PIEDMONT NATURAL GAS CO INC
Form 10-K
December 28, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

Form 10-K

(Mark One)

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the fiscal year ended October 31, 2007**
	Or
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the transition period from to**

Commission file number 1-6196
Piedmont Natural Gas Company, Inc.
(Exact name of registrant as specified in its charter)

North Carolina *(State or other jurisdiction of incorporation or organization)*	**56-0556998** *(I.R.S. Employer Identification No.)*
4720 Piedmont Row Drive, Charlotte, North Carolina *(Address of principal executive offices)*	**28210** *(Zip Code)*

Registrant s telephone number, including area code
(704) 364-3120

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

Indicate by check mark if the registrant is a well-known seasoned issuer as defined in Rule 405 of the securities Act. Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to section 13 or 15 (d) of the Act. Yes o No þ

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 þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) 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. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Act. (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No þ

State the aggregate market value of the voting common equity held by non-affiliates of the registrant as of April 30, 2007.

Common Stock, no par value $1,931,426,121

Indicate the number of shares outstanding of each of the registrant s classes of common stock, as of the latest practicable date.

Class	**Outstanding at December 20, 2007**
Common Stock, no par value	73,233,664

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Shareholders on March 6, 2008, are incorporated by reference into Part III.

Piedmont Natural Gas Company, Inc.

2007 FORM 10-K ANNUAL REPORT

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PART I

Item 1. *Business*

Piedmont Natural Gas Company, Inc. (Piedmont) was incorporated in New York in 1950 and began operations in 1951. In 1994, we merged into a newly formed North Carolina corporation with the same name for the purpose of changing our state of incorporation to North Carolina.

Piedmont is an energy services company primarily engaged in the distribution of natural gas to over one million residential, commercial and industrial customers in portions of North Carolina, South Carolina and Tennessee, including 62,000 customers served by municipalities who are our wholesale customers. We are also invested in joint venture, energy-related businesses, including unregulated retail natural gas marketing, interstate natural gas storage and intrastate natural gas transportation.

In the Carolinas, our service area is comprised of numerous cities, towns and communities. We serve Anderson, Gaffney, Greenville and Spartanburg in South Carolina and Charlotte, Salisbury, Greensboro, Winston-Salem, High Point, Burlington, Hickory, Indian Trail, Spruce Pine, Reidsville, Fayetteville, New Bern, Wilmington, Tarboro, Elizabeth City, Rockingham and Goldsboro in North Carolina. In North Carolina, we also provide wholesale natural gas service to Greenville, Monroe, Rocky Mount and Wilson. In Tennessee, our service area is the metropolitan area of Nashville, including wholesale natural gas service to Gallatin and Smyrna.

We have two reportable business segments, regulated utility and non-utility activities. Operations of our non-utility activities segment are comprised of our equity method investments in joint ventures. Operations of both segments are conducted within the United States of America. For further information on equity method investments and business segments, see Note 11 and Note 12, respectively, to the consolidated financial statements.

Operating revenues shown in the consolidated statements of income represent revenues from the regulated utility segment. The cost of purchased gas is a component of operating revenues. Increases or decreases in purchased gas costs from suppliers are passed on to customers through purchased gas adjustment procedures. Therefore, our operating revenues are impacted by changes in gas costs as well as by changes in volumes of gas sold and transported. For the year ended October 31, 2007, 44% of our operating revenues were from residential customers, 24% from commercial customers, 14% from large volume customers, including industrial, power generation and resale customers and 18% from secondary market activities. Operations of the non-utility activities segment are included in the consolidated statements of income in Income from equity method investments.

Our utility operations are regulated by the North Carolina Utilities Commission (NCUC), the Public Service Commission of South Carolina (PSCSC) and the Tennessee Regulatory Authority (TRA) as to rates, service area, adequacy of service, safety standards, extensions and abandonment of facilities, accounting and depreciation. We are regulated by the NCUC as to the issuance of securities. We are subject to or affected by various federal regulations. These federal regulations include regulations that are particular to the natural gas industry, such as regulations of the Federal Energy Regulatory Commission (FERC) that affect the availability of and the prices paid for the interstate transportation and storage of natural gas, regulations of the Department of Transportation that affect the construction, operation, maintenance, integrity and safety of natural gas distribution and transmission systems, and regulations of the Environmental Protection Agency relating to the use and release into the environment of hazardous wastes. In addition, we are subject to numerous regulations, such as those relating to employment practices, which are generally applicable to companies doing business in the United States of America.

We hold non-exclusive franchises for natural gas service in the communities we serve, with expiration dates from 2007 to 2056. The franchises are adequate for the operation of our gas distribution business and do not contain materially burdensome restrictions or conditions. Eleven franchise agreements have expired as of October 31, 2007, and ten will expire during the 2008 fiscal year. We continue to operate in those areas pursuant to the provisions of the expired franchises with no significant impact on our business. The likelihood

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of cessation of service under an expired franchise is remote. We believe that these franchises will be renewed or service continued in the ordinary course of business with no material adverse impact on us, as most government entities do not want to prevent their citizens from having access to gas service or to interfere with our required system maintenance.

The natural gas distribution business is seasonal in nature as variations in weather conditions generally result in greater revenues and earnings during the winter months when temperatures are colder. For further information on weather sensitivity and the impact of seasonality on working capital, see Financial Condition and Liquidity in Item 7 of this Form 10-K. As is prevalent in the industry, we inject natural gas into storage during the summer months (principally April through October) when customer demand is lower for withdrawal from storage during the winter months (principally November through March) when customer demand is higher. During the year ended October 31, 2007, the amount of natural gas in storage varied from 11.9 million dekatherms (one dekatherm equals 1,000,000 BTUs) to 24.2 million dekatherms, and the aggregate commodity cost of this gas in storage varied from $93.8 million to $185.1 million.

During the year ended October 31, 2007, 122.3 million dekatherms of gas were sold to or transported for large volume customers, including industrial, power generation and resale customers, compared with 115.1 million dekatherms in 2006. Deliveries to temperature-sensitive residential and commercial customers, whose consumption varies with the weather, totaled 83.7 million dekatherms in 2007, compared with 83.6 million dekatherms in 2006. Weather in 2007, as measured by degree days, was 12% warmer than normal and in 2006 was 6% warmer than normal.

The following is a five-year comparison of operating statistics for the years ended October 31, 2003 through 2007. The information presented is not comparable for all periods due to the acquisitions of North Carolina Natural Gas Corporation (NCNG) and an equity interest in Eastern North Carolina Natural Gas Company (EasternNC) effective September 30, 2003, and the remaining 50% interest of EasternNC effective October 25, 2005.

	2007	2006	2005	2004	2003
Operating Revenues (in thousands):					
Sales and Transportation:					
Residential	$ 743,637	$ 841,051	$ 686,304	$ 624,487	$ 524,933
Commercial	418,426	498,956	421,499	360,355	299,281
Industrial	190,204	205,384	215,505	179,302	112,986
For Power Generation	29,135	22,963	16,248	18,782	3,071
For Resale	13,907	11,342	40,122	38,074	1,948
Total	1,395,309	1,579,696	1,379,678	1,221,000	942,219
Secondary Market Sales	308,904	337,278	373,353	301,886	273,369
Miscellaneous	7,079	7,654	8,060	6,853	5,234
Total	$ 1,711,292	$ 1,924,628	$ 1,761,091	$ 1,529,739	$ 1,220,822
Gas Volumes Dekatherms (in thousands):					
System Throughput:					
Residential	50,072	49,119	52,966	54,412	52,603
Commercial	33,647	34,476	36,000	35,483	33,648

Industrial	79,266	80,490	81,102	83,957	60,054
For Power Generation	34,096	26,099	25,591	18,580	2,396
For Resale	8,923	8,472	8,779	8,912	623
Total	206,004	198,656	204,438	201,344	149,324
Secondary Market Sales	42,049	40,994	47,057	51,707	45,937

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	2007	2006	2005	2004	2003
Number of Retail Customers Billed (12-month average):					
Residential	835,636	815,579	792,061	771,037	657,965
Commercial	93,472	92,692	91,645	90,328	75,924
Industrial	2,959	3,008	3,146	3,194	2,626
For Power Generation	15	12	16	13	5
For Resale	15	19	15	15	4
Total	932,097	911,310	886,883	864,587	736,524
Average Per Residential Customer:					
Gas Used Dekatherms	59.92	60.23	66.87	70.57	79.95
Revenue	$ 889.90	$ 1,031.23	$ 866.48	$ 809.93	$ 797.81
Revenue Per Dekatherm	$ 14.85	$ 17.12	$ 12.96	$ 11.48	$ 9.98
Cost of Gas (in thousands):					
Natural Gas Commodity Costs	$ 1,055,600	$ 1,229,326	$ 1,226,999	$ 943,890	$ 790,118
Capacity Demand Charges	116,977	99,333	117,287	125,178	89,514
Natural Gas Withdrawn From (Injected Into) Storage, net	(12,815)	15,709	(35,151)	(11,116)	(44,069)
Regulatory Charges (Credits), net	27,365	56,781	(47,183)	(16,582)	2,379
Total	$ 1,187,127	$ 1,401,149	$ 1,261,952	$ 1,041,370	$ 837,942
Supply Available for Distribution (dekatherms in thousands):					
Natural Gas Purchased	143,598	140,999	155,614	163,257	143,716
Transportation Gas	108,355	101,414	97,959	91,795	52,895
Natural Gas Withdrawn From (Injected Into) Storage, net	(1,640)	(197)	856	775	(2,490)
Company Use	(141)	(127)	(133)	(135)	(147)
Total	250,172	242,089	254,296	255,692	193,974

We purchase natural gas under firm contracts to meet our design-day requirements for firm sales customers. These contracts provide that we pay a reservation fee to the supplier to reserve or guarantee the availability of gas supplies for delivery. Under these provisions, absent force majeure conditions, any disruption of supply deliverability is subject to penalty and damage assessment against the supplier. We ensure the delivery of the gas supplies to our distribution system to meet the peak day, seasonal and annual needs of our firm customers by using a variety of firm transportation and storage capacity contracts. The pipeline capacity contracts require the payment of fixed demand charges to reserve firm transportation or storage entitlements. We align the contractual agreements for supply with the firm capacity agreements in terms of volumes, receipt and delivery locations and demand fluctuations. We may supplement these firm contracts with other supply arrangements to serve our interruptible market.

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As of October 31, 2007, we had contracts for the following pipeline firm transportation capacity in dekatherms per day:

Williams-Transco	632,200
El Paso-Tennessee Pipeline	74,100
Spectra-Texas Eastern (through arrangements with East Tennessee and Transco)	37,000
NiSource-Columbia Gas (through arrangements with Transco and Columbia Gulf)	42,800
NiSource-Columbia Gulf	10,000
ONEOK-Midwestern (through arrangements with Tennessee, Columbia Gulf, East Tennessee and Transco)	40,000
Total	836,100

In January 2008, additional transportation capacity of 80,000 dekatherms is anticipated to be added from Midwestern Gas Transmission Company (Midwestern).

As of October 31, 2007, we had the following assets or contracts for local peaking facilities and storage for seasonal or peaking capacity in dekatherms of daily deliverability to meet the firm demands of our markets. This deliverability varies from five days to one year:

Piedmont Liquefied Natural Gas (LNG)	280,000
Pine Needle LNG (through arrangements with Transco)	263,400
Williams-Transco Storage	86,100
NiSource-Columbia Gas Storage	96,400
Hardy Storage (through arrangements with Columbia Gas and Transco)	39,100
Dominion Storage (through arrangements with Transco)	13,200
El Paso-Tennessee Pipeline Storage	55,900
Total	834,100

As of October 31, 2007, we own or have under contract 34.2 million dekatherms of storage capacity, either in the form of underground storage or LNG. This capability is used to supplement or replace regular pipeline supplies.

The source of the gas we distribute is primarily from the Gulf Coast production region, and is purchased primarily from major producers and marketers. The natural gas production, processing and pipeline infrastructure in the Gulf of Mexico has recovered from the hurricane-related supply disruptions of 2005-2006. Natural gas demand is continuing to grow in our service area. As part of our long-term plan to diversify our reliance away from the Gulf Coast region, we are now receiving firm storage service from the Hardy Storage Company, LLC underground facility in West Virginia and firm transportation service from Midwestern that accesses gas supplies from Canada and the Rocky Mountains. For further information on gas supply and regulation, see Gas Supply and Regulatory Proceedings in Item 7 of this Form 10-K and Note 3 to the consolidated financial statements.

During the year ended October 31, 2007, approximately 5% of our margin (operating revenues less cost of gas) was generated from deliveries to industrial or large commercial customers that have the capability to burn a fuel other than natural gas. The alternative fuels are primarily fuel oil and propane and, to a much lesser extent, coal or wood. Our ability to maintain or increase deliveries of gas to these customers depends on a number of factors, including weather conditions, governmental regulations, the price of gas from suppliers and the price of alternate fuels. Under FERC regulations, certain large-volume customers located in proximity to the interstate pipelines delivering gas to us could attempt to bypass us and take delivery of gas directly from the pipeline or from a third party connecting with the pipeline. During the fiscal year ended October 31, 2007, no bypass activity was experienced. The future level of bypass activity cannot be predicted.

The regulated utility competes in the residential and commercial customer markets with other energy products. The most significant competition is between natural gas and electricity for space heating, water heating and cooking. There are four major electric companies within our service areas. We continue to attract the majority of the new residential construction market on or near our distribution mains, and we believe that the consumer s preference for natural gas is influenced by such factors as reliability, comfort, convenience and environmental factors. Natural gas has historically maintained a price advantage over electricity in our service areas; however, with a tighter national supply and demand balance, wholesale natural gas prices and price volatility have increased over recent years. Increases in the price of natural gas can negatively impact our competitive position by decreasing or eliminating the price benefits of natural gas to the consumer.

As indicated above, many of our customers can utilize a fuel other than natural gas, and our ability to maintain industrial market share is largely dependent on price. The relationship between supply and demand has the greatest impact on the price of natural gas. With a tighter balance between domestic supply and demand, the cost of natural gas from non-domestic sources may play a greater role in establishing the future market prices of natural gas. The price of oil depends upon a number of factors beyond our control, including the relationship between supply and demand and the policies of foreign and domestic governments. Our revenues could be impacted, either positively or negatively, as a result of alternate fuel decisions made by industrial customers.

During the year ended October 31, 2007, our largest customer contributed $13.2 million, or less than 1%, to total operating revenues.

Our costs for research and development are not material and are primarily limited to gas industry-sponsored research projects.

Compliance with federal, state and local environmental protection laws have had no material effect on construction expenditures, earnings or competitive position. For further information on environmental issues, see Environmental Matters in Item 7 of this Form 10-K.

As of October 31, 2007, our fiscal year end, we had 1,876 employees, compared with 2,051 as of October 31, 2006.

Our reports on Form 10-K, Form 10-Q and Form 8-K, and amendments to these reports, are available at no cost on our website at www.piedmontng.com as soon as reasonably practicable after the report is filed with or furnished to the Securities and Exchange Commission.

Item 1A. *Risk Factors*

Further increases in the wholesale price of natural gas could reduce our earnings. In recent years, natural gas prices have increased dramatically due to growing demand and limitations on access to North American gas reserves. The cost we pay for natural gas is passed directly through to our customers. Therefore, significant increases in the price of natural gas may cause our existing customers to conserve or motivate them to switch to alternate sources of energy. Significant price increases could also cause new home developers and new customers to select alternative sources of energy. Decreases in the volume of gas we sell could reduce our earnings in the absence of decoupled rate structures, and a decline in new customers could impede growth in our future earnings. In addition, during periods when natural gas prices are significantly higher than historical levels, customers may have trouble paying the resulting higher bills and bad debt expenses may increase and reduce our earnings.

A decrease in the availability of adequate upstream, interstate pipeline transportation capacity and natural gas supply could reduce our earnings. We purchase all of our gas supply from interstate sources that must then be transported to our service territory. Interstate pipeline companies transport the gas to our system under firm service agreements that are designed to meet the requirements of our core markets. A significant disruption to that supply or interstate pipeline capacity due to unforeseen events, including but not limited to, hurricanes, freeze off of natural gas wells, terrorist attacks or other acts of war could reduce our normal interstate supply of gas, which could reduce our earnings. Moreover, if additional natural gas infrastructure, including but not limited to exploration and drilling platforms, processing and gathering systems, off-shore pipelines, interstate pipelines and storage cannot be built at a pace that meets demand, then our growth opportunities would be limited and our earnings negatively impacted.

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Changes in federal laws or regulations could reduce the availability or increase the cost of our interstate pipeline capacity and/or gas supply and thereby reduce our earnings. The FERC has the power to regulate the interstate transportation of natural gas and the terms and conditions of service. Additionally, Congress has enacted laws that deregulate the price of natural gas sold at the wellhead. Any Congressional legislation or agency regulation that would alter these or other similar statutory and regulatory structures in a way to significantly raise costs that could not be recovered in rates from our customers, that would reduce the availability of supply or capacity, or that would reduce our competitiveness would negatively impact our earnings. Furthermore, Congress has for some time been considering various forms of climate change legislation. There is a possibility that, when and if enacted, the final form of such legislation could impact the company s growth and put upward pressure on wholesale natural gas prices.

Weather conditions may cause our earnings to vary from year to year. Our earnings can vary from year to year, depending in part on weather conditions. Currently, we have in place regulatory mechanisms that account for this and normalize our margin for weather, providing for an adjustment up or down, to take into account warmer-than-normal or colder-than-normal weather. We estimate that approximately 50% to 60% of our annual gas sales are to temperature-sensitive customers. As a result, mild winter temperatures can cause a decrease in the amount of gas we sell and deliver in any year. If our rates and tariffs were modified to eliminate weather protection, then we would be exposed to significant risk associated with weather and our earnings could vary as a result.

Governmental actions at the state level could result in lower earnings. Our regulated utility segment is regulated by the NCUC, the PSCSC and the TRA. These agencies set the rates that we charge our customers for our services. If a state regulatory commission were to prohibit us from setting rates that timely recover our costs and a reasonable return by significantly lowering our allowed return or negatively altering our cost allocation, rate design, cost trackers (including margin decoupling, weather normalization and cost of gas) or other tariff provisions, then our earnings could be impacted. Additionally, the state agencies foster a competitive regulatory model that, for example, allows us to recover any margin losses associated with negotiated transactions designed to retain large volume customers that could use alternative fuels or that may directly access natural gas supply through their own connection to an interstate pipeline. If there were changes in regulatory philosophies that altered our ability to compete for these customers, then we could lose customers, or incur significant unrecoverable expenses to retain them. Both scenarios would impact our earnings.

Operational interruptions to our gas distribution activities caused by accidents, strikes, severe weather such as a major hurricane, pandemic or acts of terrorism could adversely impact earnings. Inherent in our gas distribution activities are a variety of hazards and operation risks, such as leaks, ruptures and mechanical problems that, if severe enough or led to operational interruptions, could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental damage, impairment of our operations and substantial loss to us. The location of pipeline and storage facilities near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering places, could increase the level of damages resulting from these risks. Additionally, we have a workforce that is partially represented by the union that exposes us to the risk of a strike. The occurrence of any of these events could adversely affect our financial position, results of operations and cash flows.

Increases in our debt ratios could adversely affect our ability to service our debt obligations and our ability to access capital on favorable terms. An increase in our leverage could adversely affect us by:

- increasing the cost of future debt financing;
- making it more difficult for us to satisfy our existing financial obligations;

limiting our ability to obtain additional financing, if we need it, for working capital, capital expenditures, debt service requirements or other purposes;

increasing our vulnerability to adverse economic and industry conditions;

requiring us to dedicate a substantial portion of our cash flows from operations to payments on our debt, which would reduce funds available for operations, future business opportunities or other purposes; and

limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we compete.

We do not generate sufficient cash flows to meet all our cash needs. Historically, we have made large capital expenditures in order to finance the expansion and upgrading of our distribution system. We have also purchased and will continue to purchase natural gas to store in inventory. Moreover, we have made several equity method investments and will continue to pursue other similar investments, all of which are and will be important to our revenues and profits. We have funded a portion of our cash needs for these purposes, as well as contributions to our employee pensions and benefit plans, through borrowings under credit arrangements and by offering new securities in the market. Our dependency on external sources of financing creates the risks that our profits could decrease as a result of high capital costs and that we may not be able to secure external sources of cash necessary to fund our operations and new investments on terms acceptable to us.

As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all of our outstanding obligations in the event of a default on our part. The terms of our senior indebtedness, including our credit facility, contain cross-default provisions which provide that we will be in default under such agreements in the event of certain defaults under the indenture or other loan agreements. Accordingly, should an event of default occur under any of those agreements, we face the prospect of being in default under all of our debt agreements, obliged in such instance to satisfy all of our outstanding indebtedness and unable to satisfy all of our outstanding obligations simultaneously. In such an event, we might not be able to obtain alternative financing or, if we are able to obtain such financing, we might not be able to obtain it on terms acceptable to us.

We are exposed to credit risk of counterparties with whom we do business. Adverse economic conditions affecting, or financial difficulties of, counterparties with whom we do business could impair the ability of these counterparties to pay for our services or fulfill their contractual obligations. We depend on these counterparties to remit payments or fulfill their contractual obligations on a timely basis. Any delay or default in payment or failure of the counterparties to meet their contractual obligation could adversely affect our financial position, results of operations or cash flows.

Poor investment performance of pension plan holdings and other factors impacting pension plan costs could unfavorably impact our liquidity and results of operations. Our costs of providing a non-contributory defined benefit pension plan is dependent on a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plan, future government regulation and our required or voluntary contributions made to the plan. Without sustained growth in the pension investments over time to increase the value of our plan assets and depending upon the other factors impacting our cost as listed above, we could be required to fund our plan with significant amounts of cash. Such cash funding obligations could have a material impact on our liquidity by reducing cash flows and could negatively affect results of operations.

We are subject to numerous environmental laws and regulations that may require significant expenditures or increase operating costs. We are subject to numerous federal and state environmental laws and regulations affecting many aspects of our present and future operations. These laws and regulations can result in increased capital, operating and other costs. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and approvals. Compliance with these laws and regulations can require significant expenditures for clean-up costs and damages arising out of contaminated properties. Failure to comply may result in fines, penalties and injunctive measures affecting operating assets.

An overall economic downturn could negatively impact our earnings. A lower level of economic activity in our markets could result in a decline in customer additions and energy consumption which could adversely affect our revenues or restrict our future growth. Additionally, a significant slow down in the housing market in our service area could restrict our future growth and negatively impact our earnings.

Our inability to attract and retain professional and technical employees could impact our earnings. Our ability to implement our business strategy and serve our customers is dependent upon the continuing ability to employ talented professionals and attract and retain a technically skilled workforce. Without such a skilled workforce, our ability to provide quality service to our customers and meet our regulatory requirements will be challenged and this could negatively impact our earnings.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

All property included in the consolidated balance sheets in Utility Plant is owned by us and used in our regulated utility segment. This property consists of intangible plant, production plant, storage plant, transmission plant, distribution plant and general plant as categorized by natural gas utilities, with 94% of the total invested in utility distribution and transmission plant to serve our customers. We have approximately 3,100 miles of lateral pipelines up to 30 inches in diameter that connect our distribution systems with the transmission systems of our pipeline suppliers. We distribute natural gas through approximately 23,900 miles (three-inch equivalent) of distribution mains. The lateral pipelines and distribution mains are located on or under public streets and highways, or property owned by others, for which we have obtained the necessary legal rights to place and operate our facilities on private property. All of these properties are located in North Carolina, South Carolina and Tennessee. Utility Plant includes Construction work in progress which primarily represents distribution, transmission and general plant projects that have not been placed into service pending completion.

None of our property is encumbered and all property is in use.

We own or lease for varying periods our corporate headquarters building located in Charlotte, North Carolina and district and regional offices in the locations shown below. Lease payments for these various offices totaled $3.9 million for the year ended October 31, 2007.

North Carolina	**South Carolina**	**Tennessee**
Burlington	Anderson	Nashville
Cary	Gaffney	
Charlotte	Greenville	
Elizabeth City	Spartanburg	
Fayetteville		
Goldsboro		
Greensboro		
Hickory		
High Point		
Indian Trail		
New Bern		
Reidsville		
Rockingham		
Salisbury		
Spruce Pine		
Tarboro		

Wilmington
Winston-Salem

Property included in the consolidated balance sheets in "Other Physical Property" is owned by the parent company and one of its subsidiaries. The property owned by the parent company primarily consists of residential and commercial water heaters leased to natural gas customers. The property owned by the subsidiary is real estate. None of our other subsidiaries directly own property as their operations consist solely of participating in joint ventures as an equity member.

Item 3. *Legal Proceedings*

We have only routine litigation in the normal course of business.

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

No matters were submitted to a vote of security holders during our fourth quarter ended October 31, 2007.

PART II

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

(a) Our common stock (symbol PNY) is traded on the New York Stock Exchange (NYSE). The following table provides information with respect to the high and low sales prices from the NYSE Composite for each quarterly period for the years ended October 31, 2007 and 2006.

2007	**High**	**Low**
Quarter ended:		
January 31	$ 28.44	$ 25.78
April 30	27.50	24.33
July 31	27.50	22.00
October 31	27.50	23.09

2006	**High**	**Low**
Quarter ended:		
January 31	$ 24.94	$ 21.26
April 30	25.23	23.21
July 31	26.17	23.31
October 31	27.27	24.72

(b) As of December 20, 2007, our common stock was owned by 15,660 shareholders of record.

(c) The following table provides information with respect to quarterly dividends paid on common stock for the years ended October 31, 2007 and 2006. We expect that comparable cash dividends will continue to be paid in the future.

2007	**Dividends Paid Per Share**
Quarter ended:	
January 31	24¢
April 30	25¢
July 31	25¢

October 31	25¢

2006	**Dividends Paid Per Share**
Quarter ended:	
January 31	23¢
April 30	24¢
July 31	24¢
October 31	24¢

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The amount of cash dividends that may be paid on common stock is restricted by provisions contained in certain note agreements under which long-term debt was issued, with those for the senior notes being the most restrictive. We cannot pay or declare any dividends or make any other distribution on any class of stock or make any investments in subsidiaries or permit any subsidiary to do any of the above (all of the foregoing being restricted payments) except out of net earnings available for restricted payments. As of October 31, 2007, net earnings available for restricted payments were greater than retained earnings; therefore, our retained earnings were not restricted.

The following table provides information with respect to repurchases of our common stock under the Common Stock Open Market Purchase Program during the fourth quarter ended October 31, 2007.

Period	**Total Number of Shares Purchased**	**Average Price Paid per Share**	**Total Number of Shares Purchased as Part of Publicly Announced Program**	**Maximum Number of Shares that May Yet be Purchased Under the Program ***
				4,612,074
8/1/07 8/31/07		$		4,612,074
9/1/07 9/30/07		$		4,612,074
10/1/07 10/31/07		$		4,612,074
Total		$		

* The Common Stock Open Market Purchase Program was announced on June 4, 2004, to purchase up to three million shares of common stock for reissuance under our dividend reinvestment, stock purchase and incentive compensation plans. On December 16, 2005, the Board of Directors approved an increase in the number of shares in this program from three million to six million to reflect the two-for-one stock split in 2004. The Board also approved on that date an amendment of the Common Stock Open Market Purchase Program to provide for the purchase of up to four million additional shares of common stock to maintain our debt-to-equity capitalization ratios at target levels. These combined actions increased the total authorized share repurchases from three million to ten million shares. The additional four million shares are referred to as our accelerated share repurchase (ASR) program and have an expiration date of December 31, 2010.

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Comparisons of Cumulative Total Shareholder Returns

The following performance graph compares the Company s cumulative total shareholder return from October 31, 2002, through October 31, 2007 (a five-year period), with the Standard & Poor s 500 Stock Index, a broad market index (the S&P 500), and with our utility peer group. Large natural gas distribution companies that are representative of our peers in the natural gas distribution industry are included in the LDC Peer Group index.

The graph assumes that the value of an investment in Common Stock and in each index was $100 at October 31, 2002, and that all dividends were reinvested. Stock price performances shown on the graph are not indicative of future price performances.

Comparisons of Five-Year Cumulative Total Returns
Value of $100 Invested as of October 31, 2002

LDC Peer Group The following companies are included: AGL Resources, Inc., Atmos Energy Corporation, New Jersey Resources, NICOR, Inc., NiSource, Inc., Northwest Natural Gas Company, Piedmont Natural Gas Company, Southwest Gas Corporation, Vectren Corporation and WGL Holdings, Inc.

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Item 6. *Selected Financial Data*

The following table provides selected financial data for the years ended October 31, 2003 through 2007. The information presented is not comparable for all periods due to the acquisitions of North Carolina Natural Gas Corporation (NCNG) and an equity interest in Eastern North Carolina Natural Gas Company (EasternNC) effective September 30, 2003, and the remaining 50% interest of EasternNC effective October 25, 2005, as discussed in Note 2 to the consolidated financial statements.

	2007	2006	2005	2004	2003
			In thousands except per share amounts		
Operating Revenues	$ 1,711,292	$ 1,924,628	$ 1,761,091	$ 1,529,739	$ 1,220,822
Margin (Operating Revenues less Cost of Gas)	$ 524,165	$ 523,479	$ 499,139	$ 488,369	$ 382,880
Net Income	$ 104,387	$ 97,189	$ 101,270	$ 95,188	$ 74,362
Earnings per Share of Common Stock:					
Basic	$ 1.41	$ 1.28	$ 1.32	$ 1.28	$ 1.11
Diluted	$ 1.40	$ 1.28	$ 1.32	$ 1.27	$ 1.11
Cash Dividends per Share of Common Stock	$ 0.990	$ 0.950	$ 0.905	$ 0.8525	$ 0.8225
Total Assets	$ 2,820,318	$ 2,733,939	$ 2,602,490	$ 2,392,164	$ 2,339,283
Long-Term Debt (less current maturities)	$ 824,887	$ 825,000	$ 625,000	$ 660,000	$ 460,000

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

Forward-Looking Statements

This report as well as other documents we file with the Securities and Exchange Commission (SEC) may contain forward-looking statements. In addition, our senior management and other authorized spokespersons may make forward-looking statements in print or orally to analysts, investors, the media and others. These statements are based on management s current expectations and information currently available and are believed to be reasonable and are made in good faith. However, the forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those projected in the statements. Factors that may make the actual results differ from anticipated results include, but are not limited to:

Regulatory issues affecting us and those from whom we purchase natural gas transportation and storage service, including those that affect allowed rates of return, terms and conditions of service, rate structures and financings. We monitor our effectiveness in achieving the allowed rates of return and initiate rate proceedings or operating changes as needed.

Residential, commercial and industrial growth in our service areas. The ability to grow our customer base and the pace of that growth are impacted by general business and economic conditions, such as interest rates, inflation, fluctuations in the capital markets and the overall strength of the economy in our service areas and the country, and fluctuations in the wholesale prices of natural gas and competitive energy sources.

Deregulation, regulatory restructuring and competition in the energy industry. We face competition from electric companies and energy marketing and trading companies, and we expect this competitive environment to continue. We must be able to adapt to the changing environments and the competition.

The potential loss of large-volume industrial customers to alternate fuels or to bypass, or the shift by such customers to special competitive contracts or to tariff rates that are at lower per-unit margins than that customer s existing rate.

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Regulatory issues, customer growth, deregulation, economic and capital market conditions, the cost and availability of natural gas and weather conditions can impact our ability to meet internal performance goals.

The capital-intensive nature of our business. In order to maintain growth, we must add to our natural gas distribution system each year. The cost of this construction may be affected by the cost of obtaining governmental approvals, compliance with federal and state pipeline safety and integrity regulations, development project delays and changes in project costs. Weather, general economic conditions and the cost of funds to finance our capital projects can materially alter the cost of a project.

Capital market conditions. Our internally generated cash flows are not adequate to finance the full cost of capital expenditures. As a result, we rely on access to both short-term and long-term capital markets as a significant source of liquidity for capital requirements not satisfied by cash flows from operations. Changes in the capital markets could affect access to and cost of capital.

Changes in the availability and cost of natural gas. To meet firm customer requirements, we must acquire sufficient gas supplies and pipeline capacity to ensure delivery to our distribution system while also ensuring that our supply and capacity contracts allow us to remain competitive. Natural gas is an unregulated commodity market subject to supply and demand and price volatility. Producers, marketers and pipelines are subject to operating and financial risks associated with exploring, drilling, producing, gathering, marketing and transporting natural gas and have risks that increase our exposure to supply and price fluctuations.

Changes in weather conditions. Weather conditions and other natural phenomena can have a material impact on our earnings. Severe weather conditions, including destructive weather patterns such as hurricanes, can impact our suppliers and the pipelines that deliver gas to our distribution system. Weather conditions directly influence the supply of, demand for and the cost of natural gas.

Changes in environmental, safety and system integrity regulations and the cost of compliance. We are subject to extensive federal, state and local regulations. Compliance with such regulations may result in increased capital or operating costs.

Ability to retain and attract professional and technical employees. To provide quality service to our customers and meet regulatory requirements, we are dependent on our ability to recruit, train, motivate and retain qualified employees.

Changes in accounting regulations and practices. We are subject to accounting regulations and practices issued periodically by accounting standard-setting bodies. New accounting standards may be issued that could change the way we record revenues, expenses, assets and liabilities. Future changes in accounting standards could affect our reported earnings or increase our liabilities.

Earnings from our equity method investments. We invest in companies that have risks that are inherent in their businesses and we assume such risks as an equity investor.

Other factors may be described elsewhere in this report. All of these factors are difficult to predict and many of them are beyond our control. For these reasons, you should not rely on these forward-looking statements when making investment decisions. When used in our documents or oral presentations, the words expect, believe, project, anticipa intend, should, could, will, assume, can, estimate, forecast, future, indicate, outlook, plan, and variations of such words and similar expressions are intended to identify forward-looking statements.

Forward-looking statements are only as of the date they are made and we do not undertake any obligation to update publicly any forward-looking statement either as a result of new information, future events or otherwise except as required by applicable laws and regulations. Please reference our website at www.piedmontng.com for current information. Our reports on Form 10-K, Form 10-Q and Form 8-K and amendments to these reports are available at no cost on our website as soon as reasonably practicable after the report is filed with or furnished to the SEC.

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Overview

Piedmont Natural Gas Company is an energy services company whose principal business is the distribution of natural gas to residential, commercial and industrial customers in portions of North Carolina, South Carolina and Tennessee. We also have equity method investments in joint venture, energy-related businesses. Our operations are comprised of two business segments the regulated utility segment and the non-utility activities segment.

The regulated utility segment is the largest segment of our business with approximately 97% of our consolidated assets. This segment is regulated by three state regulatory commissions that approve rates and tariffs that are designed to give us the opportunity to generate revenues to cover our gas and non-gas costs and to earn a fair rate of return for our shareholders. Factors critical to the success of the regulated utility include a safe, reliable natural gas distribution system and the ability to recover the costs and expenses of the business in rates charged to customers. For the twelve months ended October 31, 2007, 79% of our earnings before taxes came from our regulated utility segment.

The non-utility activities segment consists of our equity method investments in joint venture, energy-related businesses that are involved in unregulated retail natural gas marketing, interstate natural gas storage and intrastate natural gas transportation. We invest in joint ventures that are aligned with our business strategies to complement or supplement income from utility operations. We continually monitor performance of these ventures against expectations.

Weather conditions directly influence the volumes of natural gas delivered by the regulated utility. Significant portions of our revenues are generated during the winter season. During warm winters or unevenly cold winters, heating customers may significantly reduce their consumption of natural gas. In South Carolina and Tennesee, we have weather normalization adjustment (WNA) mechanisms that are designed to protect a portion of our revenues against warmer-than-normal weather as deviations from normal weather can affect our financial performance and liquidity. The WNA also serves to offset the impact of colder-than-normal weather by reducing the amounts we can charge our customers. In North Carolina, a Customer Utilization Tracker (CUT) provides for the recovery of our approved margin from residential and commercial customers independent of both weather and other consumption patterns. For further information, see Note 3 to the consolidated financial statements.

The majority of our natural gas supplies come from the Gulf Coast region. We believe that diversification of our supply portfolio is in our customers best interest. In January 2008, we anticipate receiving firm, long-term transportation contract service from Midwestern Gas Transmission Company (Midwestern) that will provide access to Canadian and Rocky Mountain gas supplies and the Chicago hub, primarily to serve our Tennessee markets. In April 2007, we began receiving firm, long-term market area storage service from Hardy Storage Company, LLC (Hardy Storage), a new storage facility in West Virginia.

Our strategic focus is on our core business of providing safe, reliable and quality natural gas distribution service to our customers in the growing Southeast market area. Part of our strategic plan is to manage our gas distribution business through control of our operating costs, implementation of new technologies and sound rate and regulatory initiatives. We are working to enhance the value and growth of our utility assets by good management of capital spending, including improvements for current customers and the pursuit of customer growth opportunities in our service areas. We strive for quality customer service by investing in technology, processes and people. We work with our state regulators to maintain fair rates of return and balance the interests of our customers and shareholders.

As part of our ongoing effort to improve business processes and customer service, and capture operational and organizational efficiencies, we are in the process of standardizing our customer payment and collection processes and streamlining business operations.

We seek to maintain a long-term debt-to-capitalization ratio within a range of 45% to 50%. We also seek to maintain a strong balance sheet and investment-grade credit ratings to support our operating and investment needs.

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Results of Operations

The following tables present our financial highlights for the years ended October 31, 2007, 2006 and 2005.

Income Statement Components

				Percent Change	
	2007	2006	2005	2007 vs. 2006	2006 vs. 2005
	In thousands, except per share amounts				
Operating Revenues	$ 1,711,292	$ 1,924,628	$ 1,761,091	(11.1)%	9.3%
Cost of Gas	1,187,127	1,401,149	1,261,952	(15.3)%	11.0%
Margin	524,165	523,479	499,139	0.1%	4.9%
Operations and Maintenance	214,442	219,353	206,983	(2.2)%	6.0%
Depreciation	88,654	89,696	85,169	(1.2)%	5.3%
General Taxes	32,407	33,138	29,807	(2.2)%	11.2%
Income Taxes	51,315	50,543	51,880	1.5%	(2.6)%
Total Operating Expenses	386,818	392,730	373,839	(1.5)%	5.1%
Operating Income	137,347	130,749	125,300	5.0%	4.3%
Other Income (Expense), net of tax	24,312	18,750	20,828	29.7%	(10.0)%
Utility Interest Charges	57,272	52,310	44,256	9.5%	18.2%
Income before Minority Interest in Income of Consolidated Subsidiary	104,387	97,189	101,872	7.4%	(4.6)%
Less Minority Interest in Income of Consolidated Subsidiary			602	n/a	n/a
Net Income	$ 104,387	$ 97,189	$ 101,270	7.4%	(4.0)%
Average Shares of Common Stock:					
Basic	74,250	75,863	76,680	(2.1)%	(1.1)%
Diluted	74,472	76,156	76,992	(2.2)%	(1.1)%
Earnings Per Share of Common Stock:					
Basic	$ 1.41	$ 1.28	$ 1.32	10.2%	(3.0)%
Diluted	$ 1.40	$ 1.28	$ 1.32	9.4%	(3.0)%

Gas Deliveries, Customers, Weather Statistics and Number of Employees

Percent Change	
2007 vs.	2006 vs.

Gas Sales and Deliveries in Dekatherms (in thousands)	**2007**	**2006**	**2005**	**2006**	**2005**
Sales Volumes	105,606	105,728	113,021	(0.1)%	(6.5)%
Transportation Volumes	100,398	92,928	91,417	8.0%	1.7%
Throughput	206,004	198,656	204,438	3.7%	(2.8)%
Secondary Market Volumes	42,049	40,994	47,057	2.6%	(12.9)%
Customers Billed (at period end)	922,961	903,368	877,418	2.2%	3.0%
Gross Customer Additions	30,437	34,445	32,751	(11.6)%	5.2%
Degree Days					
Actual	2,977	3,192	3,266	(6.7)%	(2.3)%
Normal	3,388	3,386	3,455	0.1%	(2.0)%
Percent colder (warmer) than normal	(12.1)%	(5.7)%	(5.5)%	n/a	n/a
Number of Employees (at period end)	1,876	2,051	2,124	(8.5)%	(3.4)%

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Net income increased $7.2 million in 2007 compared with 2006 primarily due to the following changes which increased net income:

$7.2 million increase in earnings from equity method investments.

$1.1 million increase in non-operating income.

$.7 million increase in margin (operating revenues less cost of gas).

$4.9 million decrease in operations and maintenance expenses, primarily due to organizational restructuring and process improvement initiatives.

$1 million decrease in depreciation.

$.7 million decrease in general taxes.

These changes were partially offset by the following changes which decreased net income:

$5 million increase in utility interest charges.

$3.2 million increase in income taxes.

Net income decreased $4.1 million in 2006 compared with 2005 primarily due to the following changes which decreased net income:

$12.4 million increase in operations and maintenance expenses, primarily due to restructuring charges and customer service initiatives.

$8.1 million increase in utility interest charges.

$4.5 million increase in depreciation expense.

$3.3 million increase in general taxes.

$1.7 million decrease from the non-recurring 2005 gain on the sale of corporate office land.

$1.6 million increase related to the non-recurring 2005 income tax expense true-up of the effective federal income tax rate following the sale of our propane interests.

$1.5 million decrease from the non-recurring 2005 gain on the sale of marketable securities.

These changes were partially offset by the following changes which increased net income:

$24.3 million increase in margin.

$2.3 million increase in earnings from equity method investments.

$1.4 million decrease in charitable contributions.

$.6 million decrease from the 2005 inclusion of minority interest in income of consolidated subsidiary.

Operating revenues in 2007 decreased $213.3 million compared with 2006 primarily due to the following decreases:

$212.9 million from lower commodity gas costs passed through to customers.

$28.4 million lower revenues from secondary market transactions. Secondary market transactions consist of off-system sales and capacity release arrangements.

These decreases were partially offset by the following increases:

$26.4 million related to non-commodity components in rates.

$5.2 million from increased volumes delivered to transportation customers.

$2.3 million from revenues under the WNA in South Carolina and Tennessee.

$2.3 million from revenues under the CUT in North Carolina.

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Operating revenues in 2006 increased $163.5 million compared with 2005 primarily due to the following increases:

$197.8 million from increased commodity gas costs passed through to customers.

$30.4 million from the CUT mechanism put in place as of November 1, 2005, as compared with the North Carolina WNA surcharge in 2005 of $4.7 million. As discussed in Financial Condition and Liquidity below, the CUT mechanism was in place throughout 2006, to adjust for variations in residential and commercial use per customer which may be due to conservation and/or weather. The CUT replaced the WNA in North Carolina in 2006.

These increases were partially offset by the following decreases:

$36.1 million from secondary market activity.

$32.6 million from changes in the composition of delivery services, including the impacts of sales revenues versus transportation revenues and sales and transportation services to power generation customers.

In general rate proceedings, state regulatory commissions authorize us to recover a margin, which is the applicable billing rate less cost of gas, on each unit of gas delivered. The commissions also authorize us to recover margin losses resulting from negotiating lower rates to industrial customers when necessary to remain competitive. The ability to recover such negotiated margin reductions is subject to continuing regulatory approvals.

Cost of gas in 2007 decreased $214 million compared with 2006 primarily due to decreases of $212.9 million from lower commodity gas costs passed through to sales customers.

Cost of gas in 2006 increased $139.2 million compared with 2005 primarily due to $197.8 million from increased commodity gas costs, partially offset by the following decreases:

$37.6 million from lower secondary market activity.

$28.6 million from lower volumes and changes in the composition of delivery services.

Our utility margin is defined as natural gas revenues less natural gas commodity purchases and fixed gas costs for upstream capacity. Margin, rather than revenues, is used by management to evaluate utility operations due to the impact of volatile wholesale commodity gas costs, which account for approximately 62% of revenues for the twelve months ended October 31, 2007. The company is authorized to recover from customers all prudently incurred wholesale commodity gas costs.

Our utility margin is impacted also by certain regulatory mechanisms as defined elsewhere in this document. These include WNA in Tennessee and South Carolina, the Natural Gas Rate Stabilization in South Carolina, secondary market activity in North Carolina and South Carolina, Tennessee Incentive Plan in Tennessee, CUT in North Carolina, negotiated loss treatment in all three jurisdictions and the collection of uncollectible gas costs in all three jurisdictions. We retain 25% of secondary market margins generated through off-system sales and capacity release activity in all jurisdictions, with 75% credited to customers through the incentive plans.

Margin increased $.7 million in 2007 compared with 2006 primarily due to the following increases:

$3.9 million from a new power generation customer.

$4 million net increase, which includes a net increase of 20,800 residential and commercial customers billed (twelve-month average) and an increase of $5.6 million in base rates in South Carolina, partially offset by a decrease in consumption related to warmer-than-normal weather and conservation.

These increases were partially offset by the following decreases:

$4.6 million from the regulatory ruling that discontinued the capitalizing and amortizing of storage demand charges.

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$1.9 million from adjustments related to compensating meter indices.

$1.2 million from adjustments related to the North Carolina 2006 gas cost accounting review.

Margin increased $24.3 million in 2006 compared with 2005 primarily due to growth in the residential and commercial customer base, plus base rate increases of $22.8 million. This net increase was negatively impacted by decreased consumption because of conservation in the residential and commercial classes in South Carolina and Tennessee.

Operations and maintenance expenses decreased $4.9 million in 2007 compared with 2006 primarily due to the following decreases:

$11 million in payroll primarily related to the management restructuring program in 2006, including impacts on short-term and long-term incentive plan accruals. For further information, see Note 13 to the consolidated financial statements.

$.6 million in transportation costs primarily due to fewer vehicles being used as a result of our automated meter reading initiative and continuous business process improvements.

These decreases were partially offset by the following increases:

$3.2 million in outside services primarily due to increased telephony services and our gas accounting, financial close and record retention projects.

$2 million in employee benefits primarily due to pension and postretirement health care costs and health initiative programs and adjustments in group insurance expense.

$1.3 million in regulatory expense primarily due to consulting related to gas cost accounting reviews.

Operations and maintenance expenses increased $12.4 million in 2006 compared with 2005 primarily due to the following increases:

$7.4 million in payroll primarily due to $7.9 million in one-time costs associated with the management restructuring program, increases in long-term incentive plan accruals and costs associated with providing improved customer service, partially offset by decreases in accruals for short-term incentive plans. For further information, see Note 13 to the consolidated financial statements.

$6 million in outside services primarily due to our enhanced customer service initiative.

$1.8 million in rents and leases due to leasing of corporate office space, partially offset by a reduction of 2006 expenses related to copier leases.

$2 million in other corporate expense primarily due to $.5 million of conservation programs approved by the North Carolina Utilities Commission (NCUC) as a part of a rate case settlement and $.75 million in conservation programs under the CUT settlement, and amortization of deferred operations and maintenance expenses of EasternNC. For further information, see Note 3 to the consolidated financial statements.

These increases were partially offset by the following decreases:

$2.2 million in postretirement health care and life insurance costs.

$1.3 million in the provision for uncollectibles.

$.8 million from reduced telecommunications costs.

$.8 million from reduced risk insurance premium costs.

Depreciation expense increased from $85.2 million to $88.7 million over the three-year period 2005 to 2007 primarily due to increases in plant in service, partially offset by plant retirements of short-lived technology assets in 2007.

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General taxes decreased $.7 million in 2007 compared with 2006 primarily due to the following changes:

$1.2 million decrease in property taxes related to lower assessments in South Carolina and Tennessee as well as refunds from South Carolina for prior years.

$.5 million decrease in payroll taxes.

$.9 million increase in gross receipts taxes in Tennessee.

General taxes increased $3.3 million in 2006 compared with 2005 primarily due to the following changes:

$2.2 million increase in property taxes.

$.6 million increase in other gross receipts taxes.

$.5 million increase in payroll taxes.

Income from equity method investments increased $7.2 million in 2007 compared with 2006 due to the following changes:

$5.3 million increase in earnings from SouthStar primarily due to hedging activities and retail price spreads.

$2.8 million increase in earnings from Hardy Storage primarily due to storage revenues in 2007 as phase one service to customers began in April 2007.

$.6 million decrease in earnings from Pine Needle due to reduced rates approved by the Federal Energy Regulatory Commission (FERC) in Pine Needle s 2007 rate proceeding.

Income from equity method investments increased $2.3 million in 2006 compared with 2005 primarily due to increases in earnings from SouthStar of $.9 million, Pine Needle of $.3 million and Hardy Storage of $1 million.

The gain on sale of marketable securities of $1.5 million in 2005 resulted from the sale in February 2005 of common units of Energy Transfer Partners, L.P., which we received in connection with the sale of our propane interests in 2004.

Non-operating income is comprised of non-regulated merchandising and service work, subsidiary operations, interest income and other miscellaneous income. Non-operating income in 2005 included a pre-tax gain on the sale of the corporate office land of $1.7 million.

Charitable contributions decreased $1.4 million in 2006 compared with 2005 primarily due to the $1 million contribution made to the Piedmont Natural Gas Foundation in 2005.

Utility interest charges increased $5 million in 2007 compared with 2006 primarily due to the following changes:

$5.5 million increase in interest on long-term debt due to the issuance on June 20, 2006 of $200 million of insured quarterly notes due June 1, 2036, which was partially offset by the retirement on July 30, 2006 of $35 million of senior notes.

$.9 million increase in interest expense on regulatory treatment of certain components of deferred income taxes.

$.9 million increase in interest expense related to a tax audit settlement.

$.4 million decrease in net interest expense on amounts due to/from customers due to higher net receivables in 2007.

$2.1 million decrease in interest on short-term debt due to lower balances outstanding in 2007 than in 2006 even though rates were slightly higher in the current period. See further discussion in Financial Condition and Liquidity below.

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Utility interest charges increased $8.1 million in 2006 compared with 2005 primarily due to the following changes:

$6.5 million increase in interest on short-term debt due to higher balances outstanding at interest rates that were approximately two percentage points higher in 2006 than in 2005. See further discussion in Financial Condition and Liquidity below.

$3.7 million increase in interest on long-term debt due to the issuance on June 20, 2006 of $200 million of insured quarterly notes due June 1, 2036.

$2.1 million decrease in net interest expense on amounts due to/from customers due to higher net receivables in 2006.

$.8 million decrease due to an increase in allowance for funds used during construction allocated to debt.

$.5 million increase in interest expense on regulatory treatment of certain components of deferred income taxes.

Our Business

Piedmont Natural Gas Company, Inc., which began operations in 1951, is an energy services company whose principal business is the distribution of natural gas to over one million residential, commercial and industrial customers in portions of North Carolina, South Carolina and Tennessee, including 62,000 customers served by municipalities who are our wholesale customers. We are invested in joint venture, energy-related businesses, including unregulated retail natural gas marketing, interstate natural gas storage and intrastate natural gas transportation.

In 1994, our predecessor, which was incorporated in 1950 under the same name, was merged into a newly formed North Carolina corporation for the purpose of changing our state of incorporation to North Carolina.

We continually assess the nature of our business and explore alternatives in our core business of traditional utility regulation. Non-traditional ratemaking initiatives and market-based pricing of products and services provide additional opportunities and challenges for us. We also regularly evaluate opportunities for obtaining natural gas supplies from different production regions and supply sources to maximize our natural gas portfolio flexibility and reliability. For further information, see Gas Supply and Regulatory Proceedings below and Note 3 and Note 6 to the consolidated financial statements.

We have two reportable business segments, regulated utility and non-utility activities. For further information on business segments, see Note 12 to the consolidated financial statements.

Our utility operations are regulated by the NCUC, the Public Service Commission of South Carolina (PSCSC) and the Tennessee Regulatory Authority (TRA) as to rates, service area, adequacy of service, safety standards, extensions and abandonment of facilities, accounting and depreciation. We are also regulated by the NCUC as to the issuance of securities. We are also subject to or affected by various federal regulations. These federal regulations include regulations that are particular to the natural gas industry, such as regulations of the FERC that affect the availability of and the prices paid for the interstate transportation and storage of natural gas, regulations of the Department of Transportation that affect the construction, operation, maintenance, integrity and safety of natural gas distribution and transmission systems, and regulations of the Environmental Protection Agency relating to the use and release into the environment of hazardous wastes. In addition, we are subject to numerous regulations, such as those relating to employment practices, which are generally applicable to companies doing business in the United States of America.

In the Carolinas, our service area is comprised of numerous cities, towns and communities. We provide service to Anderson, Gaffney, Greenville and Spartanburg in South Carolina and Charlotte, Salisbury, Greensboro, Winston-Salem, High Point, Burlington, Hickory, Indian Trail, Spruce Pine, Reidsville, Fayetteville, New Bern, Wilmington, Tarboro, Elizabeth City, Rockingham and Goldsboro in North Carolina. In North Carolina, we also provide wholesale natural gas service to Greenville, Monroe, Rocky Mount and

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Wilson. In Tennessee, our service area is the metropolitan area of Nashville, including wholesale natural gas service to Gallatin and Smyrna.

Our regulatory commissions approve rates and tariffs that are designed to give us the opportunity to generate revenues to cover our gas and non-gas costs and to earn a fair rate of return for our shareholders. Through October 31, 2005, we had WNA mechanisms in all three states that partially offset the impact of colder-than-normal or warmer-than-normal weather on bills rendered during the months of November through March for residential and commercial customers. The WNA formula calculates the actual weather variance from normal, using 30 years of history, which results in an increase in revenues when weather is warmer than normal and a decrease in revenues when weather is colder than normal. The gas cost portion of our costs is recoverable through purchased gas adjustment (PGA) procedures and is not affected by the WNA. Effective November 1, 2005, the WNA was eliminated in North Carolina and replaced with the CUT that provides for the recovery of our approved margin from residential and commercial customers independent of both weather and other consumption patterns. The CUT tracks our margin earned monthly and results in semi-annual rate adjustments to refund any over-collection or recover any under-collection. For further information on the CUT, see Note 3 to the consolidated financial statements.

We invest in joint ventures to complement or supplement income from our regulated utility operations. If an opportunity aligns with our overall business strategies and allows us to leverage the strengths of our markets along with our core abilities, we analyze and evaluate the project with a major factor being a projected rate of return greater than the returns allowed in our utility operations, due to the higher risk of such projects. We participate in the governance of the venture by having a management representative on the governing board of the venture. We monitor actual performance against expectations. Decisions regarding existing joint ventures are based on many factors, including performance results and continued alignment with our business strategies.

Financial Condition and Liquidity

To meet our capital and liquidity requirements, we rely on certain resources, including cash flows from operating activities, access to capital markets, cash generated from our investments in joint ventures and short-term bank borrowings. We believe that these sources will continue to allow us to meet our needs for working capital, construction expenditures, investments in joint ventures, anticipated debt redemptions and dividend payments.

Cash Flows from Operating Activities. The natural gas business is seasonal in nature. Operating cash flows may fluctuate significantly during the year and from year to year due to working capital changes within our utility and non-utility operations resulting from such factors as weather, natural gas purchases and prices, natural gas storage activity, collections from customers and deferred gas cost recoveries. We rely on operating cash flows and short-term bank borrowings to meet seasonal working capital needs. During our first and second quarters, we generally experience overall positive cash flows from the sale of flowing gas and gas in storage and the collection of amounts billed to customers during the peak heating season (November through March). Cash requirements generally increase during the third and fourth quarters due to increases in natural gas purchases for storage, paying down short-term debt and decreases in receipts from customers.

During the peak heating season, our accounts payable increase to reflect amounts due to our natural gas suppliers for commodity and pipeline capacity. The cost of the natural gas can vary significantly from period to period due to volatility in the price of natural gas, which is a function of market fluctuations in the price of natural gas, along with our changing requirements for storage volumes. Differences between natural gas costs that we have paid to suppliers and amounts that we have collected from customers are included in amounts due to/from customers. These natural gas costs can cause cash flows to vary significantly from period to period along with variations in the timing of collections from customers under our gas cost recovery mechanisms.

Cash flows from operations are impacted by weather, which affects gas purchases and sales. Warmer weather can lead to lower revenues from fewer volumes of natural gas sold or transported. Colder weather can increase volumes sold to weather-sensitive customers, but may lead to conservation by customers in order to reduce their heating bills. Temperatures above normal can lead to reduced operating cash flows, thereby increasing the need for short-term borrowings to meet current cash requirements.

Net cash provided by operating activities was $233.5 million in 2007, $103.8 million in 2006 and $183.4 million in 2005. Net cash provided by operating activities reflects a $7.2 million increase in net income for 2007, compared with 2006, as well as changes in working capital as described below:

Trade accounts receivable and unbilled utility revenues decreased $15.4 million primarily due to a decrease in unbilled volumes of 2 million dekatherms at year end compared with the prior year end due to the current period being 12% warmer than normal and 7% warmer than the similar prior period.

Amounts due to/from customers decreased $13.6 million related to the deferral of gas costs yet to be billed and collected from customers, partially offset by the CUT.

Gas in storage decreased $6.7 million primarily due to a regulatory mandated charge of $5.4 million from discontinuing the accounting practice of the capitalization of storage demand charges in 2007 and a decrease in the amount of inventory storage dekatherms in 2007 as compared with 2006.

Prepaid gas costs increased $15.3 million primarily due to the addition of the Hardy storage facility. Under asset management agreements, prepaid gas costs during the summer months represent purchases of gas that are not available for sale, and therefore not recorded in inventory, until November 1, for the Columbia and GSS storage facilities, and December 1, for the Hardy Storage storage facility.

Trade accounts payable increased $16.9 million this year primarily due to an increase in the cost of the natural gas commodity.

Our regulatory commissions approve rates that are designed to give us the opportunity to generate revenues, assuming normal weather, to cover our gas costs and fixed and variable non-gas costs and to earn a fair return for our shareholders. We have had a WNA mechanism in South Carolina and Tennessee that partially offsets the impact of colder-than-normal or warmer-than-normal weather on bills rendered in November through March for residential and commercial customers. The WNA in South Carolina and Tennessee generated charges to customers of $6.4 million in 2007, $4.1 million in 2006 and $3.7 million in 2005. In Tennessee, adjustments are made directly to the customer s bill. In South Carolina, the adjustments are calculated at the individual customer level and recorded in a deferred account for subsequent collection from or refund to all customers in the class. Effective November 1, 2005, we have a CUT mechanism in North Carolina that provides for any over- or under-collection of approved margin per customer that operates independently of both weather and consumption patterns of residential and commercial customers. The CUT mechanism provided margin of $32.7 million in 2007 and $30.4 million in 2006 as compared to North Carolina WNA that generated charges to customers of $4.7 million in 2005. Our gas costs are recoverable through PGA procedures and are not affected by the WNA or the CUT.

The financial condition of the natural gas marketers and pipelines that supply and deliver natural gas to our distribution system can increase our exposure to supply and price fluctuations. We believe our risk exposure to the financial condition of the marketers and pipelines is not significant based on our receipt of the products and services prior to payment and the availability of other marketers of natural gas to meet our firm supply needs if necessary.

We have commission approval in North Carolina, South Carolina and Tennessee that places additional credit requirements on the retail natural gas marketers that schedule gas for transportation service on our system.

The regulated utility competes with other energy products, such as electricity and propane, in the residential and commercial customer markets. The most significant product competition is with electricity for space heating, water heating and cooking. Numerous factors can influence customer demand for natural gas, such as price volatility, the availability of natural gas in relation to other energy forms, general economic conditions, weather, energy conservation, conservation and energy efficiency programs approved by regulatory bodies and the ability to convert from natural gas to other energy sources. Increases in the price of natural gas can negatively impact our competitive position by decreasing the price benefits of natural gas to the consumer.

This can impact our cash needs if customer growth slows, resulting in reduced capital expenditures, or if customers conserve, resulting in reduced gas purchases and customer billings.

In an effort to keep customer rates competitive by holding down operations and maintenance costs and as part of an ongoing effort aimed at improving business processes, capturing operational and organizational efficiencies and improving customer service, we are continuing the process of standardizing our customer payment and collection processes, streamlining business operations and further consolidating our call centers. We estimate termination benefits to employees of $3.6 million over the next four years which was recorded in 2007 resulting from this business process improvement initiative.

In the industrial market, many of our customers are capable of burning a fuel other than natural gas, with fuel oil being the most significant competing energy alternative. Our ability to maintain industrial market share is largely dependent on price. The relationship between supply and demand has the greatest impact on the price of natural gas. With growth in consumption exceeding growth of supply resulting in a tighter balance between domestic supply and demand, the cost of natural gas from non-domestic sources may play a greater role in establishing the future market price of natural gas. The price of oil depends upon a number of factors beyond our control, including the relationship between supply and demand and the policies of foreign and domestic governments and organizations. Our liquidity could be impacted, either positively or negatively, as a result of alternate fuel decisions made by industrial customers.

Cash Flows from Investing Activities. Net cash used in investing activities was $148.2 million in 2007, $167.6 million in 2006 and $159 million in 2005. Net cash used in investing activities was primarily for utility construction expenditures. Gross utility construction expenditures were $135.2 million in 2007, a 34% decrease from the $204.1 million in 2006, primarily due to the automated meter reading project in the prior year. Reimbursements from the bond fund decreased $13.9 million in 2006 from 2005 as construction of gas infrastructure in eastern North Carolina has now been completed. For further information about the bond fund, see Note 3 to the consolidated financial statements.

We have a substantial capital expansion program for construction of distribution facilities, purchase of equipment and other general improvements. This program primarily supports the growth in our customer base. Gross utility construction expenditures totaling $168.5 million, primarily to serve customer growth, are budgeted for 2008; however, we are not contractually obligated to expend capital until the work is completed. Due to projected growth in our service areas, significant utility construction expenditures are expected to continue and are a part of our long-range forecasts that are prepared at least annually and typically cover a forecast period of five years.

During 2007, we contributed $12.9 million to Hardy Storage Company LLC, a joint venture investee of one of our non-utility subsidiaries, as part of our equity contribution for construction of a FERC regulated interstate storage facility. On November 1, 2007 and December 3, 2007, we contributed an additional $8.8 million to Hardy Storage, which brought our investment in Hardy Storage to $21.7 million. We anticipate contributing up to an additional $8.3 million to Hardy Storage during the fiscal 2008 year. To the extent that more funding is needed, the members will evaluate funding options at that time.

During 2007, $2.2 million of supplier refunds was recorded as restricted funds. In September 2007, we petitioned the NCUC for authority to liquidate all certificates of deposit and similar investments that held any supplier refunds due to customers. In October 2007, the NCUC approved the transfer of these restricted funds to the North Carolina all customers deferred account. During 2006, the restrictions on cash totaling $13.2 million were removed in connection with implementing the NCUC order in a general rate proceeding.

On May 12, 2005, we sold our corporate office building located in Charlotte, North Carolina for $6.7 million in cash, net of expenses. In accordance with utility plant accounting, we recorded the disposition of the land as a pre-tax gain of $1.7 million in Other Income (Expense) in the consolidated statement of income and a loss of $1.8 million on the disposition of the building as a charge to Accumulated depreciation in the consolidated balance sheet, based on the sales price allocation from an independent third party. Under the terms of the purchase and sale agreement, we leased back the building from the new owner until our new office space was ready for occupancy. We relocated to our new office space in November 2005 under a

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negotiated ten-year lease with renewal options. The lease payments for the ten-year term range from $3 million to $3.4 million annually.

We received $2.4 million in cash in 2005 from the sale of marketable securities which we received in connection with the sale of our propane interests in 2004.

Cash Flows from Financing Activities. Net cash provided by (used in) financing activities was $(86.6) million in 2007, $65.6 million in 2006 and $(22.9) million in 2005. Funds are primarily provided from bank borrowings and the issuance of common stock through dividend reinvestment and employee stock plans, net of purchases under the common stock repurchase program. When required, we sell common stock and long-term debt to cover cash requirements when market and other conditions favor such long-term financing. Funds are primarily used to pay down outstanding short-term borrowings, to repurchase common stock under the common stock repurchase program, and the payment of quarterly dividends on our common stock. As of October 31, 2007, our current assets were $435.3 million and our current liabilities were $424.5 million, primarily due to seasonal requirements as discussed above.

As of October 31, 2007, we had committed lines of credit under our senior credit facility effective April 24, 2006 of $350 million with the ability to expand up to $600 million, for which we pay an annual fee of $35,000 plus six basis points for any unused amount up to $350 million. Outstanding short-term borrowings increased from $170 million as of October 31, 2006 to $195.5 million as of October 31, 2007, primarily due to our commitment to fill storage capacity under various contracts. During the twelve months ended October 31, 2007, short-term borrowings ranged from zero to $280.5 million, and when borrowing, interest rates ranged from 4.96% to 6.08% (weighted average of 5.57%).

As of October 31, 2007, under our credit facility, we had available letters of credit of $5 million of which $1.5 million was issued and outstanding. The letters of credit are used to guarantee claims from self-insurance under our general liability policies. Effective November 1, 2007, the letters of credit were increased to $1.9 million.

As of October 31, 2007, including the issuance of the letters of credit, unused lines of credit available under our senior credit facility totaled $153 million.

The level of short-term borrowings can vary significantly due to changes in the wholesale prices of natural gas and to the level of purchases of natural gas supplies to serve customer demand and for storage. Short-term debt may increase when wholesale prices for natural gas increase because we must pay suppliers for the gas before we collect our costs from customers through their monthly bills. Gas prices could continue to increase and fluctuate. With higher wholesale gas prices, we may incur more short-term debt to pay for natural gas supplies and other operating costs since collections from customers could be slower and some customers may not be able to pay their gas bills on a timely basis.

During 2007, we issued $15.8 million of common stock through dividend reinvestment and stock purchase plans. On November 7, 2006, through an ASR agreement, we repurchased and retired 1 million shares of common stock for $26.6 million. On January 19, 2007, we settled the transaction and paid an additional $.8 million. On April 2, 2007, through an ASR agreement, we repurchased and retired 850,000 shares of common stock for $22.5 million. On May 23, 2007, we settled the transaction and paid an additional $.4 million. During 2007 under the ASR and the Common Stock Open Market Purchase Program discussed in Note 5 to the consolidated financial statements, we paid $54.2 million for 2 million shares of common stock that are available for reissuance to these plans. During 2006, 2.1 million shares were repurchased for $50.2 million. During 2005, 1.1 million shares were repurchased for $26.1 million.

On November 1, 2007, we entered into another ASR agreement. On November 2, 2007, we purchased and retired 1 million shares of our common stock from an investment bank at the closing price of $24.70 per share. Total consideration paid to purchase the shares was $24.8 million, including $92,500 in commission and fees. Through December 14, 2007, the investment bank had purchased 708,000 shares at a cumulative weighted average price of $25.8733 per share.

Through the ASR program, we may repurchase and subsequently retire up to approximately four million shares of common stock by no later than December 31, 2010. Through the ASR on November 1, 2007, we

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have repurchased 3,850,000 shares as follows: one million shares repurchased in April 2006, one million shares repurchased in November 2006, 850,000 shares repurchased in March 2007 and one million shares repurchased on November 1, 2007. These shares are in addition to shares that are repurchased on a normal basis through the open market program.

We increased our common stock dividend on an annualized basis by $.04 per share in 2007, $.05 per share in 2006 and $.06 per share in 2005. Dividends of $73.6 million, $72.1 million and $69.4 million for 2007, 2006 and 2005, respectively, were paid on common stock. The amount of cash dividends that may be paid on common stock is restricted by provisions contained in certain note agreements under which long-term debt was issued; however, as of October 31, 2007, our retained earnings were not restricted. For further information, see Note 4 to the consolidated financial statements.

We have a shelf registration statement that can be used for either debt or equity filed with the SEC. The remaining balance of unused long-term financing available under this shelf registration statement as of October 31, 2007 is $109.4 million. Under this shelf registration, we sold $200 million of long-term debt on June 20, 2006 that was used to pay off $188 million of short-term debt on June 20 and to pay off a portion of the $35 million sinking fund on the 9.44% Senior Notes due July 30, 2006.

Our long-term targeted capitalization ratio is 45% to 50% in long-term debt and 50% to 55% in common equity. Accomplishing this capital structure objective and maintaining sufficient cash flow are necessary to maintain attractive credit ratings. As of October 31, 2007, our capitalization consisted of 48% in long-term debt and 52% in common equity.

The components of our total debt outstanding to our total capitalization as of October 31, 2007 and 2006 are summarized in the table below.

	October 31 2007	Percentage	October 31 2006	Percentage
	In thousands			
Short-term debt	$ 195,500	10%	$ 170,000	9%
Long-term debt	824,887	44%	825,000	44%
Total debt	1,020,387	54%	995,000	53%
Common stockholders equity	878,374	46%	882,925	47%
Total capitalization (including short-term debt)	$ 1,898,761	100%	$ 1,877,925	100%

As of October 31, 2007, all of our long-term debt was unsecured. Our long-term debt is rated A by Standard & Poor s Ratings Services and A3 by Moody s Investors. Currently, with respect to our long-term debt, the credit agencies maintain their stable outlook. There is no guarantee that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn by a rating agency if, in its judgment, circumstances warrant a change.

Credit ratings impact our ability to obtain short-term and long-term financing and the cost of such financings. In determining our credit ratings, the rating agencies consider various factors. The more significant quantitative factors include:

Ratio of total debt to total capitalization, including balance sheet leverage,

Ratio of net cash flows to capital expenditures,

Funds from operations interest coverage,

Ratio of funds from operations to average total debt,

Pension liabilities and funding status, and

Pre-tax interest coverage.

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Qualitative factors include, among other things:

- Stability of regulation in the jurisdictions in which we operate,
- Consistency of our earnings over time,
- Risks and controls inherent in the distribution of natural gas,
- Predictability of cash flows,
- Quality of business strategy and management,
- Corporate governance guidelines and practices,
- Industry position, and
- Contingencies.

We are subject to default provisions related to our long-term debt and short-term borrowings. The default provisions of our senior notes are:

- Failure to make principal, interest or sinking fund payments,
- Interest coverage of 1.75 times,
- Total debt cannot exceed 70% of total capitalization,
- Funded debt of all subsidiaries in the aggregate cannot exceed 15% of total company capitalization,
- Failure to make payments on any capitalized lease obligation,
- Bankruptcy, liquidation or insolvency, and
- Final judgment against us in excess of $1 million that after 60 days is not discharged, satisfied or stayed pending appeal.

The default provisions of our medium-term notes are:

- Failure to make principal, interest or sinking fund payments,
- Failure after the receipt of a 90-day notice to observe or perform for any covenant or agreement in the notes or in the indenture under which the notes were issued, and
- Bankruptcy, liquidation or insolvency.

There are cross-default provisions in all of our debt agreements, and thus event of default under one agreement may result in total outstanding issues of debt becoming due. As of October 31, 2007, we are in compliance with all default provisions.

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As of October 31, 2007, our estimated future contractual obligations were as follows.

	Payments Due by Period				
	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years	Total
	In thousands				
Long-term debt(1)	$	$ 150,000	$	$ 674,887	$ 824,887
Interest on long-term debt(1)	55,648	159,134	89,657	664,390	968,829
Pipeline and storage capacity(2)	162,032	485,581	249,809	375,617	1,273,039
Gas supply(3)	25,405	724			26,129
Telecommunications and information technology(4)	18,641	59,114	20,818		98,573
Qualified and nonqualified pension plan funding(5)	11,553	34,511	11,473		57,537
Postretirement benefits plan funding(5)	2,172	5,400	1,700		9,272
Operating leases(6)	5,076	11,781	7,125	7,565	31,547
Other purchase obligations(7)	32,446				32,446
Letter of credit	1,900	5,700	3,800		11,400
Total	$ 314,873	$ 911,945	$ 384,382	$ 1,722,459	$ 3,333,659

(1) See Note 4 to the consolidated financial statements.

(2) 100% recoverable through PGA procedures.

(3) Reservation fees that are 100% recoverable through PGA procedures.

(4) Consists primarily of maintenance fees for hardware and software applications, usage fees, local and long-distance data costs, frame relay, and cell phone and pager usage fees.

(5) Estimated funding beyond five years is not available. See Note 8 to the consolidated financial statements.

(6) See Note 7 to the consolidated financial statements.

(7) Consists primarily of pipeline products, vehicles, contractors and merchandise.

Off-balance Sheet Arrangements

We have no off-balance sheet arrangements other than operating leases that are reflected in the table above and discussed in Note 7 to the consolidated financial statements.

Piedmont Energy Partners, Inc., a wholly owned subsidiary of Piedmont, has entered into a guaranty in the normal course of business. The guaranty involves some levels of performance and credit risk that are not included on our consolidated balance sheets. We have recorded $1.3 million and $1.8 million as of October 31, 2007 and 2006, respectively. The possibility of having to perform on the guaranty is largely dependent upon the future operations of

Hardy Storage, third parties or the occurrence of certain future events. For further information on this guaranty, see Note 11 to the consolidated financial statements.

Critical Accounting Policies and Estimates

We prepare the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. We make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods reported. Actual results may differ significantly from these estimates and assumptions. We base our estimates on historical experience, where applicable, and other relevant factors that we believe are reasonable under the circumstances. On an ongoing basis, we evaluate estimates and assumptions and make adjustments in subsequent periods to reflect more current information if we determine that modifications in assumptions and estimates are warranted.

Management considers an accounting estimate to be critical if it requires assumptions to be made that were uncertain at the time the estimate was made and changes in the estimate or a different estimate that could have been used would have had a material impact on our financial condition or results of operations. We consider regulatory accounting, revenue recognition and pension and postretirement benefits to be our critical accounting estimates. Management has discussed the selection and development of the critical accounting policies and estimates presented below with the Audit Committee of the Board of Directors.

Regulatory Accounting. Our regulated utility segment is subject to regulation by certain state and federal authorities. Our accounting policies conform to Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation (Statement 71), and are in accordance with accounting requirements and ratemaking practices prescribed by the regulatory authorities. The application of these accounting policies allows us to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the income statement by an unregulated company. We then recognize these deferred regulatory assets and liabilities through the income statement in the period in which the same amounts are reflected in rates. If we, for any reason, cease to meet the criteria for application of regulatory accounting treatment for all or part of our operations, we would eliminate from the balance sheet the regulatory assets and liabilities related to those portions ceasing to meet such criteria and include them in the income statement for the period in which the discontinuance of regulatory accounting treatment occurs. Such an event could have a material effect on our results of operations in the period this action was recorded. Regulatory assets as of October 31, 2007 and 2006, totaled $134 million and $143.5 million, respectively. Regulatory liabilities as of October 31, 2007 and 2006, totaled $374 million and $337 million, respectively. The detail of these regulatory assets and liabilities is presented in Note 1.B to the consolidated financial statements.

Revenue Recognition. Utility sales and transportation revenues are based on rates approved by state regulatory commissions. Base rates charged to customers may not be changed without formal approval by the regulatory commission in that jurisdiction; however, the wholesale cost of gas component of rates may be adjusted periodically under PGA procedures. Through October 31, 2005, a WNA factor, based on the margin or base rate component of the billing rate, was included in rates charged to residential and commercial customers during the winter period of November through March in all jurisdictions except EasternNC. The WNA is designed to offset the impact of warmer-than-normal or colder-than-normal weather on customer billings during the winter season. Effective November 1, 2005, the WNA was eliminated in North Carolina and replaced with the CUT that provides for the recovery of our approved margin from residential and commercial customers independent of both weather and other consumption patterns. The CUT tracks our margin earned monthly and will result in semi-annual rate adjustments to refund any over-collection or recover any under-collection. Without the CUT or WNA, our operating revenues in 2007, 2006 and 2005 would have been lower by $39.1 million, $34.6 million and $8.4 million, respectively.

Revenues are recognized monthly on the accrual basis, which includes estimated amounts for gas delivered to customers but not yet billed under the cycle-billing method from the last meter reading date to month end. Meters are read throughout the month based on an approximate 30-day usage cycle; therefore, at any point in time, volumes are delivered to customers that have not been metered and billed. The unbilled revenue estimate reflects factors requiring judgment related to estimated usage by customer class, changes in weather during the period and the impact of the WNA or CUT mechanisms, as applicable. Secondary market, or wholesale, sales revenues are recognized when the physical sales are delivered based on contract or market prices.

Pension and Postretirement Benefits. We have a defined-benefit pension plan for the benefit of eligible full-time employees. We also provide certain postretirement health care and life insurance benefits to eligible full-time employees. Our reported costs of providing these benefits, as described in Note 8 to the consolidated financial statements, are impacted by numerous factors, including the provisions of the plans, changing employee demographics and various actuarial calculations, assumptions and accounting mechanisms. Because of the complexity of these calculations, the long-term nature of these obligations and the importance of the assumptions used, our estimate of these costs is a critical accounting estimate.

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Several statistical and other factors, which attempt to anticipate future events, are used in calculating the expenses and liabilities related to the plans. These factors include assumptions about the discount rate used in determining future benefit obligations, projected health care cost trend rates, expected long-term return on plan assets and rate of future compensation increases, within certain guidelines. In addition, we also use subjective factors such as withdrawal and mortality rates to estimate projected benefit obligations. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact on the amount of pension expense or other postretirement benefit costs recorded in future periods.

The discount rate has been separately determined for each plan by projecting the plan s cash flows and developing a zero-coupon spot rate yield curve using non-arbitrage pricing and Moody s AA or better-rated non-callable bonds. Based on this approach, the weighted average discount rate used in the measurement of the benefit obligation for the qualified pension plans changed from 5.78% in 2006 to 6.43% in 2007. For the nonqualified pension plans, the weighted average discount rate used in the measurement of the benefit obligation changed from 5.67% in 2006 to 6.06% in 2007. Similarly, based on this approach, the weighted average discount rate for postretirement benefits changed from 5.74% in 2006 to 6.25% in 2007. Based on our review of actual cost trend rates and projected future trends in establishing health care cost trend rates, we changed our health care cost trend rate from 9% in 2006 to 8.5% in 2007, declining gradually to 5% in 2012.

In determining our expected long-term rate of return on plan assets, we review past long-term performance, asset allocations and long-term inflation assumptions. We target our asset allocations for qualified pension plan assets and other postretirement benefit assets to be approximately 60% equity securities and 40% fixed income securities. The expected long-term rate of return on plan assets was 8.5% in 2005, 2006 and 2007, and will be changed to 8% in 2008. Based on a fairly stagnant inflation trend, our age-related assumed rate of increase in future compensation levels was 4.05% in 2005 and decreased to 4.01% in 2006 and 3.99% in 2007 due to changes in the demographics of the participants.

The following reflects the sensitivity of pension cost to changes in certain actuarial assumptions for our qualified pension plan, assuming that the other components of the calculation are constant.

Actuarial Assumption	**Change in Assumption**	**Impact on 2007 Pension Cost**	**Impact on Projected Benefit Obligation**
		Increase (Decrease) In thousands	
Discount rate	(.25)%	$ 644	$ 4,872
Rate of return on plan assets	(.25)%	500	N/A
Rate of increase in compensation	.25%	861	2,495

The following reflects the sensitivity of postretirement benefit cost to changes in certain actuarial assumptions, assuming that the other components of the calculation are constant.

Actuarial Assumption	**Assumption**	**Benefit Cost**	**Benefit Obligation**

		Increase (Decrease) In thousands	
Discount rate	(.25)%	$ 93	$ 719
Rate of return on plan assets	(.25)%	49	N/A
Health care cost trend rate	.25%	23	318

We utilize a number of accounting mechanisms that reduce the volatility of reported pension costs. Differences between actuarial assumptions and actual plan results are deferred and amortized into cost when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-related value of the plan assets. If necessary, the excess is amortized over the average remaining service period of active employees.

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Gas Supply and Regulatory Proceedings

We continue to pursue the diversification of our supply portfolio through pipeline capacity arrangements that access new sources of supply and market-area storage and that diversify supply concentration away from the Gulf Coast region. In January 2008, we anticipate that we will receive firm, long-term transportation service from Midwestern of 120,000 dekatherms per day that will provide access to Canadian and Rocky Mountain gas supplies via the Chicago hub, primarily to serve our Tennessee markets. We are currently using 40,000 dekatherms per day of this capacity under a short-term agreement with the above mentioned contract anticipated to become available in January 2008. As of April 2007, we began receiving firm, long-term market-area storage service from Hardy Storage in West Virginia that will provide 39,100 dekatherms per day of withdrawal service for the winter of 2007-2008. Hardy Storage withdrawal capabilities will increase over three phases. Phase 1 (2007-2008 heating season) began at 57% of capacity, phase 2 (2008-2009 heating season) is planned at 85% of capacity, and phase 3 (2009-2010 heating season) is planned at 100% of capacity. We have a 50% equity interest in this project which is more fully discussed in Note 11 to the consolidated financial statements.

Secondary market transactions permit us to market gas supplies and transportation services by contract with wholesale or off-system customers. These sales contribute smaller per-unit wholesale margins to earnings; however, the program allows us to act as a wholesale marketer of natural gas and transportation capacity in order to generate operating margin from sources not restricted by the capacity of our retail distribution system. A sharing mechanism is in effect where 75% of any margin is passed through to customers in all of our jurisdictions. However, secondary market transactions in Tennessee are included in the performance incentive plan discussed in Note 3 to the consolidated financial statements.

Regulatory proceedings in South Carolina under the South Carolina Rate Stabilization Act were completed during 2007 that will impact 2008 earnings by decreasing annual margin by $2.5 million based on an 11.2% return on equity effective November 1, 2007. For further information about these regulatory proceedings and other regulatory information, see Note 3 to the consolidated financial statements.

In the November 2005 North Carolina general rate case order, the CUT was established as an experimental tariff for a three-year period ending November 1, 2008, subject to review in a future general rate case. In accordance with that requirement, it is our intent to file a general rate case in North Carolina to be effective November 1, 2008.

Equity Method Investments

For information about our equity method investments, see Note 11 to the consolidated financial statements.

Environmental Matters

We have developed an environmental self-assessment plan to assess our facilities and program areas for compliance with federal, state and local environmental regulations and to correct any deficiencies identified. As a member of the North Carolina MGP Initiative Group, we, along with other responsible parties, work directly with the North Carolina Department of Environment and Natural Resources to set priorities for manufactured gas plant (MGP) site remediation. For additional information on environmental matters, see Note 7 to the consolidated financial statements.

Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation 48, Accounting for Uncertainty in Income Taxes (FIN 48), to clarify the accounting for uncertain tax positions in accordance with SFAS 109, Accounting for Income Taxes, and in May 2007 issued Staff Position No. FIN 48-1, Definition of Settlement in FASB

Interpretation No. 48,   (FSP 48-1). FIN 48 defines a minimum recognition threshold that a tax position must meet to be recognized in an enterprise s financial statements. Additionally, FIN 48 provides guidance on derecognition, measurement, classification, interim period accounting, disclosure

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and transition requirements in accounting for uncertain tax positions. FSP 48-1 clarifies when a tax position is considered effectively settled under FIN 48. FIN 48 is effective the beginning of the first annual period beginning after December 15, 2006, and the guidance under FSP 48-1 should be applied upon the adoption of FIN 48. Accordingly, we will adopt FIN 48 and FSP 48-1 in our fiscal year 2008. We have assessed the impact FIN 48 may have on our consolidated financial statements. The adoption will not have a material impact on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (Statement 157). Statement 157 provides enhanced guidance for using fair value to measure assets and liabilities and applies whenever other standards require (or permit) the measurement of assets or liabilities at fair value, but does not expand the use of fair value measurement to any new circumstances. Statement 157 establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data, for example, the reporting entity s own data. Under Statement 157, fair value measurements would be separately disclosed by level within the fair value hierarchy. On November 14, 2007, the FASB delayed the implementation of Statement 157 for one year only for other nonfinancial assets and liabilities. Statement 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, with earlier application encouraged for financial assets and liabilities, as well as for any other assets and liabilities that are carried at fair value on a recurring basis. Accordingly, we will adopt Statement 157 no later than our first fiscal quarter in 2009. We believe the adoption of Statement 157 will not have a material impact on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans (Statement 158). Statement 158 requires an employer to fully recognize the obligations associated with single-employer defined benefit pension, retiree healthcare and other postretirement plans in the financial statements by recognizing in its statement of financial position an asset for a plan s overfunded status or a liability for a plan s underfunded status rather than only disclosing the funded status in the footnotes to the financial statements. Statement 158 requires employers to recognize changes in the funded status of a defined benefit postretirement plan in the year in which the changes occur. Under Statement 158, gains and losses, prior service costs and credits, and any remaining transition amounts that have not yet been recognized through net periodic benefit cost will be recognized in accumulated other comprehensive income (OCI), net of tax effects, until they are amortized as a component of net periodic cost. Statement 158 also requires that the company measure a plan s assets and its obligations that determine its funded status as of the end of the employer s fiscal year. We are already in compliance with this requirement as our pension plans measurement dates are already the same as our fiscal year end date.

The requirement to recognize the funded status of a benefit plan and the related disclosure requirements applied as of the end of the fiscal year ending after December 15, 2006. Accordingly, we adopted the funded status portion of Statement 158 as of October 31, 2007. Adoption of Statement 158 on our financial position is shown below. The adoption of Statement 158 did not have a material effect on our results of operations or cash flows.

In August 2007, we filed petitions with the NCUC, the PSCSC and the TRA requesting the ability to place certain defined benefit postretirement obligations related to the implementation of Statement 158 in a regulatory deferred account instead of OCI. The petitions have been approved in all of the jurisdictions.

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Based on the measurement of the various postretirement plans assets and benefit obligations as of October 31, 2007, the effect on our consolidated balance sheet of adopting Statement 158 is as follows.

	Before Application of Statement 158	Minimum Pension Liability Adjustment	Adoption of Statement 158	Rate Deferral Adjustments	After Application of Statement 158
			In thousands		
Prepayments	$ 22,435	$	$ (22,435)	$	$
Overfunded postretirement asset			36,256		36,256
Regulatory asset for postretirement benefits, noncurrent				1,865	1,865
Accumulated other comprehensive income	(78)	24	7,346	(7,292)	
Other current liabilities			553		553
Deferred income taxes (noncurrent)	(51)	16	4,754	(4,719)	
Regulatory liability for postretirement benefits, noncurrent				13,876	13,876
Accumulated provision for postretirement benefits			17,469		17,469
Other (deferred credits and other liabilities)	16,342	(40)	(16,302)		

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (Statement 159). Statement 159 provides companies with an option to report selected financial assets and liabilities at fair value. Its objective is to reduce the complexity in accounting for financial instruments and to mitigate the volatility in earnings caused by measuring related assets and liabilities differently. Although Statement 159 does not eliminate disclosure requirements included in other accounting standards, it does establish additional presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. Statement 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007, with early adoption permitted for an entity that has elected also to apply Statement 157 early. Accordingly, we will adopt Statement 159 no later than our first fiscal quarter in 2009. We believe the adoption of Statement 159 will not have a material impact on our financial position, results of operations or cash flows.

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

We hold all financial instruments discussed below for purposes other than trading. We are potentially exposed to market risk due to changes in interest rates and the cost of gas. Our exposure to interest rate changes relates primarily to short-term debt. We are exposed to interest rate changes to long-term debt when we are in the market to issue long-term debt. As of October 31, 2007, all of our long-term debt was issued at fixed rates. Exposure to gas cost variations relates to the wholesale supply, demand and price of natural gas.

Interest Rate Risk

We have short-term borrowing arrangements to provide working capital and general corporate funds. The level of borrowings under such arrangements varies from period to period depending upon many factors, including our investments in capital projects. Future short-term interest expense and payments will be impacted by both short-term interest rates and borrowing levels.

As of October 31, 2007, we had $195.5 million of short-term debt outstanding under our credit facility at an average interest rate of 4.96%. The carrying amount of our short-term debt approximates fair value. A

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change of 100 basis points in the underlying average interest rate for our short-term debt would have caused a change in interest expense of approximately $1.2 million during 2007.

As of October 31, 2007, information about our long-term debt is presented below.

	Expected Maturity Date 2008	2009	2010	2011	2012	Thereafter	Total	Fair Value as of October 31, 2007
	In millions							
Fixed Rate Long-term Debt	$	$ 30	$ 60	$ 60	$	$ 675	$ 825	$ 893
Average Interest Rate		7.35%	7.80%	6.55%		6.64%	6.74%	

Commodity Price Risk

We manage our gas supply costs through a portfolio of short- and long-term procurement contracts with various suppliers. In the normal course of business, we utilize exchange-traded contracts of various duration for the forward purchase of a portion of our natural gas requirements. Due to cost-based rate regulation in our utility operations, our prudently incurred purchased gas costs and the prudently incurred costs of hedging our gas supplies are passed on to customers through PGA procedures.

Additional information concerning market risk is set forth in Financial Condition and Liquidity in Item 7 of this Form 10-K.

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

Consolidated financial statements required by this item are listed in Item 15 (a) 1 in Part IV of this Form 10-K.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Piedmont Natural Gas Company, Inc.

We have audited the accompanying consolidated balance sheets of Piedmont Natural Gas Company, Inc. and subsidiaries (Piedmont) as of October 31, 2007 and 2006, and the related consolidated statements of income, stockholders equity, and cash flows for each of the three years in the period ended October 31, 2007. These financial statements are the responsibility of Piedmont s management. Our responsibility is to express an opinion on the financial statements 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 accompanying consolidated financial statements present fairly, in all material respects, the financial position of Piedmont Natural Gas Company, Inc. and subsidiaries at October 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended October 31, 2007 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 8 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, effective October 31, 2007.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company s internal control over financial reporting as of October 31, 2007, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated December 28, 2007 expressed an unqualified opinion on the Company s internal control over financial reporting.

/s/ Deloitte & Touche LLP

Charlotte, North Carolina
December 28, 2007

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Piedmont Natural Gas Company, Inc.

Consolidated Balance Sheets
October 31, 2007 and 2006

	2007	2006
	In thousands	
ASSETS		
Utility Plant:		
Utility plant in service	$ 2,833,286	$ 2,714,606
Less accumulated depreciation	752,977	733,682
Utility plant in service, net	2,080,309	1,980,924
Construction work in progress	61,228	94,386
Total utility plant, net	2,141,537	2,075,310
Other Physical Property, at cost (net of accumulated depreciation of $2,197 in 2007 and $2,040 in 2006)	1,007	1,154
Current Assets:		
Cash and cash equivalents	7,515	8,886
Restricted cash	2,211	
Trade accounts receivable (less allowance for doubtful accounts of $544 in 2007 and $1,239 in 2006)	97,625	90,493
Income taxes receivable	15,699	30,849
Other receivables	649	160
Unbilled utility revenues	24,121	45,938
Inventories:		
Gas in storage	131,439	138,183
Materials, supplies and merchandise	5,222	6,221
Gas purchase options, at fair value	13,725	3,147
Amounts due from customers	76,035	89,635
Prepayments	61,007	62,356
Other	96	96
Total current assets	435,344	475,964
Investments, Deferred Charges and Other Assets:		
Equity method investments in non-utility activities	95,193	75,330
Goodwill	48,852	47,383
Overfunded postretirement asset	36,256	
Unamortized debt expense	10,565	11,306
Regulatory cost of removal asset	11,939	12,086
Other	39,625	35,406
Total investments, deferred charges and other assets	242,430	181,511

Total	$ 2,820,318	$ 2,733,939

CAPITALIZATION AND LIABILITIES

Capitalization:		
Stockholders equity:		
Cumulative preferred stock no par value 175 shares authorized	$	$
Common stock no par value shares authorized: 200,000; shares outstanding: 74,208 in 2007 and 75,464 in 2006	497,570	532,764
Paid-in capital	402	56
Retained earnings	379,682	348,765
Accumulated other comprehensive income	720	1,340
Total stockholders equity	878,374	882,925
Long-term debt	824,887	825,000
Total capitalization	1,703,261	1,707,925
Current Liabilities:		
Current maturities of long-term debt		
Notes payable	195,500	170,000
Trade accounts payable	97,156	80,304
Other accounts payable	46,411	50,935
Income taxes accrued	1,224	1,184
Accrued interest	21,811	21,273
Customers deposits	22,930	22,308
Deferred income taxes	16,422	25,085
General taxes accrued	18,980	18,522
Amounts due to customers	162	123
Other	3,915	10,655
Total current liabilities	424,511	400,389
Deferred Credits and Other Liabilities:		
Deferred income taxes	267,479	235,411
Unamortized federal investment tax credits	2,983	3,417
Regulatory liability for postretirement benefits	13,876	
Accumulated provision for postretirement benefits	17,469	
Cost of removal obligations	351,738	330,104
Other	39,001	56,693
Total deferred credits and other liabilities	692,546	625,625
Commitments and Contingencies (Note 7)		
Total	$ 2,820,318	$ 2,733,939

See notes to consolidated financial statements.

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Piedmont Natural Gas Company, Inc.

Consolidated Statements of Income
For the Years Ended October 31, 2007, 2006 and 2005

	2007	2006	2005
	In thousands except per share amounts		
Operating Revenues	$ 1,711,292	$ 1,924,628	$ 1,761,091
Cost of Gas	1,187,127	1,401,149	1,261,952
Margin	524,165	523,479	499,139
Operating Expenses:			
Operations and maintenance	214,442	219,353	206,983
Depreciation	88,654	89,696	85,169
General taxes	32,407	33,138	29,807
Income taxes	51,315	50,543	51,880
Total operating expenses	386,818	392,730	373,839
Operating Income	137,347	130,749	125,300
Other Income (Expense):			
Income from equity method investments	37,156	29,917	27,664
Gain on sale of marketable securities			1,525
Non-operating income	2,218	1,147	3,830
Charitable contributions	(587)	(321)	(1,717)
Non-operating expense	(164)	(106)	(28)
Income taxes	(14,311)	(11,887)	(10,446)
Total other income (expense), net of tax	24,312	18,750	20,828
Utility Interest Charges:			
Interest on long-term debt	55,440	49,915	46,173
Allowance for borrowed funds used during construction	(3,799)	(3,893)	(3,137)
Other	5,631	6,288	1,220
Total utility interest charges	57,272	52,310	44,256
Income before Minority Interest in Income of Consolidated Subsidiary	104,387	97,189	101,872
Less Minority Interest in Income of Consolidated Subsidiary			602
Net Income	$ 104,387	$ 97,189	$ 101,270
Average Shares of Common Stock:			
Basic	74,250	75,863	76,680

Diluted		74,472		76,156		76,992
Earnings Per Share of Common Stock:						
Basic	$	1.41	$	1.28	$	1.32
Diluted	$	1.40	$	1.28	$	1.32

See notes to consolidated financial statements.

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Piedmont Natural Gas Company, Inc.

Consolidated Statements of Cash Flows
For the Years Ended October 31, 2007, 2006 and 2005

	2007	2006	2005
		In thousands	
Cash Flows from Operating Activities:			
Net income	$ 104,387	$ 97,189	$ 101,270
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	93,355	94,111	91,677
Amortization of investment tax credits	(434)	(534)	(541)
Allowance for doubtful accounts	(695)	51	102
Allowance for funds used during construction		(3,893)	(3,137)
Gain on sale of corporate office land			(1,659)
Income from equity method investments	(37,156)	(29,917)	(27,664)
Distributions of earnings from equity method investments	27,884	28,442	23,649
Gain on sale of marketable securities			(1,525)
Deferred income taxes	23,854	22,021	18,278
Stock-based compensation expense	336		
Changes in assets and liabilities:			
Receivables	14,892	19,395	(43,214)
Inventories	7,743	12,791	(24,004)
Amounts due from customers	13,599	(37,474)	(23,329)
Settlement of legal asset retirement obligations	(1,660)		
Overfunded postretirement asset	(36,256)		
Other assets	(2,137)	7,581	(20,164)
Accounts payable	13,069	(94,095)	94,530
Amounts due to customers	39	(17,001)	(9,255)
Regulatory liability for postretirement benefits	13,876		
Accumulated provision for postretirement benefits	17,469		
Other liabilities	(18,664)	5,146	8,362
Total adjustments	129,114	6,624	82,106
Net cash provided by operating activities	233,501	103,813	183,376
Cash Flows from Investing Activities:			
Utility construction expenditures	(135,231)	(204,116)	(191,407)
Allowance for funds used during construction	(3,799)		
Reimbursements from bond fund		15,955	29,841
Contributions to equity method investments	(12,914)	(23,696)	(6,162)
Distributions of capital from equity method investments	344	28,968	695
Proceeds from sale of corporate office building and land			6,660
Proceeds from sale of marketable securities			2,394

Decrease (increase) in restricted cash	(2,211)	13,108	(376)
Other	5,576	2,227	(683)
Net cash used in investing activities	(148,235)	(167,554)	(159,038)
Cash Flows from Financing Activities:			
Increase in notes payable, net of expenses of $405 in 2006	25,500	11,095	49,000
Proceeds from issuance of long-term debt, net of expenses		193,360	
Retirement of long-term debt	(113)	(35,000)	
Expenses related to the issuance of long-term debt	(5)		
Issuance of common stock through dividend reinvestment and employee stock plans	15,782	18,377	23,536
Repurchases of common stock	(54,240)	(50,163)	(26,119)
Dividends paid	(73,561)	(72,107)	(69,366)
Net cash provided by (used in) financing activities	(86,637)	65,562	(22,949)
Net Increase (Decrease) in Cash and Cash Equivalents	(1,371)	1,821	1,389
Cash and Cash Equivalents at Beginning of Year	8,886	7,065	5,676
Cash and Cash Equivalents at End of Year	$ 7,515	$ 8,886	$ 7,065
Cash Paid During the Year for:			
Interest	$ 63,703	$ 54,669	$ 48,888
Income taxes	27,423	56,615	35,888
Noncash Investing and Financing Activities:			
Accrued construction expenditures	$ 741	$ 2,837	$ 2,036
Guaranty	485	1,820	

See notes to consolidated financial statements.

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Piedmont Natural Gas Company, Inc.

Consolidated Statements of Stockholders Equity
For the Years Ended October 31, 2007, 2006 and 2005

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
	In thousands except per share amounts				
Balance, October 31, 2004	$ 563,667	$	$ 291,397	$ (166)	$ 854,898
Comprehensive Income:					
Net income			101,270		101,270
Other comprehensive income:					
Reclassification adjustment of realized gain on marketable securities included in net income, net of tax of ($391)				(597)	
Unrealized gain from hedging activities of equity method investments, net of tax of $287				436	
Reclassification adjustment of realized gain from hedging activities of equity method investments included in net income, net of tax of ($1,280)				(1,926)	(2,087)
Total comprehensive income					99,183
Common Stock Issued	25,332				25,332
Common Stock Repurchased	(26,119)				(26,119)
Tax Benefit from Dividends Paid on ESOP Shares			264		264
Dividends Declared ($.905 per share)			(69,366)		(69,366)
Balance, October 31, 2005	562,880		323,565	(2,253)	884,192
Comprehensive Income:					
Net income			97,189		97,189
Other comprehensive income:					
Minimum pension liability, net of tax of ($51)				(78)	
Unrealized gain from hedging activities of equity method investments, net of tax of $3,013				4,644	
Reclassification adjustment of realized gain from hedging activities of equity method investments included in net income, net of tax of ($665)				(973)	3,593
Total comprehensive income					100,782

Common Stock Issued	20,047				20,047
Common Stock Repurchased	(50,163)				(50,163)
Share-Based Compensation Expense		56			56
Tax Benefit from Dividends Paid on ESOP Shares			118		118
Dividends Declared ($.95 per share)			(72,107)		(72,107)
Balance, October 31, 2006	532,764	56	348,765	1,340	882,925
Comprehensive Income:					
Net income			104,387		104,387
Other comprehensive income:					
Minimum pension liability, net of tax of $18				24	
Unrealized gain from hedging activities of equity method investments, net of tax of $314				578	
Reclassification adjustment of realized gain from hedging activities of equity method investments included in net income, net of tax of ($762)				(1,276)	(674)
Total comprehensive income					103,713
Adjustment to initially apply Statement 158, net of tax				54	54
Common Stock Issued	19,046				19,046
Common Stock Repurchased	(54,240)				(54,240)
Share-Based Compensation Expense		336			336
Dividends Incentive Compensation Plan		10	(10)		
Tax Benefit from Dividends Paid on ESOP Shares			101		101
Dividends Declared ($.99 per share)			(73,561)		(73,561)
Balance, October 31, 2007	$ 497,570	$ 402	$ 379,682	$ 720	$ 878,374

The components of accumulated other comprehensive income as of October 31, 2007 and 2006, are as follows.

	2007	**2006**
	In thousands	
Minimum pension liability	$	$ (78)
Unrealized gain from hedging activities of equity method investments	720	1,418
Accumulated other comprehensive income	$ 720	$ 1,340

See notes to consolidated financial statements.

Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

A. Operations and Principles of Consolidation.

Piedmont is an energy services company primarily engaged in the distribution of natural gas to residential, commercial and industrial customers in portions of North Carolina, South Carolina and Tennessee. We are invested in joint venture, energy-related businesses, including unregulated retail natural gas marketing, interstate natural gas storage and intrastate natural gas transportation. Our utility operations are regulated by three state regulatory commissions. For further information on regulatory matters, see Note 3 to the consolidated financial statements.

The consolidated financial statements reflect the accounts of Piedmont, its wholly owned subsidiaries and, through October 25, 2005, its 50% equity interest in Eastern North Carolina Natural Gas Company (EasternNC). On October 25, 2005, we purchased the remaining 50% interest in EasternNC and merged it into Piedmont. See Note 2 to the consolidated financial statements for further information on acquisitions.

Investments in non-utility activities are accounted for under the equity method as we do not have controlling voting interests or otherwise exercise control over the management of such companies. Our ownership interest in each entity is recorded in Equity method investments in non-utility activities in the consolidated balance sheets. Earnings or losses from equity method investments are recorded in Income from equity method investments in the consolidated statements of income. For further information on equity method investments, see Note 11 to the consolidated financial statements. Revenues and expenses of all other non-utility activities are included in Non-operating income in the consolidated statements of income. Inter-company transactions have been eliminated in consolidation where appropriate; however, we have not eliminated inter-company profit on sales to affiliates and costs from affiliates in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, Accounting For The Effects of Certain Types of Regulation (Statement 71).

B. Rate-Regulated Basis of Accounting.

Our utility operations are subject to regulation with respect to rates, service area, accounting and various other matters by the regulatory commissions in the states in which we operate. Statement 71 provides that rate-regulated public utilities account for and report assets and liabilities consistent with the economic effect of the manner in which independent third-party regulators establish rates. In applying Statement 71, we capitalize certain costs and benefits as regulatory assets and liabilities, respectively, in order to provide for recovery from or refund to utility customers in future periods.

Our regulatory assets are recoverable through either rate riders or base rates specifically authorized by a state regulatory commission. Base rates are designed to provide both a recovery of cost and a return on investment during the period the rates are in effect. As such, all of our regulatory assets are subject to review by the respective state regulatory commission during any future rate proceedings. In the event that the provisions of Statement 71 were no longer applicable, we would recognize a write-off of net regulatory assets (regulatory assets less regulatory liabilities) that would result in a charge to net income. Although the natural gas distribution industry is becoming increasingly competitive, our utility operations continue to recover their costs through cost-based rates established by the state regulatory commissions. As a result, we believe that the accounting prescribed under Statement 71 remains appropriate. It is also our opinion that all regulatory assets are recoverable in future rate proceedings, and therefore we have not recorded any regulatory assets that are recoverable but are not yet included in base rates or contemplated in a future rate recovery proceeding.

Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

Regulatory assets and liabilities in the consolidated balance sheets as of October 31, 2007 and 2006, are as follows.

	2007	2006
	In thousands	
Regulatory Assets:		
Unamortized debt expense	$ 10,565	$ 11,306
Amounts due from customers	76,035	89,635
Environmental costs*	4,223	3,812
Demand-side management costs*	2,631	3,554
Deferred operations and maintenance expenses*	9,286	9,234
Deferred pipeline integrity expenses*	4,417	2,121
Deferred pension and other retirement benefits costs*	11,146	8,748
FAS 158 pension and other retirement benefits costs*	1,865	
Regulatory cost of removal asset	11,939	12,086
Other*	1,866	2,972
Total	$ 133,973	$ 143,468
Regulatory Liabilities:		
Regulatory cost of removal obligations	$ 334,079	$ 310,989
Amounts due to customers	162	123
Deferred income taxes	25,463	25,134
FAS 158 pension and other retirement benefits costs	13,876	
Environmental liability due customers*	386	772
Total	$ 373,966	$ 337,018

* Regulatory assets are included in Other in Investments, Deferred Charges and Other Assets and regulatory liabilities are included in Other in Deferred Credits and Other Liabilities in the consolidated balance sheets.

As of October 31, 2007, we had regulatory assets totaling $1.7 million on which we do not earn a return during the recovery period. The original amortization periods for these assets range from 3 to 15 years and, accordingly, $.8 million will be fully amortized by 2008, $.1 million will be fully amortized by 2010 and the remaining $.8 million will be fully amortized by 2018.

C. Utility Plant and Depreciation.

Utility plant is stated at original cost, including direct labor and materials, allocable overhead charges and allowance for funds used during construction (AFUDC). For the years ended October 31, 2007, 2006 and 2005, AFUDC totaled $3.8 million, $3.9 million and $3.1 million, respectively. The portion of AFUDC attributable to equity funds is included in Other Income (Expense) and the portion attributable to borrowed funds is shown as a reduction of Utility

Interest Charges in the consolidated statements of income. The costs of property retired are removed from utility plant and charged to accumulated depreciation.

We compute depreciation expense using the straight-line method over periods ranging from four to 88 years. The composite weighted-average depreciation rates were 3.23% for 2007, 3.46% for 2006 and 3.46% for 2005.

Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

Depreciation rates for utility plant are approved by our regulatory commissions. In North Carolina, we are required to conduct a depreciation study every five years and propose new depreciation rates for approval. No such five-year requirement exists in South Carolina or Tennessee; however, we periodically propose revised rates in those states based on depreciation studies. The approved depreciation rates are comprised of two components, one based on average service life and one based on cost of removal. Through depreciation expense, we accrue estimated non-legal costs of removal on any depreciable asset that includes cost of removal in its depreciation rates.

D. Asset Retirement Obligations.

SFAS No. 143, Accounting for Asset Retirement Obligations (AROs) (Statement 143), addresses the financial accounting and reporting for AROs associated with the retirement of long-lived assets that result from the acquisition, construction, development and operation of the asset. Statement 143 requires the recognition of the fair value of a liability for an ARO in the period in which the liability is incurred if a reasonable estimate of fair value can be made. We have determined that AROs exist for our underground mains and services.

In accordance with long-standing regulatory treatment, our depreciation rates are comprised of two components, one based on average service life and one based on cost of removal, as stated above. We collect through rates the estimated costs of removal on certain regulated properties through depreciation expense, with a corresponding credit to accumulated depreciation. These removal costs are non-legal obligations as defined by Statement 143. Because these estimated removal costs meet the requirements of Statement 71, we have accounted for these non-legal asset removal obligations as a regulatory liability. We have reclassified the estimated non-legal asset removal obligations from Accumulated depreciation to Cost of removal obligations in Deferred Credits and Other Liabilities in our consolidated balance sheets. In the rate setting process, the liability for non-legal costs of removal is treated as a reduction to the net rate base upon which the regulated utility has the opportunity to earn its allowed rate of return.

In 2006, we applied the Financial Accounting Standards Board Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations (FIN 47), that requires recognition of a liability for the fair value of a conditional ARO when incurred if the liability can be reasonably estimated. An ARO will be capitalized concurrently by increasing the carrying amount of the related asset by the same amount of the liability. In periods subsequent to the initial measurement, any changes in the liability resulting from the passage of time (accretion) or due to the revisions of either timing or the amount of the originally estimated cash flows to settle the conditional ARO must be recognized. Any accretion will not be reflected in the income statement as we have received regulatory treatment for deferral as a regulatory asset with netting against a regulatory liability. We have recorded a liability on our distribution and transmission mains and services.

The cost of removal obligations recorded in our consolidated balance sheets as of October 31, 2007 and 2006, are shown below.

	2007	2006
	In thousands	
Regulatory non-legal asset removal obligations	$ 334,079	$ 310,989
Conditional asset retirement obligations	17,659	19,115

Total cost of removal obligations	$ 351,738	$ 330,104

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Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

A reconciliation of our FIN 47 conditional ARO for the year ended October 31, 2007, is presented below.

	In thousands
Beginning of period	$ 19,115
Liabilities incurred during the period	2,564
Liabilities settled during the period	(1,660)
Accretion	1,102
Adjustment to estimated cash flows*	(3,462)
End of period	$ 17,659

* Adjustment is primarily due to the change in the credit adjusted risk-free rate from 5.78% as of October 31, 2006 to 6.24% as of October 31, 2007.

E. Trade Accounts Receivable and Allowance for Doubtful Accounts.

Trade accounts receivable consist of natural gas sales and transportation services, merchandise sales and service work. We maintain an allowance for doubtful accounts, which we adjust periodically, based on the aging of receivables and our historical and projected charge-off activity. Our estimate of recoverability could differ from actual experience based on customer credit issues, the level of natural gas prices and general economic conditions. Effective November 1, 2005 as approved in an order by the North Carolina Utilities Commission (NCUC), we are allowed the recovery of all uncollected gas costs in North Carolina through the gas cost deferral account. As a result, only the portion of accounts written off relating to the non-gas costs, or margin, is included in base rates and, accordingly, only this portion is included in the provision for uncollectibles expense. Merchandise receivables due beyond one year are included in Other in Investments, Deferred Charges and Other Assets in the consolidated balance sheets.

A reconciliation of changes in the allowance for doubtful accounts for the years ended October 31, 2007, 2006 and 2005, is as follows.

	2007	2006	2005
		In thousands	
Balance at beginning of year	$ 1,239	$ 1,188	$ 1,086
Additions charged to uncollectibles expense	4,981	4,706	6,224
Accounts written off, net of recoveries	(5,676)	(4,655)	(6,122)
Balance at end of year	$ 544	$ 1,239	$ 1,188

F. Goodwill, Equity Method Investments and Long-Lived Assets.

All of our goodwill is attributable to the regulated utility segment. We evaluate goodwill for impairment annually on October 31, or more frequently if impairment indicators arise during the year. An impairment charge would be recognized if the carrying value of the reporting unit, including goodwill, exceeded its fair value.

Our annual goodwill impairment assessment was performed at October 31, 2007, and we determined that there was no impairment to the carrying value of our goodwill. No impairment has been recognized during the years ended October 31, 2007, 2006 and 2005.

We review our equity method investments and long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. There were no events or circumstances during the years ended October 31, 2007, 2006 and 2005, that resulted in any impairment charges. For further information on equity method investments, see Note 11 to the consolidated financial statements.

Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

G. Unamortized Debt Expense.

Unamortized debt expense consists of costs, such as underwriting and broker dealer fees, discounts and commissions, legal fees, registration fees and rating agency fees, related to issuing long-term debt. We amortize debt expense on a straight-line basis, which approximates the effective interest method, over the life of the related debt which has lives ranging from 10 to 30 years.

H. Inventories.

We maintain gas inventories on the basis of average cost. Injections into storage are priced at the purchase cost at the time of injection and withdrawals from storage are priced at the weighted average purchase price in storage. The cost of gas in storage is recoverable under rate schedules approved by state regulatory commissions. Inventory activity is subject to regulatory review on an annual basis in gas cost recovery proceedings.

Materials, supplies and merchandise inventories are valued at the lower of average cost or market and removed from such inventory at average cost.

I. Deferred Purchased Gas Adjustments.

Rate schedules for utility sales and transportation customers include purchased gas adjustment (PGA) provisions that provide for the recovery of prudently incurred gas costs. With regulatory commission approval, we revise rates periodically without formal rate proceedings to reflect changes in the cost of gas. Under PGA provisions, charges to cost of gas are based on the gas cost amounts recoverable under approved rate schedules. By jurisdiction, differences between gas costs incurred and gas costs billed to customers are deferred and included in Amounts due from customers or Amounts due to customers in the consolidated balance sheets. We review gas costs and deferral activity periodically and, with regulatory commission approval, increase rates to collect under-recoveries or decrease rates to refund over-recoveries over a subsequent period.

J. Taxes.

Deferred income taxes are determined based on the estimated future tax effects of differences between the book and tax basis of assets and liabilities. Deferred taxes are primarily attributable to utility plant, equity method investments and revenues and cost of gas. We have provided valuation allowances to reduce the carrying amount of deferred tax assets to amounts that are more likely than not to be realized. To the extent that the establishment of deferred income taxes is different from the recovery of taxes through the ratemaking process, the differences are deferred pursuant to Statement 71, and a regulatory asset or liability is recognized for the impact of tax expenses or benefits that will be collected from or refunded to customers in different periods pursuant to rate orders. We amortize deferred investment tax credits to income over the estimated useful lives of the property to which the credits relate.

General taxes consist primarily of property taxes and payroll taxes. These taxes are not included in revenues.

K. Revenue Recognition.

Utility sales and transportation revenues are based on rates approved by state regulatory commissions. Base rates charged to jurisdictional customers may not be changed without formal approval by the regulatory commission in that jurisdiction; however, the wholesale cost of gas component of rates may be adjusted periodically under PGA provisions. A weather normalization adjustment (WNA) factor is included in rates charged to residential and commercial customers during the winter period November through March in all jurisdictions except EasternNC. The WNA is designed to offset the impact that warmer-than-normal or colder-

Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

than-normal weather has on customer billings during the winter season. Effective November 1, 2005, in North Carolina, through a general rate case proceeding, the Customer Utilization Tracker (CUT) eliminated the WNA that had previously been used. The CUT provides for the recovery of our approved margin from residential and commercial customers independent of both weather and consumption patterns.

Revenues are recognized monthly on the accrual basis, which includes estimated amounts for gas delivered to customers but not yet billed under the cycle-billing method from the last meter reading date to month end. The unbilled revenue estimate reflects factors requiring judgment related to estimated usage by customer class, changes in weather during the period and the impact of the WNA or CUT mechanisms, as applicable.

Secondary market, or wholesale, sales revenues are recognized when the physical sales are delivered based on contract or market prices. See Note 3 regarding revenue sharing of secondary market transactions.

L. Earnings Per Share.

We compute basic earnings per share using the weighted average number of shares of common stock outstanding during each period. A reconciliation of basic and diluted earnings per share for the years ended October 31, 2007, 2006 and 2005, is presented below.

	2007	2006	2005
	In thousands except per share amounts		
Net Income	$ 104,387	$ 97,189	$ 101,270
Average shares of common stock outstanding for basic earnings per share	74,250	75,863	76,680
Contingently issuable shares under the Executive Long-Term Incentive Plan and Incentive Compensation Plan	222	293	312
Average shares of dilutive stock	74,472	76,156	76,992
Earnings Per Share:			
Basic	$ 1.41	$ 1.28	$ 1.32
Diluted	$ 1.40	$ 1.28	$ 1.32

M. Statements of Cash Flows.

For purposes of reporting cash flows, we consider instruments purchased with an original maturity at date of purchase of three months or less to be cash equivalents.

N. Use of Estimates.

We make estimates and assumptions when preparing the consolidated financial statements. These estimates and assumptions affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from estimates.

O. Recently Issued Accounting Standards.

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation 48, Accounting for Uncertainty in Income Taxes (FIN 48), to clarify the accounting for uncertain tax positions in accordance with SFAS 109, Accounting for Income Taxes, and in May 2007 issued Staff Position No. FIN 48-1, Definition of Settlement in FASB Interpretation No. 48, (FSP 48-1). FIN 48 defines a minimum recognition threshold that a tax position must meet to be recognized in an enterprise s financial statements. Additionally,

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Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

FIN 48 provides guidance on derecognition, measurement, classification, interim period accounting, disclosure and transition requirements in accounting for uncertain tax positions. FSP 48-1 clarifies when a tax position is considered effectively settled under FIN 48. FIN 48 is effective the beginning of the first annual period beginning after December 15, 2006, and the guidance under FSP 48-1 should be applied upon the adoption of FIN 48. Accordingly, we will adopt FIN 48 and FSP 48-1 in our fiscal year 2008. We have assessed the impact FIN 48 may have on our consolidated financial statements. The adoption will not have a material impact on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (Statement 157). Statement 157 provides enhanced guidance for using fair value to measure assets and liabilities and applies whenever other standards require (or permit) the measurement of assets or liabilities at fair value, but does not expand the use of fair value measurement to any new circumstances. Statement 157 establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data, for example, the reporting entity s own data. Under Statement 157, fair value measurements would be separately disclosed by level within the fair value hierarchy. On November 14, 2007, the FASB delayed the implementation of Statement 157 for one year only for other nonfinancial assets and liabilities. Statement 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, with earlier application encouraged for financial assets and liabilities, as well as for any other assets and liabilities that are carried at fair value on a recurring basis. Accordingly, we will adopt Statement 157 no later than our first fiscal quarter in 2009. We believe the adoption of Statement 157 will not have a material impact on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans (Statement 158). Statement 158 requires an employer to fully recognize the obligations associated with single-employer defined benefit pension, retiree healthcare and other postretirement plans in the financial statements by recognizing in its statement of financial position an asset for a plan s overfunded status or a liability for a plan s underfunded status rather than only disclosing the funded status in the footnotes to the financial statements. Statement 158 requires employers to recognize changes in the funded status of a defined benefit postretirement plan in the year in which the changes occur. Under Statement 158, gains and losses, prior service costs and credits, and any remaining transition amounts that have not yet been recognized through net periodic benefit cost will be recognized in accumulated other comprehensive income (OCI), net of tax effects, until they are amortized as a component of net periodic cost. Statement 158 also requires that the company measure a plan s assets and its obligations that determine its funded status as of the end of the employer s fiscal year. We are already in compliance with this requirement as our pension plans measurement dates are already the same as our fiscal year end date.

The requirement to recognize the funded status of a benefit plan and the related disclosure requirements applied as of the end of the fiscal year ending after December 15, 2006. Accordingly, we adopted the funded status portion of Statement 158 as of October 31, 2007. Adoption of Statement 158 on our financial position is shown below. The adoption of Statement 158 did not have a material effect on our results of operations or cash flows.

In August 2007, we filed petitions with the NCUC, the Public Service Commission of South Carolina (PSCSC) and the Tennessee Regulatory Authority (TRA) requesting the ability to place certain defined benefit postretirement obligations related to the implementation of Statement 158 in a regulatory deferred account instead of OCI. The petitions have been approved in all of the jurisdictions.

Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

Based on the measurement of the various postretirement plans assets and benefit obligations as of October 31, 2007, the effect on our consolidated balance sheet of adopting Statement 158 is as follows.

	Before Application of Statement 158	Minimum Pension Liability Adjustment	Adoption of Statement 158	Rate Deferral Adjustments	After Application of Statement 158
			In thousands		
Prepayments	$ 22,435	$	$ (22,435)	$	$
Overfunded postretirement asset			36,256		36,256
Regulatory asset for postretirement benefits, noncurrent				1,865	1,865
Accumulated other comprehensive income	(78)	24	7,346	(7,292)	
Other current liabilities			553		553
Deferred income taxes (noncurrent)	(51)	16	4,754	(4,719)	
Regulatory liability for postretirement benefits, noncurrent				13,876	13,876
Accumulated provision for postretirement benefits			17,469		17,469
Other (deferred credits and other liabilities)	16,342	(40)	(16,302)		

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (Statement 159). Statement 159 provides companies with an option to report selected financial assets and liabilities at fair value. Its objective is to reduce the complexity in accounting for financial instruments and to mitigate the volatility in earnings caused by measuring related assets and liabilities differently. Although Statement 159 does not eliminate disclosure requirements included in other accounting standards, it does establish additional presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. Statement 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007, with early adoption permitted for an entity that has elected also to apply Statement 157 early. Accordingly, we will adopt Statement 159 no later than our first fiscal quarter in 2009. We believe the adoption of Statement 159 will not have a material impact on our financial position, results of operations or cash flows.

2. Acquisitions

Effective at the close of business on September 30, 2003, we purchased for $7.5 million in cash Progress Energy, Inc. s (Progress) equity interest in EasternNC. At that time, EasternNC was a regulated utility with a certificate of public convenience and necessity to provide natural gas service to 14 counties in eastern North Carolina that previously were not served with natural gas. Progress equity interest in EasternNC consisted of 50% of EasternNC s outstanding common stock and 100% of EasternNC s outstanding preferred stock.

We recorded the assets purchased on September 30, 2003, at fair value, except for utility plant, franchises and consents and miscellaneous intangible property that were recorded at book value in accordance with Statement 71. We recorded estimated goodwill at closing of $1.1 million for EasternNC.

Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

On October 25, 2005, we purchased the remaining 50% interest in EasternNC for $1. EasternNC was merged into Piedmont immediately following the closing. The primary reason for the purchase of the remaining 50% interest was to integrate the rate structure of EasternNC into Piedmont s rate structure.

3. Regulatory Matters

Our utility operations are regulated by the NCUC, PSCSC and TRA as to rates, service area, adequacy of service, safety standards, extensions and abandonment of facilities, accounting and depreciation. We are also regulated by the NCUC as to the issuance of securities.

In April 2005, we filed a general rate case with the NCUC requesting a consolidation of the respective rate bases, revenues and expenses of Piedmont, North Carolina Natural Gas Corporation (NCNG) and EasternNC. In addition to a unified and uniform rate structure for all customers served by us in North Carolina, the application requested a general restructuring and increase in rates and charges for customers to produce an overall annual increase in margin of $36.7 million, a consolidation and/or amortization of certain deferred accounts, changes to cost allocations and rate design including a tariff mechanism that decouples margin recovery from residential and commercial customer consumption, changes and unification of existing service regulations and tariffs, common depreciation rates for plant and recovery of uncollectible gas costs through the gas cost deferred account.

In November 2005, the NCUC issued an order approving, among other things, an annual increase in margin of $20.2 million under the 2005 general rate case and authorizing new rates, effective November 1, 2005. The order provided for the elimination of the WNA mechanism in North Carolina and the establishment of a CUT that decouples margin recovery from residential and commercial customer consumption. The CUT is experimental and can be effective for no more than three years, subject to review and approval for extension in a future general rate case proceeding. The CUT provides for the recovery of our approved margin from residential and commercial customers independent of weather or other usage and consumption patterns. The CUT tracks our margin earned monthly and will result in semi-annual rate adjustments to refund any over-collection or recover any under-collection. We have been operating under the CUT for two years. During this time, we have made four rate adjustment filings to recover under-collections from residential and commercial customers. The latest of these four filings was made in October 2007, where we requested a rate adjustment, beginning November 1, 2007, to collect $32.1 million attributable to the period ended August 31, 2007. Each of these rate adjustment filings, including the October 2007 filing, has been approved by the NCUC.

Under the NCUC s orders approving the CUT, in each of the three years the CUT is effective, we allocate $500,000 to energy conservation program funding and share, in each of the three years the CUT is effective, the first $3 million of CUT dollars that are non-weather related. Annually, the first $3 million of non-weather related CUT amounts will be allocated 25% to customer rate reduction, 25% to energy conservation program funding and 50% to us. Since the inception of the CUT on November 1, 2005, we have incurred charges of $4.2 million for the benefit of residential and commercial customers. The charges consist of $2.5 million for the funding of conservation programs in North Carolina, $1.5 million for the reduction of residential and commercial customer rates in North Carolina and $.2 million for interest accruals on the conservation funding and reduction of customer rates. The conservation programs are subject to review and approval by the NCUC. At October 31, 2007, we have a liability of $1.5 million out of the $4.2 million incurred charges related to these conservation programs.

The North Carolina General Assembly enacted the Clean Water and Natural Gas Critical Needs Act of 1998 which provided for the issuance of $200 million of general obligation bonds of the state for the purpose of providing grants, loans or other financing for the cost of constructing natural gas facilities in unserved areas of North Carolina. In 2000, the NCUC issued an order awarding EasternNC an exclusive franchise to provide natural gas service to 14 counties in the eastern-most part of North Carolina that had not been able to obtain gas service because of the relatively small population of those counties and the resulting uneconomic

Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

feasibility of providing service. The order also granted $38.7 million in state bond funding. In 2001, the NCUC issued an order granting EasternNC an additional $149.6 million, for a total of $188.3 million. During the fiscal year ended October 31, 2006, we were reimbursed $16 million in construction costs by the state, the remaining balance of the bond fund as of October 31, 2005.

The NCUC had allowed EasternNC to defer its operations and maintenance expenses during the first eight years of operation or until the first rate case order, whichever occurred first, with a maximum deferral of $15 million. The deferred amounts accrued interest at a rate of 8.69% per annum. In December 2003, the NCUC confirmed that these deferred expenses should be treated as a regulatory asset for future recovery from customers to the extent they are deemed prudent and proper. As a part of the general rate case proceeding discussed above, deferral ceased on October 31, 2005, and the balance in the deferred account as of June 30, 2005, $7.9 million, including accrued interest, is being amortized over 15 years beginning November 1, 2005. Amortization of amounts totaling $1.3 million that were deferred between July 1 and October 31, 2005, will be addressed in our next North Carolina general rate case.

In October 2004, we filed a petition with the NCUC seeking deferred accounting treatment for certain pipeline integrity management costs to be incurred by us in compliance with the Pipeline Safety Improvement Act of 1992 and regulations of the United States Department of Transportation. The NCUC approved deferral treatment of these costs applicable to all incremental expenditures beginning November 1, 2004. As a part of the 2005 general rate case discussed above, the balance of $.4 million in the deferred account as of June 30, 2005, is being amortized over three years beginning November 1, 2005, and subsequent expenditures that total $4.3 million as of October 31, 2007 will continue to be deferred. Any unamortized balance at the end of the three years will be addressed in a future rate case.

On February 16, 2005, the Natural Gas Rate Stabilization Act (RSA) of 2005 became effective in South Carolina. The law provides electing natural gas utilities, including Piedmont, with a mechanism for the regular, periodic and more frequent (annual) adjustment of rates which is intended to: (1) encourage investment by natural gas utilities, (2) enhance economic development efforts, (3) reduce the cost of rate adjustment proceedings and (4) result in smaller but more frequent rate changes for customers. If the utility elects to operate under the Act, the annual filing will provide that the utility s rate of return on equity will remain within a 50-basis points band above or below the current allowed rate of return on equity. In April 2005, we filed an election with the PSCSC to adopt this new mechanism.

In June 2005, we filed with the PSCSC a quarterly monitoring report for the twelve months ended March 31, 2005, along with revenue deficiency calculations and proposed changes in our tariff rates. In the filing, we requested an increase in annual margin of $3.2 million. In October 2005, the PSCSC issued an order approving an increase in annual margin of $2.6 million, effective November 1, 2005.

In June 2006, we filed with the PSCSC a quarterly monitoring report for the twelve months ended March 31, 2006, along with revenue deficiency calculations and proposed changes in our tariff rates. In the filing, we requested an increase in annual margin of $10.3 million. In September 2006, we, the Office of Regulatory Staff (ORS) and the South Carolina Energy Users Committee (SCEUC) filed a settlement agreement with the PSCSC addressing our proposed rate changes under the RSA. In September 2006, the PSCSC issued an order approving a $5.6 million increase in margin based on 11.2% return on equity effective November 1, 2006.

In June 2007, we filed with the PSCSC a quarterly monitoring report for the twelve months ended March 31, 2007 and a cost and revenue study as permitted by the RSA requesting no change in margin. In August 2007, we, the ORS and the SCEUC filed a settlement agreement with the PSCSC which will result in a $2.5 million annual decrease in margin based on a return of equity of 11.2%. In October 2007, the PSCSC issued an order approving the settlement, effective November 1, 2007.

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All three jurisdictions regulate our gas purchasing practices under a standard of prudence and audit our gas cost accounting practices. As part of this jurisdictional oversight, all three states address our gas supply hedging activities. Additionally, as detailed below, all three states allow for recovery of uncollectible gas costs through the PGA.

In August 2007, the NCUC approved our accounting for gas costs during the twelve months ended May 31, 2006, with adjustments agreed to by us as a result of the North Carolina Public Staff s audit of the 2006 gas cost review period. We were deemed prudent on our gas purchasing policies and practices during this review period and allowed 100% recovery. In this order the NCUC also required us to discontinue the accounting practice of capitalizing and amortizing storage demand charges, effective no later than November 1, 2007. This action resulted in a margin decrease of $5.4 million in 2007.

During 2007, under the provisions of the August 2007 NCUC order, we recorded as restricted funds $2.2 million, including interest, of supplier refunds. In September 2007, we petitioned the NCUC for authority to liquidate all certificates of deposit and similar investments that held any supplier refunds due to customers. In October 2007, the NCUC approved the transfer of these restricted funds to the North Carolina all customers deferred account. The various certificates of deposit all mature by January 31, 2008.

In November 2007, the NCUC approved our accounting of gas costs for the twelve months ended May 31, 2007, with adjustments agreed to by us as a result of the North Carolina Public Staff s audit of the 2007 gas cost review period. We were deemed prudent on our gas purchasing policies and practices during this review period and allowed 100% recovery.

Our hedging plan for North Carolina targets 30% to 60% of annual normalized sales volumes for North Carolina and operates using historical pricing indices that are tied to future projected gas prices as traded on a national exchange. Unlike South Carolina as discussed below, recovery of costs associated with the North Carolina hedging plan is not pre-approved by the NCUC, and the costs are treated as gas costs subject to the annual gas cost prudence review. Any gain or loss recognition are deemed to be reductions in or additions to gas costs, respectively, which, along with any hedging expenses, are flowed through to North Carolina customers in rates. The August 2007 gas cost review order and our November 2007 gas cost review order found our hedging activities during the two review periods to be reasonable and prudent.

Since November 1, 2005, the NCUC has allowed the recovery of all uncollectible gas costs through the gas cost PGA deferral account. As a result, the portion of uncollectibles related to gas costs is recovered through the deferred account and only the non-gas costs, or margin, portion of uncollectibles is included in base rates and uncollectibles expense.

In South Carolina, the PSCSC approved a settlement in August 2006 between us, the ORS and the SCEUC accepting our purchased gas adjustments and finding our gas purchasing policies prudent for the twelve months ended March 31, 2006. As part of this settlement, we began recovering uncollectible gas costs through the PGA effective November 1, 2006 in South Carolina. A settlement between us, the ORS and the SCEUC accepting our purchased gas adjustments and finding our gas purchasing policies prudent for the twelve months ended March 31, 2007 is pending before the PSCSC. We cannot determine the outcome of the proceeding at this time.

The PSCSC has approved a gas cost hedging plan for the purpose of cost stabilization for South Carolina customers. The plan targets 30% to 60% of annual normalized sales volumes for South Carolina and operates using historical pricing indices that are tied to future projected gas prices as traded on a national exchange. All properly accounted for costs incurred in accordance with the plan are deemed to be prudently incurred and are recovered in rates as gas costs. Any gain or loss recognition are deemed to be reductions in or additions to gas costs, respectively, and are flowed through to South Carolina customers in rates.

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Piedmont Natural Gas Company, Inc.

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In Tennessee, the Tennessee Incentive Plan (TIP) replaced annual prudence reviews under the Actual Cost Adjustment (ACA) mechanism in 1996 by benchmarking gas costs against amounts determined by published market indices and by sharing secondary market (capacity release and off-system sales) activity performance. The costs and benefits of hedging instruments and all other gas costs incurred are components of the TIP. In July 2005, in the order approving our 2004 TIP filing, the TRA established a separate docket to address issues raised by the Tennessee Consumer Advocate Staff and the TRA Staff related to the breadth of secondary market activities covered by the TIP, the method for selecting the independent consultant to review performance under the TIP, and the procedures utilized with respect to requests for proposal. In October 2007, the TRA approved our settlement with the staff of the TRA and the Tennessee Consumer Advocate Staff modifying our TIP with an effective date of July 1, 2006. The modifications clarify and simplify the calculation of allocated gains and losses to ratepayers and shareholders by adopting a uniform 75/25 sharing ratio, maintain the current $1.6 million annual incentive cap on gains and losses, improve the transparency of plan operations by an agreed to request for proposal procedures for asset management transactions and provide for a triennial review of TIP operations by an independent consultant.

In March 2003, we, along with two other natural gas companies in Tennessee, filed a petition with the TRA requesting a declaratory order that the gas cost portion of uncollectible accounts be recovered through PGA procedures. We requested that to the extent that the gas cost portion of net write-offs for a fiscal year is less than the gas cost portion included in base rates, the difference would be refunded to customers through the ACA filings. With TRA approval, this methodology was used on an experimental basis for two years. In August 2006, the TRA approved the methodology permanently.

Due to the seasonal nature of our business, we contract with customers in the secondary market to sell supply and capacity assets when available. In North Carolina and South Carolina, we operate under sharing mechanisms approved by the NCUC and the PSCSC for secondary market transactions where 75% of the net margins are flowed through to jurisdictional customers in rates and 25% is retained by us. In Tennessee, we operate under the amended TIP where gas purchase benchmarking gains and losses are combined with secondary market transaction gains and losses and shared 75% by customers and 25% by us. Our share of net gains or losses in Tennessee is subject to an overall annual cap of $1.6 million.

We filed a petition with the NCUC and the PSCSC in September 2006, and with the TRA in September 2006, for authorization to place certain ARO costs in deferred accounts so that the regulatory treatment for these costs will not be altered due to our adoption of FIN 47. The petitions were approved in all of the jurisdictions in November 2007, effective October 31, 2006.

In August 2007, we filed petitions with the NCUC, the PSCSC and the TRA requesting the ability to place certain defined benefit postretirement obligations related to the implementation of Statement 158 in a deferred account instead of OCI. The petitions have been approved in all of the jurisdictions.

We currently have commission approval in all three states that place additional credit requirements on the retail natural gas marketers that schedule gas into our system in order to mitigate the risk exposure to the financial condition of the marketers.

In August 2007, we requested authorization from the NCUC and the PSCSC to defer certain settlement charges that we believed we may have been required to recognize under SFAS No. 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits as a result of lump sum distributions from our pension plans in our current fiscal year. Because these charges did not accrue, we withdrew the filing from North Carolina and it will not be necessary to exercise the authority we received from South Carolina.

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Notes to Consolidated Financial Statements (Continued)

4. Long-Term Debt

All of our long-term debt is unsecured. Long-term debt as of October 31, 2007 and 2006, is as follows.

	2007	2006
	In thousands	
Senior Notes:		
8.51%, due 2017	$ 35,000	$ 35,000
Insured Quarterly Notes:		
6.25%, due 2036	199,887	200,000
Medium-Term Notes:		
7.35%, due 2009	30,000	30,000
7.80%, due 2010	60,000	60,000
6.55%, due 2011	60,000	60,000
5.00%, due 2013	100,000	100,000
6.87%, due 2023	45,000	45,000
8.45%, due 2024	40,000	40,000
7.40%, due 2025	55,000	55,000
7.50%, due 2026	40,000	40,000
7.95%, due 2029	60,000	60,000
6.00%, due 2033	100,000	100,000
Total	824,887	825,000
Less current maturities		
Total	$ 824,887	$ 825,000

Current maturities for the next five years ending October 31 and thereafter are as follows.

	In thousands
2008	$
2009	30,000
2010	60,000
2011	60,000
2012	
Thereafter	674,887
Total	$ 824,887

We have a shelf registration statement that can be used for either debt or equity securities filed with the Securities and Exchange Commission (SEC). The remaining balance of unused long-term financing available under this shelf registration statement is $109.4 million.

On September 1, 2007, $.1 million was paid to noteholders of the 6.25% insured quarterly notes based on a redemption right upon the death of the owner of the notes, within specified limitations.

The amount of cash dividends that may be paid on common stock is restricted by provisions contained in certain note agreements under which long-term debt was issued, with those for the senior notes being the most restrictive. We cannot pay or declare any dividends, make any other distribution on any class of stock or make any investments in subsidiaries, or permit any subsidiary to do any of the above (all of the foregoing being restricted payments), except out of net earnings available for restricted payments. As of October 31, 2007, we could make restricted payments totaling $540.7 million. Retained earnings as of this date were $379.7 million; therefore, our retained earnings were not restricted.

Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

We are subject to cross-default provisions related to our long-term debt. An event of default under any of our debt agreements may result in total outstanding issues of debt becoming due. As of October 31, 2007, we are in compliance with all default provisions.

5. Capital Stock and Accelerated Share Repurchase

Changes in common stock for the years ended October 31, 2005, 2006 and 2007, are as follows.

	Shares	Amount
	In thousands	
Balance, October 31, 2004	76,670	$ 563,667
Issued to participants in the Employee Stock Purchase Plan (ESPP)	43	904
Issued to the Dividend Reinvestment and Stock Purchase Plan (DRIP)	1,013	22,632
Issued to participants in the Executive Long-Term Incentive Plan (LTIP)	77	1,796
Shares repurchased under Common Stock Open Market Repurchase Plan	(1,105)	(26,119)
Balance, October 31, 2005	76,698	562,880
Issued to ESPP	36	882
Issued to DRIP	735	17,496
Issued to LTIP	75	1,669
Shares repurchased under Common Stock Open Market Repurchase Plan	(1,080)	(25,871)
Shares repurchased under Accelerated Share Repurchase (ASR) Plan	(1,000)	(24,292)
Balance, October 31, 2006	75,464	532,764
Issued to ESPP	34	809
Issued to DRIP	593	14,973
Issued to LTIP	117	3,264
Shares repurchased under Common Stock Open Market Repurchase Plan	(150)	(3,953)
Shares repurchased under ASR	(1,850)	(50,287)
Balance, October 31, 2007	74,208	$ 497,570

In June 2004, the Board of Directors approved a Common Stock Open Market Purchase Program that authorizes the repurchase of up to three million shares of currently outstanding shares of common stock. We implemented the program in September 2004. We utilize a broker to repurchase the shares on the open market and such shares are cancelled and become authorized but unissued shares available for issuance under the ESPP, DRIP and LTIP.

On December 16, 2005, the Board of Directors approved an increase in the number of shares in this program from three million to six million to reflect the stock split in 2004. The Board also approved the repurchase of up to four million additional shares of currently outstanding shares of common stock and amended the program to provide for repurchases to maintain our debt-to-equity capitalization ratios at target levels. These combined actions increased the total authorized share repurchases from three million to ten million shares.

On November 3, 2006, we entered into an ASR agreement. On November 7, 2006, we purchased and retired 1 million shares of our common stock from an investment bank at the closing price that day of $26.48 per share. Total consideration paid to purchase the shares of $26.6 million, including $118,800 in commissions and other fees, was recorded in Stockholders equity as a reduction in Common stock.

As part of the ASR, we simultaneously entered into a forward sale contract with the investment bank that was expected to mature in approximately 50 trading days. Under the terms of the forward sale contract, the investment bank was required to purchase, in the open market, 1 million shares of our common stock during the term of the contract to fulfill its obligation related to the shares it borrowed from third parties and sold to

Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

us. At settlement, we, at our option, were required to either pay cash or issue registered or unregistered shares of our common stock to the investment bank if the investment bank s weighted average purchase price was higher than the November 7, 2006 closing price. The investment bank was required to pay us either cash or shares of our common stock, at our option, if the investment bank s weighted average price for the shares purchased was lower than the November 7, 2006 closing price. At settlement on January 19, 2007, we paid cash of $.8 million to the investment bank and recorded this amount in Stockholders equity as a reduction in Common stock. The $.8 million was the difference between the investment bank s weighted average purchase price of $27.3234 and the November 7, 2006 closing price of $26.48 per share multiplied by 1 million shares.

On March 30, 2007, we entered into an ASR agreement under the same terms. On April 2, 2007, we purchased and retired an additional 850,000 shares of our common stock from an investment bank at the closing price that day of $26.38 per share. Total consideration paid to purchase the shares of $22.5 million, including $25,500 in commissions and other fees, was recorded in Stockholders equity as a reduction in Common stock. At settlement on May 23, 2007, we paid cash of $.4 million to the investment bank and recorded this amount in Stockholders equity as a reduction in Common stock. The $.4 million was the difference between the investment bank s weighted average purchase price of $26.8459 and the March 30, 2007 closing price of $26.38 per share multiplied by 1 million shares.

As of October 31, 2007, 2 million shares of common stock were reserved for issuance as follows.

	In thousands
ESPP	107
DRIP	896
LTIP	1,030
Total	2,033

6. Financial Instruments and Related Fair Value

We have a syndicated five-year revolving credit facility with aggregate commitments totaling $350 million, that may be increased up to $600 million, and that includes annual renewal options. We pay an annual fee of $35,000 plus six basis points for any unused amount up to $350 million. The facility provides a line of credit for letters of credit up to $5 million of which $1.5 million and $1.2 million were issued and outstanding at October 31, 2007 and 2006, respectively. These letters of credit are used to guarantee claims from self-insurance under our general liability policies. The credit facility bears interest based on the 30-day LIBOR rate plus from .15% to .35%, based on our credit ratings.

As of October 31, 2007 and 2006, outstanding borrowings under the lines are included in Notes payable in the consolidated balance sheets, and consisted of $195.5 million and $170 million, respectively, in LIBOR cost-plus loans at a weighted average interest rate of 4.96% in 2007 and 5.57% in 2006. Our credit facility s financial covenants require us to maintain a ratio of total debt to total capitalization of no greater than 70%, and the actual ratio was 54% at October 31, 2007. As of October 31, 2007, the unused committed lines of credit totaled $153 million.

Our principal business activity is the distribution of natural gas. As of October 31, 2007, our trade accounts receivable consisted of gas receivables of $95.5 million and merchandise and jobbing receivables of $2.1 million, net of an allowance for doubtful accounts of $.5 million. We believe that we have provided an adequate allowance for any receivables which may not be ultimately collected.

In February 2005, we sold 37,244 common units of Energy Transfer Partners, LP, which we received in connection with the sale in January 2004 of our propane interests, for proceeds of $2.4 million, resulting in a pre-tax gain of $1.5 million. For further information on this transaction, see Note 11 to the consolidated financial statements.

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Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

The carrying amounts in the consolidated balance sheets of cash and cash equivalents, restricted cash, receivables, notes payable and accounts payable approximate their fair values due to the short-term nature of these financial instruments. Based on quoted market prices of similar issues having the same remaining maturities, redemption terms and credit ratings, the estimated fair value amounts of long-term debt as of October 31, 2007 and 2006, including current portion, were as follows.

	2007		2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	In thousands			
Long-term debt	$ 824,887	$ 892,506	$ 825,000	$ 913,739

The use of different market assumptions or estimation methodologies could have a material effect on the estimated fair value amounts. The fair value amounts reflect principal amounts that we will ultimately be required to pay.

We purchase natural gas for our regulated operations for resale under tariffs approved by the state regulatory commissions having jurisdiction over the service area where the customer is located. We recover the cost of gas purchased for regulated operations through purchased gas cost recovery mechanisms. We structure the pricing, quantity and term provisions of our gas supply contracts to maximize flexibility and minimize cost and risk for our customers. Our risk management policies allow us to use financial instruments to hedge risks. We have a management-level Energy Risk Management Committee that monitors risks in accordance with our risk management policies.

We have purchased and sold financial options for natural gas in all three states for our gas purchase portfolios. The gains or losses on financial derivatives utilized in the regulated utility segment are included in our gas cost adjustments to customers subject to appropriate regulatory review. Current period changes in the assets and liabilities from these risk management activities are recorded as a component of gas costs in amounts due to/from customers in accordance with Statement 71. Accordingly, there is no earnings impact on the regulated utility segment as a result of the use of these financial derivatives. As of October 31, 2007 and 2006, the total fair value of gas purchase options included in the consolidated balance sheets was $13.7 million and $3.1 million, respectively.

7. Commitments and Contingent Liabilities

Leases

We lease certain buildings, land and equipment for use in our operations under noncancelable operating leases. For the years ended October 31, 2007, 2006 and 2005, operating lease payments were $6.6 million, $7.2 million and $6.9 million, respectively.

Future minimum lease obligations for the next five years ending October 31 and thereafter are as follows.

In thousands

2008	$	5,076
2009		4,461
2010		3,728
2011		3,592
2012		3,553
Thereafter		11,137
Total	$	31,547

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Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

Long-term contracts

We routinely enter into long-term gas supply commodity and capacity commitments and other agreements that commit future cash flows to acquire services we need in our business. These commitments include pipeline and storage capacity contracts and gas supply contracts to provide service to our customers and telecommunication and information technology contracts and other purchase obligations. The time periods for pipeline and storage capacity contracts range from one to sixteen years. The time periods for gas supply contracts range from one to four years. The time periods for the telecommunications and technology contracts providing maintenance fees for hardware and software applications, usage fees, local and long-distance data costs, frame relay, cell phone and pager usage fees range from one to five years. Other purchase obligations consist primarily of commitments for pipeline products, vehicles and contractors.

Certain storage and pipeline capacity contracts require the payment of demand charges that are based on rates approved by the Federal Energy Regulatory Commission (FERC) in order to maintain the ability to access the natural gas storage or the pipeline capacity on a firm basis during the contract term. The demand charges that are incurred in each period are recognized in the consolidated statement of operations as part of gas purchases and included in cost of gas.

As of October 31, 2007, future unconditional purchase obligations for the next five years ending October 31 and thereafter are as follows.

	Pipeline and Storage Capacity	Gas Supply	Telecommunications and Information Technology	Other	Total
			In thousands		
2008	$ 162,032	$ 25,405	$ 18,641	$ 32,446	$ 238,524
2009	161,730	545	19,163		181,438
2010	161,309	125	19,700		181,134
2011	162,542	54	20,251		182,847
2012	156,744		20,818		177,562
Thereafter	468,682				468,682
Total	$ 1,273,039	$ 26,129	$ 98,573	$ 32,446	$ 1,430,187

Legal

We have only routine litigation in the normal course of business.

Letters of Credit

We use letters of credit to guarantee claims from self-insurance under our general liability policies. We had $1.5 million in letters of credit that were issued and outstanding at October 31, 2007. Additional information concerning letters of credit is included in Note 6.

Environmental Matters

Our three state regulatory commissions have authorized us to utilize deferral accounting in connection with environmental costs. Accordingly, we have established regulatory assets for actual environmental costs incurred and for estimated environmental liabilities recorded.

Several years ago, we entered into a settlement with a third party with respect to nine manufactured gas plant (MGP) sites that we have owned, leased or operated and paid an amount, charged to the estimated environmental liability, that released us from any investigation and remediation liability. On one of these nine properties, we performed additional clean-up activities, including the removal of an underground storage tank,

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Notes to Consolidated Financial Statements (Continued)

in anticipation of an impending sale. Although no such claims are pending or, to our knowledge, threatened, the settlement did not cover any third-party claims for personal injury, death, property damage and diminution of property value or natural resources. Three other MGP sites that we also have owned, leased or operated were not included in the settlement. In addition to these sites, we acquired the liability for an MGP site located in Reidsville, North Carolina, in connection with the acquisition in 2002 of certain assets and liabilities of North Carolina Gas Services, a division of NUI Utilities, Inc.

As part of a voluntary agreement with the North Carolina Department of Environment and Natural Resources (NCDENR), we started the initial steps for remediating the Hickory, North Carolina MGP site in 2007. In order to formalize the remediation process, the NCDENR sent us a letter requesting the initiation of a remedial investigation of this site. Because we no longer own the property, access to the property had to be obtained from the current owner, and the initial file search and survey had to be completed. We submitted our site investigation plan in September 2007, and the proposed investigation activities were approved by the NCDENR in October 2007. Based on the limited site assessment report we have concluded that gas plant residuals remaining on the Hickory site are thought to be mostly contained within two former tar separators associated with the site s operations. Based on the initial investigations activities that began in October 2007, the costs to remediate the property is expected to be approximately $200,000.

During 2007, we performed a more extensive investigation of our MGP site located in Nashville to determine if the accrued amounts were sufficient to cover the clean up of that site. Based on the results of this study, we believed that an adjustment was necessary to cover additional clean up of the site expected to cost approximately $500,000. In accordance with the deferral accounting authorized by our regulatory commissions, we adjusted the regulatory asset and the estimated liability for this additional amount.

As of October 31, 2007, our undiscounted environmental liability totaled $3.9 million, and consisted of $3.4 million for the remaining four sites and $.5 million for underground storage tanks not yet remediated. We increased the liability in 2007 by $.1 million and in 2006 by $.1 million to reflect the impact of inflation based on the consumer price index.

As of October 31, 2007, our regulatory assets for unamortized environmental costs totaled $4.2 million. The portion of the regulatory assets representing actual costs incurred, including the settlement payment to the third party, is being amortized as recovered in rates from customers.

In connection with the 2003 NCNG acquisition, several MGP sites owned by NCNG were transferred to a wholly owned subsidiary of Progress prior to closing. Progress has complete responsibility for performing all of NCNG s remediation obligations to conduct testing and clean-up at these sites, including both the cost of such testing and clean-up and the implementation of any affirmative remediation obligations that NCNG has related to the sites. Progress responsibility does not include any third-party claims for personal injury, death, property damage and diminution of property value or natural resources. We know of no such pending or threatened claims.

In October 2003, in connection with a 2003 NCNG general rate case proceeding, the NCUC ordered an environmental regulatory liability of $3.5 million be established for refund to customers over the three-year period beginning November 1, 2003. This liability resulted from a payment made to NCNG by its insurers prior to our acquisition of NCNG. As a part of the 2005 general rate case proceeding discussed in Note 3 to the consolidated financial statements, the NCUC ordered a new three-year amortization period for the unamortized balance as of June 30, 2005, beginning November 1, 2005.

In July 2005, we were notified by the NCDENR that we were named as a potentially responsible party for alleged environmental problems associated with an underground storage tank site in Clemmons, North Carolina. We had operations at this site from March 1986 until June 1988 in connection with a non-utility venture. There have been at least four owners of the site. We contractually transferred any clean-up costs to the new owner of the site when we sold this venture in June 1988. Our current estimate of the cost to

Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

remediate the site is approximately $128,500. It is unclear how many of the former owners may ultimately be held liable for this site; however, based on the uncertainty of the ultimate liability, we established a non-regulated environmental liability for $32,100, one-fourth of the estimated cost.

Further evaluations of the MGP sites and the underground storage tank sites could significantly affect recorded amounts; however, we believe that the ultimate resolution of these matters will not have a material adverse effect on our financial position, cash flows or results of operations.

8. Employee Benefit Plans

We have a noncontributory defined benefit pension plan for the benefit of eligible full-time employees. An employee becomes eligible on the January 1 or July 1 following either the date on which he or she attains age 30 or attains age 21 and completes 1,000 hours of service during the 12-month period commencing on the employment date. Plan benefits are generally based on credited years of service and the level of compensation during the five consecutive years of the last ten years prior to retirement during which the participant received the highest compensation. Our policy is to fund the plan in an amount not in excess of the amount that is deductible for income tax purposes. The pension plan has been amended, effective January 1, 2008, to close the plan to new employees hired after December 31, 2007 and to modify how benefits are accrued in the future for existing employees. This amendment does not apply to employees covered by the Nashville, Tennessee bargaining unit contract.

We provide certain postretirement health care and life insurance benefits (OPEB) to eligible full-time employees. The liability associated with such benefits is funded in irrevocable trust funds that can only be used to pay the benefits. Employees are first eligible to retire and receive these benefits at age 55 with ten or more years of service after the age of 45. Employees who met this requirement in 1993 or who retired prior to 1993 are in a grandfathered group for whom we pay the full cost of the retiree s coverage and the retiree pays the full cost of dependent coverage. Retirees not in the grandfathered group have 80% of the cost of retiree coverage paid by us, subject to certain annual contribution limits. Retirees are responsible for the full cost of dependent coverage. Employees hired on or after January 1, 2008 will have to complete ten years of service after age 50 to be eligible for benefits, and no benefits will be provided to those employees after age 65. This amendment does not apply to employees covered by the Nashville, Tennessee bargaining unit contract.

In connection with the September 2003 acquisition of NCNG, we acquired certain pension and OPEB obligations of former employees of NCNG. The accrued pension benefits for this group were placed in a separate frozen plan at this date. The transferred active pension plan participants began accruing benefits under the Piedmont pension plan as of October 1, 2003. There were no assets attributable to the OPEB liability transferred from Progress. We merged the frozen qualified NCNG pension plan with the Piedmont pension plan as of December 31, 2006.

As a result of the Medicare Prescription Drug Improvement and Modernization Act of 2003, we amended our postretirement benefit plan in August 2005, to eliminate prescription drug coverage beginning January 1, 2006, for retirees who are Medicare eligible. This prescription drug benefit was replaced by a defined dollar benefit to pay the premiums for Medicare Part D.

We have pension liabilities related to supplemental executive retirement plans (SERPs) for certain former employees, non-employee directors or the surviving spouse. There are no assets related to the SERPs and no additional benefits accrue to the participants. Payments to the participants are made from operating funds during the year. These nonqualified plans are presented below.

We also have a SERP covering all officers at the vice president level and above. It provides supplemental retirement income for officers whose benefits under the Company s qualified retirement plan are limited by tax code provisions. The level of insurance benefit and target retirement income benefits intended to be

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Notes to Consolidated Financial Statements (Continued)

provided under the SERP depend upon the position of the officer. The SERP is funded by life insurance policies covering each officer, and the policy is owned exclusively by each officer. Premiums on these policies paid and expensed by us, as grossed up for taxes to the individual officer, totaled $.5 million in 2007, $.7 million in 2006 and $1 million in 2005.

At the end of our fourth quarter of 2007, we adopted the provisions of Statement 158 requiring employers to recognize the overfunded or underfunded status of a defined benefit postretirement plan as an asset or liability in the balance sheet, measured as the difference between the fair value of the plan assets and the actuarial value of the benefit obligation. Changes in the funded status would be recognized through other comprehensive income. We are already in compliance with the measurement date requirement of Statement 158 as our plan s measurement date is the same as our fiscal year end date. As a regulated utility, we expect continued future rate recovery of the eligible costs of our pension and postretirement plans. We requested and have been allowed by our state regulators to record a regulatory asset or liability that would otherwise have been recorded to OCI.

Based on the measurement of the various postretirement plans assets and benefit obligations as of October 31, 2007, the effect on our consolidated balance sheets of adopting Statement 158 is as follows.

	Before Application of Statement 158	Minimum Pension Liability Adjustment	Adoption of Statement 158	Rate Deferral Adjustments	After Application of Statement 158
			In thousands		
Prepayments	$ 22,435	$	$ (22,435)	$	$
Overfunded postretirement asset			36,256		36,256
Regulatory asset for postretirement benefits, noncurrent				1,865	1,865
Accumulated other comprehensive income	(78)	24	7,346	(7,292)	
Other current liabilities			553		553
Deferred income taxes (noncurrent)	(51)	16	4,754	(4,719)	
Regulatory liability for postretirement benefits, noncurrent				13,876	13,876
Accumulated provision for postretirement benefits			17,469		17,469
Other (deferred credits and other liabilities)	16,342	(40)	(16,302)		

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Notes to Consolidated Financial Statements (Continued)

A reconciliation of changes in the plans benefit obligations and fair value of assets for the years ended October 31, 2007 and 2006, and a statement of the funded status and the amounts reflected in the consolidated balance sheets for the years ended October 31, 2007 and 2006, are presented below.

	Qualified Pension		Nonqualified Pension		Other Benefits	
	2007	2006	2007	2006	2007	2006
			In thousands			
Accumulated benefit obligation at year end	$ 169,367	$ 177,377	$ 4,845	$ 4,342	N/A	N/A
Change in benefit obligation:						
Obligation at beginning of year	$ 236,329	$ 236,608	$ 4,342	$ 4,484	$ 34,252	$ 30,732
Adjustment to reflect prior obligation			857			
Service cost	11,142	10,972	60	66	1,324	1,134
Interest cost	12,926	13,436	276	239	1,886	1,747
Plan amendments	(29,795)					
Actuarial (gain) loss	(14,844)	(190)	(95)	84	(778)	3,816
Benefit payments	(27,060)	(24,497)	(595)	(531)	(3,072)	(3,177)
Obligation at end of year	$ 188,698	$ 236,329	$ 4,845	$ 4,342	$ 33,612	$ 34,252
Change in fair value of plan assets:						
Fair value at beginning of year	$ 211,926	$ 199,159	$	$	$ 16,800	$ 15,275
Actual return on plan assets	24,045	22,681			1,169	1,740
Employer contributions	16,500	15,100	595	531	5,538	2,962
Administrative expenses	(457)	(517)				
Benefit payments	(27,060)	(24,497)	(595)	(531)	(3,072)	(3,177)
Fair value at end of year	$ 224,954	$ 211,926	$	$	$ 20,435	$ 16,800
Funded status(1):						
Funded status at end of year	$ 36,256	$ (24,403)	$ (4,845)	$ (4,342)	$ (13,177)	$ (17,452)
Unrecognized transition obligation	N/A		N/A		N/A	4,669
Unrecognized prior-service cost	N/A	4,395	N/A		N/A	
Unrecognized actuarial (gain) loss	N/A	34,615	N/A	220	N/A	(1,553)
Accrued benefit asset (liability)	$ 36,256	$ 14,607	$ (4,845)	$ (4,122)	$ (13,177)	$ (14,336)

(1)

After adoption of Statement 158 on October 31, 2007, these amounts are recorded, and this reconciliation is no longer required.

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Notes to Consolidated Financial Statements (Continued)

	Qualified Pension		Nonqualified Pension		Other Benefits	
	2007	**2006**	**2007**	**2006**	**2007**	**2006**
			In thousands			
Amounts recognized in the consolidated balance sheets consist of:						
For years prior to adoption of FAS 158:						
Prepayments		$ 14,607		$		$
Regulatory asset						
Current liabilites				(4,342)		(14,336)
Accumulated other comprehensive income				220		
Other deferred credits and other liabilities						
Net amount recognized at year end		$ 14,607		$ (4,122)		$ (14,336)
For years after the adoption of FAS 158:						
Noncurrent assets	$ 36,256		$		$	
Current liabilities			(553)			
Noncurrent liabilities			(4,292)		(13,177)	
Net amount recognized	$ 36,256		$ (4,845)		$ (13,177)	
Amounts Not Yet Recognized as a Component of Cost and Recognized as Regulatory Asset or Liability(2):						
Unrecognized transition obligation	$		$		$ (4,002)	
Unrecognized prior service credit	25,991					
Unrecognized actuarial gain (loss)	(12,170)		(34)		2,227	
Regulatory (asset) liability	13,821		(34)(3)		(1,775)	
Cumulative employer contribution in excess of cost	22,435		(4,811)		(11,402)	
Net amount recognized	$ 36,256		$ (4,845)		$ (13,177)	
	$	$	$ 24	$ 84	$	$

Other comprehensive income attributable to change in additional minimum pension liability recognition, net of tax

(2) As the future recovery of pension and OPEB costs is probable, we were granted permission to record the amount that would have been recorded in accumulated other comprehensive income as a regulatory asset.

(3) Amount is composed of a regulatory asset of $89 and a regulatory liability of $55.

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Notes to Consolidated Financial Statements (Continued)

The 2008 estimated amortization of the following items that are recorded in a regulatory asset or liability instead of OCI discussed above and expected refunds for our plans are as follows.

	Qualified Pension	Nonqualified Pension In thousands	Other Benefits
Amortization of transition obligation	$	$	$ 667
Amortization of unrecognized prior service credit	(1,893)		
Refunds expected	(1,893)		667

Net periodic benefit cost for the years ended October 31, 2007, 2006 and 2005, includes the following components.

	Qualified Pension			Nonqualified Pension			Other Benefits		
	2007	2006	2005	2007	2006 In thousands	2005	2007	2006	2005
Service cost	$ 11,142	$ 10,972	$ 11,278	$ 60	$ 66	$ 61	$ 1,324	$ 1,134	$ 1,391
Interest cost	12,926	13,436	12,816	276	239	255	1,886	1,747	2,151
Expected return on plan assets	(17,013)	(17,112)	(16,593)				(1,273)	(1,151)	(1,030)
Amortization of transition obligation							667	667	879
Amortization of prior service cost	590	933	933						1,285
Amortization of actuarial (gain) loss	1,027	604	378					(218)	
Total	$ 8,672	$ 8,833	$ 8,812	$ 336	$ 305	$ 316	$ 2,604	$ 2,179	$ 4,676

Equity market performance and corporate bond rates have a significant effect on our funded status, as the primary factors that drive its value are the assumed discount rate and the actual return on plan assets. In addition, equity market performance has a significant effect on our market-related value of plan assets. In determining the market-related value of plan assets, we use the following methodology: The asset gain or loss is determined each year by comparing the fund s actual return to the expected return, based on the disclosed expected return on investment assumption. Such asset gain or loss is then recognized ratably over a five-year period. Thus, the market-related value of assets as of year end is determined by adjusting the market value of assets by the portion of the prior five years gains or losses that has not yet been recognized. This method has been applied consistently in all years presented in the consolidated financial statements. The discount rate can vary from plan year to plan year. October 31 is the measurement date for the plans.

The discount rate has been separately determined for each plan by projecting the plan s cash flows and developing a zero-coupon spot rate yield curve using non-arbitrage pricing and Moody s AA or better-rated non-callable bonds that produces similar results to a hypothetical bond portfolio. As of October 31, 2007, the benchmark was 6.43% for the pension plan, 6.05% for the NCNG SERP, 6.16% for the directors SERP, 5.82% for the Piedmont SERP, 5.8% for the Tennessee SERP and 6.25% for OPEB.

We amortize unrecognized prior-service cost over the average remaining service period for active employees. We amortize the unrecognized transition obligation over the average remaining service period for active employees expected to receive benefits under the plan as of the date of transition. We amortize gains and losses in excess of 10% of the greater of the benefit obligation and the market-related value of assets over the average remaining service period for active employees. The method of amortization in all cases is straight-line.

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Notes to Consolidated Financial Statements (Continued)

The weighted average assumptions used in the measurement of the benefit obligation as of October 31, 2007 and 2006, are presented below.

	Qualified Pension		Nonqualified Pension		Other Benefits	
	2007	2006	2007	2006	2007	2006
Discount rate	6.43%	5.78%	6.06%	5.67%	6.25%	5.74%
Rate of compensation increase	3.99%	4.01%	N/A	N/A	N/A	N/A

The weighted average assumptions used to determine the net periodic benefit cost as of October 31, 2007, 2006 and 2005, are presented below.

	Qualified Pension			Nonqualified Pension			Other Benefits		
	2007	2006	2005	2007	2006	2005	2007	2006	2005
Discount rate	5.78%	6.00%	5.75%	5.67%	5.75%	5.75%	5.74%	5.89%	5.75%
Expected long-term rate of return on plan assets	8.50%	8.50%	8.50%	N/A	N/A	N/A	8.50%	8.50%	8.50%
Rate of compensation increase	4.01%	4.05%	3.97%	N/A	N/A	N/A	N/A	N/A	N/A

The weighted-average asset allocations by asset category for the pension plan and the OPEB plan as of October 31, 2007 and 2006, are presented below.

	Pension Benefits			Other Benefits		
	2007	2006	Target	2007	2006	Target
Domestic equity securities	48%	55%	50%	42%	41%	50%
International equity securities	10%	13%	10%	8%	7%	10%
Fixed income securities	41%	32%	40%	26%	26%	40%
Cash	1%	%	%	24%	26%	%
Total	100%	100%	100%	100%	100%	100%

Our primary investment objective is to generate sufficient assets to meet plan liabilities. The plans assets will therefore be invested to maximize long-term returns consistent with the plans liabilities, cash flow requirements and risk tolerance. The plans liabilities are primarily defined in terms of participant salaries. Given the nature of these liabilities, and recognizing the long-term benefits of investing in both domestic and international equity securities, we invest in a diversified portfolio which includes a significant exposure to these investments. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements and periodic asset/liability studies.

Specific financial targets include:

- Achieve full funding over the longer term,
- Control fluctuation in pension expense from year to year,
- Achieve satisfactory performance relative to other similar pension plans, and
- Achieve positive returns in excess of inflation over short to intermediate time frames.

To develop the expected long-term rate of return on assets assumption, we considered historical returns and future expectations for returns for each asset class, as well as target asset allocation of the pension and OPEB portfolios. We intend to use 8% as the expected long-term rate of return on the pension and OPEB plans for 2008.

We anticipate that we will contribute $11 million to the qualified pension plans, $.6 million to the nonqualified pension plans and $2.2 million to the OPEB plan in 2008.

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The Pension Protection Act of 2006 (PPA) was signed into law by the President of the United States on August 17, 2006. The PPA primarily impacts how lump sum distributions are calculated and how minimum funding requirements for plan years beginning in 2008 are determined for the defined benefit pension plan. The expected impact of the change in the lump sum calculation is reflected in the obligations disclosed.

The expected impact of the changes in the minimum funding requirement is to reduce our contributions to the pension plan that would otherwise have been required to be made beginning in 2008, deferring them to a later year. However, the amount of future year-by-year contributions is not expected to be materially different from our current projections.

Benefit payments, which reflect expected future service, as appropriate, are expected to be paid for the next ten years ending October 31 as follows.

	Qualified Pension	Nonqualified Pension	Other Benefits
		In thousands	
2008	$ 11,677	$ 553	$ 2,865
2009	9,995	506	2,768
2010	11,486	504	2,746
2011	12,117	502	2,708
2012	11,922	473	2,678
2013-2017	76,303	2,005	15,043

The assumed health care cost trend rates used in measuring the accumulated OPEB obligation for the medical plans for all participants as of October 31, 2007 and 2006, are presented below.

	2007	2006
Health care cost trend rate assumed for next year	8.25%	9.00%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2012	2012

The health care cost trend rate assumptions could have a significant effect on the amounts reported. A change of 1% would have the following effects.

	1% Increase	1% Decrease
	In thousands	
Effect on total of service and interest cost components of net periodic postretirement health care benefit cost for the year ended October 31, 2007	$ 88	$ (99)
Effect on the health care cost component of the accumulated postretirement benefit obligation as of October 31, 2007	1,145	(1,114)

We maintain salary investment plans which are profit-sharing plans under Section 401(a) of the Internal Revenue Code of 1986, as amended (the Tax Code), which include qualified cash or deferred arrangements under Tax Code Section 401(k). The salary investment plans are subject to the provisions of the Employee Retirement Income Security Act. Full-time employees who have completed 30 days of continuous service and have attained age 18 are eligible to participate. Participants may defer a portion of their base salary to the plans and we match a portion of their contributions. Employee contributions vest immediately and company contributions vest after six months of service. For the years ended October 31, 2007, 2006 and 2005, our matching contributions totaled \$3.2 million, \$3.3 million and \$3.2 million, respectively. There are several investment options available to enable participants to diversify their accounts. Participants may invest in Piedmont stock up to a maximum of 20% of their account.

As a result of a plan merger effective in 2001, participants accounts in our employee stock ownership plan (ESOP) were transferred into our salary investment plans. Former ESOP participants may remain invested

Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

in Piedmont common stock in their salary investment plan or may sell the common stock at any time and reinvest the proceeds in other available investment options. The tax benefit of any dividends paid on ESOP shares still in participants accounts is reflected in the consolidated statement of stockholders equity as an increase in retained earnings.

9. Employee Share-Based Plans

Under the LTIP and Incentive Compensation Plan (ICP) approved by the Company s shareholders on March 3, 2006, the Board of Directors has awarded units to eligible officers and other participants. Depending upon the levels of performance targets achieved by Piedmont during multi-year performance periods, distribution of those awards may be made in the form of shares of common stock and cash withheld for payment of applicable taxes on the compensation. The LTIP and ICP require that a minimum threshold performance be achieved in order for any award to be distributed. For the years ended October 31, 2007, 2006 and 2005, we recorded compensation expense for the LTIP and ICP of $1.7 million, $5.4 million and $4 million, respectively. Shares of common stock to be issued under the LTIP and ICP are contingently issuable shares and are included in our calculation of fully diluted earnings per share.

We have four awards under the LTIP and ICP with three-year performance periods ending October 31, 2007, October 31, 2008, October 31, 2009 and October 31, 2010. Fifty percent of the units awarded will be based on achievement of a target annual compounded increase in basic earnings per share (EPS). For this 50% portion, an EPS performance of 80% of target will result in an 80% payout, an EPS performance of 100% of target will result in a 100% payout and an EPS performance of 120% of target will result in a maximum 120% payout, and EPS performance levels between these levels will be subject to mathematical interpolation. EPS performance below 80% of target will result in no payout of this portion. The other 50% of the units awarded will be based on the achievement of a target total annual shareholder return (increase in our common stock price plus dividends paid over the specified period of time) in comparison to a peer group consisting of the natural gas distribution companies formerly comprising the A. G. Edwards Large Natural Gas Distribution Index (peer group). The total shareholder return performance measure will be the registrant s percentile ranking in relationship to the peer group. For this 50% portion, a ranking below the 25th percentile will result in no payout, a ranking between the 25th and 39th percentile will result in an 80% payout, a ranking between the 40th and 49th percentile will result in a 90% payout, a ranking between the 50th and 74th percentile will result in a 100% payout, a ranking between the 75th and 89th percentile will result in a 110% payout, and a ranking at or above the 90th percentile will result in a maximum 120% payout.

We have one additional award with a five-year performance period that ended October 31, 2006, for a group of retired employees with 75% of the units awarded being based on achievement of a target cumulative increase in net income and 25% of the units awarded based on achievement of a target total annual shareholder return in comparison to the A. G. Edwards Large Natural Gas Distribution Index industry peer group and in the same percentile rankings. The payout under this award will occur over a three-year period with the first payout occurring in fiscal 2007.

As of October 31, 2007 and 2006, we have accrued $6.2 million and $11.4 million for these awards. The accrual is based on the fair market value of our stock at the end of each quarter. The liability is re-measured to market value at the settlement date.

On September 1, 2006, the Board of Directors approved a grant under our ICP to our President and Chief Executive Officer of 65,000 restricted shares of our common stock with a value at the date of grant of $1.7 million, based on the closing stock price on the date of the grant. The restricted shares shall vest and be payable on the following schedule only if he is an employee on the vesting date for each tranche:

20% on September 1, 2009,

30% on September 1, 2010, and

50% on September 1, 2011.

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Notes to Consolidated Financial Statements (Continued)

During the vesting period, any dividends paid on these shares will be accrued and converted into additional shares at the closing price on the date of the dividend payment. The additional shares will vest according to the vesting schedule above. As of October 31, 2007 and 2006, we have recorded $.3 million and $.06 million, respectively, as compensation expense. We are recording compensation under the ICP for the restricted stock agreement on the straight-line method.

On a quarterly basis, we issue shares of common stock under the ESPP and have accounted for the issuance as an equity transaction. The purchase price is calculated as 95% of the fair market value on the purchase date of each quarter where fair market value is determined by calculating the mean average of the high and low trading prices on the purchase date.

As discussed in Note 5, we repurchase shares on the open market and such shares are then cancelled and become authorized but unissued shares available for issuance under our employee plans, including the ESPP, LTIP and ICP.

10. Income Taxes

The components of income tax expense for the years ended October 31, 2007, 2006 and 2005, are as follows.

	2007		2006		2005	
	Federal	State	Federal	State	Federal	State
			In thousands			
Charged to operating income:						
Current	$ 28,233	$ 4,987	$ 27,470	$ 4,977	$ 19,073	$ 3,880
Deferred	15,250	3,279	14,775	3,855	24,006	5,462
Amortization of investment tax credits	(434)		(534)		(541)	
Total	43,049	8,266	41,711	8,832	42,538	9,342
Charged to other income (expense):						
Current	7,557	1,153	9,052	1,427	15,588	2,966
Deferred	4,644	957	1,107	301	(6,407)	(1,701)
Total	12,201	2,110	10,159	1,728	9,181	1,265
Total	$ 55,250	$ 10,376	$ 51,870	$ 10,560	$ 51,719	$ 10,607

A reconciliation of income tax expense at the federal statutory rate to recorded income tax expense for the years ended October 31, 2007, 2006 and 2005, is as follows.

	2007	2006	2005
		In thousands	
Federal taxes at 35%	$ 59,504	$ 55,867	$ 57,258
State income taxes, net of federal benefit	6,745	6,864	6,894
Amortization of investment tax credits	(434)	(534)	(541)
Sale of propane interests			(1,624)
Other, net	(189)	233	339
Total	$ 65,626	$ 62,430	$ 62,326

Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

As of October 31, 2007 and 2006, deferred income taxes consisted of the following temporary differences.

	2007	2006
	In thousands	
Utility plant	$ 239,448	$ 226,866
Equity method investments	20,554	15,419
Revenues and cost of gas	23,741	25,356
Deferred cost	21,594	9,494
Other, net	(21,436)	(16,639)
Net deferred income tax liabilities	$ 283,901	$ 260,496

As of October 31, 2007 and 2006, total deferred income tax liabilities were $321.3 million and $281.8 million and total net deferred income tax assets were $37.4 million and $21.3 million, respectively. Total net deferred income tax assets as of October 31, 2007 and 2006, were net of a valuation allowance of $.4 million and $.6 million, respectively, for net operating loss carryforwards that we believed were more likely than not to expire before we could use them. Piedmont and its wholly owned subsidiaries file a consolidated federal income tax return. As of October 31, 2007 and 2006, we had federal and state net operating loss carryforwards of $6.9 million and $7.2 million, respectively, that expire from 2017 through 2025. Piedmont may use the loss carryforwards to offset taxable income, subject to an annual limitation of $.3 million.

A reconciliation of changes in the deferred tax valuation allowance for the years ended October 31, 2007, 2006 and 2005, is as follows.

	2007	2006	2005
		In thousands	
Balance at beginning of year	$ 568	$ 583	$ 1,245
Charged (credited) to income tax expense	(174)	(15)	(662)
Balance at end of year	$ 394	$ 568	$ 583

During the year ended October 31, 2007, the Internal Revenue Service finalized its audit of our returns for the tax years ended October 31, 2003 through 2005. The audit results, which did not have a material effect on our financial position or results of operations, have been reflected in the consolidated financial statements.

11. Equity Method Investments

The consolidated financial statements include the accounts of wholly owned subsidiaries whose investments in joint venture, energy-related businesses are accounted for under the equity method. These investments are an integral part of our strategy to meeting our gas supply and storage capacity needs. Our ownership interest in each entity is included in Equity method investments in non-utility activities in the consolidated balance sheets. Earnings or losses from equity method investments are included in Income from equity method investments in the consolidated statements of income.

As of October 31, 2007, there were no amounts that represented undistributed earnings of our 50% or less owned equity method investments in our retained earnings.

Cardinal Pipeline Company, L.L.C.

We own 21.49% of the membership interests in Cardinal Pipeline Company, L.L.C., a North Carolina limited liability company. The other members are subsidiaries of The Williams Companies, Inc., and SCANA

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Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

Corporation. Cardinal owns and operates an intrastate natural gas pipeline in North Carolina and is regulated by the NCUC. Cardinal has firm service agreements with local distribution companies for 100% of the firm transportation capacity on the pipeline, of which Piedmont subscribes to approximately 37%. Cardinal is dependent on the Williams-Transco pipeline system to deliver gas into its system for service to its customers. Cardinal s long-term debt is secured by Cardinal s assets and by each member s equity investment in Cardinal.

We have related party transactions as a transportation customer of Cardinal, and we record in cost of gas the transportation costs charged by Cardinal. For each of the years ended October 31, 2007, 2006 and 2005, these gas costs were $4.5 million, $4.7 million and $4.7 million, respectively. As of October 31, 2007 and 2006, we owed Cardinal $.3 million and $.1 million, respectively.

Summarized unaudited financial information provided to us by Cardinal for 100% of Cardinal as of September 30, 2007 and 2006, and for the twelve months ended September 30, 2007, 2006 and 2005, is presented below.

	2007	2006	2005
		In thousands	
Current assets	$ 8,706	$ 8,717	
Non-current assets	83,388	85,933	
Current liabilities	3,814	4,458	
Non-current liabilities	33,637	35,520	
Revenues	15,369	15,524	$ 15,525
Gross profit	15,369	15,524	15,525
Income before income taxes	8,371	8,785	8,368

Pine Needle LNG Company, L.L.C.

We own 40% of the membership interests in Pine Needle LNG Company, L.L.C., a North Carolina limited liability company. The other members are the Municipal Gas Authority of Georgia and subsidiaries of The Williams Companies, Inc., SCANA Corporation and Hess Corporation. Pine Needle owns and operates an interstate liquefied natural gas storage facility in North Carolina and is regulated by the FERC. Pine Needle has firm service agreements for 100% of the storage capacity of the facility, of which Piedmont subscribes to approximately 64%.

Pine Needle enters into interest-rate swap agreements to modify the interest characteristics of its long-term debt. Our share of movements in the market value of these agreements are recorded as a hedge in Accumulated other comprehensive income in the consolidated balance sheets. Pine Needle s long-term debt is secured by Pine Needle s assets and by each member s equity investment in Pine Needle.

We have related party transactions as a customer of Pine Needle, and we record in cost of gas the storage costs charged by Pine Needle. For the years ended October 31, 2007, 2006 and 2005, these gas costs were $11.7 million, $12.7 million and $12.4 million, respectively. As of October 31, 2007 and 2006, we owed Pine Needle $.9 million and $1.1 million, respectively.

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Notes to Consolidated Financial Statements (Continued)

Summarized unaudited financial information provided to us by Pine Needle for 100% of Pine Needle as of September 30, 2007 and 2006, and for the twelve months ended September 30, 2007, 2006 and 2005, is presented below.

	2007	2006	2005
		In thousands	
Current assets	$ 11,178	$ 10,823	
Non-current assets	85,506	88,879	
Current liabilities	9,401	8,208	
Non-current liabilities	29,862	34,835	
Revenues	18,668	19,231	$ 19,870
Gross profit	18,668	19,231	19,870
Income before income taxes	8,827	10,047	9,480

US Propane, L.P.

Prior to January 20, 2004, we owned 20.69% of the membership interests in US Propane, L.P. The other members were subsidiaries of TECO Energy, Inc., AGL Resources, Inc. and Atmos Energy Corporation. US Propane owned all of the general partnership interest and approximately 26% of the limited partnership interest in Heritage Propane Partners, L.P. (Heritage Propane), a marketer of propane through a nationwide retail distribution network. In January 2004, we, along with the other members, completed the sale of US Propane s general and limited partnership interests in Heritage Propane for $130 million.

In connection with the sale, the former members of US Propane formed TAAP, LP, a limited partnership, to receive the approximately 180,000 common units of Heritage Propane retained in the sale. On May 21, 2004, TAAP distributed to us 37,244 common units of Energy Transfer Partners, LP (formerly Heritage Propane) as our share of the retained units. The market value of these units was recorded as an investment in marketable securities in the consolidated balance sheet. On February 1, 2005, we sold 18,622 of the units and on February 2, 2005, we sold the remaining 18,622 units for total cash proceeds of $2.4 million. We recorded a pre-tax gain of $1.5 million in the consolidated statement of income for the year ended October 31, 2005.

SouthStar Energy Services LLC

We own 30% of the membership interests in SouthStar Energy Services LLC, a Delaware limited liability company. Under the terms of the Amended and Restated Limited Liability Company Agreement (Restated Agreement) effective January 1, 2004, earnings and losses are allocated 25% to us and 75% to the other member, Georgia Natural Gas Company (GNGC), a subsidiary of AGL Resources, Inc., with the exception of earnings and losses in the Ohio and Florida markets, which are allocated to us at our ownership percentage of 30%. SouthStar primarily sells natural gas to residential, commercial and industrial customers in the southeastern United States with most of its business being conducted in the unregulated retail gas market in Georgia.

The SouthStar Restated Agreement includes a provision granting three options to GNGC to purchase our ownership interest in SouthStar. By November 1, 2007, with the option effective on January 1, 2008 (2008 option), GNGC had the option to purchase one-third of our 30% interest in SouthStar. With the same notice in the following years, GNGC has the option to purchase 50% of our interest to be effective on January 1, 2009 (2009 option), and 100% of our interest to be effective on January 1, 2010. The purchase price would be based on the market value of SouthStar as defined in the Restated Agreement. GNGC did not exercise the 2008 option. If GNGC exercises the 2009 option, we, at our discretion, may cause GNGC to purchase our entire ownership interest.

For further information on this provision, please see the Restated Agreement that was filed with the SEC as Exhibit 10.1 in our Form 10-Q for the quarter ended April 30, 2004.

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Notes to Consolidated Financial Statements (Continued)

SouthStar s business is seasonal in nature as variations in weather conditions generally result in greater revenue and earnings during the winter months when weather is colder. Also, because SouthStar is not a rate-regulated company, the timing of its earnings can be affected by changes in the wholesale price of natural gas. While SouthStar uses financial contracts to moderate the effect of price changes on the timing of its earnings, wholesale price volatility can cause variations in the timing of the recognition of earnings.

These financial contracts, in the form of futures, options and swaps, are considered to be derivatives and fair value is based on selected market indices. Our share of movements in the market value of these contracts are recorded as a hedge in Accumulated other comprehensive income in the consolidated balance sheets.

We have related party transactions as we sell wholesale gas supplies to SouthStar, and we record in operating revenues the amounts billed to SouthStar. For the years ended October 31, 2007, 2006 and 2005, these operating revenues were $8.9 million, $21.6 million and $10.3 million, respectively. As of October 31, 2007 and 2006, SouthStar owed us $1.7 million and $.8 million, respectively.

Summarized unaudited financial information provided to us by SouthStar for 100% of SouthStar as of September 30, 2007 and 2006, and for the twelve months ended September 30, 2007, 2006 and 2005, is presented below.

	2007	2006	2005
		In thousands	
Current assets	$ 204,598	$ 195,893	
Non-current assets	8,899	11,136	
Current liabilities	60,783	69,438	
Non-current liabilities	53	870	
Revenues	908,416	1,053,770	$ 861,091
Gross profit	177,822	155,416	148,885
Income before income taxes	112,260	88,765	91,200

Hardy Storage Company LLC

Piedmont Hardy Storage Company, LLC (Piedmont Hardy), a wholly-owned subsidiary of Piedmont, owns 50% of the membership interests in Hardy Storage Company, LLC (Hardy Storage), a West Virginia limited liability company. The other owner is a subsidiary of Columbia Gas Transmission Corporation, a subsidiary of NiSource Inc. Hardy Storage owns and operates an underground interstate natural gas storage facility located in Hardy and Hampshire Counties, West Virginia, that is regulated by the FERC. Phase one service to customers began April 1, 2007 when customers began injecting gas into storage for subsequent winter withdrawals. Hardy Storage is now in the final stages of project construction.

On June 29, 2006, Hardy Storage signed a note purchase agreement for interim notes and a revolving equity bridge facility for up to a total of $173.1 million for funding during the construction period. At October 31, 2007, there was $133.6 million outstanding on the interim notes and the equity line. In addition, the members had invested equity of $25.9 million in Hardy Storage in cash and contributed assets, of which our share was $12.9 million. On November 1, 2007, Hardy Storage paid off the equity line of $10.2 million with member equity contributions, leaving an amount outstanding on the interim notes of $123.4 million. Also, on November 1, 2007, the members funded additional construction expenditures of $7 million. As Hardy Storage finishes its construction and at such time that contingency wells are needed, the members intend to target a capitalization structure of 70% debt and 30% equity. After the satisfaction of certain conditions in the note purchase agreement, amounts outstanding under the interim notes will convert to a fifteen-year mortgage-style debt instrument without recourse to the members. We expect the conversion to occur in late spring to late summer of 2008. To the extent that more funding is needed, the members will evaluate options at that time.

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The members of Hardy Storage have each agreed to guarantee 50% of the construction financing. The guaranty was executed by Piedmont Energy Partners, Inc. (PEP), a wholly owned subsidiary of Piedmont and a sister company of Piedmont Hardy. Our share of the guaranty is capped at $111.5 million. Depending upon the facility s performance over the first three years after the in-service date, there could be additional construction expenditures of up to $10 million, of which PEP will guarantee 50%.

Securing PEP s guaranty is a pledge of intercompany notes issued by Piedmont held by non-utility subsidiaries of PEP. Should Hardy Storage be unable to perform its payment obligation under the construction financing, PEP will call on Piedmont for the payment of the notes, plus accrued interest, for the amount of the guaranty. Also pledged is our membership interests in Hardy Storage.

We are recording a liability at fair value for this guaranty based on the present value of 50% of the construction financing outstanding at the end of each quarter, with a corresponding increase to our investment account in the venture. As our risk in the project changes, the fair value of the guaranty is adjusted accordingly through a quarterly evaluation.

As of October 31, 2007, with $133.6 million outstanding under the construction financing, we have recorded a guaranty liability of $1.3 million.

We have related party transactions as a customer of Hardy Storage beginning in April 2007, and we record in cost of gas the storage costs charged to us by Hardy Storage. For the year ended October 31, 2007, these gas costs were $3.5 million. As of October 31, 2007, we owed Hardy Storage $.2 million.

Summarized unaudited financial information provided to us by Hardy Storage for 100% of Hardy Storage as of October 31, 2007 and 2006, and for the twelve months ended October 31, 2007, 2006 and 2005, is presented below.

	2007	2006	2005
	In thousands		
Current assets	$ 19,972	$ 12,807	
Non-current assets	160,326	87,260	
Current liabilities	21,388	39,872	
Non-current liabilities	123,410	58,983	
Revenues	13,902	*	*
Gross profit	13,902	*	*
Income before income taxes	8,918	707	48

* Hardy Storage is not in service during the periods presented. The income above is related to AFUDC associated with the financing and construction activities of the storage facilities, and is recorded in accordance with regulatory guidelines. 2006 includes interest expense from a construction loan and operating expenses in addition to AFUDC.

12. Business Segments

We have two reportable business segments, regulated utility and non-utility activities. These segments were identified based on products and services, regulatory environments and our current corporate organization and business decision-making activities. Operations of our regulated utility segment are conducted by the parent company and, through October 25, 2005, by EasternNC. Operations of our non-utility activities segment are comprised of our equity method investments in joint ventures.

Operations of the regulated utility segment are reflected in operating income in the consolidated statements of income. Operations of the non-utility activities segment are included in the consolidated statements of income in Income from equity method investments.

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Notes to Consolidated Financial Statements (Continued)

We evaluate the performance of the regulated utility segment based on margin, operations and maintenance expenses and operating income. We evaluate the performance of the non-utility activities segment based on earnings from the ventures. All of our operations are within the United States. No single customer accounts for more than 10% of our consolidated revenues.

Operations by segment for the years ended October 31, 2007, 2006 and 2005, and as of October 31, 2007 and 2006, are presented below.

	Regulated Utility	Non-Utility Activities In thousands	Total
2007			
Revenues from external customers	$ 1,711,292	$	$ 1,711,292
Margin	524,165		524,165
Operations and maintenance expenses	214,442	325	214,767
Depreciation	88,654	29	88,683
Income from equity method investments		37,156	37,156
Interest expense	57,272		57,272
Operating income (loss) before income taxes	188,662	(518)	188,144
Income before income taxes	133,726	36,287	170,013
Total assets	2,655,311	95,707	2,751,018
Equity method investments in non-utility activities		95,193	95,193
Construction expenditures	135,241		135,241
2006			
Revenues from external customers	$ 1,924,628	$	$ 1,924,628
Margin	523,479		523,479
Operations and maintenance expenses	219,353	503	219,856
Depreciation	89,696	4	89,700
Income from equity method investments		29,917	29,917
Interest expense	52,310	50	52,360
Operating income (loss) before income taxes	181,292	(623)	180,669
Income before income taxes	130,730	28,889	159,619
Total assets	2,600,411	75,877	2,676,288
Equity method investments in non-utility activities		75,330	75,330
Construction expenditures	196,730	551	197,281
2005			
Revenues from external customers	$ 1,761,091	$	$ 1,761,091
Margin	499,139		499,139
Operations and maintenance expenses	206,983	214	207,197
Depreciation	85,169		85,169
Income from equity method investments		27,664	27,664

Interest expense	44,256	52	44,308
Operating income (loss) before income taxes	177,180	(403)	176,777
Income before income taxes and minority interest	135,758	28,440	164,198
Construction expenditures	157,883		157,883

Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

Reconciliations to the consolidated financial statements for the years ended October 31, 2007, 2006 and 2005, and as of October 31, 2007 and 2006, are as follows.

Operating Income:			
Segment operating income before income taxes	$ 188,144	$ 180,669	$ 176,777
Utility income taxes	(51,315)	(50,543)	(51,880)
Non-utility activities before income taxes	518	623	403
Total	$ 137,347	$ 130,749	$ 125,300
Net Income:			
Income before income taxes and minority interest for reportable segments	$ 170,013	$ 159,619	$ 164,198
Income taxes	(65,626)	(62,430)	(62,326)
Less minority interest			(602)
Total	$ 104,387	$ 97,189	$ 101,270
Consolidated Assets:			
Total assets for reportable segments	$ 2,751,018	$ 2,676,288	
Eliminations/Adjustments	69,300	57,651	
Total	$ 2,820,318	$ 2,733,939	

13. Restructuring and Other Termination Benefits

In 2006, we restructured our management group and recognized a liability and expense of $7.9 million, which was included in the regulated utility segment in operations and maintenance expense for the cost of the restructuring program. This restructuring was the beginning of an ongoing, larger effort aimed at streamlining business processes, capturing operational and organizational efficiencies and improving customer service. This liability included early retirement for 22 employees of the management group and severance for 17 additional employees through further consolidation. Due to the short discount period, the liability for the program was recorded at its gross value. As of October 31, 2007 and 2006, there was a liability of zero and $1.2 million, respectively, for the management group restructuring program. During 2007, we paid severance costs of $1.1 million and adjusted the liability by $.1 million.

We continued additional organizational changes under our business process improvement program during 2007. As a part of this effort, we began initiating changes in our customer payment and collection processes, including no longer accepting customer payments in our business offices, streamlining our district operations and closing some of these office locations. We also further consolidated our call centers. Collections of delinquent accounts will be consolidated in our central business office. These new initiatives will be phased in through 2010 and may be accelerated and completed earlier.

We have accrued costs in connection with these initiatives in the form of severance benefits to employees who will be either voluntarily or involuntarily severed. These benefits were paid pursuant to existing arrangements and accounted for in accordance with SFAS No. 112, Employers Accounting for Postemployment Benefits. All costs are included in the regulated utility segment in operations and maintenance expenses in the consolidated statements of income.

We accrued \$3.6 million during the year ended October 31, 2007 and paid \$2.2 million in the period. The liability as of October 31, 2007 was \$1.4 million.

Piedmont Natural Gas Company, Inc.

Notes to Consolidated Financial Statements (Continued)

14. Subsequent Events

On November 1, 2007, we entered into an ASR agreement. On November 2, 2007, we purchased and retired 1 million shares of our common stock from an investment bank at the closing price that day of $24.70 per share. Total consideration paid to purchase the shares of $24.8 million, including $92,500 in commissions and other fees, was recorded in Stockholders equity as a reduction in Common stock. As part of the ASR, we simultaneously entered into a forward sale contract with the investment bank that is expected to mature in approximately 60 trading days. Under the terms of the forward sale contract, the investment bank is required to purchase, in the open market, 1 million shares of our common stock during the term of the contract to fulfill its obligation related to the shares it borrowed from third parties and sold to us. At settlement, we, at our option, are required to either pay cash or issue registered or unregistered shares of our common stock to the investment bank if the investment bank s weighted average purchase price is higher than the November 1, 2007 closing price. The investment bank is required to pay us either cash or shares of our common stock, at our option, if the investment bank s weighted average price for the shares purchased is lower than the November 1, 2007 closing price. Through December 14, 2007, the investment bank had purchased 708,000 shares at a cumulative weighted average price of $25.8733 per share.

* * * * *

Selected Quarterly Financial Data (In thousands except per share amounts) (Unaudited)

	Operating Revenues	Margin	Operating Income (Loss)	Net Income (Loss)	Earnings (Loss) Per Share of Common Stock Basic	Earnings (Loss) Per Share of Common Stock Diluted
Fiscal Year 2007						
January 31	$ 677,241	$ 208,485	$ 81,697	$ 70,716	$ 0.95	$ 0.94
April 30	531,579	159,727	50,621	51,120	0.69	0.69
July 31	224,442	75,158	1,021	(9,140)	(0.12)	(0.12)
October 31	278,030	80,795	4,008	(8,309)	(0.11)	(0.11)
Fiscal Year 2006						
January 31	$ 921,347	$ 209,372	$ 81,161	$ 71,997	$ 0.94	$ 0.94
April 30	483,198	154,010	44,200	43,742	0.57	0.57
July 31	237,874	72,982	(1,026)	(12,389)	(0.16)	(0.16)
October 31	282,209	87,115	6,414	(6,161)	(0.08)	(0.08)

The pattern of quarterly earnings is the result of the highly seasonal nature of the business as variations in weather conditions generally result in greater earnings during the winter months. Basic earnings per share are calculated using the weighted average number of shares outstanding during the quarter. The annual amount may differ from the total of the quarterly amounts due to changes in the number of shares outstanding during the year.

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

None.

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

Management s Evaluation of Disclosure Controls and Procedures

Management, including the President and Chief Executive Officer and the Senior Vice President and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures. Such disclosure controls and procedures are designed to ensure that all information required to be disclosed in our reports filed with the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Based on our evaluation process, the Chief Executive Officer and the Chief Financial Officer have concluded that we have effective disclosure controls and procedures as of October 31, 2007. Management s report on internal control over financial reporting and the attestation report of our independent registered public accounting firm are immediately following. There were no changes in our internal control over financial reporting during the fourth quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

December 28, 2007

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting as that term is defined in Rules 13a-15(f) under the Securities Exchange Act of 1934 is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. The Company s internal control over financial reporting is supported by a program of internal audits and appropriate reviews by management, written policies and guidelines, careful selection and training of qualified personnel and a written Code of Business Conduct and Ethics adopted by the Company s Board of Directors and applicable to all Company Directors, officers and employees.

Because of the inherent limitations, any system of internal control over financial reporting, no matter how well designed, may not prevent or detect misstatements due to the possibility that a control can be circumvented or overridden or that misstatements due to error or fraud may occur that are not detected. Also, projections of the effectiveness to future periods are subject to the risk that the internal controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures included in such controls may deteriorate.

We have conducted an evaluation of the effectiveness of our internal control over financial reporting based upon the framework in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based upon such evaluation, our management concluded that as of October 31, 2007, our internal control over financial reporting was effective.

Management s assessment of the effectiveness of our internal control over financial reporting as of October 31, 2007, has been audited by Deloitte and Touche LLP, an independent registered public accounting firm.

Piedmont Natural Gas Company, Inc.

/s/ Thomas E. Skains
Thomas E. Skains
Chairman, President and Chief Executive Officer

/s/ David J. Dzuricky
David J. Dzuricky
Senior Vice President and Chief Financial Officer

/s/ Jose M. Simon
Jose M. Simon
Vice President and Controller

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Piedmont Natural Gas Company, Inc.

We have audited the internal control over financial reporting of Piedmont Natural Gas, Inc. and subsidiaries (the Company) as of October 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and effected by the company s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of October 31, 2007, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended October 31, 2007, and our report dated December 28, 2007 expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding the Company s adoption of Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans.

/s/ Deloitte & Touche LLP

Charlotte, North Carolina
December 28, 2007

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

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

Information concerning our executive officers and directors is set forth in the sections entitled The Board of Directors and Executive Officers in our Proxy Statement for the 2008 Annual Meeting of Shareholders, which sections are incorporated in this annual report on Form 10-K by reference. Information concerning compliance with Section 16(a) of the Securities Exchange Act of 1934, as amended, is set forth in the section entitled Section 16(a) Beneficial Ownership Reporting Compliance in our Proxy Statement for the 2008 Annual Meeting of Shareholders, which section is incorporated in this annual report on Form 10-K by reference.

Information concerning our Audit Committee and our Audit Committee financial experts is set forth in the section entitled Committees of the Board in our Proxy Statement for the 2008 Annual Meeting of Shareholders, which section is incorporated in this annual report on Form 10-K by reference.

We have adopted a Code of Business Conduct and Ethics that is applicable to all our directors, officers and employees, including our principal executive officer, principal financial officer and principal accounting officer. The Code of Business Conduct and Ethics was filed as Exhibit 14.1 to our annual report on Form 10-K for the year ended October 31, 2003, and is available on our website at www.piedmontng.com. If we amend the Code of Business Conduct and Ethics or grant a waiver, including an implicit waiver, from the Code of Business Conduct and Ethics that apply to the principal executive officer, principal financial officer and controller or persons performing similar functions and that relate to any element of the code enumerated in Item 406(b) of Regulation S-K, we will disclose the amendment or waiver on the About Us-Corporate Governance section of our website within four business days of such amendment or waiver.

Item 11. ***Executive Compensation***

Information for this item is set forth in the sections entitled Executive Compensation, Director Compensation, Compensation Committee Interlocks and Insider Participation, and Compensation Committee Report in our Proxy Statement for the 2008 Annual Meeting of Shareholders, which sections are incorporated in this annual report on Form 10-K by reference.

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

Information for this item is set forth in the section entitled Security Ownership of Management and Certain Beneficial Owners in our Proxy Statement for the 2008 Annual Meeting of Shareholders, which section is incorporated in this annual report on Form 10-K by reference.

We know of no arrangement, or pledge, which may result in a change in control. Information describing any material changes to the procedures for recommending nominees to the Board is set forth in the section entitled Commonly Asked Questions in our Proxy Statement for the 2008 Annual Meeting of Shareholders, which section is incorporated in this annual report on Form 10-K by reference.

Information concerning securities authorized for issuance under our equity compensation plans is set forth in the section entitled Equity Compensation Plan Information in our Proxy Statement for the 2008 Annual Meeting of Shareholders, which section is incorporated in this annual report on Form 10-K by reference.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

Information for this item is set forth in the section entitled Independence of Board Members and Related Party Transactions in our Proxy Statement for the 2008 Annual Meeting of Shareholders, which section is incorporated in this annual report on Form 10-K by reference.

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

Information for this item is set forth in the table entitled Fees For Services in Proposal B Ratification of Deloitte & Touche LLP As Independent Registered Public Accounting Firm For Fiscal Year 2008 in our Proxy Statement for the 2008 Annual Meeting of Shareholders, which section is incorporated in this annual report on Form 10-K by reference.

PART IV

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

(a) 1. *Financial Statements*

The following consolidated financial statements for the year ended October 31, 2007, are included in Item 8 of this report as follows:

(a) 2. *Supplemental Consolidated Financial Statement Schedules*

None

Schedules and certain other information are omitted for the reason that they are not required or are not applicable, or the required information is shown in the consolidated financial statements or notes thereto.

(a) 3. *Exhibits*

Where an exhibit is filed by incorporation by reference to a previously filed registration statement or report, such registration statement or report is identified in parentheses. Upon written request of a shareholder, we will provide a copy of the exhibit at a nominal charge.

The exhibits numbered 10.1 through 10.25 are management contracts or compensatory plans or arrangements.

3.1 Articles of Incorporation of the Company as of March 3, 2006, filed in the Department of State of the State of North Carolina (Exhibit 4.1, Form S-8 Registration Statement No. 333-132738).

3.2

Copy of Certificate of Merger (New York) and Articles of Merger (North Carolina), each dated March 1, 1994, evidencing merger of Piedmont Natural Gas Company, Inc., with and into PNG Acquisition Company, with PNG Acquisition Company being renamed Piedmont Natural Gas Company, Inc. (Exhibits 3.2 and 3.1, Registration Statement on Form 8-B, dated March 2, 1994).

3.3 By-Laws of Piedmont Natural Gas Company, Inc., dated December 15, 2006.

4.1 Note Agreement, dated as of September 21, 1992, between Piedmont and Provident Life and Accident Insurance Company (Exhibit 4.30, Form 10-K for the fiscal year ended October 31, 1992).

4.2 Amendment to Note Agreement, dated as of September 16, 2005, by and between Piedmont and Provident Life and Accident Insurance Company.

4.3 Medium-Term Note, Series A, dated as of July 23, 1993 (Exhibit 4.7, Form 10-K for the fiscal year ended October 31, 1993).

4.4 Medium-Term Note, Series A, dated as of October 6, 1993 (Exhibit 4.8, Form 10-K for the fiscal year ended October 31, 1993).

4.5 First Supplemental Indenture, dated as of February 25, 1994, between PNG Acquisition Company, Piedmont Natural Gas Company, Inc., and Citibank, N.A., Trustee (Exhibit 4.2, Form S-3 Registration Statement No. 33-59369).

4.6 Medium-Term Note, Series A, dated as of September 19, 1994 (Exhibit 4.9, Form 10-K for the fiscal year ended October 31, 1994).

4.7 Form of Master Global Note (Exhibit 4.4, Form S-3 Registration Statement No. 33-59369).

4.8 Pricing Supplement of Medium-Term Notes, Series B, dated October 3, 1995 (Exhibit 4.10, Form 10-K for the fiscal year ended October 31, 1995).

4.9 Pricing Supplement of Medium-Term Notes, Series B, dated October 4, 1996 (Exhibit 4.11, Form 10-K for the fiscal year ended October 31, 1996).

4.10 Rights Agreement, dated as of February 27, 1998, between Piedmont and Wachovia Bank, N.A., as Rights Agent, including the Rights Certificate (Exhibit 10.1, Form 8-K dated February 27, 1998).

4.11 Agreement of Substitution and Amendment of Common Shares Rights Agreement, dated as of December 18, 2003, between Piedmont and American Stock Transfer and Trust Company, Inc. (Exhibit 4.10, Form S-3 Registration Statement No. 333-111806).

4.12 Form of Master Global Note, executed September 9, 1999 (Exhibit 4.4, Form S-3 Registration Statement No. 333-26161).

4.13 Pricing Supplement of Medium-Term Notes, Series C, dated September 15, 1999 (Rule 424(b)(3) Pricing Supplement to Form S-3 Registration Statement Nos. 33-59369 and 333-26161).

4.14 Pricing Supplement of Medium-Term Notes, Series C, dated September 15, 1999 (Rule 424(b)(3) Pricing Supplement to Form S-3 Registration Statement Nos. 33-59369 and 333-26161).

4.15 Pricing Supplement No. 3 of Medium-Term Notes, Series C, dated September 26, 2000 (Rule 424(b)(3) Pricing Supplement to Form S-3 Registration Statement No. 333-26161).

4.16 Form of Master Global Note, executed June 4, 2001 (Exhibit 4.4, Form S-3 Registration Statement No. 333-62222).

4.17 Pricing Supplement No. 1 of Medium-Term Notes, Series D, dated September 18, 2001 (Rule 424(b)(3) Pricing Supplement to Form S-3 Registration Statement No. 333-62222).

4.18 Second Supplemental Indenture, dated as of June 15, 2003, between Piedmont and Citibank, N.A., Trustee (Exhibit 4.3, Form S-3 Registration Statement No. 333-106268).

4.19 Form of 5% Medium-Term Note, Series E, dated as of December 19, 2003 (Exhibit 99.1, Form 8-K, dated December 23, 2003).

4.20 Form of 6% Medium-Term Note, Series E, dated as of December 19, 2003 (Exhibit 99.2, Form 8-K, dated December 23, 2003).

4.21 Third Supplemental Indenture, dated as of June 20, 2006, between Piedmont Natural Gas Company, Inc. and Citibank, N.A., as trustee (Exhibit 4.1, Form 8-K dated June 20, 2006).

4.22 Form of 6.25% Insured Quarterly Note Series 2006, Due 2036 (Exhibit 4.2 (as included in Exhibit 4.1), Form 8-K dated June 20, 2006).

4.23 Agreement of Resignation, Appointment and Acceptance dated as of March 29, 2007, by and among the registrant, Citibank, N.A., and The Bank of New York Trust Company, N.A. (Exhibit 4.1, Form 10-Q for quarter ended April 30, 2007).

Compensatory Contracts:

10.1 Form of Director Retirement Benefits Agreement with outside directors, dated September 1, 1999 (Exhibit 10.54, Form 10-K for the fiscal year ended October 31, 1999).

10.2 Resolution of Board of Directors, September 2, 2005, establishing compensation for non-management directors (Exhibit 10.1, Form 8-K dated September 9, 2005).

10.3

	Executive Long-Term Incentive Plan, dated February 27, 2004 (Exhibit 10.2, Form 10-Q for quarter ended April 30, 2004).
10.4	Establishment of Measures for Long-Term Incentive Plan 10 (filed in Form 8-K dated October 20, 2006, as Item 1.01).

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10.5	Form of Award Agreement under Executive Long-Term Incentive Plan (Exhibit 10.5, Form 10-K for the fiscal year ended October 31, 2006).
10.6	Employment Agreement with David J. Dzuricky, dated December 1, 1999 (Exhibit 10.37, Form 10-K for the fiscal year ended October 31, 1999).
10.7	Employment Agreement with Thomas E. Skains, dated December 1, 1999 (Exhibit 10.40, Form 10-K for the fiscal year ended October 31, 1999).
10.8	Employment Agreement with Franklin H. Yoho, dated March 18, 2002 (Exhibit 10.23, Form 10-K for the fiscal year ended October 31, 2002).
10.9	Employment Agreement with Michael H. Yount, dated May 1, 2006 (Exhibit 10.1, Form 10-Q for the quarter ended April 30, 2006).
10.10	Employment Agreement with Kevin M. O Hara, dated May 1, 2006 (Exhibit 10.2, Form 10-Q for the quarter ended April 30, 2006).
10.11	Form of Severance Agreement with Thomas E. Skains, dated September 4, 2007 (Substantially identical agreements have been entered into as of the same date with David J. Dzuricky, Franklin H. Yoho, Michael H. Yount, Kevin M. O Hara, June B. Moore and Jane R. Lewis-Raymond) (Exhibit 10.2, Form 10-Q for the quarter ended July 31, 2007).
10.12	Schedule of Severance Agreements with Executives (Exhibit 10.2a, Form 10-Q for the quarter ended July 31, 2007).
10.13	Piedmont Natural Gas Company, Inc. Supplemental Executive Benefit Plan (Amended and Restated as of November 1, 2004) (Exhibit 10.1, Form 8-K dated December 10, 2004).
10.14	Form of Participation Agreement under the Piedmont Natural Gas Company, Inc. Supplemental Executive Benefit Plan (Amended and Restated as of November 1, 2004) (with supplemental retirement benefit) (Exhibit 10.14, Form 10-K for the fiscal year ended October 31, 2004).
10.15	Form of Participation Agreement under the Piedmont Natural Gas Company, Inc. Supplemental Executive Benefit Plan (Amended and Restated as of November 1, 2004) (without supplemental retirement benefit) (Exhibit 10.15, Form 10-K for the fiscal year ended October 31, 2004).
10.16	Establishment of Measures for 2007 Short-Term Incentive Plan (Item 1.01, Form 8-K dated October 20, 2006).
10.17	Jerry W. Amos Engagement Letter dated January 3, 2005 (Exhibit 10.1, Form 8-K filed January 6, 2005) (Exhibit 10.18, Form 10-K for the fiscal year ended October 31, 2004).
10.18	Piedmont Natural Gas Company, Inc. Incentive Compensation Plan (Exhibit 10.1, Form 8-K dated March 3, 2006).
10.19	Restricted Stock Award Agreement between Piedmont Natural Gas Company, Inc. and Thomas E. Skains, dated September 1, 2006 (Exhibit 10.26, Form 10-K for the fiscal year ended October 31, 2006).
10.20	Form of Participation Agreement under the Piedmont Natural Gas Company, Inc. Short-Term Incentive Plan (STIP) (Exhibit 10.1, Form 10-Q for the quarter ended April 30, 2007).
10.21	Form of Performance Unit Award Agreement (Exhibit 10.1, Form 10-Q for the quarter ended July 31, 2007).
10.22	Amendment No. 1 to the Piedmont Natural Gas Company Executive Long-Term Incentive Plan, dated September 7, 2007.
10.23	Resolution of Board of Directors, September 7, 2007, establishing compensation for non-management directors.
10.24	Incentive Compensation Plan Interpretive Guidelines as of September 7, 2007.
10.25	Description of Measures for Piedmont Natural Gas Company, Inc. Long-Term Incentive Plan Awards No. 8, 9 and 11.
	Other Contracts:
10.26	Amended and Restated Limited Liability Company Agreement of SouthStar Energy Services LLC, effective January 1, 2004, between Piedmont Energy Company and Georgia Natural Gas Company

(Exhibit 10.1, Form 10-Q for the quarter ended April 30, 2004).

10.27	First Amendment to Amended and Restated Limited Liability Company Agreement of SouthStar Energy Services LLC, dated as of July 31, 2006, between Piedmont Energy Company and Georgia Natural Gas Company (Exhibit 10.28, Form 10-K for the fiscal year ended October 31, 2006).
10.28	Amendment by Written Consent to Amended and Restated Limited Liability Company Agreement of SouthStar Energy Services LLC, dated as of August 28, 2006, between Piedmont Energy Company and Georgia Natural Gas Company (Exhibit 10.29, Form 10-K for the fiscal year ended October 31, 2006).
10.29	Amendment by Written Consent to Amended and Restated Limited Liability Company Agreement of SouthStar Energy Services LLC, dated as of September 20, 2006, between Piedmont Energy Company and Georgia Natural Gas Company (Exhibit 10.30, Form 10-K for the fiscal year ended October 31, 2006).
10.30	Equity Contribution Agreement, dated as of November 12, 2004, between Columbia Gas Transmission Corporation and Piedmont Natural Gas Company (Exhibit 10.1, Form 8-K dated November 16, 2004).
10.31	Construction, Operation and Maintenance Agreement by and Between Columbia Gas Transmission Corporation and Hardy Storage Company, LLC, dated November 12, 2004 (Exhibit 10.2, Form 8-K dated November 16, 2004).
10.32	Operating Agreement of Hardy Storage Company, LLC, dated as of November 12, 2004 (Exhibit 10.3, Form 8-K dated November 16, 2004).
10.33	Guaranty of Principal dated as of June 29, 2006, by Piedmont Energy Partners, Inc. in favor of U.S. Bank National Association, as agent (Exhibit 10.1, Form 8-K dated July 5, 2006).
10.34	Residual Guaranty dated as of June 29, 2006, by Piedmont Energy Partners, Inc. in favor of U.S. Bank National Association, as agent (Exhibit 10.2, Form 8-K dated July 5, 2006).
12	Computation of Ratio of Earnings to Fixed Charges.
21	List of Subsidiaries.
23.1	Consent of Independent Registered Public Accounting Firm.
31.1	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of the Chief Executive Officer.
31.2	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of the Chief Financial Officer.
32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of the Chief Executive Officer.
32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of the Chief Financial Officer.

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.

Piedmont Natural Gas Company, Inc.
(Registrant)

By: /s/ Thomas E. Skains

Thomas E. Skains
Chairman of the Board, President
and Chief Executive Officer

Date: December 28, 2007

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 dates indicated.

Signature	Title
/s/ Thomas E. Skains Thomas E. Skains Date: December 28, 2007	Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)
/s/ David J. Dzuricky David J. Dzuricky Date: December 28, 2007	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Jose M. Simon Jose M. Simon Date: December 28, 2007	Vice President and Controller (Principal Accounting Officer)

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Signature	Title
/s/ Jerry W. Amos	Director
Jerry W. Amos	
/s/ E. James Burton	Director
E. James Burton	
/s/ D. Hayes Clement	Director
D. Hayes Clement	
/s/ Malcolm E. Everett III	Director
/s/ Malcolm E. Everett III	
/s/ John W. Harris	Director
John W. Harris	
/s/ Aubrey B. Harwell, Jr.	Director
Aubrey B. Harwell, Jr.	
/s/ Frank B. Holding, Jr.	Director
Frank B. Holding, Jr.	
/s/ Frankie T. Jones, Sr.	Director
Frankie T. Jones, Sr.	
/s/ Vicki McElreath	Director
Vicki McElreath	
/s/ Minor M. Shaw	Director
Minor M. Shaw	
/s/ Muriel W. Sheubrooks	Director
Muriel W. Sheubrooks	
/s/ David E. Shi	Director

David E. Shi

Piedmont Natural Gas Company, Inc.

Form 10-K

For the Fiscal Year Ended October 31, 2007

Exhibits

3.3	By-Laws of Piedmont Natural Gas Company, Inc., dated December 15, 2006
4.2	Amendment to Note Agreement, dated as of September 16, 2005, by and between Piedmont and Provident Life and Accident Insurance Company
10.22	Amendment No. 1 to the Piedmont Natural Gas Company Executive Long-Term Incentive Plan, dated September 7, 2007
10.23	Resolution of Board of Directors, September 7, 2007, establishing compensation for non-management directors
10.24	Incentive Compensation Plan Interpretive Guidelines as of September 7, 2007
10.25	Description of Measures for Piedmont Natural Gas Company, Inc. Long-Term Incentive Plan Awards No. 8, 9 and 11
12	Computation of Ratio of Earnings to Fixed Charges
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31.2	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of the Chief Financial Officer
32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of the Chief Executive Officer
32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of the Chief Financial Officer