled the terms of the Consent Orders.

We are a party to other environmental matters and claims that arose in the ordinary course of our business, including certain environmental matters and claims that arose in the ordinary course of the business of TXU Gas Company, the natural gas distribution and pipeline operations we acquired on October 1, 2004. While the ultimate results of response actions to these environmental matters and claims cannot be predicted with certainty, we believe the final outcome of such response actions will not have a material adverse effect on our financial condition, results of operations or net cash flows because we believe that the expenditures related to such response actions will either be recovered through rates, shared with other parties or are adequately covered by insurance.

Purchase Commitments

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2004, AEM was committed to purchase 55.7 Bcf within one year and 11.1 Bcf within one to three years under indexed contracts. AEM is committed to purchase 0.5 Bcf within one year and 0.1 Bcf within one to three years under fixed-price contracts with prices ranging from $4.08 to $6.25. Purchases under these contracts totaled $1,252.2 million, $1,454.8 million and $725.6 million for 2004, 2003 and 2002.

Our utility segment maintains supply contracts with several vendors, generally for a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract.

14. Leases

Leasing Operations

Atmos Power Systems, Inc. constructs and operates electric peaking power generating plants and associated facilities and may enter into agreements to either lease or sell these plants. We completed a sales-type lease transaction for one distributed electric generation plant in 2001 and a second sales-type lease transaction in 2003. In 2001, we recognized a gain of $0.8 million and deferred $4.7 million of income, which will be recognized using the interest method through August 2011. In 2003, we recognized a gain of $3.9 million and deferred $8.6 million in income, which will be recognized using the interest method through September 2012. As of September 30, 2004 and 2003, we recorded receivables of $25.5 million and

$28.4 million and recorded income of $1.9 million, $2.0 million and $0.7 million for fiscal years 2004, 2003 and 2002. The future minimum lease payments to be received for each of the five succeeding years are as follows:

	Minimum Lease Receipts
	(In thousands)
2005	$ 2,973
2006	2,973
2007	2,973
2008	2,973
2009	2,973
Thereafter	10,619
Total minimum lease receipts	$25,484

Capital and Operating Leases

We have entered into non-cancelable operating leases for office and warehouse space used in our operations. The remaining lease terms range from one to 20 years and generally provide for the payment of taxes, insurance and maintenance by the lessee. Renewal options exist for certain of these leases. We have also entered into capital leases for division offices and operating facilities. Property, plant and equipment included amounts for capital leases of $5.8 million and $5.2 million at September 30, 2004 and 2003. Accumulated depreciation for these capital leases totaled $2.4 million and $2.2 million at September 30, 2004 and 2003. Depreciation expense for these assets is included in consolidated depreciation expense on the consolidated statement of income.

The related future minimum lease payments at September 30, 2004 were as follows:

	Capital Leases	Operating Leases
	(In thousands)	
2005	$ 1,139	$ 9,648
2006	631	8,726
2007	433	8,248
2008	362	8,197
2009	311	7,479
Thereafter	1,667	37,753
Total minimum lease payments	4,543	$80,051
Less amount representing interest	(1,753)	
Present value of net minimum lease payments	$ 2,790	

Consolidated lease and rental expense amounted to $8.1 million, $8.9 million and $8.1 million for fiscal 2004, 2003 and 2002.

15. Concentration of Credit Risk

Credit risk is the risk of financial loss to us if a customer fails to perform its contractual obligations. We engage in transactions for the purchase and sale of products and services with major companies in the energy industry and with industrial, commercial, residential and municipal energy consumers. These transactions principally occur in the southern and midwestern regions of the United States. We believe that this geographic concentration does not contribute significantly to our overall exposure to credit risk. Credit risk associated with trade accounts receivable for the utility segment is mitigated by the large number of individual customers and diversity in customer base. Due to minimal receivables, the credit risk for our other nonutility segment is not significant.

The diversification in AEM's customers helps mitigate its credit exposure. AEM maintains credit policies with respect to its counterparties that it believes minimizes overall credit risk. Where appropriate, such policies include the evaluation of a prospective counterparty's financial condition, collateral requirements and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. AEM also monitors the financial condition of existing counterparties on an ongoing basis. Customers not meeting minimum standards are required to provide adequate assurance of financial performance.

AEM maintains a provision for credit losses based upon factors surrounding the credit risk of customers, historical trends and other information. We believe, based on our credit policies and our provisions for credit losses, that our financial position, results of operations and cash flows will not be materially affected as a result of counterparty nonperformance.

AEM's estimated credit exposure is monitored in terms of the percentage of its customers that are rated as investment grade versus non-investment grade. Credit exposure is defined as the total of (1) accounts receivable, (2) delivered, but unbilled physical sales and (3) mark-to-market exposure for sales and purchases. Investment grade determinations are set internally by the credit department, but are primarily based on external ratings provided by Moody's Investor Service and/or Standard & Poor's Rating Service. For non-rated entities, the default rating for municipalities is investment grade, while the default rating for non-guaranteed industrials and commercials is non-investment grade. The table below shows the percentages related to the investment ratings as of September 30, 2004 and 2003. As indicated below, a majority of AEM's customers are rated as investment grade.

	September 30, 2004	September 30, 2003
Investment grade	55%	59%
Non-investment grade	45%	41%
Total	100%	100%

The following table presents our derivative counterparty credit exposure by operating segment based upon the unrealized fair value of our derivative contracts that represent assets as of September 30, 2004. Investment grade counterparties have minimum credit ratings of BBB-, assigned by Standard & Poor's Rating Group; or Baa3, assigned by Moody's Investor Service. Non-investment grade counterparties are composed of counterparties that are below investment grade or that have not been assigned an internal investment grade rating due to the short-term nature of the contracts associated with that counterparty. This category is composed of numerous smaller counterparties, none of which is individually significant.

	At September 30, 2004			
	Utility Segment[1]	Natural Gas Marketing Segment	Other Nonutility Segment	Consolidated
	(In thousands)			
Investment grade counterparties	$25,692	$18,888	$ —	$44,580
Non-investment grade counterparties	—	422	—	422
	$25,692	$19,310	$ —	$45,002

(1) Counterparty risk for our utility segment is minimized because hedging gains and losses are passed through to our customers.

16. Supplemental Cash Flow Disclosures

Supplemental disclosures of cash flow information for 2004, 2003 and 2002 are presented below.

	2004	2003	2002
		(In thousands)	
Cash paid for interest	$65,700	$62,088	$59,639
Cash paid for income taxes	$ 1,677	$ 408	$16,588

There were no significant noncash transactions during fiscal 2004. In June 2003, we contributed to the Atmos Energy Corporation Master Retirement Trust for the benefit of the Atmos Pension Account Plan 1,169,700 shares of Atmos restricted common stock with a value of $28.8 million. In December 2002, we partially funded the acquisition of MVG through the issuance of $74.7 million in Atmos Energy common stock consisting of 3,386,287 unregistered shares.

17. Segment Information

Atmos Energy Corporation and its subsidiaries are engaged primarily in the natural gas utility business as well as certain nonutility businesses. We distribute natural gas through sales and transportation arrangements to approximately 1.7 million residential, commercial, public-authority and industrial customers through our six regulated utility divisions, which covered service areas located in 12 states. In addition, we transport natural gas for others through our distribution system.

Through our nonutility businesses, we provide natural gas management and marketing services to industrial customers, municipalities and other local distribution companies located in 18 states.

Our operations are divided into three segments:

- The utility segment, which includes our regulated natural gas distribution and sales operations,
- The natural gas marketing segment, which includes a variety of natural gas management services and
- The other nonutility segment, which includes all of our other nonutility operations.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. We evaluate performance based on net income or loss of the respective operating units. Summarized income statements and capital expenditures by segment are shown in the following tables.

	For the Year Ended September 30, 2004				
	Utility	Natural Gas Marketing	Other Nonutility	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$1,636,636	$1,279,424	$3,977	$ —	$2,920,037
Intersegment revenues	1,092	339,178	19,174	(359,444)	—
	1,637,728	1,618,602	23,151	(359,444)	2,920,037
Purchased gas cost	1,134,594	1,571,971	9,383	(358,102)	2,357,846
Gross profit	503,134	46,631	13,768	(1,342)	562,191
Depreciation and amortization	92,954	2,089	1,604	—	96,647
Other operating expenses	250,290	16,816	6,119	(1,376)	271,849
Operating income	159,890	27,726	6,045	34	193,695
Miscellaneous income (expense)	5,847	843	8,579	(5,762)	9,507
Interest charges	65,399	2,711	3,055	(5,728)	65,437
Income before income taxes	100,338	25,858	11,569	—	137,765
Income tax expense	37,242	9,225	5,071	—	51,538
Net income	$ 63,096	$ 16,633	$6,498	$ —	$ 86,227
Capital expenditures	$ 189,291	$ 520	$ 474	$ —	$ 190,285

	For the Year Ended September 30, 2003				
	Utility	Natural Gas Marketing	Other Nonutility	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$1,552,857	$1,234,447	$12,612	$ —	$2,799,916
Intersegment revenues	1,225	434,046	9,018	(444,289)	—
	1,554,082	1,668,493	21,630	(444,289)	2,799,916
Purchased gas cost	1,062,679	1,644,328	1,540	(443,607)	2,264,940
Gross profit	491,403	24,165	20,090	(682)	534,976
Depreciation and amortization	83,849	1,261	1,891	—	87,001
Other operating expenses	246,420	9,335	5,062	(682)	260,135
Operating income	161,134	13,569	13,137	—	187,840
Miscellaneous income (expense)	(218)	1,855	5,004	(4,450)	2,191
Interest charges	63,226	2,864	2,020	(4,450)	63,660
Income before income taxes and cumulative effect of accounting change	97,690	12,560	16,121	—	126,371
Income tax expense	35,553	5,757	5,600	—	46,910
Income before cumulative effect of accounting change	62,137	6,803	10,521	—	79,461
Cumulative effect of accounting change, net of income tax benefit	—	(7,773)	—	—	(7,773)
Net income (loss)	$ 62,137	$ (970)	$10,521	$ —	$ 71,688
Capital expenditures	$ 154,777	$ 1,884	$ 2,778	$ —	$ 159,439

	For the Year Ended September 30, 2002				
	Utility	Natural Gas Marketing	Other Nonutility	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$936,054	$ 700,519	$14,391	$ —	$1,650,964
Intersegment revenues	1,472	331,355	10,314	(343,141)	—
	937,526	1,031,874	24,705	(343,141)	1,650,964
Purchased gas cost	559,891	994,318	8,022	(342,407)	1,219,824
Gross profit	377,635	37,556	16,683	(734)	431,140
Depreciation and amortization	77,704	2,069	1,696	—	81,469
Other operating expenses	174,425	14,877	5,772	(734)	194,340
Operating income	125,506	20,610	9,215	—	155,331
Miscellaneous income (expense)	1,427	1,331	554	(4,633)	(1,321)
Interest charges	58,796	2,866	2,145	(4,633)	59,174
Income before income taxes	68,137	19,075	7,624	—	94,836
Income tax expense	25,143	6,461	3,576	—	35,180
Net income	$ 42,994	$ 12,614	$ 4,048	$ —	$ 59,656
Capital expenditures	$129,632	$ 779	$ 1,841	$ —	$ 132,252

The following table summarizes our revenues by products and services for the year ended September 30.

	2004	2003	2002
		(In thousands)	
Utility revenues:			
Gas sales revenues:			
Residential	$ 923,773	$ 873,375	$ 535,981
Commercial	400,704	367,961	221,728
Public authority and other	77,178	65,921	31,731
Industrial	187,187	192,676	98,765
Total gas sales revenues	1,588,842	1,499,933	888,205
Transportation revenues	30,622	29,583	36,591
Other gas revenues	17,172	23,341	11,258
Total utility revenues	1,636,636	1,552,857	936,054
Natural gas marketing revenues	1,279,424	1,234,447	700,519
Other nonutility revenues	3,977	12,612	14,391
Total operating revenues	$2,920,037	$2,799,916	$1,650,964

Balance sheet information at September 30, 2004 and 2003 by segment is presented in the following tables:

	At September 30, 2004				
	Utility	Natural Gas Marketing	Other Nonutility	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$1,669,304	$ 7,875	$ 45,342	$ —	$1,722,521
Investment in subsidiaries	164,300	(1,484)	—	(162,816)	—
Current assets					
Cash and cash equivalents	182,846	18,734	352	—	201,932
Assets from risk management activities	25,692	24,412	—	(5,664)	44,440
Other current assets	253,829	170,363	32,288	(25,740)	430,740
Intercompany receivables	1,995	—	7,911	(9,906)	—
Total current assets	464,362	213,509	40,551	(41,310)	677,112
Intangible assets	—	4,160	—	—	4,160
Goodwill	199,400	24,282	10,430	—	234,112
Noncurrent assets from risk management activities	—	734	—	(172)	562
Deferred charges and other assets	207,019	1,661	22,736	—	231,416
	$2,704,385	$250,737	$119,059	$(204,298)	$2,869,883
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$1,133,459	$103,376	$ 60,924	$(164,300)	$1,133,459
Long-term debt	853,472	—	7,839	—	861,311
Total capitalization	1,986,931	103,376	68,763	(164,300)	1,994,770
Current liabilities					
Current maturities of long-term debt	3,917	—	1,991	—	5,908
Short-term debt	—	—	—	—	—
Liabilities from risk management activities	34,304	11,407	—	(6,253)	39,458
Other current liabilities	236,257	124,577	31,572	(23,304)	369,102
Intercompany payables	—	9,906	—	(9,906)	—
Total current liabilities	274,478	145,890	33,563	(39,463)	414,468
Deferred income taxes	208,325	(3,360)	8,938	27	213,930
Noncurrent liabilities from risk management activities	—	1,700	—	(562)	1,138
Regulatory cost of removal obligation	103,579	—	—	—	103,579
Deferred credits and other liabilities	131,072	3,131	7,795	—	141,998
	$2,704,385	$250,737	$119,059	$(204,298)	$2,869,883

	At September 30, 2003				
	Utility	Natural Gas Marketing	Other Nonutility	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$1,555,381	$ 9,288	$ 59,725	$ —	$1,624,394
Investment in subsidiaries	133,586	(2,662)	—	(130,924)	—
Current assets					
Cash and cash equivalents	—	14,880	803	—	15,683
Assets from risk management activities	202	22,941	—	(884)	22,259
Other current assets	230,609	197,239	85,119	(92,912)	420,055
Intercompany receivables	114,550	—	—	(114,550)	—
Total current assets	345,361	235,060	85,922	(208,346)	457,997
Intangible assets	—	5,030	—	—	5,030
Goodwill	233,741	22,600	12,128	—	268,469
Noncurrent assets from risk management activities	—	1,896	—	(197)	1,699
Investment in U.S. Propane L.P.	—	—	21,071	—	21,071
Deferred charges and other assets	218,840	2,214	25,781	—	246,835
	$2,486,909	$273,426	$204,627	$(339,467)	$2,625,495
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$ 857,517	$ 74,759	$ 58,827	$(133,586)	$ 857,517
Long-term debt	857,302	—	5,198	—	862,500
Total capitalization	1,714,819	74,759	64,025	(133,586)	1,720,017
Current liabilities					
Current maturities of long-term debt	8,227	—	1,118	—	9,345
Short-term debt	118,595	—	—	—	118,595
Liabilities from risk management activities	7,941	13,400	—	(551)	20,790
Other current liabilities	190,399	183,082	10,008	(90,470)	293,019
Intercompany payables	—	5,549	109,001	(114,550)	—
Total current liabilities	325,162	202,031	120,127	(205,571)	441,749
Deferred income taxes	221,912	(9,498)	11,081	(145)	223,350
Noncurrent liabilities from risk management activities	—	928	—	(165)	763
Regulatory cost of removal obligation	102,371	—	—	—	102,371
Deferred credits and other liabilities	122,645	5,206	9,394	—	137,245
	$2,486,909	$273,426	$204,627	$(339,467)	$2,625,495

18. Related Party Transactions

AEM provides a variety of natural gas management services to our Colorado-Kansas, Kentucky, Louisiana and Mid-States divisions including furnishing natural gas supplies at fixed and market-based prices and the management of certain of our underground storage facilities. Additionally, at times, AEM places financial instruments for our various divisions to partially insulate us and our customers from gas price volatility.

Atmos Pipeline and Storage (APS) provides asset management services for certain of our utility storage fields in exchange for a contractually negotiated demand charge.

Atmos Energy Services (AES) provides natural gas management services for our own utility operations. Prior to the second quarter of fiscal 2004, this entity conducted limited operations. However, beginning April 1, 2004, AES began providing natural gas supply management services to our utility operations in a limited number of states. These services include aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices. We have expanded these services to substantially all of our utility service areas as of the end of fiscal 2004.

The following summarizes our significant affiliate transactions with AEM, APS and AES.

	2004	2003	2002
	(In thousands, unless otherwise indicated)		
Gas purchases(1):			
Dollars	$235,320	$333,390	$190,594
Volumes (Mcf)	42,518	62,729	67,657
Average sales price per Mcf	$ 5.53	$ 5.31	$ 2.82
Storage contract fees	$ 2,765	$ 4,236	$ 4,305
Natural gas management services	$ 682	$ —	$ —

(1) Gas purchases are made in a competitive bidding process, reflect market prices and exclude demand and other charges.

JD Woodward became Senior Vice President, Nonutility Operations of the Company on April 1, 2001. Woodward Marketing L.L.C., a wholly-owned subsidiary of the Company through September 30, 2003 and its successor, AEM (see Note 1), leases office space from one corporation owned by Mr. Woodward. The lease originated in April 2002 and expires in March 2007. Base lease payments are $225,000 in the first year of the lease and increase to $253,000 in the final year.

During 2004, 2003 and 2002, our utility division leased office space and vehicles from our natural gas marketing and other nonutility segments. Base lease payments were $1.2 million in 2004 and 2003 and $1.4 million in 2002.

Effective in October 1994, Charles Vaughan retired as an officer and employee of the Company and entered into a consulting agreement with the Company. Under the terms of the agreement, Mr. Vaughan performed such consulting services as the Board requested from time to time. During fiscal 2002, Mr. Vaughan received $130,000 in payment for his services during that period. In addition, pursuant to the terms of the agreement, upon early termination of the agreement by the Company in September 2002, Mr. Vaughan received a total of $175,000, representing the total sums due him under the remainder of the agreement that was due to expire September 30, 2004.

19. Selected Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below. The sum of net income per share by quarter may not equal the net income per share for the year due to variations in the weighted average shares outstanding used in computing such amounts. Our businesses are seasonal due to weather conditions in our service areas. For further information on its effects on quarterly results, see the "Results of Operations" discussion included in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section herein.

	Quarter Ended			
	December 31	March 31	June 30	September 30
	(In thousands, except per share data)			
Fiscal year 2004:				
Operating revenues				
Utility segment	$460,488	$ 708,282	$256,252	$212,706
Natural gas marketing segment	373,829	517,218	364,339	363,216
Other nonutility segment	3,628	10,654	6,210	2,659
Intersegment eliminations	(74,329)	(118,669)	(80,743)	(85,703)
	763,616	1,117,485	546,058	492,878
Gross profit	159,053	206,126	107,492	89,520
Operating income	63,541	105,414	21,460	3,280
Net income (loss)	29,541	58,305	4,765	(6,384)
Net income (loss) per basic share	$ 0.57	$ 1.12	$ 0.09	$ (0.11)
Net income (loss) per diluted share	$ 0.57	$ 1.12	$ 0.09	$ (0.11)
Fiscal year 2003:				
Operating revenues				
Utility segment	$399,968	$ 696,561	$245,998	$211,555
Natural gas marketing segment	343,498	620,402	374,832	329,761
Other nonutility segment	2,900	9,657	3,685	5,388
Intersegment eliminations	(65,934)	(132,478)	(136,045)	(109,832)
	680,432	1,194,142	488,470	436,872
Gross profit	137,166	202,968	95,064	99,778
Operating income	52,624	107,878	14,056	13,282
Income (loss) before cumulative effect of accounting change	25,793	56,305	(201)	(2,436)
Cumulative effect of accounting change, net of income tax benefit	—	(7,773)	—	—
Net income (loss)	25,793	48,532	(201)	(2,436)
Income (loss) before cumulative effect of accounting change per basic and diluted share	$ .60	$ 1.24	$ (.00)	$ (.05)
Cumulative effect of accounting change, net of income tax benefit, per basic and diluted share	$ —	$ (.17)	$ —	$ —
Net income (loss) per basic and diluted share	$ .60	$ 1.07	$ (.00)	$ (.05)

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including the Chairman, President and Chief Executive Officer and Senior Vice President and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15. Based upon that evaluation, the Chairman, President and Chief Executive Officer, and Senior Vice President and Chief Financial Officer have concluded that our disclosure controls and procedures continue to be effective.

Such disclosure controls and procedures are controls and procedures designed to ensure that all information required to be disclosed in our reports filed under the Exchange Act is recorded, processed, summarized and reported within the time periods set forth in applicable Securities and Exchange Commission forms, rules and regulations. In addition, we have reviewed our internal control over financial reporting and have concluded that there has been no change in such internal control during the fourth quarter of fiscal 2004 that has materially affected or is reasonably likely to materially affect the Company's internal control over financial reporting.

Item 9B. ***Other Information***

None.

PART III

Item 10. ***Directors and Executive Officers of the Registrant***

Information regarding directors and compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated herein by reference from the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 9, 2005. Information regarding executive officers is included in Part I of this Form 10-K.

Identification of the members of the Audit Committee of the Board of Directors as well as the Board of Directors' determination as to whether one or more audit committee financial experts is serving on the Audit Committee of the Board of Directors is incorporated herein by reference from the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 9, 2005.

The Company has adopted a code of ethics for its principal executive officer and senior financial officers. Such code of ethics is represented by the Company's Code of Conduct, which is applicable to all directors, officers and employees of the Company, including the Company's principal executive officer and senior financial officers. A copy of the Company's Code of Conduct is posted on the Company's website at www.atmosenergy.com under "Corporate Governance". In addition, any amendment to or waiver granted from, a provision of the Company's Code of Conduct will be posted on the Company's website under "Corporate Governance".

Item 11. ***Executive Compensation***

Incorporated herein by reference from the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 9, 2005.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

Incorporated herein by reference from the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 9, 2005.

Item 13. ***Certain Relationships and Related Transactions***

Incorporated herein by reference from the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 9, 2005.

Item 14. ***Principal Accountant Fees and Services***

Incorporated herein by reference from the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 9, 2005.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) 1. and 2. *Financial statements and financial statement schedules.*

The financial statements and financial statement schedule listed in the Index to Financial Statements in Item 8 are filed as part of this Form 10-K.

3. *Exhibits*

The exhibits listed in the accompanying Exhibits Index are filed as part of this Form 10-K. The exhibits numbered 10.8(a) through 10.19(b) are management contracts or compensatory plans or arrangements.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ATMOS ENERGY CORPORATION
(Registrant)

By /s/ JOHN P. REDDY

John P. Reddy
Senior Vice President
and Chief Financial Officer

Date: November 19, 2004

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints Robert W. Best and John P. Reddy, or either of them acting alone or together, as his true and lawful attorney-in-fact and agent with full power to act alone, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Form 10-K, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ ROBERT W. BEST Robert W. Best	Chairman, President and Chief Executive Officer	November 19, 2004
/s/ JOHN P. REDDY John P. Reddy	Senior Vice President and Chief Financial Officer	November 19, 2004
/s/ F.E. MEISENHEIMER F.E. Meisenheimer	Vice President and Controller (Principal Accounting Officer)	November 19, 2004
/s/ TRAVIS W. BAIN, II Travis W. Bain, II	Director	November 19, 2004
/s/ DAN BUSBEE Dan Busbee	Director	November 19, 2004
/s/ RICHARD W. CARDIN Richard W. Cardin	Director	November 19, 2004
/s/ THOMAS J. GARLAND Thomas J. Garland	Director	November 19, 2004
/s/ RICHARD K. GORDON Richard K. Gordon	Director	November 19, 2004
/s/ GENE C. KOONCE Gene C. Koonce	Director	November 19, 2004
/s/ THOMAS C. MEREDITH Thomas C. Meredith	Director	November 19, 2004
/s/ PHILLIP E. NICHOL Phillip E. Nichol	Director	November 19, 2004

/s/ NANCY K. QUINN Nancy K. Quinn	Director	November 19, 2004
/s/ CHARLES K. VAUGHAN Charles K. Vaughan	Director	November 19, 2004
/s/ RICHARD WARE II Richard Ware II	Director	November 19, 2004

ATMOS ENERGY CORPORATION

VALUATION AND QUALIFYING ACCOUNTS
Three Years Ended September 30, 2004
(In thousands)

	Balance at Beginning of Period	Additions: Charged to cost & expenses	Additions: Charged to other accounts	Deductions	Balance at End of Period
2004					
Allowance for doubtful accounts	$13,051	$ 5,379	$ —	$11,216[2]	$ 7,214
2003					
Allowance for doubtful accounts	$10,509	$13,249	$ —	$10,707[2]	$13,051
2002					
Allowance for doubtful accounts	$16,151	$ —	$1,500[1]	$ 7,142[2]	$10,509

[1] This amount was charged to regulatory assets within deferred charges and other assets as recovery was specifically permitted by the relevant regulators.

[2] Uncollectible accounts written off.

EXHIBITS INDEX
Item 14.(a)(3)

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Plan of Reorganization	
2.1	Purchase and Sale Agreement (Louisiana Gas Operations), by and among Citizens Utilities Company (now known as Citizens Communications Company), LGS Natural Gas Company and Atmos Energy Corporation, dated as of April 13, 2000	Exhibit 2.1 to Registration Statement on Form S-3/A filed November 6, 2000 (File No. 333-73705)
2.2	Agreement and Plan of Merger and Reorganization dated as of September 21, 2001, by and among Atmos Energy Corporation, Mississippi Valley Gas Company and the Shareholders Named on the Signature Pages hereto	Exhibit 2.2 of Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)
2.3(a)	Agreement and Plan of Merger by and between TXU Gas Company and LSG Acquisition Corporation dated June 17, 2004	Exhibit 2.1 of Form 8-K dated June 17, 2004 (File No. 1-10042)
2.3(b)	Amendment No. 1 to Merger Agreement, dated as of September 30, 2004, by and between LSG Acquisition Corporation and TXU Gas Company LP	Exhibit 2.1 of Form 8-K dated September 30, 2004 (File No. 1-10042)
	Articles of Incorporation and Bylaws	
3.1	Amended and Restated Articles of Incorporation of Atmos Energy Corporation (as of February 10, 1999)	Exhibit 4.1 of Form S-3 dated August 31, 2004 (File No. 333-118706)
3.2	Amended and Restated Bylaws of Atmos Energy Corporation (as of August 13, 2003)	Exhibit 4.2 of Form S-3 dated August 31, 2004 (File No. 333-118706)
	Instruments Defining Rights of Security Holders	
4.1	Specimen Common Stock Certificate (Atmos Energy Corporation)	Exhibit (4)(b) of Form 10-K for fiscal year ended September 30, 1988 (File No. 1-10042)
4.2	Rights Agreement, dated as of November 12, 1997, between the Company and BankBoston, N.A., as Rights Agent	Exhibit 4.1 of Form 8-K dated November 12, 1997 (File No. 1-10042)
4.3	First Amendment to Rights Agreement dated as of August 11, 1999, between the Company and BankBoston, N.A., as Rights Agent	Exhibit 2 of Form 8-A, Amendment No. 1, dated August 12, 1999 (File No. 1-10042)
4.4	Second Amendment to Rights Agreement dated as of February 13, 2002, between the Company and EquiServe Trust Company, N.A., fka BankBoston, N.A., as Rights Agent	Exhibit 4 of Form 10-Q for quarter ended December 31, 2001 (File No. 1-10042)
4.5	Registration Rights Agreement, dated as of June 30, 2003, between Atmos Energy Corporation and Gary A. Morris, as Asset Manager	Exhibit 4.1 of Form 10-Q for quarter ended June 30, 2003 (File No. 1-10042)
4.6	Registration Rights Agreement, dated as of December 3, 2002, by and among Atmos Energy Corporation and the Shareholders of Mississippi Valley Gas Company	Exhibit 99.2 of Form 8-K/A, dated December 3, 2002 (File No. 110042)
4.7	Standstill Agreement, dated as of December 3, 2002, by and among Atmos Energy Corporation and the Shareholders of Mississippi Valley Gas Company	Exhibit 99.3 of Form 8-K/A, dated December 3, 2002 (File No. 1-10042)
4.8	Indenture dated as of July 15, 1998 between Atmos Energy Corporation and U.S. Bank Trust National Association, Trustee	Exhibit 4.8 of Form S-3 dated August 31, 2004 (File No. 333-118706)

Exhibit Number	Description	Page Number or Incorporation by Reference to
4.9	Indenture between Atmos Energy Corporation, as Issuer, and SunTrust Bank, Trustee dated as of May 22, 2001	Exhibit 99.3 of Form 8-K dated May 15, 2001 (File No. 1-10042)
4.10(a)	Indenture of Mortgage, dated as of July 15, 1959, from United Cities Gas Company to First Trust of Illinois, National Association, and M.J. Kruger, as Trustees, as amended and supplemented through December 1, 1992 (the Indenture of Mortgage through the 20th Supplemental Indenture)	Exhibit to Registration Statement of United Cities Gas Company on Form S-3 (File No. 33-56983)
4.10(b)	Twenty-First Supplemental Indenture dated as of February 5, 1997 by and among United Cities Gas Company and Bank of America Illinois and First Trust National Association and Russell C. Bergman supplementing Indenture of Mortgage dated as of July 15, 1959	Exhibit 10.7(a) of Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
4.10(c)	Twenty-Second Supplemental Indenture dated as of July 29, 1997 by and among Atmos Energy Corporation and First Trust National Association and Russell C. Bergman supplementing Indenture of Mortgage dated as of July 15, 1959	Exhibit 4.10(c) of Form S-3 dated August 31, 2004 (File No. 333-118706)
4.11(a)	Indenture between United Cities Gas Company and Bank of America Illinois, as Trustee dated as of November 15, 1995	Exhibit 4.11(a) of Form S-3 dated August 31, 2004 (File No. 333-118706)
4.11(b)	First Supplemental Indenture between Atmos Energy Corporation and Bank of America Illinois, as Trustee dated as of July 29, 1997	Exhibit 4.11(b) of Form S-3 dated August 31, 2004 (File No. 333-118706)
4.12(a)	Seventh Supplemental Indenture, dated as of October 1, 1983 between Greeley Gas Company ("The Greeley Gas Division") and the Central Bank of Denver, N.A. ("Central Bank")	Exhibit 10.1 of Form 10-Q for quarter ended June 30, 1994 (File No. 1-10042)
4.12(b)	Ninth Supplemental Indenture, dated as of April 1, 1991, between Greeley Gas Company and Central Bank Denver, N.A	Exhibit 4.12(b) of Form S-3 dated August 31, 2004 (File No. 333-118706)
4.12(c)	Tenth Supplemental Indenture, dated as of December 1, 1993, between the Company and Colorado National Bank, formerly Central Bank	Exhibit 10.4 of Form 10-Q for quarter ended June 30, 1994 (File No. 1-10042)
9	Not Applicable	
	Material Contracts	
10.1	Bond Purchase Agreement, dated as of April 1, 1991, between the Greeley Division and Central Bank	Exhibit 10.3 of Form 10-Q for quarter ended June 30, 1994 (File No. 1-10042)
10.2(a)	Debenture Certificate for the 6¾% Debentures due 2028	Exhibit 99.2 of Form 8-K dated July 22, 1998 (File No. 1-10042)
10.2(b)	Global Security for the 7⅜% Senior Notes due 2011	Exhibit 99.2 of Form 8-K dated May 15, 2001 (File No. 1-10042)
10.2(c)	Global Security for the 5⅛% Senior Notes due 2013	
10.2(d)	Global Security for the Floating Rate Senior Notes due 2007	
10.2(e)	Global Security for the 4.00% Senior Notes due 2009	
10.2(f)	Global Security for the 4.95% Senior Notes due 2014	
10.2(g)	Global Security for the 5.95% Senior Notes due 2034	

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.3	Revolving Credit Agreement, dated as of October 22, 2004, among Atmos Energy Corporation, Bank One, NA, as Administrative Agent, SunTrust Bank, as Syndication Agent and Bank of America, N.A., Wachovia Bank, National Association and Societe Generale, as Co-Documentation Agents, and the lenders identified therein	Exhibit 10.1 of Form 8-K dated October 21, 2004 (File No. 1-10042)
10.4	364-Day Revolving Credit Agreement, dated as of September 24, 2004, by and among Atmos Energy Corporation, Bank One, NA, as Administrative Agent, Merrill Lynch, Pierce, Fenner & Smith Incorporated, as Syndication Agent and Lead Arranger and Book Runner, Bank of America, N.A. and SunTrust Bank, as Co-Documentation Agents, and the Lenders identified therein	Exhibit 10.1 of Form 8-K dated September 24, 2004 (File No. 1-10042)
10.5	Guaranty of Atmos Energy Corporation dated June 17, 2004	Exhibit 10.2 of Form 8-K dated June 17, 2004 (File No. 1-10042)
10.6(a)	Transitional Services Agreement, dated as of October 1, 2004, by and between Atmos Energy Corporation and TXU Gas Company LP	Exhibit 10.1 of Form 8-K dated September 30, 2004 (File No. 1-10042)
10.6(b)	Transitional Services Agreement, dated as of October 1, 2004, by and between Atmos Energy Corporation, Oncor Utility Solutions (Texas) Company and TXU Electric Delivery Company	Exhibit 10.2 of Form 8-K dated September 30, 2004 (File No. 1-10042)
10.6(c)	Transitional Services Agreement, dated as of October 1, 2004, by and between Atmos Energy Corporation and TXU Business Services Company (Exhibit A to Schedule 2 containing listing of employee credit and procurement cards is omitted, to be supplementally furnished to the Commission upon request)	Exhibit 10.3 of Form 8-K dated September 30, 2004 (File No. 1-10042)
10.6(d)	Transitional Access Agreement, dated as of October 1, 2004, by and among Atmos Energy Corporation and TXU Energy Retail Company LP, TXU Business Services Company, TXU Properties Company and TXU Electric Delivery Company	Exhibit 10.4 of Form 8-K dated September 30, 2004 (File No. 1-10042)
10.7(a)	Uncommitted Amended and Restated Credit Agreement, dated to be effective July 1, 2002, among Woodward Marketing, L.L.C., Fortis Capital Corp., BNP Paribas and the other financial institutions which may become parties hereto	Exhibit 10.1 of Form 10-Q for quarter ended June 30, 2002 (File No. 1-10042)
10.7(b)	First Amendment, entered into effective as of December 23, 2002, to the Uncommitted Amended and Restated Credit Agreement, dated as of July 1, 2002, among Woodward Marketing, L.L.C., Fortis Capital Corp., BNP Paribas and the other financial institutions which may become parties hereto	Exhibit 10.1 of Form 10-Q for quarter ended March 31, 2003 (File No. 1-10042)
10.7(c)	Second Amendment, entered into effective as of February 7, 2003, to the Uncommitted Amended and Restated Credit Agreement, dated as of July 1, 2002, among Woodward Marketing, L.L.C., Fortis Capital Corp., BNP Paribas and the other financial institutions which may become parties hereto	Exhibit 10.2 of Form 10-Q for quarter ended March 31, 2003 (File No. 1-10042)

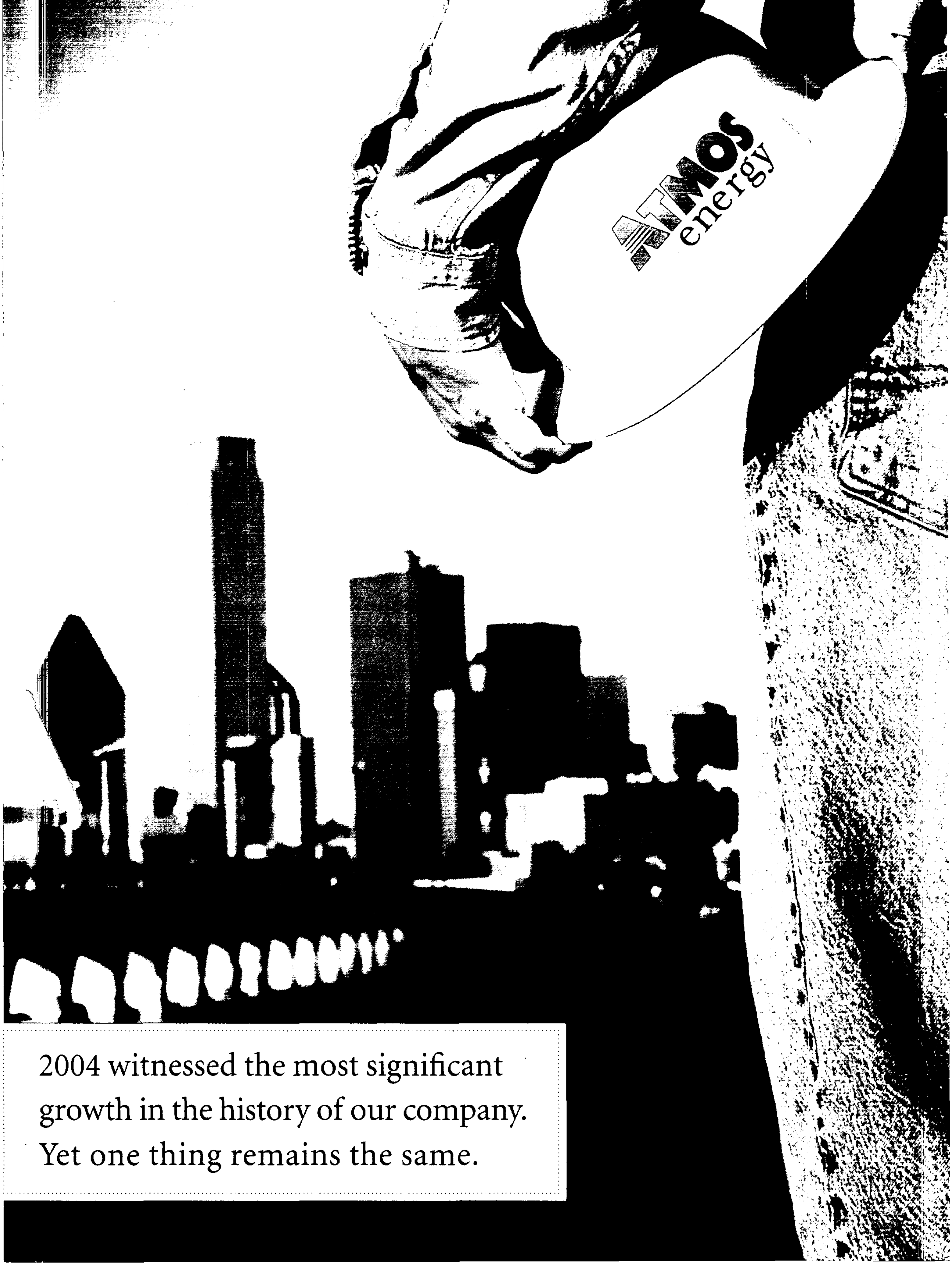
Exhibit Number	Description	Page Number or Incorporation by Reference to
10.7(d)	Third Amendment, entered into effective as of February 28, 2003, to the Uncommitted Amended and Restated Credit Agreement, dated as of July 1, 2002, among Woodward Marketing, L.L.C., Fortis Capital Corp., BNP Paribas and the other financial institutions which may become parties hereto	Exhibit 10.3 of Form 10-Q for quarter ended March 31, 2003 (File No. 1-10042)
10.7(e)	Fourth Amendment, entered into effective as of March 31, 2003, to the Uncommitted Amended and Restated Credit Agreement, dated as of July 1, 2002, among Woodward Marketing, L.L.C., Fortis Capital Corp., BNP Paribas and the other financial institutions which may become parties hereto	Exhibit 10.4 of Form 10-Q for quarter ended March 31, 2003 (File No. 1-10042)
10.7(f)	Fifth Amendment and Waiver, entered into effective as of April 28, 2003, to the Uncommitted Amended and Restated Credit Agreement, dated as of July 1, 2002, among Woodward Marketing, L.L.C., Fortis Capital Corp., BNP Paribas and the other financial institutions which may become parties hereto	Exhibit 10.5 of Form 10-Q for quarter ended March 31, 2003 (File No. 1-10042)
10.7(g)	Sixth Amendment to Credit Agreement, Global Amendment to Loan Documents and Waiver, entered into effective as of October 1, 2003, to the Uncommitted Amended and Restated Credit Agreement, dated as of July 1, 2002, among Woodward Marketing, L.L.C., Fortis Capital Corp., BNP Paribas and the other financial institutions which may become parties hereto	Exhibit 10.3(h) of Form 10-K for fiscal year ended September 30, 2003 (File No. 1-10042)
10.7(h)	Seventh Amendment and Joinder Agreement, dated as of December 19, 2003, in respect of the Uncommitted Amended and Restated Credit Agreement, dated as of July 1, 2002, among Atmos Energy Marketing, LLC (formerly known as Woodward Marketing, L.L.C.), the financial institutions from time to time parties thereto, Fortis Capital Corp. and BNP Paribas	Exhibit 10.1 of Form 10-Q for quarter ended December 31, 2003 (File No. 1-10042)
10.7(i)	Eighth Amendment and Joinder Agreement to Credit Agreement and First Amendment to Subordination, dated as of February 18, 2004, in respect of the Uncommitted Amended and Restated Credit Agreement, dated as of July 1, 2002, among Atmos Energy Marketing, LLC, the financial institutions from time to time parties thereto, Fortis Capital Corp. and BNP Paribas	Exhibit 10.1 of Form 10-Q for quarter ended March 31, 2004 (File No. 1-10042)
10.7(j)	Ninth Amendment to Credit Agreement, dated as of March 31, 2004, in respect of the Uncommitted Amended and Restated Credit Agreement, dated as of July 1, 2002, among Atmos Energy Marketing, LLC, the financial institutions from time to time parties thereto, Fortis Capital Corp. and BNP Paribas	Exhibit 10.2 of Form 10-Q for quarter ended March 31, 2004 (File No. 1-10042)
10.7 (k)	Tenth Amendment to Credit Agreement and First Amendment to Support Agreement, dated as of September 17, 2004, in respect of(i) the Uncommitted Amended and Restated Credit Agreement, dated as of July 1, 2002, among Atmos Energy Marketing, LLC, the financial institutions from time to time parties thereto, Fortis Capital Corp. and BNP Paribas, and (ii) the Support Agreement, dated as of July 1, 2002, of Atmos Energy Corporation	

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Executive Compensation Plans and Arrangements	
10.8(a)*	Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier I	Exhibit 10.21(b) of Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042)
10.8(b)*	Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier II	Exhibit 10.21(c) of Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042)
10.9*	Atmos Energy Corporation Long-Term Stock Plan for the United Cities Gas Company Division	Exhibit 99.1 of Form S-8 filed July 29, 1997 (File No. 333-32343)
10.10(a)*	Atmos Energy Corporation Executive Retiree Life Plan	Exhibit 10.31 of Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.10(b)*	Amendment No. 1 to the Atmos Energy Corporation Executive Retiree Life Plan	Exhibit 10.31(a) of Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.11(a)*	Description of Financial and Estate Planning Program	Exhibit 10.25(b) of Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.11(b)*	Description of Sporting Events Program	Exhibit 10.26(c) of Form 10-K for fiscal year ended September 30, 1993 (File No. 1-10042)
10.12(a)*	Atmos Energy Corporation Supplemental Executive Benefits Plan, Amended and Restated in its Entirety August 12, 1998	Exhibit 10.26 of Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042)
10.12(b)*	Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan, Effective Date August 12, 1998	Exhibit 10.32 of Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042)
10.12(c)*	Amendment No. One to the Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan, Effective Date January 1, 1999	Exhibit 10.2 of Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.12(d)*	Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan Trust Agreement, Effective Date December 1, 2000	Exhibit 10.1 of Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.12(e)*	Form of Individual Trust Agreement for the Supplemental Executive Benefits Plan	Exhibit 10.3 of Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.13*	Atmos Energy Corporation Restricted Stock Grant Plan (Amended and Restated as of February 12, 1998)	Exhibit 99.1 of Form S-8 filed February 13, 1998 (File No. 333-46337)
10.14*	Atmos Energy Corporation Executive Nonqualified Deferred Compensation Plan	Exhibit 10.33 of Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042)
10.15(a)*	Mini-Med/Dental Benefit Extension Agreement dated October 1, 1994	Exhibit 10.28(f) of Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)
10.15(b)*	Amendment No. 1 to Mini-Med/Dental Benefit Extension Agreement dated August 14, 2001	Exhibit 10.28(g) of Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)
10.15(c)*	Amendment No. 2 to Mini-Med/Dental Benefit Extension Agreement dated December 31, 2002	Exhibit 10.1 of Form 10-Q for quarter ended December 31, 2002 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.16*	Atmos Energy Corporation Equity Incentive and Deferred Compensation Plan for Non-Employee Directors	Exhibit C of Definitive Proxy Statement on Schedule 14A filed December 30, 1998 (File No. 1-10042)
10.17(a)*	Atmos Energy Corporation Retirement Plan for Outside Directors	Exhibit 10(y) of Form 10-K for fiscal year ended September 30, 1992 (File No. 1-10042)
10.17(b)*	Amendment No. 1 to the Atmos Energy Corporation Retirement Plan for Outside Directors	Exhibit 10.2 of Form 10-Q for quarter ended December 31, 1996 (File No. 1-10042)
10.18*	Atmos Energy Corporation Outside Directors Stock-for-Fee Plan (Amended and Restated as of November 12, 1997)	Exhibit 10.28 of Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.19(a)*	Atmos Energy Corporation 1998 Long-Term Incentive Plan (as amended and restated February 14, 2002)	Exhibit 10.1 of Form 10-Q for quarter ended March 31, 2002 (File No. 1-10042)
10.19(b)*	Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated February 14, 2002)	Exhibit 10.2 of Form 10-Q for quarter ended March 31, 2002 (File No. 1-10042)
11	Not applicable	
12	Computation of ratio of earnings to fixed charges	
13	Not applicable	
16	Not applicable	
18	Not applicable	
	Other Exhibits, as indicated	
21	Subsidiaries of the registrant	
22	Not applicable	
23	Consent of independent auditor, Ernst & Young LLP	
24	Power of Attorney	Signature page of Form 10-K for fiscal year ended September 30, 2004
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications **	
99	Annual Certification Pursuant to Section 303A.12 of the New York Stock Exchange Listed Company Manual	

* This exhibit constitutes a "management contract or compensatory plan, contract, or arrangement."

** These certifications pursuant to 18 U.S.C. Section 1350 by the Company's Chief Executive Officer and Chief Financial Officer, furnished as Exhibit 32 to this Annual Report on Form 10-K, will not be deemed to be filed with the Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.



2004 witnessed the most significant growth in the history of our company. Yet one thing remains the same.

Atmos Energy

customers miles of pipe employees communities gas storage core values

at the beginning of 2004

1,672,798

45,267

2,905

1,012

49 Bcf

5

*By any measure,

it's been a year of incredible growth. But we believe the most important number, by far, is the one that did not change—our *five* core values of customer focus, employee focus, enterprise thinking, value creation, and honesty and integrity.

In fact, we believe our values made such growth possible. And that's why, in this year's summary annual report, we illustrate how each of these values shines in our employees and in our way of doing business. Since these core values are a constant, they help us—even in times of incredible growth and change—to maintain our focus and stability. After all, a company must fully understand where it comes from in order to know where it is going.

The acquisition of TXU Gas was measured carefully against each of these core values. That's because, while growth is important, it's counterproductive if it's haphazard or unmanaged. In our case, TXU Gas was not only a good fit, but also an evolution—one that increases our resources and better prepares us for continued growth and strength.

Atmos Energy embraces growth, knowing that it helps us better serve our customers and our investors in the coming years. But rest assured, we never will undertake growth just for the sake of achieving bigger numbers.

at the beginning of 2005

3,161,136

80,209

4,208

1,565

84 Bcf

5*

YEAR ENDED SEPTEMBER 30 (Dollars in thousands, except per share data)	2004	2003	Change
Operating revenues	**$ 2,920,037**	$ 2,799,916	4.3%
Gross profit	**$ 562,191**	$ 534,976	5.1%
Utility net income	**$ 63,096**	$ 62,137	1.5%
Natural gas marketing net income (loss)	**16,633**	(970)	1814.7%
Other nonutility net income	**6,498**	10,521	-38.2%
Total	**$ 86,227**	$ 71,688	20.3%
Total assets	**$ 2,869,883**	$ 2,625,495	9.3%
Total capitalization	**$ 1,994,770**	$ 1,720,017	16.0%
Net income per share – diluted	**$ 1.58**	$ 1.54	2.6%
Cash dividends per share	**$ 1.22**	$ 1.20	1.7%
Book value per share at end of year	**$ 18.05**	$ 16.66	8.3%
Consolidated utility segment throughput (MMcf)	**246,033**	247,965	-0.8%
Consolidated natural gas marketing segment throughput (MMcf)	**222,572**	225,961	-1.5%
Heating degree days	**3,271**	3,473	-5.8%
Degree days as a percentage of normal	**96%**	101%	-5.0%
Meters in service at end of year	**1,679,136**	1,672,798	0.4%
Return on average shareholders' equity	**9.1%**	9.9%	-8.1%
Shareholders' equity as a percentage of total capitalization (including short-term debt) at end of year	**56.7%**	46.4%	22.2%
Shareholders of record	**27,555**	28,510	-3.3%
Weighted average shares outstanding – diluted (000s)	**54,416**	46,496	17.0%

DEAR FELLOW SHAREHOLDER:

Our 2004 fiscal year will stand as one of the biggest years in Atmos Energy's history. Not only did we do well financially, we virtually doubled in size to become the largest pure-gas utility in America. However, size is only important if it is accompanied by performance, and Atmos Energy performed exceptionally well in 2004.

Consolidated net income rose to $86.2 million, or $1.58 per diluted share, compared with $71.7 million, or $1.54 per diluted share, in 2003. Our total return to shareholders was an enviable 10.4 percent, including cash dividends of $1.22 paid during fiscal 2004. Return on average shareholders' equity was 9.1 percent.

Based on these strong results and our positive forecast for 2005, the Board of Directors increased the annual indicated dividend rate by 2 cents to $1.24 per share. The increase marked our 17th consecutive annual dividend increase. When adjusted for mergers and acquisitions, Atmos Energy has paid higher dividends every year since its founding in 1983. Fewer than 2.5 percent of American corporations can match our dividend history.

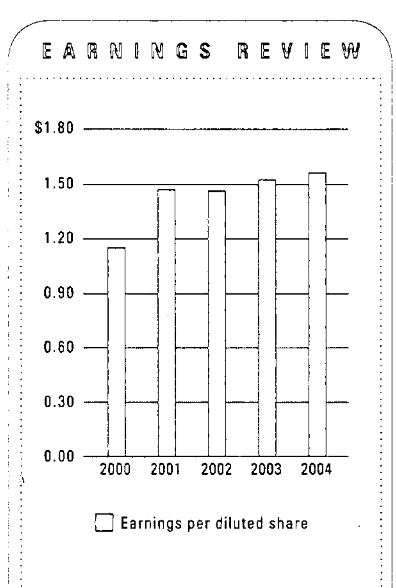
TXU GAS ACQUISITION

Our 2004 results were exceeded only by the leap we made in our regulated operations. On October 1, 2004, we completed our acquisition of the natural gas distribution and pipeline operations of TXU Gas Company. This acquisition added 1.5 million utility customers in one of the more dynamic American growth markets. It also placed us in an excellent position to benefit in the future for the following reasons:

Immediate contribution to 2005 earnings. We expect that the operations of our new Mid-Tex Division will contribute from 5 cents to 10 cents to earnings per share in 2005. We are forecasting our earnings per diluted share in fiscal 2005 to be between $1.65 and $1.75.

Above-average residential and commercial growth. Our new division serves rapidly growing communities in the Dallas-Fort Worth Metroplex and northern suburbs of Austin. The division's net growth in customers is approximately 2 percent a year, almost double our former growth rate.

Added value from new gas pipeline operations. The intrastate pipeline we acquired as part of the TXU Gas operations runs from one end of Texas to the other. It interconnects at three of the state's major hubs, or gas transfer points, with dozens of other intrastate and interstate gas pipelines. The 6,162-mile pipeline system delivers gas to the 550 cities served by the new division. Owning this asset gives us expansion opportunities to transport more natural gas for others besides our own utility operations.



Dedicated and experienced employees. Our new division already was a well-run natural gas system. Its 1,344 gas professionals who transferred to Atmos Energy are working to integrate the operations as soon as possible and are contributing their "knowledge capital" to benefit our entire system.

Prompt recovery of new capital investment. Texas law permits a utility to make annual adjustments for additions to net plant, using its most recent return on investment, depreciation rate and tax rates. The law lets us recover our capital investment in new pipelines and other facilities much faster without having to file a general rate case. As we invest in our expanding Texas markets, we will be able to earn a return on our investment faster than in most of our other jurisdictions.

About 90 percent of earnings from regulated operations. Adding the TXU Gas properties has increased the proportion of our assets regulated by state commissions. Many investors see this increase as positive because, although it does not guarantee our profitability, it increases our opportunity for consistent, long-term earnings growth.

> Excellence in customer service stands as a key part of our corporate vision—we call it our Spirit of Service.℠

SUCCESSFUL FINANCINGS

Atmos Energy paid approximately $1.905 billion in cash for the TXU Gas operations. To finance the acquisition, we sold 9.9 million shares of common stock through a public offering in July. Because of strong interest, the offering raised approximately $235.7 million in net proceeds, with the purchasers mainly being retail holders.

In October 2004, we made another public offering, selling 16.1 million common shares to raise approximately $382.5 million in net proceeds before other offering costs. The purchasers were mainly large institutional holders. In a separate offering at the same time, we also sold four series of senior unsecured notes to raise net proceeds of approximately $1.39 billion.

We are gratified by the success of all three offerings. We believe the prices that investors bid indicate the market's confidence in our ability to integrate and operate the TXU Gas operations successfully. Within the next three to five years, we expect to apply some of the additional cash flow from the new operations to return to a 50 percent to 55 percent debt-to-capitalization ratio, as we have done consistently after completing our nine previous major acquisitions.

COMPLEMENTARY NONUTILITY OPERATIONS

Our nonutility operations achieved impressive results in fiscal 2004, building on initiatives begun in 2003 to reduce the risk from volatile natural gas prices. The contribution to net income from our nonutility operations in 2004 was 27 percent. We expect these contributions to remain strong during the next five years.

One of the keys to our nonutility growth will be managing the pipeline and storage assets acquired with TXU Gas. Although these assets remain regulated, we expect to operate them to deliver more volumes to wholesale customers. We also are working on optimizing our nonutility natural gas marketing and storage operations. During 2004, for example, we made changes in the way we procure the billions of cubic feet of natural gas for our utility system to take better advantage of our nonutility operations' expertise.

CONCENTRATION ON PERFORMANCE

Our goal has been to provide an attractive rate of return through both capital appreciation and dividends. We expect earnings per share to grow between 3 percent and 6 percent a year and our dividend yield to remain an attractive 4 percent to 5 percent.

We expect to provide investors with a total annual return between 8 percent and 11 percent. We have done this consistently in the past and expect to continue to do so in the future. We have accomplished this through an intense focus on improving efficiency and managing costs, mitigating the effects of weather on our utility operations and fostering productive relationships with the regulators in our operating jurisdictions.

We also have been successful because of our focus on the basics. While many in the industry are claiming a return to the basics, we can confidently say we never left the basics. We always have been dedicated to natural gas distribution as our core business.

KEEPING RATES CURRENT

In 2004, we added $16.2 million in net revenues through rate increases. During the next five years, we expect to receive approximately $15 million to $20 million in average annual rate increases. One of our goals is to monitor our rates of return in all jurisdictions to keep our actual returns as close as possible to our allowed rates of return.

In states that have warmer winters, we have sought to adjust our rates using a weather normalization adjustment. We now have WNA or higher base rates in our eight largest states. Only about 17 percent of our margins are exposed to weather in the 2004–2005 heating season.

We have proposed other rate adjustments to offset the effects of declining natural gas consumption. Nationally, gas consumption has been going down about 2 percent a year during the past decade. We also have sought to recoup higher collection expenses and to recover bad debt expense incurred during winter cutoff moratoriums.

In addition, we have advocated that states adopt a measure similar to a Texas law that allows for faster recognition in rates of essential capital investment needed to maintain the system and serve new customers. The Gas Reliability Infrastructure Program in Texas reduces the effects of regulatory lag on cash flow and earnings.

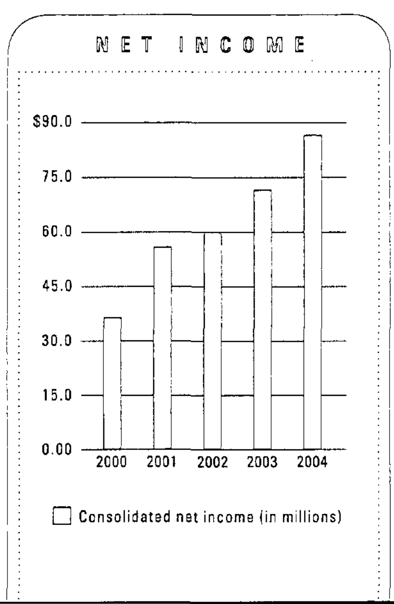
CUSTOMER SERVICE EXCELLENCE

Excellence in customer service stands as a key part of our corporate vision—we call it our Spirit of Service.SM Our reputation in the community is directly influenced by how we perform. During the past two years, we have conducted extensive training efforts and intend to expand the programs further in 2005. We also are organizing programs to help our employees better understand the dynamics of our business as it grows.

INVESTMENT IN A STRONG CORPORATE CULTURE

Another intangible, but essential, investment that we are pursuing is to build a strong corporate culture. In 2004, we took additional steps to invest in our employees through expanded training, improved benefits programs and increased communications.

Instilling our core values throughout the organization is essential to our future success. As we have integrated major acquisitions into our operations, we have found that our values make a tangible difference. Having the right corporate culture guides us in dealing appropriately with business issues. Moreover, the right corporate culture emphasizes to our employees the values and integrity on which we will continue to grow.



NEED FOR A NATIONAL ENERGY POLICY

With the contentious 2004 elections now past, we trust that Congress and the Administration can focus on one of the most pressing national issues that received almost no attention during the campaign—the need for a comprehensive national energy policy.

Natural gas prices have continued to rise during the past five years. In the 2004–2005 heating season, home heating bills will likely go up from 10 percent to 15 percent above bills of last winter. These price increases are the result of normal market responses. Yet, that response is prompted by our nation's lack of a national energy policy.

We need a policy that permits additional drilling for natural gas in the United States and incentives to build new pipeline capacity, such as a pipeline to transport abundant natural gas supplies from the North Slope of Alaska to the contiguous 48 states.

Industry experts estimate that large resources of natural gas remain to be tapped. However, only when additional supplies come to market will gas commodity prices moderate and reduce the volatility of gas price spikes that are hurting consumers, businesses and utilities alike.

BOARD CHANGES

Two significant milestones in our corporate governance occurred during 2004. The first was the retirement of one of our longtime directors, Carl S. Quinn. Carl's service to Atmos Energy was matched only by his legacy in the natural gas industry as one of its leading statesmen. We shall miss his wise counsel, steady direction and solid integrity.

However, we were pleased in August when we marked a second milestone, the addition of our first woman director, Nancy K. Quinn. Ms. Quinn brings a wealth of experience in investment banking and energy industry financing. She also is a respected woman entrepreneur and benefactor of the arts. We feel honored that she agreed to join our board.

FUTURE EXPECTATIONS

As we look to 2005, we are excited about the tremendous potential that we foresee. Our acquisition of TXU Gas has given us greater size and scale. Our existing utility operations continue to achieve exceptional results. Our non-utility operations are positioned to make complementary contributions in the future.

We remain committed to keeping Atmos Energy a financially successful company by showing respect for all who deal with us and by expecting the highest ethical behavior of all who work for us. We anticipate growing earnings at 3 percent to 6 percent a year and continuing to pay higher annual dividends. Being financially successful is the best way we can reward our investors, serve our customers, invest in our employees and contribute to our 1,500 communities.

We intend to continue to operate the business through a dedication to a strong financial foundation, a disciplined attitude to operations, a successful approach to making and integrating acquisitions, a devotion to serve our customers exceptionally well and an adherence to our core values.

Robert W. Best

Robert W. Best
Chairman, President and Chief Executive Officer
November 19, 2004

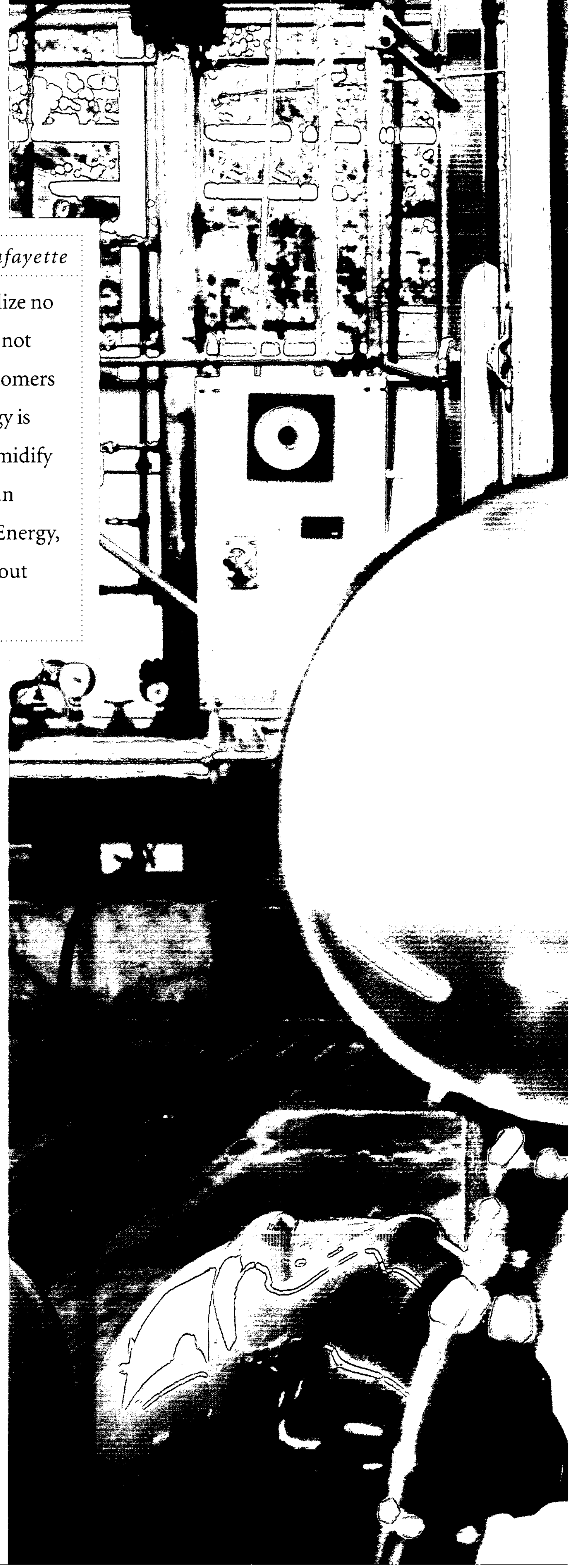
VALUE

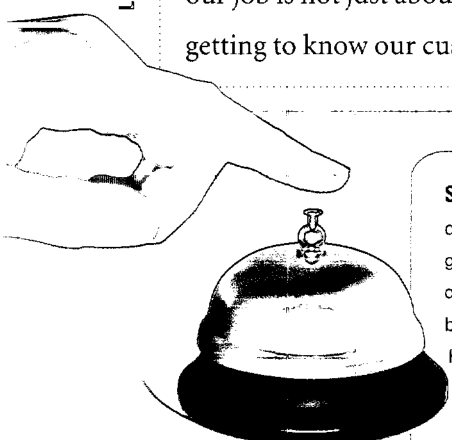
customer focus

Anthony Ponter, Ph.D. *University of Louisiana, Lafayette*

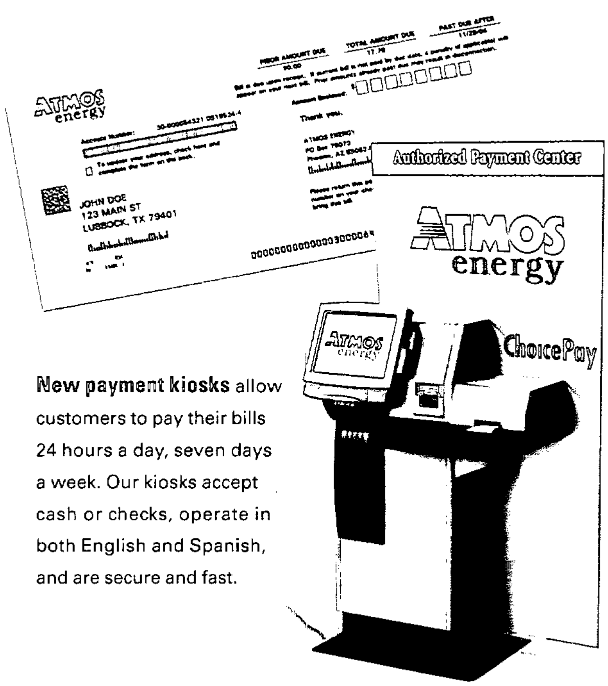
LAFAYETTE, LOUISIANA

When you focus on your customers, right away you realize no two are exactly the same. That's how we know our job is not just about supplying energy, it's about helping our customers do their jobs better. Natural gas supplied by Atmos Energy is used by the University of Louisiana, Lafayette, to dehumidify the air so that Dean Ponter's engineering students can conduct more precise science experiments. At Atmos Energy, our job is not just about getting more customers, it's about getting to know our customers' needs.



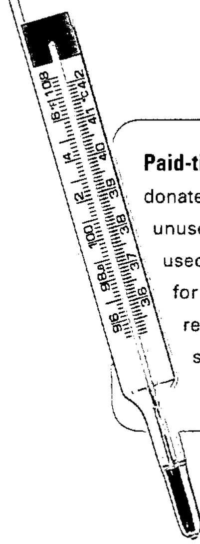


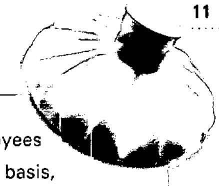
Spirit of Service℠ Training is designed to help our employees go beyond simply what our customers "expect" and focus on building customer relationships. Highly interactive and participative, Spirit of Service Training gives our employees the approach they need to effectively address customer needs.



New payment kiosks allow customers to pay their bills 24 hours a day, seven days a week. Our kiosks accept cash or checks, operate in both English and Spanish, and are secure and fast.

SPOUTS, SLUGS
FLUIDIZED
HOUSE
GEN





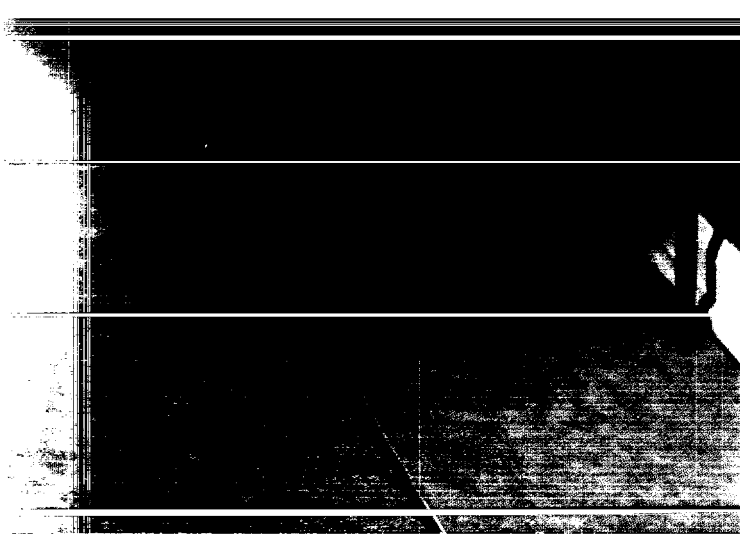
Paid-time-off pools let employees donate, on a strictly voluntary basis, unused paid time off to a donation bank used by other Atmos Energy employees for personal or family illnesses that require extended time off work. It's a simple way for all of us to help others in their time of need.

VALUE employee focus

Jack Britton *Atmos Energy Customer Service Agent*

When Jack Britton was called upon to serve his country in Iraq, he and his family were facing enough uncertainty. At Atmos Energy, we felt it was our responsibility not to add to that. So, even as he joined his engineering battalion in Fallujah, Jack knew he would have his job and full benefits. In fact, Jack's fellow employees took care of the lawn and invited his wife to company functions. Now safely back in Mississippi, Jack says, "I was okay. Uncle Sam was going to take care of me. But Atmos Energy took care of my wife." It was just our way of thanking Jack for his teamwork, with a little teamwork of our own. We're proud of the many Atmos Energy employees who've served bravely and of all our employees at home who volunteered to help these soldiers' families.

TUPELO, MISSISSIPPI



Rising Spirit Award. Each year, Atmos Energy recognizes employees who've gone above and beyond in offering superior service to our customers. This past May, 13 employees were recognized for their commitment both to our customers and to our core values.

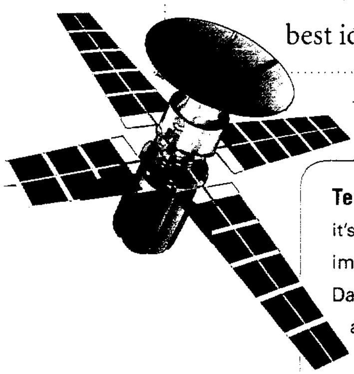
VALUE 3

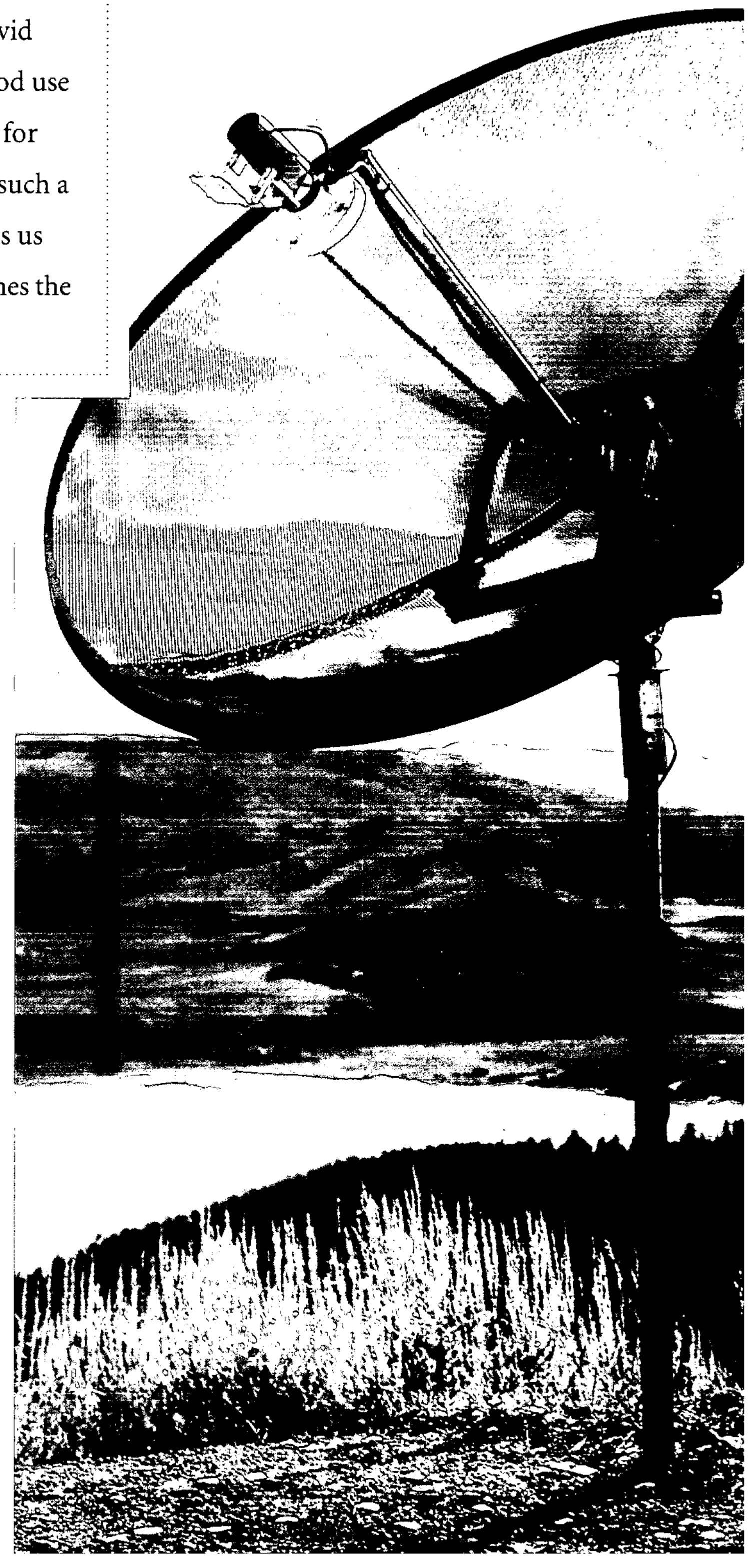
enterprise thinking

CRAIG, COLORADO

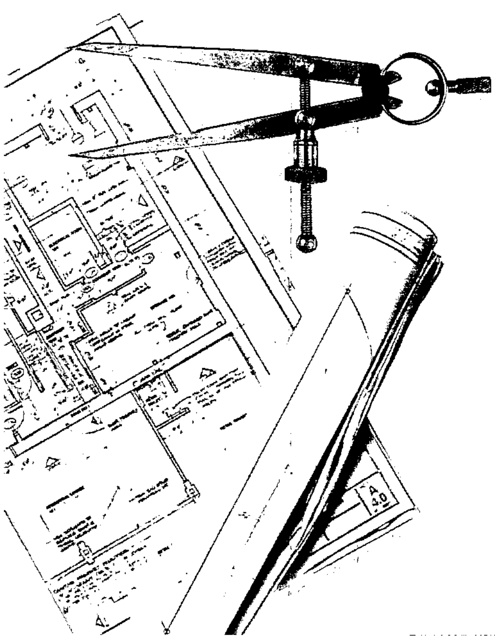
David Anglin *Vice President of Operations—Colorado*

David Anglin had this crazy idea. Fortunately, David works for a company that encourages original thinking. He works for us. In his travels throughout Colorado, David kept seeing outdated satellite dishes just sitting in people's yards. David suggested we offer to remove them and put them to good use once again as part of the company's satellite network for training and employee broadcasts. Turns out, it wasn't such a crazy idea after all. It makes us a lot more efficient, saves us a lot of money and forever made us believe that sometimes the best ideas are the craziest ideas.





Technology isn't just a buzz word with us; it's something we're constantly seeking to improve upon. In addition to the big dishes David suggested we put to good use, you'll also see small domes on our service trucks. They keep us in contact with cell towers or satellite dishes when cell coverage is intermittent. This allows us to update service orders to our trucks en route, saving time and money.



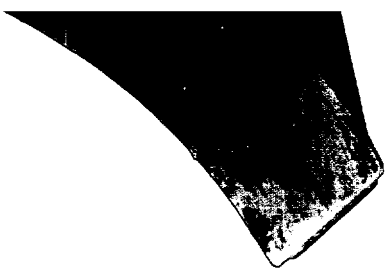
Our Blueprint Program.
A while back, we created a benchmark for staffing in our utility divisions. This helps us keep a handle on staffing needs without layoffs or understaffing. Not only is it a job protection program, it's an incentive program to move employees from overstaffed to understaffed locations.

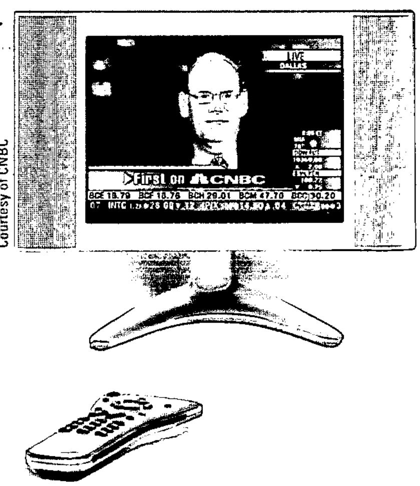
value creation

Bob Davison *Project Manager for New Construction*

Where some see wide open spaces, others see wide open opportunities. Bob Davison is one of the latter. As a manager of new construction in the Dallas-Fort Worth area, Bob helps guide the growth brought about by our acquisition of TXU Gas. At Sendera Ranch, a planned development of more than 20,000 lots, Atmos Energy will supply natural gas to a booming community. By adding natural gas appliances, builders increase the value and energy efficiency of their new homes. Growing by acquisitions is just one of the ways we assure our shareholders of growth in their investment for years to come.

FORT WORTH, TEXAS

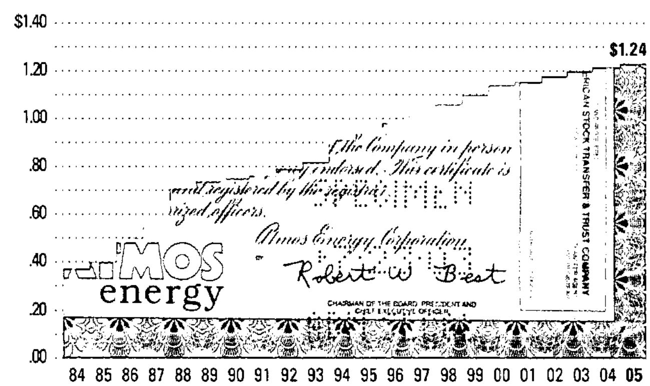


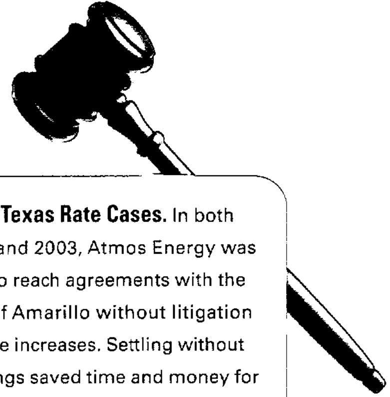


Courtesy of CNBC

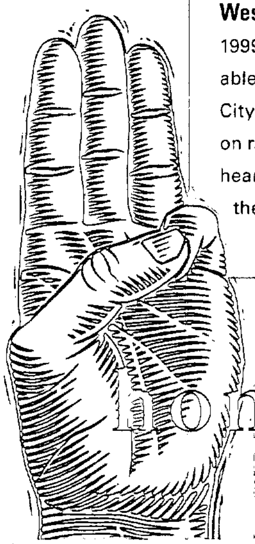
Atmos Energy's commitment to value creation has been recognized all over the world, such as when CEO Bob Best appeared live on CNBC's "Squawk Box" to announce the acquisition of TXU Gas on June 17, 2004.

Increasing dividends is one of Atmos Energy's commitments to value creation that has yielded tangible and consistent results over the years. We're proud to have provided our shareholders 21 consecutive years of annual increases in dividends (adjusted for mergers and acquisitions).





West Texas Rate Cases. In both 1999 and 2003, Atmos Energy was able to reach agreements with the City of Amarillo without litigation on rate increases. Settling without hearings saved time and money for the city and, ultimately, for our customers and shareholders.



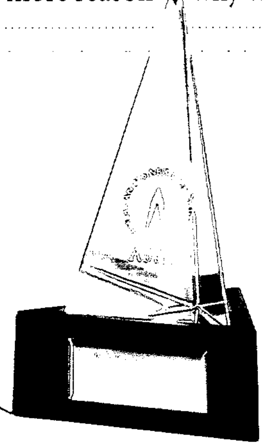
VALUE

honesty & integrity

LEBANON, TENNESSEE

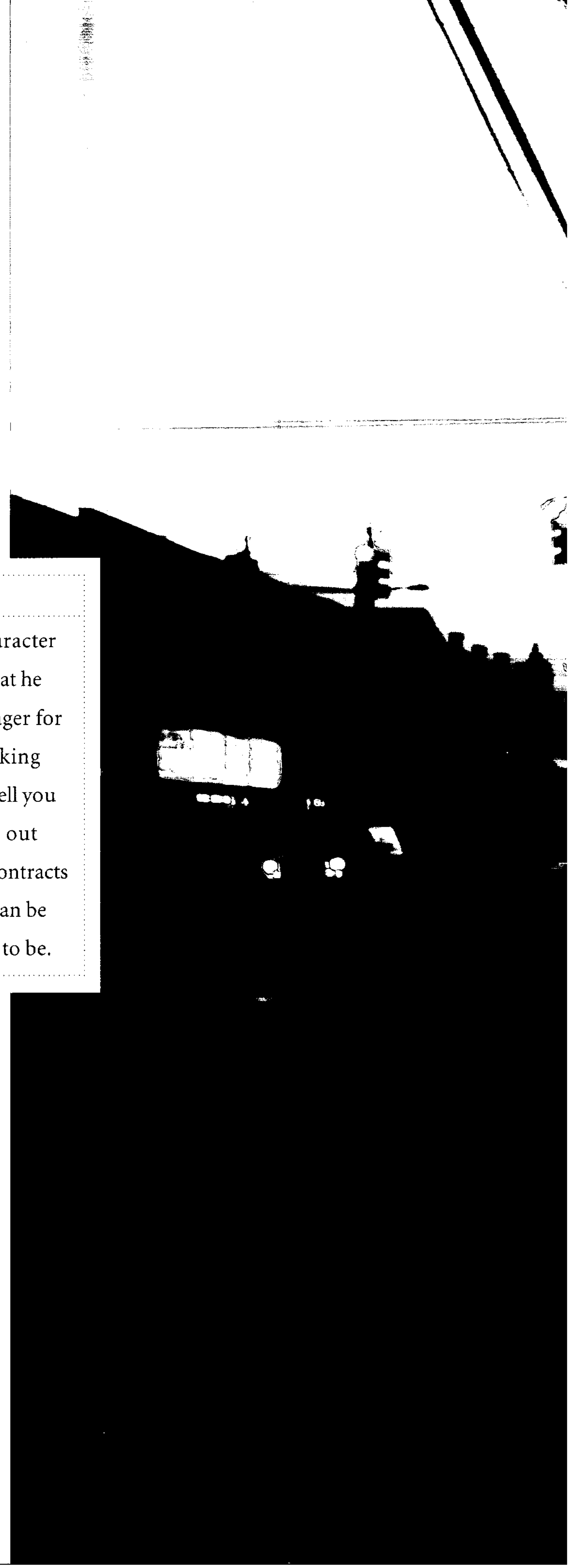
Don Cozart *City of Lebanon Gas Manager*

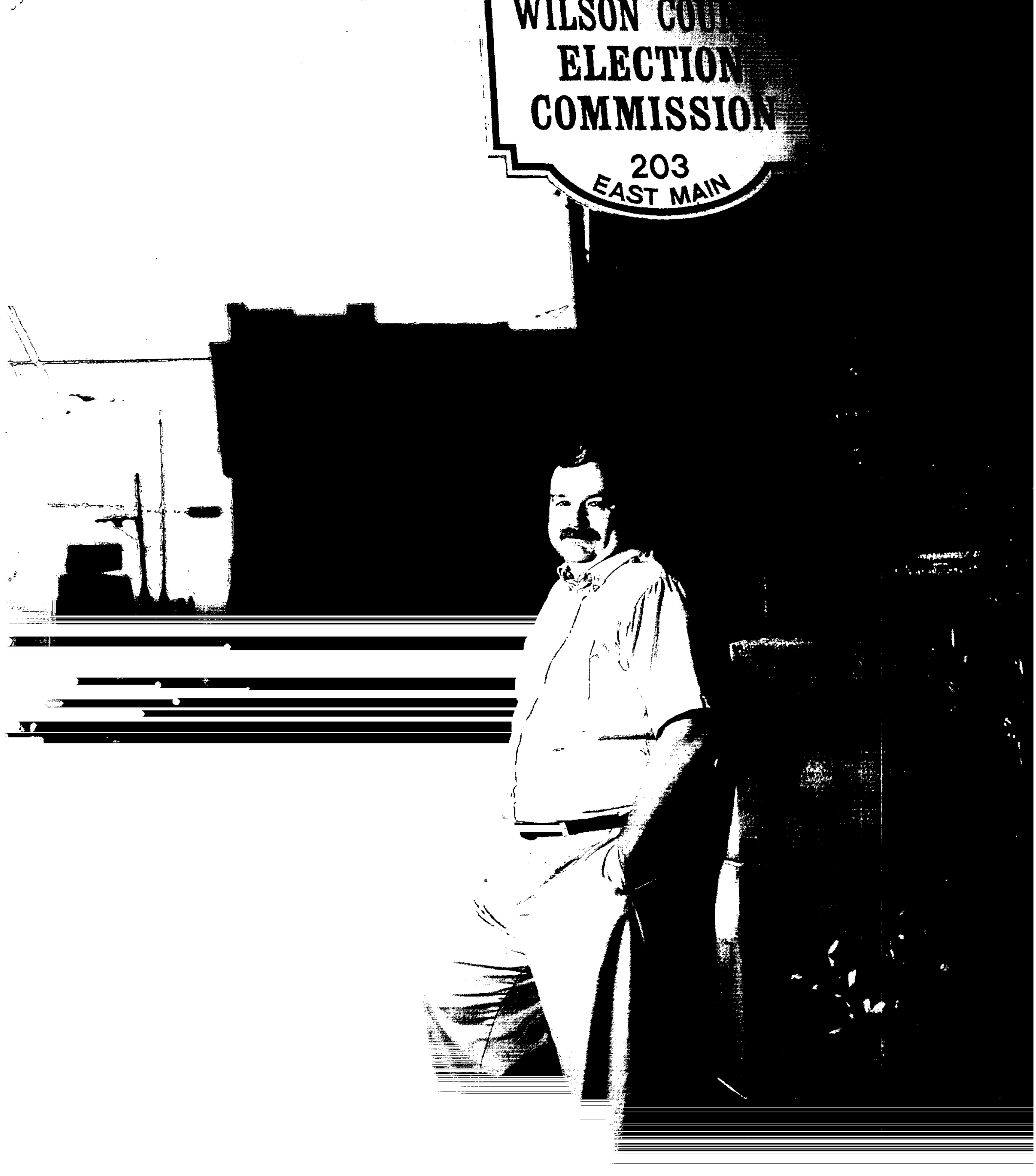
Prices fluctuate. Markets constantly change. Your character shouldn't. That's how Don Cozart sees it. And that's what he looks for in suppliers and associates. As the gas manager for the City of Lebanon, Tennessee, Don has been working with Atmos Energy since 1986. Ask him why, and he'll tell you how in 1989, when cold weather in the Gulf froze out many gas wells, Atmos Energy was there honoring $3 contracts when prices had jumped to $28 per Mcf. Yes, markets can be erratic. Which is all the more reason why we refuse to be.



In 2001, Atmos Energy received the inaugural **Greater Dallas Business Ethics Award** for demonstrating a commitment to ethical business practices. Our value system isn't just a statement. It's a way of life.

"Our commitment to ethical behavior is not driven by the letter of the law but, more importantly, by the spirit of the law." – Bob Best, Chairman, President and CEO




ELECTION
COMMISSION
203
EAST MAIN

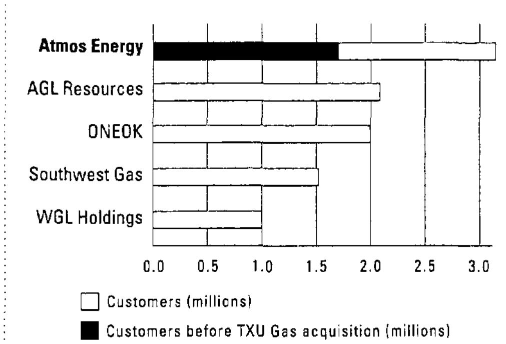
RESULTS OF OPERATIONS

Atmos Energy's consolidated net income for fiscal 2004 was $86.2 million, or $1.58 per diluted share. That compares with $71.7 million, or $1.54 per diluted share, in fiscal 2003. Utility operations contributed 73 percent of earnings, and nonutility operations provided 27 percent. Return on average shareholders' equity was 9.1 percent, and total return to our shareholders was 10.4 percent. We paid cash dividends in 2004 of $1.22 per share for an annualized dividend yield at year-end of 4.8 percent.

TXU GAS ACQUISITION

On June 17, Atmos Energy announced it would acquire the natural gas distribution and pipeline operations of TXU Gas Company, the largest gas utility in Texas. After receiving the required approvals from three state utility regulatory commissions, we completed the transaction on October 1, 2004, paying an adjusted cash price of $1.905 billion.

CUSTOMER COMPARISON



Adding TXU Gas' 1.5 million utility customers made Atmos Energy the largest natural-gas-only utility in the United States. The operations also provide us above-average annual growth in customer accounts, the ability to earn a return on capital investments promptly through automatic rate adjustments and the opportunity to deliver more gas to wholesale customers through one of the largest intrastate gas pipeline systems in Texas.

Because of these factors, we estimate that the TXU Gas operations, since renamed our Mid-Tex Division, will contribute from 5 cents to 10 cents to earnings per diluted share in fiscal 2005. Adding the TXU Gas operations increased Atmos Energy's proportion of operating income from regulated operations to about 90 percent.

OTHER ACQUISITIONS AND DIVESTITURES

In February, we acquired the natural gas distribution assets of ComFurT Gas, Inc., a privately held gas utility system in Buena Vista, Colorado. We paid $1.95 million cash for a 49-mile distribution system, serving approximately 1,800 utility customers.

During 2004, we and three other utility partners completed the sale of our interests in the general partnership and limited partnerships of Heritage Propane Partners, L.P. We received cash proceeds of approximately $26.6 million and recorded a $5.9 million pretax book gain, ending our interest in the propane business.

WEATHER AND THROUGHPUT

Weather during fiscal 2004 was 6 percent warmer than in fiscal 2003 and 4 percent warmer than normal, as adjusted for jurisdictions with weather-normalized operations.

Primarily because of lower consumption, our utility gas throughput in 2004 declined about 1 percent from that in 2003 to 246.0 billion cubic feet (Bcf). Of this total, utility gas transportation volumes were 72.8 Bcf. In our nonutility segment, natural gas marketing sales volumes declined 1.5 percent from those in 2003 to 222.6 Bcf.

In states with warmer winter weather, we have sought weather-normalization adjustments in our rates. Weather normalization protects our customers from steep increases in their winter gas bills when the weather turns unusually cold and it protects our earnings when the winter is unseasonably warm.

We now have weather normalization or higher base rates in eight of our largest states. About 17 percent of our margins are exposed to weather in the 2004–2005 heating season, an increase from 10 percent due to the addition of the Mid-Tex operations.

Adding TXU Gas' 1.5 million customers made Atmos Energy the largest natural-gas-only utility in the United States.

RATE ADJUSTMENTS

During 2004, we added $16.2 million in net revenues from rate filings in Kansas, Texas and Mississippi. We expect to add $15 million to $20 million a year in average annual rate increases over the next five years. To keep our actual rates of return as close as possible to our allowed returns, we are seeking other rate adjustments, as well.

We are proposing weather normalization in jurisdictions with warmer weather, shifting more revenue from the gas commodity charge to base rates, improving our rate design to mitigate the effects of declining usage per customer, recovering the gas cost portion of bad debt expense and working to eliminate regulatory lag for capital spending on gas utility infrastructure improvements.

NATURAL GAS PRICES

Natural gas prices continued to rise during fiscal 2004. Our utility system's average cost of gas purchased for customers was $6.55 per thousand cubic feet (Mcf), an increase of 13.7 percent over the $5.76 per Mcf we paid in fiscal 2003. The increase was largely due to a tightening of natural gas supply and demand. Although gas resources remain abundant in North America, gas production has not kept pace with the steady rise in demand.

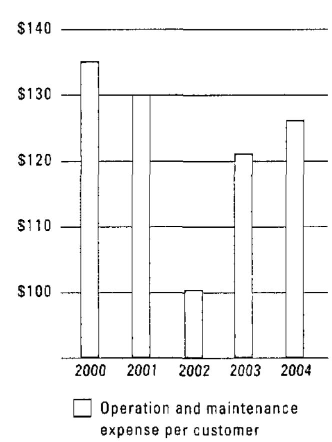
During the 2004–2005 heating season, residential heating bills will likely increase 10 percent to 15 percent above bills of the previous heating season, according to the federal Energy Information Administration. Tight supplies also are causing greater volatility in natural gas prices.

To help protect our customers, we offer budget billing plans, assistance for low-income customers and information about lowering energy costs. We also have advocated vigorously for federal energy legislation to offer incentives for more natural gas production and for increased energy assistance to aid indigent and low-income customers.

CONTROLLING KEY EXPENSES

To control our purchased gas costs, we use a combination of gas storage, fixed physical contracts and fixed financial contracts. We have fixed the price for about 50 percent of our expected 2004–2005 winter gas supply requirements. Of the total amount hedged, about 45 percent is a combination of our underground storage assets and contracted pipeline storage; this storage provides a natural hedge for our gas supply purchases. The other 55 percent of the quantity hedged is through financial contracts.

O&M EXPENSES



Hedging is good financial management because it protects our capital and cash flow. It also cushions the effects of higher gas prices on our customers' winter bills, on our receivables and, ultimately, on our collections.

Despite rising natural gas prices, we have continued to keep our utility bad-debt expense low. Our collection efforts, coupled with credit qualification before reconnecting customers and expanded customer payment options, helped us maintain our allowance for doubtful accounts in 2004 at just 0.29 percent of residential and commercial revenues, which is considerably lower than our historical accrual rate.

OPERATING EFFICIENCY

Atmos Energy has earned a reputation for being one of the most efficient natural gas utilities in the country. We continue to be an industry leader in two key indicators: operation and maintenance expense per customer and customers served per employee.

We benchmark our performance each year against our industry peer group. Since 1997, we have reduced operating costs and expenses by about $57 per customer, or 31 percent. For fiscal 2004, our O&M-per-customer expense was $126, compared to our peer group's average of $193, which is 53 percent higher than ours. We served 566 customers per employee, compared to the industry peer group's average of 546 customers.

Our control of operating expenses is even more remarkable, considering that we have operated primarily in rural and smaller communities across 12 states. The structure of our operations has made it more difficult to achieve efficiencies, compared with a company serving a large customer base in a metropolitan area or limited geographical area.

CUSTOMER SATISFACTION

Customer service excellence is one of our major goals. The most recent independent survey of our customers' attitudes, conducted in the fall of 2004, found an overall satisfaction rating among residential and commercial customers of 94 percent. Compared with other utility service providers, Atmos Energy ranked among the industry's leaders in overall satisfaction.

NONUTILITY OPERATIONS

Our nonutility operations during 2004 achieved major improvements in margins and in reduced exposure to risks from volatile gas commodity prices. Our natural gas marketing business expanded into the Mobile Bay area of Alabama. In Kansas, nonutility gas storage facilities were transferred to our Colorado-Kansas Division for utility operations.

A major development was the acquisition of the natural gas pipeline and storage assets of TXU Gas. Although regulated, these assets will be managed under our nonutility operations.

The 6,162-mile pipeline extends across Texas to transport natural gas to third parties. It has extensive connections in nine major gas-producing basins and three interconnection hubs to other major producing areas and many interstate pipelines. Five underground gas storage reservoirs contain 39 Bcf of working storage, including one salt-dome facility with higher delivery capabilities.

We believe this pipeline and storage system is well situated to transport larger volumes of natural gas. Its operations create additional gas marketing and other opportunities for our nonutility businesses.

FISCAL 2005 FORECAST

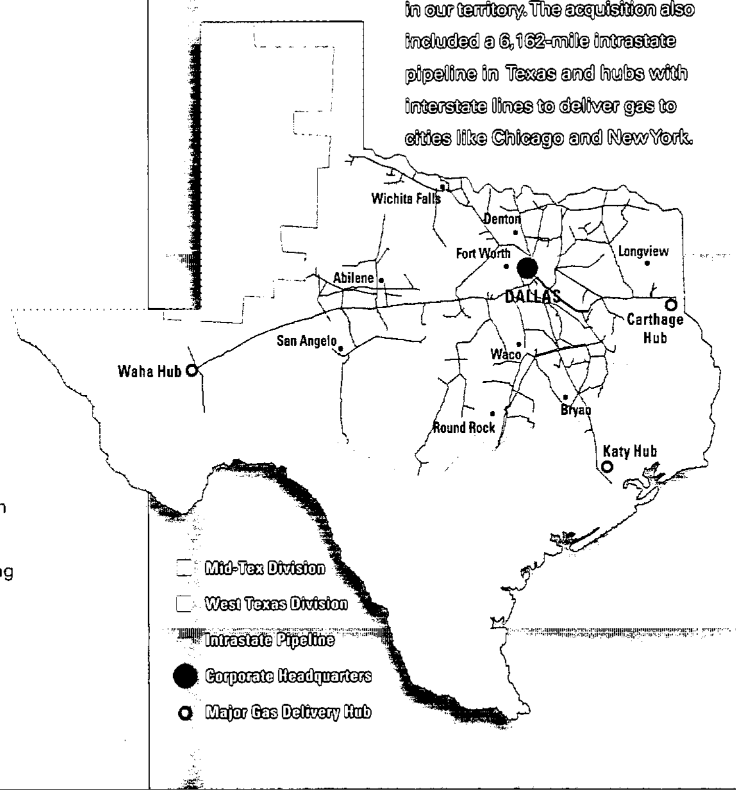
We anticipate our earnings will increase at 3 percent to 6 percent a year, on average, during the next five years. We also expect to continue paying higher annual dividends.

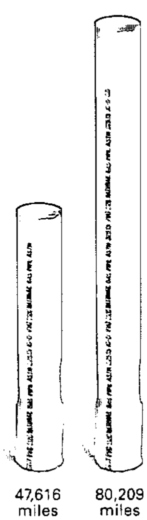
In fiscal 2005, we expect to earn between $1.65 and $1.75 per diluted share and to pay an indicated dividend rate of $1.24 per share. Our capital expenditures are expected to approximate $340 million to $350 million, with about 60 percent of that total being spent on projects in our new Mid-Tex Division.

From rural to urban communities, Atmos Energy spans the largest geographic area of any natural gas utility in the country. Diversity in economic conditions, weather patterns, regional climates and regulatory conditions allows us to accommodate extremes without significant risk.

ATMOS ENERGY ACQUIRED TERRITORY

The acquisition of TXU Gas gives Atmos Energy the opportunity to serve 550 additional communities, including two within the Top-10 largest gas markets in the U.S. as well as several others equal to or larger than cities elsewhere in our territory. The acquisition also included a 6,162-mile intrastate pipeline in Texas and hubs with interstate lines to deliver gas to cities like Chicago and New York.





Our acquisition of TXU Gas increased our miles of pipeline by approximately 68 percent. Our Texas intrastate system allows us to deliver more natural gas to wholesale customers, thereby bringing more revenue to our business.

IOWA
ILLINO
DENVER
COLORADO
KANSAS
MISSOURI
OKLAHOMA
ARKANSAS
LUBBOCK
MISSIS
DALLAS
JACKSON
LOUISIANA
TEXAS
BATON ROUGE
HOUSTON
NEW ORLEANS
Atmos Energy Headquarters
Atmos Energy Utility Division Offices
Atmos Energy Marketing Headquarters
Atmos Energy Marketing Regional Offices
States with Both Utility and Nonutility Operations
States with Only Nonutility Operations
Utility Service Areas

SUMMARY ANNUAL REPORT

The financial information presented in this report about Atmos Energy Corporation is condensed. Our complete financial statements, including notes as well as management's discussion and analysis of financial condition and results of operations, are presented in our Annual Report on Form 10-K. Atmos Energy's chief executive officer and its chief financial officer have complied with, and have executed, all certifications of these financial statements required under the Sarbanes-Oxley Act of 2002 and all related rules of the Securities and Exchange Commission with respect to the financial statements contained therein. Investors may request, without charge, our Annual Report on Form 10-K for the fiscal year ended September 30, 2004, by calling Shareholder Relations at (972) 855-3729 between 8 a.m. and 5 p.m. Central time. Our Form 10-K also is available on Atmos Energy's Web site at www.atmosenergy.com. Additional investor information is presented on page 32 of this report.

YEAR ENDED SEPTEMBER 30	2004	2003
Meters in service		
Residential	1,506,777	1,498,586
Commercial	151,381	151,008
Industrial	2,436	3,799
Agricultural	8,397	9,514
Public authority and other	10,145	9,891
Total meters	1,679,136	1,672,798
Heating degree days		
Actual (weighted average)	3,271	3,473
Percent of normal	96%	101%
Utility sales volumes (MMcf)		
Residential	92,208	97,953
Commercial	44,226	45,611
Industrial	22,330	23,738
Agricultural	4,642	7,884
Public authority and other	9,813	9,326
Total	173,219	184,512
Utility transportation volumes (MMcf)	87,746	70,159
Total utility throughput (MMcf)	260,965	254,671
Intersegment activity (MMcf)	(14,932)	(6,706)
Consolidated utility throughput (MMcf)	246,033	247,965
Consolidated natural gas marketing throughput (MMcf)	222,572	225,961
Operating revenues (000s)		
Gas utility sales revenues		
Residential	$ 923,773	$ 873,375
Commercial	400,704	367,961
Industrial (including agricultural)	187,187	192,676
Public authority and other	77,178	65,921
Total gas sales revenues	1,588,842	1,499,933
Transportation revenues	30,622	29,583
Other gas revenues	17,172	23,341
Total utility revenues	1,636,636	1,552,857
Natural gas marketing revenues	1,279,424	1,234,447
Other nonutility revenues	3,977	12,612
Total operating revenues (000s)	**$ 2,920,037**	**$ 2,799,916**
Other statistics		
Gross plant (000s)	$ 2,633,651	$ 2,480,139
Net plant (000s)	$ 1,722,521	$ 1,624,394
Miles of pipe	47,616	45,267
Employees	2,864	2,905

SEPTEMBER 30 (Dollars in thousands, except share data)	2004	2003
Assets		
Property, plant and equipment	$ 2,595,374	$ 2,463,992
Construction in progress	38,277	16,147
	2,633,651	2,480,139
Less accumulated depreciation and amortization	911,130	855,745
Net property, plant and equipment	**1,722,521**	**1,624,394**
Current assets		
Cash and cash equivalents	201,932	15,683
Cash held on deposit in margin account	—	17,903
Accounts receivable, less allowance for doubtful accounts of $7,214 in 2004 and $13,051 in 2003	211,810	216,783
Gas stored underground	200,134	168,765
Other current assets	63,236	38,863
Total current assets	677,112	457,997
Goodwill and intangible assets	238,272	273,499
Deferred charges and other assets	231,978	269,605
	$ 2,869,883	**$ 2,625,495**
Capitalization and Liabilities		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 100,000,000 shares authorized, issued and outstanding: 2004 – 62,799,710 shares, 2003 – 51,475,785 shares	$ 314	$ 257
Additional paid-in capital	1,005,644	736,180
Retained earnings	142,030	122,539
Accumulated other comprehensive loss	(14,529)	(1,459)
Shareholders' equity	1,133,459	857,517
Long-term debt	861,311	862,500
Total capitalization	**1,994,770**	**1,720,017**
Current liabilities		
Accounts payable and accrued liabilities	185,295	179,852
Other current liabilities	223,265	133,957
Short-term debt	—	118,595
Current maturities of long-term debt	5,908	9,345
Total current liabilities	414,468	441,749
Deferred income taxes	213,930	223,350
Regulatory cost of removal obligation	103,579	102,371
Deferred credits and other liabilities	143,136	138,008
	$ 2,869,883	**$ 2,625,495**

SEPTEMBER 30 (Dollars in thousands, except per share data)	2004	2003	2002
Operating revenues			
Utility segment	$ 1,637,728	$ 1,554,082	$ 937,526
Natural gas marketing segment	1,618,602	1,668,493	1,031,874
Other nonutility segment	23,151	21,630	24,705
Intersegment eliminations	(359,444)	(444,289)	(343,141)
	2,920,037	2,799,916	1,650,964
Purchased gas cost			
Utility segment	1,134,594	1,062,679	559,891
Natural gas marketing segment	1,571,971	1,644,328	994,318
Other nonutility segment	9,383	1,540	8,022
Intersegment eliminations	(358,102)	(443,607)	(342,407)
	2,357,846	2,264,940	1,219,824
Gross profit	562,191	534,976	431,140
Operating expenses			
Operation and maintenance	214,470	205,090	158,119
Depreciation and amortization	96,647	87,001	81,469
Taxes, other than income	57,379	55,045	36,221
Total operating expenses	368,496	347,136	275,809
Operating income	193,695	187,840	155,331
Miscellaneous income (expense)	9,507	2,191	(1,321)
Interest charges	65,437	63,660	59,174
Income before income taxes and cumulative effect of accounting change	137,765	126,371	94,836
Income tax expense	51,538	46,910	35,180
Income before cumulative effect of accounting change	86,227	79,461	59,656
Cumulative effect of accounting change, net of income tax benefit	—	(7,773)	—
Net income	**$ 86,227**	**$ 71,688**	**$ 59,656**
Per share data			
Basic income per share:			
Income before cumulative effect of accounting change	$ 1.60	$ 1.72	$ 1.45
Cumulative effect of accounting change, net of income tax benefit	—	(.17)	—
Net income	$ 1.60	$ 1.55	$ 1.45
Diluted income per share:			
Income before cumulative effect of accounting change	$ 1.58	$ 1.71	$ 1.45
Cumulative effect of accounting change, net of income tax benefit	—	(.17)	—
Net income	**$ 1.58**	**$ 1.54**	**$ 1.45**
Weighted average shares outstanding:			
Basic	54,021	46,319	41,171
Diluted	54,416	46,496	41,250

YEAR ENDED SEPTEMBER 30 (Dollars in thousands)	2004	2003	2002
Cash Flows from Operating Activities			
Net income	$ 86,227	$ 71,688	$ 59,656
Adjustments to reconcile net income to net cash provided by operating activities:			
Cumulative effect of accounting change, net of income tax benefit	—	7,773	—
Gain on sales of assets	(6,700)	—	—
Depreciation and amortization:			
Charged to depreciation and amortization	96,647	87,001	81,469
Charged to other accounts	1,465	2,193	2,452
Deferred income taxes	36,997	53,867	14,509
Other	(1,772)	(5,885)	(3,371)
Changes in assets and liabilities	57,870	(167,186)	142,680
Net cash provided by operating activities	270,734	49,451	297,395
Cash Flows Used in Investing Activities			
Capital expenditures	(190,285)	(159,439)	(132,252)
Acquisitions, net of cash received	(1,957)	(74,650)	(15,747)
Retirements of property, plant and equipment, net	(570)	704	(1,725)
Assets for leasing activities	—	—	(8,511)
Proceeds from sale of assets	27,919	—	—
Net cash used in investing activities	(164,893)	(233,385)	(158,235)
Cash Flows from Financing Activities			
Net decrease in short-term debt	(118,595)	(27,196)	(55,456)
Net proceeds from issuance of long-term debt	5,000	253,267	—
Proceeds from bridge loan	—	147,000	—
Repayment of bridge loan	—	(147,000)	—
Repayment of long-term debt	(9,713)	(73,165)	(20,651)
Repayment of Mississippi Valley Gas debt	—	(70,938)	—
Cash dividends paid	(66,736)	(55,291)	(48,646)
Issuance of common stock	34,715	25,720	18,321
Net proceeds from equity offering	235,737	99,229	—
Net cash provided (used) by financing activities	80,408	151,626	(106,432)
Net increase (decrease) in cash and cash equivalents	186,249	(32,308)	32,728
Cash and cash equivalents at beginning of year	15,683	47,991	15,263
Cash and cash equivalents at end of year	**$ 201,932**	**$ 15,683**	**$ 47,991**

BOARD OF DIRECTORS
ATMOS ENERGY CORPORATION

We have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Atmos Energy Corporation at September 30, 2004 and 2003, and the related consolidated statements of income, shareholders' equity and cash flows for each of the three years in the period ended September 30, 2004 (not presented herein) and in our report dated November 9, 2004, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheets and statements of income and cash flows are fairly stated in all material respects in relation to the basic consolidated financial statements from which they have been derived.

Ernst + Young LLP

Dallas, Texas
November 9, 2004

YEAR ENDED SEPTEMBER 30	2004	2003	2002	2001	2000
Balance Sheet Data at September 30 (000s)					
Capital expenditures	$ 190,285	$ 159,439	$ 132,252	$ 113,109	$ 75,557
Net property, plant and equipment	1,722,521	1,624,394	1,380,070	1,409,432	1,045,484
Working capital	262,644	16,248	(139,150)	(90,968)	(185,267)
Total assets	2,869,883	2,625,495	2,059,631	2,108,841	1,410,668
Shareholders' equity	1,133,459	857,517	573,235	583,864	392,466
Long-term debt, excluding current maturities	861,311	862,500	668,959	691,026	361,970
Total capitalization	1,994,770	1,720,017	1,242,194	1,274,890	754,436
Income Statement Data					
Operating revenues* (000s)	$ 2,920,037	$ 2,799,916	$ 1,650,964	$ 1,725,481	$ 850,152
Gross profit* (000s)	562,191	534,976	431,140	375,208	325,706
Net income (000s)	86,227	71,688	59,656	56,090	35,918
Net income per diluted share	1.58	1.54	1.45	1.47	1.14
Common Stock Data					
Shares outstanding (000s)					
End of year	62,800	51,476	41,676	40,792	31,952
Weighted average	54,416	46,496	41,250	38,247	31,594
Cash dividends per share	$ 1.22	$ 1.20	$ 1.18	$ 1.16	$ 1.14
Shareholders of record	27,555	28,510	28,829	30,524	32,394
Market price – High	$ 26.86	$ 25.45	$ 24.46	$ 26.25	$ 25.00
Low	$ 23.68	$ 20.70	$ 18.37	$ 19.31	$ 14.75
End of year	$ 25.19	$ 23.94	$ 21.50	$ 21.60	$ 20.63
Book value per share at end of year	$ 18.05	$ 16.66	$ 13.75	$ 14.31	$ 12.28
Price/Earnings ratio at end of year	15.94	15.55	14.83	14.69	18.09
Market/Book ratio at end of year	1.40	1.44	1.56	1.51	1.68
Annualized dividend yield at end of year	4.8%	5.0%	5.5%	5.4%	5.5%
Customers and Volumes (As metered)					
Consolidated utility gas sales volumes (MMcf)	173,219	184,512	145,488	156,544	119,470
Consolidated utility gas transportation volumes (MMcf)	72,814	63,453	63,053	61,230	59,365
Consolidated utility throughput (MMcf)	246,033	247,965	208,541	217,774	178,835
Consolidated natural gas marketing throughput (MMcf)	222,572	225,961	204,027	55,469	—
Meters in service at end of year	1,679,136	1,672,798	1,389,341	1,386,323	1,096,599
Heating degree days#	3,271	3,473	3,368	4,124	2,096
Degree days as a percentage of normal	96%	101%	94%	115%	82%
Utility average cost of gas per Mcf sold	$ 6.55	$ 5.76	$ 3.87	$ 6.82	$ 3.67
Utility average transportation fee per Mcf	$ .36	$ .43	$ .41	$ .41	$ .37
Statistics					
Return on average shareholders' equity	9.1%	9.9%	9.9%	10.4%	9.3%
Number of employees	2,864	2,905	2,338	2,361	1,885
Net utility plant per meter	$ 994	$ 930	$ 939	$ 977	$ 931
Utility operation, maintenance and administrative expense per meter	$ 116	$ 115	$ 101	$ 130+	$ 135
Meters per employee – utility	612	594	616	603	591
Times interest earned before income taxes	3.05	2.75	2.55	2.83	2.28

* In conjunction with the adoption of EITF 02-03 in fiscal 2003, energy trading contracts resulting in delivery of a commodity where we are the principal in the transaction are included as operating revenues or purchased gas cost. Fiscal years 2000-2002 have been reclassified to conform with this new presentation.

\# Heating degree days for fiscal years 2001-2004 are adjusted for service areas with weather-normalized operations. Heating degree days for 2000 are not adjusted for service areas with weather-normalized operations, as that information was not available.

+ Adjusted for partial-year results of Louisiana Gas Service Company, which was acquired in July 2001.

The matters discussed or incorporated by reference in this Summary Annual Report may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 or Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this report are forward-looking statements made in good faith by the Company and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this report or in any of the Company's other documents or oral presentations, the words "anticipate," "believes," "estimate," "expect," "forecast," "goal," "intends," "objective," "plans," "projection," "seek," "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those discussed in this report, including the successful integration of the Company's acquisition of the operations of TXU Gas, the Company's ability to continue to access the capital markets and other factors discussed in the Company's SEC filings. These factors include the risks and uncertainties discussed in the Company's Form 10-K for the fiscal year ended September 30, 2004. Although the Company believes these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, the Company undertakes no obligation to update or revise its forward-looking statements, whether as a result of new information, future events or otherwise.

SENIOR MANAGEMENT TEAM

Robert W. Best
Chairman, President and Chief Executive Officer

J. Patrick Reddy
Senior Vice President and Chief Financial Officer

R. Earl Fischer
Senior Vice President, Utility Operations, and President, Mid-Tex Division

JD Woodward
Senior Vice President, Nonutility Operations

Louis P. Gregory
Senior Vice President and General Counsel

Wynn D. McGregor
Vice President, Human Resources

UTILITY DIVISIONS

J. Kevin Akers
President, Mississippi Valley Gas Division

Thomas R. Blose, Jr.
President, Mid-States Division

Gary W. Gregory
President, West Texas Division

Tom S. Hawkins, Jr.
President, Louisiana Division

John A. Paris
President, Kentucky Division

Gary L. Schlessman
President, Colorado-Kansas Division

NONUTILITY BUSINESS

Richard A. Erskine
President, Atmos Pipeline and Storage, LLC

Ron W. McDowell
Vice President, New Business Ventures

SHARED SERVICES

Verlon R. Aston, Jr.
Vice President, Governmental Affairs

Leslie H. Duncan
Vice President and Chief Information Officer

Conrad E. Gruber
Vice President, Strategic Planning

Susan C. Kappes
Vice President, Investor Relations and Corporate Communications

Dwala J. Kuhn
Corporate Secretary

Robert E. Mattingly
Vice President, Gas Supply

Fred E. Meisenheimer
Vice President and Controller

Gordon J. Roy
Vice President, Security and Compliance

Laurie M. Sherwood
Vice President, Corporate Development, and Treasurer

Travis W. Bain II
Chairman, Texas Custom Pools, Inc.
Plano, Texas
Board member since 1988
Committees: Work Session/Annual Meeting (Chairman), Audit, Human Resources

Robert W. Best
Chairman, President and Chief Executive Officer
Atmos Energy Corporation
Dallas, Texas
Board member since 1997
Committee: Executive

Dan Busbee
Adjunct Professor, Dedman School of Law, Southern Methodist University; Senior Visiting Fellow, Centre for Commercial Law Studies, University of London
Dallas, Texas
Board member since 1988
Committees: Audit (Chairman), Human Resources

Richard W. Cardin
Retired partner of Arthur Andersen LLP
Nashville, Tennessee
Board member since 1997
Committees: Audit, Nominating and Corporate Governance

Thomas J. Garland
Chairman of the Tusculum Institute for Public Leadership and Policy
Greeneville, Tennessee
Board member since 1997
Committees: Human Resources, Work Session/Annual Meeting

Richard K. Gordon
General Partner
Juniper Capital LP and Juniper Advisory LP
Houston, Texas
Board member since 2001
Committees: Human Resources, Nominating and Corporate Governance

Gene C. Koonce
Formerly Chairman of the Board, President and Chief Executive Officer, United Cities Gas Company
Nashville, Tennessee
Board member since 1997
Committees: Human Resources (Chairman), Executive, Work Session/Annual Meeting

Dr. Thomas C. Meredith
Chancellor of the University System of Georgia
Atlanta, Georgia
Board member since 1995
Committees: Audit, Nominating and Corporate Governance

Phillip E. Nichol
Formerly Senior Vice President of Central Division Staff
UBS PaineWebber Incorporated
Dallas, Texas
Board member since 1985
Committees: Nominating and Corporate Governance (Chairman), Human Resources, Work Session/Annual Meeting

Nancy K. Quinn
Principal, Hanover Capital, LLC
East Hampton, New York
Board member since 2004
Committees: Audit, Nominating and Corporate Governance

Charles K. Vaughan
Formerly Chairman of the Board
Atmos Energy Corporation
Dallas, Texas
Board member since 1983
Committee: Executive (Chairman)

Richard Ware II
President, Amarillo National Bank
Amarillo, Texas
Board member since 1994
Committees: Nominating and Corporate Governance, Work Session/Annual Meeting

Lee E. Schlessman
Honorary Director
President, Dolo Investment Company
Denver, Colorado
Retired from Board in 1998

COMMON STOCK LISTING

New York Stock Exchange. Trading symbol: ATO

STOCK TRANSFER AGENT AND REGISTRAR

American Stock Transfer and Trust Company
59 Maiden Lane
Plaza Level
New York, New York 10038
(800) 543-3038

To inquire about your Atmos Energy stock, please call AST at the telephone number above. You may use the agent's interactive voice response system 24 hours a day to learn about transferring stock or to check your recent account activity—all without the assistance of a customer service representative. Please have available your Atmos Energy shareholder account number and your Social Security or federal taxpayer ID number.

To speak to an AST customer service representative, please call the same number between 8 a.m. and 7 p.m. Eastern time, Monday through Thursday, and 8 a.m. to 5 p.m. Eastern time on Friday.

You also may send an e-mail message on our agent's Web site at http://www.amstock.com. Please refer to Atmos Energy in your e-mail and include your Atmos Energy shareholder account number and your Social Security or federal taxpayer ID number.

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Ernst & Young LLP
2121 San Jacinto, Suite 1500
Dallas, Texas 75201
(214) 969-8000

FORM 10-K

Atmos Energy Corporation's Annual Report on Form 10-K is available upon request from Shareholder Relations, Atmos Energy Corporation, P.O. Box 650205, Dallas, Texas 75265-0205 or by calling (972) 855-3729 between 8 a.m. and 5 p.m. Central time. Atmos Energy's Form 10-K may also be viewed on Atmos Energy's Web site at http://www.atmosenergy.com.

ANNUAL MEETING OF SHAREHOLDERS

The Annual Meeting of Shareholders will be held in the Lincoln West Ballroom at the Hilton Hotel Lincoln Centre, 5410 Lyndon B. Johnson Freeway, Dallas, Texas 75240 on Wednesday, February 9, 2005, at 11 a.m. Central time.

DIRECT STOCK PURCHASE PLAN

Atmos Energy Corporation has a Direct Stock Purchase Plan that is available to all investors. For an Enrollment Application Form and a Plan Prospectus, please call AST at (800) 543-3038. The Prospectus is also available on the Internet at http://www.atmosenergy.com. You may also obtain information by writing to Shareholder Relations, Atmos Energy Corporation, P.O. Box 650205, Dallas, Texas 75265-0205.

This is not an offer to sell, or a solicitation to buy, any securities of Atmos Energy Corporation. Shares of Atmos Energy common stock purchased through the Direct Stock Purchase Plan will be offered only by Prospectus.

ATMOS ENERGY ON THE INTERNET

Information about Atmos Energy is available on the Internet at http://www.atmosenergy.com. Our Web site includes news releases, current and historical financial reports, other investor data, corporate governance documents, management biographies, customer information and facts about Atmos Energy's operations.

ATMOS ENERGY CORPORATION CONTACTS

To contact Atmos Energy's Shareholder Relations, call (972) 855-3729 between 8 a.m. and 5 p.m. Central time or send an e-mail message to InvestorRelations@atmosenergy.com.

For financial information for securities analysts and investment managers, contact:
Susan C. Kappes
Vice President, Investor Relations and Corporate Communications
(972) 855-3729 (972) 855-3040 (fax)
InvestorRelations@atmosenergy.com

ATMOS energy

Atmos Energy Corporation P.O. Box 650205 Dallas, Texas 75265-0205 atmosenergy.com